Columbia Gas of Pennsylvania
A NiSource Company

Nicole Paloney
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Director
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March 1, 2024

VIA E-FILE

Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120-3265

Re: Columbia Gas of Pennsylvania, Inc. - Purchased Gas Cost Tariff Filing
Effective October 1, 2024

Dear Secretary Chiavetta:

On April 1, 2024, Columbia Gas of Pennsylvania, Inc. ("Columbia") will file a tariff supplement to become effective for service rendered on and after October 1, 2024. The tariff will be filed on that date, as required by Section 1307(f) of the Public Utility Code and the Commission's regulations, to provide for changes in rates resulting from changes in purchased gas costs.

Attached please find Columbia's "Information Submitted in Compliance with Act 74 of 1984 and Pursuant to Title 52, Pennsylvania Code, Sections 53.64 and 53.65 Supporting Recovery of Purchased Gas Costs." This filing contains certain "prefiling" data that is to be submitted, as required by Commission regulations.

Columbia's currently effective gas cost recovery rate applicable to all firm sales rate schedules is $0.41059/Therm. On the attached pre-filing data (Exhibit No. 1- A) Columbia projects that it will propose a increase in gas cost recovery rates of $0.01968/Therm to $0.43027/Therm effective for service rendered on and after October 1, 2024.

Please direct any inquiry about this filing to me at (724.416.6388) or to Columbia's outside counsel, Michael W. Hassell, Post & Schell P.C. at (717-612- 6029). Parties have been served with a copy of the instant filing in accordance with the certificate of service.

Sincerely,

Nicole Paloney

Nicole M. Paloney

cc: Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA E-MAIL

NazAarah Sabree
Small Business Advocate
Office of Small Business Advocate
555 Walnut Street
Forum Place, 1st Floor
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Bureau of Investigation & Enforcement
Commonwealth Keystone Building
400 North Street, 2nd Floor West
P.O. Box 3265
Harrisburg, PA 17105-3265
akaster@pa.gov

Date: March 1, 2024

Lindsay A. Berkstresser
/Lindsay A. Berkstresser

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Columbia Gas of Pennsylvania, Inc.
121 Champion Way
Suite 100
Canonsburg, Pennsylvania

SUPPLEMENT NO. ____
TO
TARIFF GAS - PA. P.U.C. NO. 9
1307(f) RATE PROCEEDING

ISSUED: April 1, 2024 **EFFECTIVE: October 1, 2024**

Information Submitted in Compliance with Act 74 of 1984 and
Pursuant to Title 52 Pennsylvania Code Sections 53.64 and 53.65
Supporting Recovery of Purchased Gas Costs

COLUMBIA GAS OF PENNSYLVANIA, INC.
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§53.64(e): For the purposes of § § 53.61—53.63, this section and § § 53.65—53.68, the filing of a tariff may refer either to the filing of a tariff supplement or the filing of an addendum to the utility's officially filed tariff. To prevent excessive paperwork, a tariff addendum shall be filed as provided in subsection (a), and a tariff supplement shall only be filed after Commission approval, when the utility files its compliance filing.

Response:

A tariff Addendum will be submitted April 1, 2024, the Company's scheduled filing date.

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPUTATION OF CHANGE IN RATE PURSUANT TO SECTION 1307(f)
APPLICATION PERIOD: OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Description		Amount	
			(1)	
1	Purchased Gas Commodity Cost		$	
2	Commodity Cost of Gas (Exhibit 1-B, Schedule 1)		93,936,776	
3	Projected tariff sales for the twelve billing periods of			
4	October, 2024 through September, 2025		396,376,468	Therms
5	PGCC (Line 2/Line 4)		0.23699	
6	Commodity (Over)/Under Collection			
7	Commodity E-Factor			
8	(Exhibit No. 1-E)		480,133	
9	Projected sales for the twelve billing periods of			
10	October, 2024 through September, 2025		396,376,468	Therms
11	Commodity E-Factor (Line 8/ Line 10)		0.00121	
12	Purchased Gas Demand Cost			
13	Demand cost of gas (Exhibit 1-B, Schedule 1)		90,415,169	
14	Less: Purchased Gas Demand recovered under Rate SS			
15	(Exhibit 1-A, Schedule 2, Sheet 2)		944,842	
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)		89,470,327	
19	Projected sales for the twelve billing periods of			
20	October, 2024 through September, 2025	1_/	469,941,653	Therms
21	PGDC Rate prior to Capacity Release Credit (Line 18 / Line 20)		0.19039	
22	Off System Sales and Capacity Release Credit		(0.00582)	
23	PGDC Rate		0.18457	
24	Demand (Over)/Under Collection			
25	Demand E- Factor			
26	(Exhibit No. 1-E)		3,526,312	
27	Projected sales for the twelve billing periods of			
28	October, 2024 through September, 2025	1_/	469,941,653	Therms
29	Demand E-Factor (Line 26 / Line 28)		0.00750	
30	Total Purchased Gas Cost			
31	PGCC Rate (Line 5)		0.23699	
32	PGDC Rate (Line 23)		0.18457	
33	PGC Rate		0.42156	
34	Currently effective PGC		0.40337	
35	Increase (Decrease) in PGC		0.01819	
36	Net (Over) Under Collection			
37	Commodity E-Factor (Line 11)		0.00121	
38	Demand E-Factor (Line 29)		0.00750	
39	E-Factor		0.00871	
40	Currently effective E-Factor		0.00722	
41	Increase (Decrease) in E-Factor		0.00149	
42	PGC Rate		0.42156	
43	E-Factor		0.00871	
44	Total Rate		0.43027	
45	Currently effective Rate		0.41059	
46	Increase (Decrease) in Rate		0.01968	

1_/ Includes 73,565,185 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, 2024 THROUGH SEPTEMBER, 2025

Line No.	Description	Detail (1)		Total (2)
1	Total estimated demand charges for the period			
2	October, 2024 through September, 2025	90,415,169		
3	Estimated Demand Quantity (Therms) 1_/	81,748,680		
4	Daily purchased gas demand rate (Line 2 / line 3)	$1.10601	per Therm	
5	Daily purchased gas demand (Therms)	854,280	Therms	
6	Daily purchased gas demand rate per Therm	$1.10601		
7	Total rate SS Daily Demand Cost to be			
8	Recovered (Line 5 x Line 6)			$944,842

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, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Sales Subject To PGCC (1) Therms	PGCC Rate 1_/ (2) $/Therm	PGCC Revenue (3=1x2) $	Sales Subject To PGDC (4) Therms	PGDC Rate 1_/ (5) $/Therm	PGDC Revenue (6=4x5) $	Purchased Gas Cost Revenue (7=3+6) $
1	October - 2024	9,459,646	0.23699	2,241,842	11,506,943	0.19039	2,190,807	4,432,649
2	November	25,388,003	0.23699	6,016,703	30,610,860	0.19039	5,828,002	11,844,705
3	December	55,676,190	0.23699	13,194,700	65,645,488	0.19039	12,498,244	25,692,944
4	January - 2025	75,752,468	0.23699	17,952,577	89,381,325	0.19039	17,017,310	34,969,887
5	February	76,948,963	0.23699	18,236,135	90,885,361	0.19039	17,303,664	35,539,799
6	March	63,699,539	0.23699	15,096,154	75,163,262	0.19039	14,310,333	29,406,487
7	April	42,335,811	0.23699	10,033,164	49,998,154	0.19039	9,519,149	19,552,313
8	May	19,504,058	0.23699	4,622,267	23,223,951	0.19039	4,421,608	9,043,875
9	June	9,697,441	0.23699	2,298,197	11,686,503	0.19039	2,224,993	4,523,190
10	July	6,166,610	0.23699	1,461,425	7,513,102	0.19039	1,430,419	2,891,844
11	August	5,731,398	0.23699	1,358,284	6,998,853	0.19039	1,332,512	2,690,796
12	September	6,016,341	0.23699	1,425,813	7,327,851	0.19039	1,395,150	2,820,963
13	Total	396,376,468		93,937,261	469,941,653		89,472,191	183,409,452

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, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Daily Purchased Gas Demand Quantity	Daily Gas Demand Rate	Daily Purchased Gas Demand Revenue
		(1)	(2)	(3=1x2)
		Therms	$/Therm	$
1	October - 2024	71,190	1.10601	78,737
2	November	71,190	1.10601	78,737
3	December	71,190	1.10601	78,737
4	January - 2025	71,190	1.10601	78,737
5	February	71,190	1.10601	78,737
6	March	71,190	1.10601	78,737
7	April	71,190	1.10601	78,737
8	May	71,190	1.10601	78,737
9	June	71,190	1.10601	78,737
10	July	71,190	1.10601	78,737
11	August	71,190	1.10601	78,737
12	September	71,190	1.10601	78,737
13	Total	854,280		944,842

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PROJECTED SALES QUANTITIES AND REVENUES FOR THE PERIOD
SALES AT BANKING AND BALANCING RATES
OCTOBER, 2024 THROUGH SEPTEMBER, 2025

Line No.	Month	Lg. Quantity GDS Deliveries	Rate	Revenue	Sm. Quantity GDS Deliveries	Rate	Revenue	Total Trans. Revenue
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)	(7=3+6)
		Therms	$/Therm	$	Therms	$/Therm	$	$
1	October - 2024	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 - 2025	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 2024 1307(f) PERIOD
OCTOBER, 2024 THROUGH SEPTEMBER, 2025

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 - 2024	2,241,842	2,883,148	(641,306)	2,269,544	8,491,934	(6,222,390)	(6,863,696)
2	November	6,016,703	8,149,508	(2,132,805)	5,906,739	8,662,861	(2,756,122)	(4,888,927)
3	December	13,194,700	16,829,389	(3,634,689)	12,576,981	8,699,471	3,877,510	242,821
4	January - 2025	17,952,577	21,618,764	(3,666,187)	17,096,047	8,699,471	8,396,576	4,730,389
5	February	18,236,135	18,980,099	(743,964)	17,382,401	8,699,471	8,682,930	7,938,966
6	March	15,096,154	11,431,877	3,664,277	14,389,070	8,699,471	5,689,599	9,353,876
7	April	10,033,164	7,221,496	2,811,668	9,597,886	6,490,415	3,107,471	5,919,139
8	May	4,622,267	2,889,425	1,732,842	4,500,345	6,394,415	(1,894,070)	(161,229)
9	June	2,298,197	1,009,693	1,288,504	2,303,730	6,394,415	(4,090,685)	(2,802,182)
10	July	1,461,425	923,511	537,914	1,509,156	6,394,415	(4,885,259)	(4,347,345)
11	August	1,358,284	856,463	501,821	1,411,249	6,394,415	(4,983,166)	(4,481,345)
12	September	1,425,813	1,143,402	282,411	1,473,887	6,394,415	(4,920,528)	(4,638,118)
13	Total	93,937,261	93,936,776	484	90,417,033	90,415,169	1,864	2,349

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, 2025

$90,415,169		1. Projected Demand Costs Oct. 2024 through Sept. 2025 (Exh. 1-B, Sch. 1)
(944,842)		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
3,526,312		1c. Experienced Demand Net Under/(Over) Collection (Exhibit No. 1-E)
$92,996,639		2. Total Adjusted Demand Costs per 1307(f) Filing (1) + (1a) + (1b) + (1c)
$120.15	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)
46,994	MMDth	4. Projected Sales & Choice Requirements for 12 billing periods of October, 2024 through September, 2025
47,516	MMDth	5. Projected Sales & Choice Requirements 12 months ended September 2025, including Unaccounted For @ 1.1%
21,755	MMDth	6. Annual Injections and Withdrawals, Normal Weather
1	Dth	7a. Quantity Delivered to the Customer
1.1%		7b. Unaccounted-for & Co. Use Factor from Volume Balancing System
1.0111	Dth	7c. Quantity Delivered to the City Gate. (7a)/(1-7b)
$1.9789	per Dth	8. Unit Demand Charge: (2) / (4)
($0.0582)	per Dth	9. OSS and Capacity Release Credit
0.0028	Dth	10. Average Daily FT Delivery: (7c) / 365 days
$0.3364	per Dth	11. Annual Demand Charge for the Assigned FT Capacity payable to the pipeline(s): (3) X (10)
$1.6425	per Dth	12. Annual Demand Charge for other capacity that CPA retains (8) - (11)
0.4629	Dth	13. Quantity Injected and Withdrawn to Deliver 1 Dth to the Customer: (6) / (4)
$0.0071		14a. Injection Charge @ $0.0153/Dth
$0.0050		14b. FSS Shrinkage @ 0.405% for gas at $2.6588/Dth
$0.0071		14c. Withdrawal Charge @ $0.0153/Dth
$0.0068		14d. SST Commodity Charge @ $0.0146/Dth
$0.0281		14e. SST retention @ 2.132% for gas at $2.6588/Dth
$0.0541	per Dth	14f. Total Annual Variable Storage Costs
		15. Credit to Purchased Gas Demand Charge for the CHOICE Customer:
$0.3364	per Dth	15a. For Demand Cost Paid to Pipelines: = (11)
($0.0541)	per Dth	15b. Less Storage Costs: = (14f)
$0.2823	per Dth	15c. Net Credit: (15a) + (15b)
$0.02823	per Therm	15d. Per Therm: (15c)/10 - Capacity Assignment Factor
$1.6384	per Dth	16. Purchased Gas Demand Charge Paid By the CHOICE Customer: (8)+(9) - (15c)
$0.16384	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	129,716		5,000	1/	
3. Projected Demand Costs					
4. Annual Demand Cost 2/	$15,828,984		$356,958		
4a. Monthly Billing Determinants	129,716		5,000		
4b. Annual Demand Charge (4/ 4a)	$122.03		$71.39		
4c. Monthly Demand Charge (4b / number of months)	$10.169		$5.949		
Allocation Capacity and Costs.					
5. Retained Volume:	1.0000		1.0000		
6. Number of Months	12		12		
7. Capacity Allocation	0.9629	3/	0.0371	4/	
8. Unit Annual Cost of City Gate Capacity: (4c) x (5) x (6) x (7) $/Dth	$117.50		$2.65		$120.15

Notes:

1/ Non-storage EGTS FT capacity
2/ Projected demand costs for the period 12 months ended September, 2025.
3/ 129,716/(129,716+5,000) = 0.9629
4/ 5,000/(129,716+5,000) = 0.0371

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
For the Period October 2024 Through September 2025

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
1	Total Quantity													
2	DTH	1,760,000	4,511,000	7,078,000	8,566,000	7,795,000	5,825,000	2,769,000	1,093,000	362,000	333,000	309,000	419,000	40,820,000
3	Total Demand Costs	8,491,934	8,662,861	8,699,471	8,699,471	8,699,471	8,699,471	6,490,415	6,394,415	6,394,415	6,394,415	6,394,415	6,394,415	90,415,169
4	Total Commodity Costs	2,883,148	8,149,508	16,829,389	21,618,764	18,980,099	11,431,877	7,221,496	2,889,425	1,009,693	923,511	856,463	1,143,402	93,936,776
5	Total Estimated Gas Costs (Line 5 = Line 3 + Line 4)	11,375,082	16,812,369	25,528,860	30,318,235	27,679,570	20,131,348	13,711,911	9,283,840	7,404,108	7,317,926	7,250,878	7,537,817	184,351,945

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Demand Costs

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Columbia Gas Transmission	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	78,538,134
2	Texas Eastern Transmission	297,325	297,325	333,935	333,935	333,935	333,935	284,405	284,405	284,405	284,405	284,405	284,405	3,636,820
3	Eastern Gas Transmission and Storage	254,680	296,325	296,325	296,325	296,325	296,325	254,680	254,680	254,680	254,680	254,680	254,680	3,264,385
4	Tennessee Gas	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	1,338,564
5	National Fuel Gas	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	1,170,840
6	Equitrans	216,736	346,018	346,018	346,018	346,018	346,018	216,600	120,600	120,600	120,600	120,600	120,600	2,766,426
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	8,491,934	8,662,861	8,699,471	8,699,471	8,699,471	8,699,471	6,490,415	6,394,415	6,394,415	6,394,415	6,394,415	6,394,415	90,415,169

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Costs

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
1	Term	119,931	1,275,638	4,154,838	4,897,325	4,338,412	1,927,653	67,384	70,682	69,569	74,231	75,066	64,107	17,134,836
2	Spot	4,613,737	71,694	8,105,978	9,323,888	7,368,198	1,011,538	15,244,612	10,889,435	9,151,748	9,204,592	8,617,510	7,062,832	90,665,762
3	Local	30,129	40,194	58,289	70,752	61,490	61,952	53,403	55,385	53,960	56,903	56,529	49,350	648,336
4	Storage	(1,880,649)	6,761,982	4,510,284	7,326,799	7,211,999	8,430,734	(8,143,903)	(8,126,077)	(8,265,584)	(8,412,215)	(7,892,642)	(6,032,887)	(14,512,158)
5	Total Commodity Cost	2,883,148	8,149,508	16,829,389	21,618,764	18,980,099	11,431,877	7,221,496	2,889,425	1,009,693	923,511	856,463	1,143,402	93,936,776

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Quantities

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
	Term													
1	Total-DTH	92,000	667,000	1,465,000	1,464,000	1,323,000	687,000	27,000	29,000	28,000	29,000	30,000	29,000	5,870,000
	Spot													
2	Total-DTH	3,197,000	39,000	2,918,000	2,796,000	2,251,000	356,000	5,915,000	4,253,000	3,450,000	3,401,000	3,210,000	2,875,000	34,661,000
	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	(1,551,000)	3,784,000	2,673,000	4,284,000	4,201,000	4,760,000	(3,194,000)	(3,211,000)	(3,137,000)	(3,119,000)	(2,953,000)	(2,506,000)	31,000
	Total - All Sources													
5	Total-DTH	1,760,000	4,511,000	7,078,000	8,566,000	7,795,000	5,825,000	2,769,000	1,093,000	362,000	333,000	309,000	419,000	40,820,000

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line		2024			2025									
No.	Description	October	November	December	January	February	March	April	May	June	July	August	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)	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	
3	Net Billing Determinant - Dth	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	
4	Demand Rate	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	
5	Demand Cost	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	15,828,984
	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	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	
8	Demand Cost	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	13,405,212
	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	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	
11	Demand Cost	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	13,511,604
	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	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	
14	Demand Cost	3,976,926	3,976,926	3,976,926	3,976,926	3,976,926	3,976,926	1,988,463	1,988,463	1,988,463	1,988,463	1,988,463	1,988,463	35,792,334
15	Total TCO Demand Cost	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	7,539,076	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	78,538,134

(1) Columbia has included in the application period a projection for the release of 5,215 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.

Exhibit 1-B
Schedule 3
Sheet 1 of 1

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line		2024			2025									
No.	Description	October	November	December	January	February	March	April	May	June	July	August	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	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	
3	Demand Cost	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	293,472
	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	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	
6	Demand Cost	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	1,119,120
	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	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	
9	Demand Cost	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	660,672
	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	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	
12	Demand Cost	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	1,200,048
	CDS - Chambersburg													
13	Billing Determinant-Dth	158	158	158	158	158	158	158	158	158	158	158	158	
14	Demand Rate	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	
15	Demand Cost	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	44,592
	FT1-TCO @ Eagle Zone 3 Zone 3													
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	4.9530	4.9530	4.9530	4.9530	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
18	Demand Cost	0	0	49,530	49,530	49,530	49,530	0	0	0	0	0	0	198,120
	FT1-MX													
19	Billing Determinant-Dth	100	100	100	100	100	100	100	100	100	100	100	100	
20	Demand Rate	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	
21	Demand Cost	161	161	161	161	161	161	161	161	161	161	161	161	1,932
	FT1-M2													
22	Billing Determinant-Dth	3,200	3,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	
23	Demand Rate	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	
24	Demand Cost	20,672	20,672	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	7,752	118,864
25	Total TETCO Demand Cost	297,325	297,325	333,935	333,935	333,935	333,935	284,405	284,405	284,405	284,405	284,405	284,405	3,636,820

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 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	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	
3	Demand Cost	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	770,376
	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	5.9493	5.9493	5.9493	5.9493	5.9493	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Demand Cost	0	35,696	35,696	35,696	35,696	35,696	0	0	0	0	0	0	178,480
	FT													
10	Billing Determinant-Dth	23,903	24,903	24,903	24,903	24,903	24,903	23,903	23,903	23,903	23,903	23,903	23,903	
11	Total-DTH	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	
12	Demand Cost	142,206	148,155	148,155	148,155	148,155	148,155	142,206	142,206	142,206	142,206	142,206	142,206	1,736,217
13	Total DTI Demand Cost	254,680	296,325	296,325	296,325	296,325	296,325	254,680	254,680	254,680	254,680	254,680	254,680	3,264,385

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 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	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	
3	Demand Cost	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	923,748
	Tennessee Gas FT-A (Direct) Pitt Teminal - 219 Line													
4	Billing Determinant-Dth	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	
5	Demand Rate	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	
6	Demand Cost	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	34,568	414,816
7	Total Tennessee Gas Demand Cost	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	111,547	1,338,564

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 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	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	
3	Demand Cost	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	423,960
	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	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	
6	Demand Cost	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	405,504
	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	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	
9	Demand Cost	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	113,772
	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	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	
12	Demand Cost	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	227,604
13	Total National Fuel Demand Cost	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	1,170,840

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Equitrans

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
		$	$	$	$	$	$	$	$	$	$	$	$	$
	Equitrans													
	FTS													
1	Billing Determinant-Dth	27,092	26,741	26,741	26,741	26,741	26,741	27,075	15,075	15,075	15,075	15,075	15,075	
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	216,736	213,928	213,928	213,928	213,928	213,928	216,600	120,600	120,600	120,600	120,600	120,600	2,105,976
	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	216,736	346,018	346,018	346,018	346,018	346,018	216,600	120,600	120,600	120,600	120,600	120,600	2,766,426

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Term Contracts

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
	TERM													
	COLUMBIA TRANSMISSION													
1	Quantity - DTH	0	0	547,000	547,000	494,000	0	0	0	0	0	0	0	1,588,000
2	Rate-$/DTH	0.0000	0.0000	2.7218	3.3007	3.1561	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
3	Cost-$	0	0	1,488,825	1,805,483	1,559,113	0	0	0	0	0	0	0	4,853,421
	TEXAS EASTERN													
4	Quantity - DTH	92,000	667,000	687,000	686,000	620,000	687,000	27,000	29,000	28,000	29,000	30,000	29,000	3,611,000
5	Rate-$/DTH	1.3036	1.9125	2.7766	3.2604	3.1654	2.8059	2.4957	2.4373	2.4846	2.5597	2.5022	2.2106	
6	Cost-$	119,931	1,275,638	1,907,524	2,236,634	1,962,548	1,927,653	67,384	70,682	69,569	74,231	75,066	64,107	9,850,967
	TENNESSEE GAS PIPELINE													
7	Quantity - DTH	0	0	231,000	231,000	209,000	0	0	0	0	0	0	0	671,000
8	Rate-$/DTH	0.0000	0.0000	3.2835	3.7022	3.9079	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Cost-$	0	0	758,489	855,208	816,751	0	0	0	0	0	0	0	2,430,448
	CAP													
10	Quantity - DTH	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Rate-$/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
12	Cost-$	0	0	0	0	0	0	0	0	0	0	0	0	0
	LESS CAP BILLING													
13	Quantity - DTH	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Rate-$/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15	Cost-$	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total - DTH	92,000	667,000	1,465,000	1,464,000	1,323,000	687,000	27,000	29,000	28,000	29,000	30,000	29,000	5,870,000
17	Total Term Commodity													
18	Cost-$	119,931	1,275,638	4,154,838	4,897,325	4,338,412	1,927,653	67,384	70,682	69,569	74,231	75,066	64,107	17,134,836

*Beginning October 1, 2021, CAP customers will be served by Columbia sales service until a new supplier submits a successful bid to provide CAP gas supply.

Exhibit 1-B
Schedule 9
Sheet 1 of 1

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line		2024			2025									
No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
	SPOT													
	Base													
1	Quantity - DTH	1,379,000	37,000	2,445,000	2,718,000	2,251,000	356,000	3,440,000	3,105,000	2,893,000	2,864,000	993,000	960,000	23,441,000
2	Rate-$/DTH	1.5728	1.8375	2.8071	3.3357	3.2733	2.8414	2.6018	2.5809	2.6887	2.7434	2.8732	2.6909	
3	Cost-$	2,168,891	67,988	6,863,360	9,066,433	7,368,198	1,011,538	8,950,192	8,013,695	7,778,409	7,857,098	2,853,088	2,583,264	64,582,154
	Swing													
4	Quantity - DTH	1,818,000	2,000	473,000	78,000	0	0	2,475,000	1,148,000	557,000	537,000	2,217,000	1,915,000	11,220,000
5	Rate-$/DTH	1.3448	1.8528	2.6271	3.3007	0.0000	0.0000	2.5432	2.5050	2.4656	2.5093	2.6001	2.3392	
6	Cost-$	2,444,846	3,706	1,242,618	257,455	0	0	6,294,420	2,875,740	1,373,339	1,347,494	5,764,422	4,479,568	26,083,608
7	Total - DTH	3,197,000	39,000	2,918,000	2,796,000	2,251,000	356,000	5,915,000	4,253,000	3,450,000	3,401,000	3,210,000	2,875,000	34,661,000
8	Total Spot													
9	Commodity Cost - $	4,613,737	71,694	8,105,978	9,323,888	7,368,198	1,011,538	15,244,612	10,889,435	9,151,748	9,204,592	8,617,510	7,062,832	90,665,762
	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-$/DTH	1.3695	1.9140	2.6495	3.2160	3.0745	2.8160	2.5430	2.5175	2.5695	2.5865	2.5695	2.3500	
12	Cost-$	30,129	40,194	58,289	70,752	61,490	61,952	53,403	55,385	53,960	56,903	56,529	49,350	648,336
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 - $	30,129	40,194	58,289	70,752	61,490	61,952	53,403	55,385	53,960	56,903	56,529	49,350	648,336

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs

Storage

Line No.	Description	October	November	December	January	February	March	April	May	June	July	August	September	Total
		2024			2025									
	EASTERN - GSS													
1	Injections - DTH	(204,000)	0	0	0	0	0	(179,000)	(252,000)	(253,000)	(254,000)	(253,000)	(252,000)	(1,647,000)
2	Injection Rate - $/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
3	Withdrawals - DTH	0	294,000	0	552,000	493,000	337,000	0	0	0	0	0	0	1,676,000
4	Withdrawl Rate - $/Dth	1.8143	1.8143	1.8142	1.8143	1.8143	1.8142	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
5	Cost-$	(293,515)	533,404	0	1,001,494	894,450	611,385	(461,247)	(644,969)	(670,652)	(686,918)	(678,571)	(618,257)	(1,013,396)
6	Injection Rate $/Dth	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	
7	Withdrawl Rate $/Dth	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	
8	Cost - $	8,017	7,526	0	14,131	12,621	8,627	7,035	9,904	9,943	9,982	9,943	9,904	107,633
	EQUITRANS - SS													
9	Injections - DTH	(194,000)	0	0	0	0	0	(294,000)	(214,000)	(214,000)	(216,000)	(214,000)	(214,000)	(1,560,000)
10	Injection Rate - $/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
11	Withdrawals - DTH	0	355,000	210,000	230,000	249,000	517,000	0	0	0	0	0	0	1,561,000
12	Withdrawl Rate - $/Dth	1.8143	1.8143	1.8142	1.8143	1.8143	1.8142	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
13	Cost-$	(279,127)	644,077	380,982	417,289	451,761	937,941	(757,579)	(547,712)	(567,271)	(584,150)	(573,969)	(525,028)	(1,002,786)
14	Inject/With. Rate $/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15	Cost - $	0	0	0	0	0	0	0	0	0	0	0	0	0
	TCO - FSS													
16	Injections - DTH	(1,317,000)	0	0	0	0	0	(2,803,000)	(3,057,000)	(3,055,000)	(3,055,000)	(2,895,000)	(2,414,000)	(18,596,000)
17	Injection Rate - $/Dth	1.4388	1.9086	2.7966	3.3377	3.2744	2.8180	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
18	Withdrawals - DTH	0	3,247,000	2,916,000	4,179,000	4,074,000	4,180,000	0	0	0	0	0	0	18,596,000
19	Withdrawl Rate - $/Dth	1.8143	1.8143	1.8142	1.8143	1.8143	1.8142	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
20	Cost-$	(1,894,900)	5,891,032	5,290,207	7,581,960	7,391,458	7,583,356	(7,222,770)	(7,824,086)	(8,098,194)	(8,261,942)	(7,764,680)	(5,922,508)	(13,251,067)
21	Inject/With. Rate $/DTH	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	
22	Cost - $	20,150	49,679	44,615	63,939	62,332	63,954	42,886	46,772	46,742	46,742	44,294	36,934	569,039
	NATIONAL FUEL - ESS													
23	Injections - DTH	(48,000)	0	0	0	0	0	0	(25,000)	(47,000)	(48,000)	(48,000)	(47,000)	(263,000)
24	Injection Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.5768	2.5594	2.6508	2.7044	2.6821	2.4534	
25	Withdrawals - DTH	0	54,000	44,000	47,000	48,000	61,000	9,000	0	0	0	0	0	263,000
26	Withdrawl Rate - $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.2173	2.3421	2.4250	2.4841	2.5174	2.5094	
27	Cost-$	0	0	0	0	0	0	19,956	(63,985)	(124,588)	(129,811)	(128,741)	(115,310)	(542,479)
28	Inject/With. Rate $/DTH	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	
29	Cost - $	1,834	2,063	1,681	1,795	1,834	2,330	344	955	1,795	1,834	1,834	1,795	20,094
30	Quantity - DTH	(1,763,000)	3,950,000	3,170,000	5,008,000	4,864,000	5,095,000	(3,267,000)	(3,548,000)	(3,569,000)	(3,573,000)	(3,410,000)	(2,927,000)	30,000
31	Total Purchase Cost	(2,467,542)	7,068,513	5,671,189	9,000,743	8,737,669	9,132,682	(8,421,640)	(9,080,752)	(9,460,705)	(9,662,821)	(9,145,961)	(7,181,103)	(15,267,249)
32	Total Inject/With. Cost	30,001	59,268	46,296	79,865	76,787	74,911	50,265	57,631	58,480	58,558	56,071	48,633	676,672

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Storage Transportation Charges

Line No.	Description	2024 October	2024 November	2024 December	2025 January	2025 February	2025 March	2025 April	2025 May	2025 June	2025 July	2025 August	2025 September	Total
	TCO - SST													
1	Injections - DTH	(1,317,000)	0	0	0	0	0	(2,803,000)	(3,057,000)	(3,055,000)	(3,055,000)	(2,895,000)	(2,414,000)	(18,596,000)
2	Withdrawals - DTH	0	3,247,000	2,916,000	4,179,000	4,074,000	4,180,000	0	0	0	0	0	0	18,596,000
3	Trans. Chrg. $/Dth	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	
4	Cost-$	19,228	47,406	42,574	61,013	59,480	61,028	40,924	44,632	44,603	44,603	42,267	35,244	543,002
	EASTERN - GSS													
5	Injections - DTH	(204,000)	0	0	0	0	0	(179,000)	(252,000)	(253,000)	(254,000)	(253,000)	(252,000)	(1,647,000)
6	Withdrawals - DTH	0	294,000	0	552,000	493,000	337,000	0	0	0	0	0	0	1,676,000
7	Trans. Chrg. $/Dth	0.0146	0.0112	0.0112	0.0112	0.0112	0.0112	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	
8	Cost-$	2,978	3,293	0	6,182	5,522	3,774	2,613	3,679	3,694	3,708	3,694	3,679	42,816
	EQUITRANS - SS													
9	Injections - DTH	(194,000)	0	0	0	0	0	(294,000)	(214,000)	(214,000)	(216,000)	(214,000)	(214,000)	(1,560,000)
10	Withdrawals - DTH	0	355,000	210,000	230,000	249,000	517,000	0	0	0	0	0	0	1,561,000
11	Trans. Chrg. $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
12	Cost-$	0	0	0	0	0	0	0	0	0	0	0	0	0
	NATIONAL FUEL													
13	Injections - DTH	(48,000)	0	0	0	0	0	0	(25,000)	(47,000)	(48,000)	(48,000)	(47,000)	(263,000)
14	Withdrawals - DTH	0	54,000	44,000	47,000	48,000	61,000	9,000	0	0	0	0	0	263,000
15	Trans. Chrg. $/Dth	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	
16	Cost-$	1,138	1,280	1,043	1,114	1,138	1,446	213	593	1,114	1,138	1,138	1,114	12,469
17	Total Storage - DTH	(1,763,000)	3,950,000	3,170,000	5,008,000	4,864,000	5,095,000	(3,267,000)	(3,548,000)	(3,569,000)	(3,573,000)	(3,410,000)	(2,927,000)	30,000
18	Total EUB - DTH	212,000	(166,000)	(497,000)	(724,000)	(663,000)	(335,000)	73,000	337,000	432,000	454,000	457,000	421,000	1,000
19	Total DTH	(1,551,000)	3,784,000	2,673,000	4,284,000	4,201,000	4,760,000	(3,194,000)	(3,211,000)	(3,137,000)	(3,119,000)	(2,953,000)	(2,506,000)	31,000
20	Total Purchase Cost	(2,467,542)	7,068,513	5,671,189	9,000,743	8,737,669	9,132,682	(8,421,640)	(9,080,752)	(9,460,705)	(9,662,821)	(9,145,961)	(7,181,103)	(15,809,728)
21	Total Choice Bank Cost	533,548	(417,778)	(1,250,818)	(1,822,118)	(1,668,597)	(843,107)	183,722	848,140	1,087,230	1,142,599	1,150,149	1,059,546	2,517
22	Total Inject/With. Cost	30,001	59,268	46,296	79,865	76,787	74,911	50,265	57,631	58,480	58,558	56,071	48,633	696,766
23	Total Transp. Charge	23,344	51,979	43,617	68,309	66,140	66,248	43,750	48,904	49,411	49,449	47,099	40,037	598,287
24	Total Storage Cost	(1,880,649)	6,761,982	4,510,284	7,326,799	7,211,999	8,430,734	(8,143,903)	(8,126,077)	(8,265,584)	(8,412,215)	(7,892,642)	(6,032,887)	(14,512,158)

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
For the Period February 2024 Through September 2024

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
1	Total Quantity									
2	DTH	7,755,000	5,787,000	2,742,000	1,082,000	358,000	330,000	305,000	414,000	18,773,000
3	Total Demand Costs	8,744,230	8,712,391	6,503,335	6,407,335	6,407,335	6,407,335	6,407,335	6,407,335	55,996,631
4	Total Commodity Costs	17,873,841	14,081,919	4,419,699	1,905,441	746,061	690,858	981,438	1,141,696	41,840,952
5	Total Estimated Gas Costs									
6	(Line 6 = Line 3 + Line 4)	26,618,071	22,794,310	10,923,034	8,312,776	7,153,396	7,098,193	7,388,773	7,549,031	97,837,583

Exhibit 1-C
Schedule 1
Sheet 2 of 4

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Demand Costs

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$
1	Columbia Gas Transmission	7,539,076	7,539,076	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	48,381,830
2	Texas Eastern Transmission	346,855	346,855	297,325	297,325	297,325	297,325	297,325	297,325	2,477,660
3	Eastern Gas Transmission and Storage	296,325	296,325	254,680	254,680	254,680	254,680	254,680	254,680	2,120,730
4	Tennessee Gas	143,386	111,547	111,547	111,547	111,547	111,547	111,547	111,547	924,215
5	National Fuel Gas	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	780,560
6	Equitrans	346,018	346,018	216,600	120,600	120,600	120,600	120,600	120,600	1,511,636
7	Less Elective Balancing Service Credit	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	200,000
8	Total Demand Cost	8,744,230	8,712,391	6,503,335	6,407,335	6,407,335	6,407,335	6,407,335	6,407,335	55,996,631

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Costs

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$
1	Term	2,666,155	1,078,247	42,437	43,778	45,121	49,320	47,991	38,518	4,011,567
2	Spot	5,320,856	535,122	8,487,861	6,411,668	5,450,496	5,582,740	5,247,280	4,439,639	41,475,662
3	Local	37,800	35,024	32,970	35,123	34,598	36,905	36,817	30,954	280,191
4	Storage	9,849,030	12,433,526	(4,143,569)	(4,585,128)	(4,784,154)	(4,978,107)	(4,350,650)	(3,367,415)	(3,926,468)
5	Total Commodity Cost	17,873,841	14,081,919	4,419,699	1,905,441	746,061	690,858	981,438	1,141,696	41,840,952

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Costs
Commodity Quantities

Line No.	Description	February 2024	March 2024	April 2024	May 2024	June 2024	July 2024	August 2024	September 2024	Total
	Term									
1	Total-DTH	1,371,000	687,000	28,000	29,000	29,000	30,000	30,000	29,000	2,233,000
	Spot									
2	Total-DTH	2,731,000	337,000	5,379,000	3,961,000	3,181,000	3,131,000	2,952,000	2,838,000	24,510,000
	Local & Appalachian									
3	Total-DTH	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	171,000
	Storage									
4	Total-DTH	3,633,000	4,741,000	(2,686,000)	(2,930,000)	(2,873,000)	(2,853,000)	(2,699,000)	(2,474,000)	(8,141,000)
	Total - All Sources									
5	Total-DTH	7,755,000	5,787,000	2,742,000	1,082,000	358,000	330,000	305,000	414,000	18,773,000

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 February	March	April	May	June	July	August	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	
2	Less Capacity Release (1)	5,215	5,215	5,215	5,215	5,215	5,215	5,215	5,215	
3	Net Billing Determinant - Dth	129,716	129,716	129,716	129,716	129,716	129,716	129,716	129,716	
4	Demand Rate	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	10.1690	
5	Demand Cost	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	1,319,082	10,552,656
	FSS-Reservation									
6	Billing Determinant-Dth	395,714	395,714	395,714	395,714	395,714	395,714	395,714	395,714	
7	Demand Rate	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	2.8230	
8	Demand Cost	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	1,117,101	8,936,808
	FSS-Capacity									
9	Billing Determinant-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	
10	Demand Rate	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	0.0513	
11	Demand Cost	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	1,125,967	9,007,736
	SST									
12	Billing Determinant-Dth	395,714	395,714	197,857	197,857	197,857	197,857	197,857	197,857	
13	Demand Rate	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	10.0500	
14	Demand Cost	3,976,926	3,976,926	1,988,463	1,988,463	1,988,463	1,988,463	1,988,463	1,988,463	19,884,630
15	Total TCO Demand Cost	7,539,076	7,539,076	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	5,550,613	48,381,830

(1) Columbia has included in the application period a projection of capacity release for the release of 5,215 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	2024 February	March	April	May	June	July	August	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	
2	Demand Rate	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	
3	Demand Cost	24,456	24,456	24,456	24,456	24,456	24,456	24,456	24,456	195,648
	FT1-Uniontown									
4	Billing Determinant-Dth	11,753	11,753	11,753	11,753	11,753	11,753	11,753	11,753	
5	Demand Rate	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	7.9350	
6	Demand Cost	93,260	93,260	93,260	93,260	93,260	93,260	93,260	93,260	746,080
	CDS - Eagle/Rockwood									
7	Billing Determinant-Dth	2,342	2,342	2,342	2,342	2,342	2,342	2,342	2,342	
8	Demand Rate	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	23.5080	
9	Demand Cost	55,056	55,056	55,056	55,056	55,056	55,056	55,056	55,056	440,448
	CDS - Rockwood									
10	Billing Determinant-Dth	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	
11	Demand Rate	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	20.0009	
12	Demand Cost	100,004	100,004	100,004	100,004	100,004	100,004	100,004	100,004	800,032
	CDS - Chambersburg									
13	Billing Determinant-Dth	158	158	158	158	158	158	158	158	
14	Demand Rate	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	23.5194	
15	Demand Cost	3,716	3,716	3,716	3,716	3,716	3,716	3,716	3,716	29,728
	FT1-TCO @Eagle Zone 3 to Zone 3									
16	Billing Determinant-Dth	10,000	10,000	0	0	0	0	0	0	
17	Demand Rate	4.9530	4.9530	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
18	Demand Cost	49,530	49,530	0	0	0	0	0	0	99,060
	FT1-MX									
19	Billing Determinant-Dth	100	100	100	100	100	100	100	100	
20	Demand Rate	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	1.6120	
21	Demand Cost	161	161	161	161	161	161	161	161	1,288
	FT1-M2									
22	Billing Determinant-Dth	3,200	3,200	3,200	3,200	3,200	3,200	3,200	3,200	
23	Demand Rate	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	6.4600	
24	Demand Cost	20,672	20,672	20,672	20,672	20,672	20,672	20,672	20,672	165,376
25	Total TETCO Demand Cost	346,855	346,855	297,325	297,325	297,325	297,325	297,325	297,325	2,477,660

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 February	March	April	May	June	July	August	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	
2	Demand Rate	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	2.6749	
3	Demand Cost	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	513,584
	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	
5	Demand Rate	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	386,208
	FTNN									
7	Billing Determinant-Dth	6,000	6,000	0	0	0	0	0	0	
8	Demand Rate	5.9493	5.9493	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Demand Cost	35,696	35,696	0	0	0	0	0	0	71,392
	FT									
10	Billing Determinant-Dth	24,903	24,903	23,903	23,903	23,903	23,903	23,903	23,903	
11	Demand Rate	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	5.9493	
12	Demand Cost	148,155	148,155	142,206	142,206	142,206	142,206	142,206	142,206	1,149,546
13	Total DTI Demand Cost	296,325	296,325	254,680	254,680	254,680	254,680	254,680	254,680	2,120,730

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 February	March	April	May	June	July	August	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	
2	Demand Rate	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	4.8112	
3	Demand Cost	76,979	76,979	76,979	76,979	76,979	76,979	76,979	76,979	615,832
	Tennessee Gas FT-A (Direct) Pitt Teminal - 219 Line									
4	Billing Determinant-Dth	14,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600	
5	Demand Rate	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	4.5484	
6	Demand Cost	66,407	34,568	34,568	34,568	34,568	34,568	34,568	34,568	308,383
7	Total Tennessee Gas Demand Cost	143,386	111,547	111,547	111,547	111,547	111,547	111,547	111,547	924,215

COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$
	National - FT									
1	Billing Determinant-Dth	4,304	4,304	4,304	4,304	4,304	4,304	4,304	4,304	
2	Demand Rate	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	8.2087	
3	Demand Cost	35,330	35,330	35,330	35,330	35,330	35,330	35,330	35,330	282,640
	National - EFT									
4	Billing Determinant-Dth	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	
5	Demand Rate	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	8.4480	
6	Demand Cost	33,792	33,792	33,792	33,792	33,792	33,792	33,792	33,792	270,336
	National - ESS Reservation									
7	Billing Determinant-Dth	2,429	2,429	2,429	2,429	2,429	2,429	2,429	2,429	
8	Demand Rate	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	3.9032	
9	Demand Cost	9,481	9,481	9,481	9,481	9,481	9,481	9,481	9,481	75,848
	National - ESS Capacity									
10	Billing Determinant-Dth	267,143	267,143	267,143	267,143	267,143	267,143	267,143	267,143	
11	Demand Rate	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	0.0710	
12	Demand Cost	18,967	18,967	18,967	18,967	18,967	18,967	18,967	18,967	151,736
13	Total National Gas Demand Cost	97,570	97,570	97,570	97,570	97,570	97,570	97,570	97,570	780,560

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Demand Costs
Equitrans

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
		$	$	$	$	$	$	$	$	$
	Equitrans FTS									
1	Billing Determinant-Dth	26,741	26,741	27,075	15,075	15,075	15,075	15,075	15,075	
2	Demand Rate	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	
3	Demand Cost	213,928	213,928	216,600	120,600	120,600	120,600	120,600	120,600	1,247,456
	FTS									
4	Billing Determinant-Dth	18,870	18,870	0	0	0	0	0	0	
5	Demand Rate	7.0000	7.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
6	Demand Cost	132,090	132,090	0	0	0	0	0	0	264,180
7	Total Equitrans FTS Demand Cost	346,018	346,018	216,600	120,600	120,600	120,600	120,600	120,600	1,511,636

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Term Contracts

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
	TERM									
	COLUMBIA TRANSMISSION									
1	Quantity - DTH	512,000	0	0	0	0	0	0	0	512,000
2	Rate-$/DTH	1.9458	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
3	Cost-$	996,250	0	0	0	0	0	0	0	996,250
	TEXAS EASTERN									
4	Quantity - DTH	643,000	687,000	28,000	29,000	29,000	30,000	30,000	29,000	1,505,000
5	Rate-$/DTH	1.9033	1.5695	1.5156	1.5096	1.5559	1.6440	1.5997	1.3282	
6	Cost-$	1,223,822	1,078,247	42,437	43,778	45,121	49,320	47,991	38,518	2,569,234
	TENNESSEE GAS PIPELINE									
7	Quantity - DTH	216,000	0	0	0	0	0	0	0	216,000
8	Rate-$/DTH	2.0652	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
9	Cost-$	446,083	0	0	0	0	0	0	0	446,083
	CAP									
10	Quantity - DTH	0	0	0	0	0	0	0	0	0
11	Rate-$/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
12	Cost-$	0	0	0	0	0	0	0	0	0
	LESS CAP BILLING									
13	Quantity - DTH	0	0	0	0	0	0	0	0	0
14	Rate-$/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15	Cost-$	0	0	0	0	0	0	0	0	0
16	Total - DTH	1,371,000	687,000	28,000	29,000	29,000	30,000	30,000	29,000	2,233,000
17	Total Term Commodity									
18	Cost-$	2,666,155	1,078,247	42,437	43,778	45,121	49,320	47,991	38,518	4,011,567

*Beginning October 1, 2021, CAP customers will be served by Columbia sales service until a new supplier submits a successful bid to provide CAP gas supply.

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COLUMBIA GAS OF PENNSYLVANIA, INC.

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

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
	SPOT									
	Base									
1	Quantity - DTH	2,724,000	337,000	3,285,000	2,701,000	2,662,000	2,612,000	1,582,000	960,000	16,863,000
2	Rate-$/DTH	1.9486	1.5879	1.5926	1.6521	1.7508	1.8233	1.8762	1.7953	
3	Cost-$	5,307,986	535,122	5,231,691	4,462,322	4,660,630	4,762,460	2,968,148	1,723,488	29,651,847
	Swing									
4	Quantity - DTH	7,000	0	2,094,000	1,260,000	519,000	519,000	1,370,000	1,878,000	7,647,000
5	Rate-$/DTH	1.8385	0.0000	1.5550	1.5471	1.5219	1.5805	1.6636	1.4463	
6	Cost-$	12,870	0	3,256,170	1,949,346	789,866	820,280	2,279,132	2,716,151	11,823,815
7	Total DTH	2,731,000	337,000	5,379,000	3,961,000	3,181,000	3,131,000	2,952,000	2,838,000	24,510,000
8	Total Spot									
9	Commodity Cost - $	5,320,856	535,122	8,487,861	6,411,668	5,450,496	5,582,740	5,247,280	4,439,639	41,475,662
	Local Direct									
10	Quantity - DTH	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	171,000
11	Rate-$/DTH	1.8900	1.5920	1.5700	1.5965	1.6475	1.6775	1.6735	1.4740	
12	Cost-$	37,800	35,024	32,970	35,123	34,598	36,905	36,817	30,954	280,191
13	Total - DTH	20,000	22,000	21,000	22,000	21,000	22,000	22,000	21,000	171,000
14	Total Local									
15	Commodity Cost - $	37,800	35,024	32,970	35,123	34,598	36,905	36,817	30,954	280,191

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Storage

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
	EASTERN - GSS									
1	Injections - DTH	0	0	(247,000)	(226,000)	(226,000)	(228,000)	(226,000)	(226,000)	(1,379,000)
2	Injection Rate - $/DTH	1.9468	1.5759	1.5776	1.6178	1.7116	1.7810	1.7750	1.5613	
3	Withdrawals - DTH	487,000	371,000	0	0	0	0	0	0	858,000
4	Withdrawal Rate - $/DTH	2.5361	2.5362	2.1734	2.0011	1.9319	1.9028	1.8829	1.8428	
5	Cost-$	1,235,081	940,930	(389,667)	(365,623)	(386,822)	(406,068)	(401,150)	(352,854)	(126,173)
6	Injection Rate $/Dth	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	0.0393	
7	Withdrawl Rate $/Dth	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	0.0256	
8	Cost - $	12,467	9,498	9,707	8,882	8,882	8,960	8,882	8,882	76,160
	EQUITRANS - SS									
9	Injections - DTH	0	0	(294,000)	(214,000)	(214,000)	(216,000)	(214,000)	(214,000)	(1,366,000)
10	Injection Rate - $/DTH	1.9468	1.5759	1.5776	1.6178	1.7116	1.7810	1.7750	1.5613	
11	Withdrawals - DTH	119,000	457,000	0	0	0	0	0	0	576,000
12	Withdrawal Rate - $/DTH	2.5361	2.5362	2.1734	2.0011	1.9319	1.9028	1.8829	1.8428	
13	Cost-$	301,796	1,159,043	(463,814)	(346,209)	(366,282)	(384,696)	(379,850)	(334,118)	(814,130)
14	Inject/With. Rate $/DTH	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15	Cost - $	0	0	0	0	0	0	0	0	0
	TCO - FSS									
16	Injections - DTH	0	0	(2,203,000)	(2,823,000)	(2,825,000)	(2,823,000)	(2,676,000)	(2,414,000)	(15,764,000)
17	Injection Rate - $/DTH	1.9468	1.5759	1.5776	1.6178	1.7116	1.7810	1.7750	1.5613	
18	Withdrawals - DTH	3,688,000	4,210,000	0	0	0	0	0	0	7,898,000
19	Withdrawal Rate - $/DTH	2.5361	2.5362	2.1734	2.0011	1.9319	1.9028	1.8829	1.8428	
20	Cost-$	9,353,137	10,677,402	(3,475,453)	(4,567,049)	(4,835,270)	(5,027,763)	(4,749,900)	(3,768,978)	(6,393,874)
21	Inject/With. Rate $/DTH	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	0.0153	
22	Cost - $	56,426	64,413	33,706	43,192	43,223	43,192	40,943	36,934	362,029
	NATIONAL FUEL - ESS									
23	Injections - DTH	0	0	(9,000)	(7,000)	(47,000)	(48,000)	(48,000)	(47,000)	(206,000)
24	Injection Rate - $/DTH	1.9468	1.5759	1.5776	1.6178	1.7116	1.7810	1.7750	1.5613	
25	Withdrawals - DTH	16,000	59,000	0	0	0	0	0	0	75,000
26	Withdrawal Rate - $/DTH	2.5361	2.5362	2.1734	2.0011	1.9319	1.9028	1.8829	1.8428	
27	Cost-$	40,578	149,636	(14,198)	(11,325)	(80,445)	(85,488)	(85,200)	(73,381)	(159,823)
28	Inject/With. Rate $/DTH	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	0.0382	
29	Cost - $	611	2,254	344	267	1,795	1,834	1,834	1,795	10,734
30	Total - DTH	4,310,000	5,097,000	(2,753,000)	(3,270,000)	(3,312,000)	(3,315,000)	(3,164,000)	(2,901,000)	(9,308,000)
31	Total Purchase Cost	10,930,592	12,927,011	(4,343,132)	(5,290,206)	(5,668,819)	(5,904,015)	(5,616,100)	(4,529,331)	(7,494,000)
32	Total Inject/With. Cost	69,504	76,165	43,757	52,341	53,900	53,986	51,659	47,611	448,923

COLUMBIA GAS OF PENNSYLVANIA, INC.

Summary of Total Estimated Purchased Gas Commodity Costs
Storage Transportation Charges

Line No.	Description	2024 February	March	April	May	June	July	August	September	Total
	TCO - SST									
1	Injections - DTH	0	0	(2,203,000)	(2,823,000)	(2,825,000)	(2,823,000)	(2,676,000)	(2,414,000)	(15,764,000)
2	Withdrawals - DTH	3,688,000	4,210,000	0	0	0	0	0	0	7,898,000
3	Trans. Chrg. $/Dth	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	
4	Cost-$	53,845	61,466	32,164	41,216	41,245	41,216	39,070	35,244	345,466
	EASTERN - GSS									
5	Injections - DTH	0	0	(247,000)	(226,000)	(226,000)	(228,000)	(226,000)	(226,000)	(1,379,000)
6	Withdrawls - DTH	487,000	371,000	0	0	0	0	0	0	858,000
7	Trans. Chrg. $/Dth	0.0112	0.0112	0.0146	0.0146	0.0146	0.0146	0.0146	0.0146	
8	Cost-$	5,454	4,155	3,606	3,300	3,300	3,329	3,300	3,300	29,744
	EQUITRANS - SS									
9	Injections - DTH	0	0	(294,000)	(214,000)	(214,000)	(216,000)	(214,000)	(214,000)	(1,366,000)
10	Withdrawals - DTH	119,000	457,000	0	0	0	0	0	0	576,000
11	Trans. Chrg. $/Dth	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
12	Cost-$	0	0	0	0	0	0	0	0	0
	NATIONAL FUEL									
13	Injections - DTH	0	0	(9,000)	(7,000)	(47,000)	(48,000)	(48,000)	(47,000)	(206,000)
14	Withdrawals - DTH	16,000	59,000	0	0	0	0	0	0	75,000
15	Trans. Chrg. $/Dth	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	0.0237	
16	Cost-$	379	1,398	213	166	1,114	1,138	1,138	1,114	6,660
17	Total Storage - DTH	4,310,000	5,097,000	(2,753,000)	(3,270,000)	(3,312,000)	(3,315,000)	(3,164,000)	(2,901,000)	(9,308,000)
18	Total EUB - DTH	(677,000)	(356,000)	67,000	340,000	439,000	462,000	465,000	427,000	1,167,000
19	Total - DTH	3,633,000	4,741,000	(2,686,000)	(2,930,000)	(2,873,000)	(2,853,000)	(2,699,000)	(2,474,000)	(8,141,000)
20	Total Purchase Cost	10,930,592	12,927,011	(4,343,132)	(5,290,206)	(5,668,819)	(5,904,015)	(5,616,100)	(4,529,331)	(7,494,000)
21	Total Choice Bank Cost	(1,210,744)	(636,669)	119,823	608,055	785,106	826,239	1,170,283	1,074,647	2,736,739
22	Total Inject/With. Cost	69,504	76,165	43,757	52,341	53,900	53,986	51,659	47,611	448,923
23	Total Transp. Charge	59,678	67,019	35,983	44,682	45,659	45,683	43,508	39,658	381,870
24	Total Storage Cost	9,849,030	12,433,526	(4,143,569)	(4,585,128)	(4,784,154)	(4,978,107)	(4,350,650)	(3,367,415)	(3,926,468)

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF EXPERIENCED NET OVER (UNDER) COLLECTION
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

Line No.	Description	Total Demand $	Total Commodity $	Total Amount $
1	Remaining Balance - Over (Under) Collection from 2023 - 1307(f)			
2	(See Schedule 2a and 2b)	(239,818)	(1,020,387)	(1,260,205)
3	Unified Credit for Off-system Sales and Capacity Release for the period			
4	October, 2023 through September, 2024 (See Schedule 3 herein)	55,958	0	55,958
5	Over (Under) Collection for the period October, 2023 through			
6	September 2024 (See Schedule 4 herein)	(4,066,414)	765,789	(3,300,625)
7	Interest on Over (Under) Collection for the period October, 2023 through			
8	September, 2024 (See Schedule 4 herein)	167,788	(225,535)	(57,747)
9	Penalty Credits/Supplier Refunds Received October, 2023 through			
10	September, 2024 (See Schedule 5 herein)	556,174	0	556,174
11	TOTAL EXPERIENCED NET OVER (UNDER) COLLECTION	(3,526,312)	(480,133)	(4,006,445)

COLUMBIA GAS OF PENNSYLVANIA, INC.

RECONCILIATION OF COMMODITY COST OF GAS
FROM 2023 - 1307(f)
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

COMMODITY

Line No.	Month	Sales Subject to Commodity E-Factor Therm	Rate $/ Therm	Amount Recovered $	Net Commodity Over (Under) Collection $
1	True-up of Net Commodity Costs Included in 2023 1307(f):				956,242
2	Beginning Balance Adjustment				132,885 2_/
3	October, 2023	5,023,081	(0.01500)	(75,346)	
4		4,914,253	0.03505	172,245	
5	November	24,563,664	(0.01500)	(368,455)	
6		21,821	0.03505	765	
7	December	51,034,026	(0.01500)	(765,510)	
8	January, 2024 1_/	36,132,519	(0.00237)	(85,634)	
9		29,716,827	(0.01500)	(445,752)	
10	February	76,434,596	(0.00237)	(181,150)	
11	March	63,257,568	(0.00237)	(149,920)	
12	April	42,038,700	(0.00237)	(99,632)	
13	May	19,388,576	(0.00237)	(45,951)	
14	June	9,657,958	(0.00237)	(22,889)	
15	July	6,141,977	(0.00237)	(14,556)	
16	August	5,707,860	(0.00237)	(13,528)	
17	September	5,991,975	(0.00237)	(14,201)	
18	Amount Collected/(Passed Back) during 2023 1307(f) Period				(2,109,514)
19	Remaining Balance to be Collected in the 2024 1307(f)				(1,020,387)

1_/ Rate in effect January 1, 2024.

2_/ Represents a commodity interest adjustment for the period of February 2023 to September 2023 increasing the interest rate from 7.50% to the prime rate as of January 31, 2024 of 8.50%. Please refer to Exh. 1-E, Schedule 2a, Sheet 2 for a detailed calculation for this adjustment.

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF COMMODITY OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
FEBRUARY, 2023 THROUGH SEPTEMBER, 2023

Line No.	Month	Total Commodity Purchase Gas Cost Recovery	Total Cost of Fuel	Total Over (Under) Collection	Number of Months	Rate	Over (Under) Collection Interest	Rate	Over (Under) Collection Interest	Interest Difference
		(1)	(2)	(3 = 1 - 2)	(4)	(5)	(6=3x4x5)	(7)	(8=3x4x7)	(9=8-6)
1	February, 2023	35,495,777	28,201,626	7,294,150	14 / 12	7.50%	638,238	8.50%	723,337	85,099
2	March	24,737,786	33,018,384	(8,280,598)	13 / 12	7.50%	(672,799)	8.50%	(762,505)	(89,706)
3	April	15,025,189	3,917,019	11,108,170	12 / 12	7.50%	833,113	8.50%	944,194	111,081
4	May	7,758,943	3,320,253	4,438,690	11 / 12	7.50%	305,160	8.50%	345,848	40,688
5	June	3,584,470	4,032,397	(447,927)	10 / 12	7.50%	(27,995)	8.50%	(31,728)	(3,733)
6	July	2,668,273	2,073,429	594,844	9 / 12	7.50%	33,460	8.50%	37,921	4,461
7	August	2,381,179	979,367	1,401,812	8 / 12	7.50%	70,091	8.50%	79,436	9,345
8	September	2,564,341	6,738,519	(4,174,177)	7 / 12	7.50%	(182,620)	8.50%	(206,970)	(24,350)
9	TOTAL	94,215,958	82,280,995	11,934,964			996,648		1,129,533	132,885

COLUMBIA GAS OF PENNSYLVANIA, INC.

RECONCILIATION OF DEMAND COST OF GAS
FROM 2023 - 1307(f)
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

DEMAND

Line No.	Month	Sales Subject to Demand E-Factor	Rate	Amount	Net Demand Over (Under) Collection
		Therm	$/ Therm	$	$
1	True-up of Net Demand Costs Included in 2023 1307(f):				(4,573,405)
2	Beginning Balance Adjustment				(45,680) 2_/
3	October, 2023	6,126,472	0.01026	62,858	
4		6,033,697	(0.00419)	(25,281)	
5	November	29,955,713	0.01026	307,345	
6		32,104	(0.00419)	(135)	
7	December	61,422,103	0.01026	630,191	
8	January, 2024 1_/	43,580,472	0.00959	417,937	
9		36,081,231	0.01026	370,193	
10	February	90,860,158	0.00959	871,349	
11	March	75,126,012	0.00959	720,458	
12	April	49,963,375	0.00959	479,149	
13	May	23,233,357	0.00959	222,808	
14	June	11,715,115	0.00959	112,348	
15	July	7,535,157	0.00959	72,262	
16	August	7,020,240	0.00959	67,324	
17	September	7,347,310	0.00959	70,461	
18	Amount Collected/(Passed Back) during 2023 1307(f) Period				4,379,267
19	Remaining Balance to be Collected in the 2024 1307(f)				(239,818)

1_/ Rate in effect January 1, 2024.

2_/ Represents a commodity interest adjustment for the period of February 2023 to September 2023 increasing the interest rate from 7.50% to the prime rate as of January 31, 2024 of 8.50%. Please refer to Exh. 1-E, Schedule 2b, Sheet 2 for a detailed calculation for this adjustment.

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF DEMAND OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
FEBRUARY, 2023 THROUGH SEPTEMBER, 2023

Line No.	Month	Total Purchased Gas Cost Recovery	Total Cost of Fuel	Total Over (Under) Collection	Number of Months	Rate	Over (Under) Collection Interest	Rate	Over (Under) Collection Interest	Interest Difference
		(1)	(2)	(3 = 1 - 2)	(4)	(5)	(6=3x4x5)	(7)	(8=3x4x7)	(9=8-6)
1	February, 2023	12,909,625	8,290,146	4,619,479	14 / 12	7.50%	404,204	8.50%	458,098	53,894
2	March	10,505,916	8,291,602	2,214,313	13 / 12	7.50%	179,913	8.50%	203,901	23,988
3	April	7,816,358	6,056,320	1,760,038	12 / 12	7.50%	132,003	8.50%	149,603	17,600
4	May	4,376,955	6,417,842	(2,040,887)	11 / 12	7.50%	(140,311)	8.50%	(159,019)	(18,708)
5	June	2,098,066	6,224,368	(4,126,302)	10 / 12	7.50%	(257,894)	8.50%	(292,280)	(34,386)
6	July	1,741,356	6,194,108	(4,452,752)	9 / 12	7.50%	(250,467)	8.50%	(283,863)	(33,396)
7	August	1,761,320	6,191,128	(4,429,808)	8 / 12	7.50%	(221,490)	8.50%	(251,022)	(29,532)
8	September	1,882,048	6,191,870	(4,309,822)	7 / 12	7.50%	(188,555)	8.50%	(213,695)	(25,140)
9	TOTAL	43,091,644	53,857,383	(10,765,740)			(342,597)		(388,277)	(45,680)

Exhibit 1-E
Schedule 3

COLUMBIA GAS OF PENNSYLVANIA, INC.

RECONCILIATION OF OFF SYSTEM SALES CREDIT
FROM 2023 - 1307(f)
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

DEMAND

Line No.	Month	Sales Subject to Off-System Sales Credit	Rate	Amount	Net Demand Over (Under) Collection
		Therm	$/Therm	$	$
1	October, 2023	6,126,472	(0.00454)	(27,814)	
2		6,033,697	(0.00352)	(21,239)	
3	November	29,955,713	(0.00454)	(135,999)	
4		32,104	(0.00352)	(113)	
5	December	61,422,103	(0.00454)	(278,856)	
6	January, 2024	79,661,703	(0.00454)	(361,664)	
7	February	90,860,158	(0.00454)	(412,505)	
8	March	75,126,012	(0.00454)	(341,072)	
9	April	49,963,375	(0.00454)	(226,834)	
10	May	23,233,357	(0.00454)	(105,479)	
11	June	11,715,115	(0.00454)	(53,187)	
12	July	7,535,157	(0.00454)	(34,210)	
13	August	7,020,240	(0.00454)	(31,872)	
14	September	7,347,310	(0.00454)	(33,357)	
15	Amount Passed Back in the 2023 1307(f)				(2,064,201)
16	Current Estimate Unified Sharing Mechanism - $2,120,159				2,120,159
17	Amount to be Passed Back in the 2023 1307(f)				55,958

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF COMMODITY OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

Line No.	Month	Total Commodity Sales Revenue	Rate Schedule NSS Gas Cost Recovery	Total Commodity Purchase Gas Cost Recovery	Total Commodity Cost of Fuel	Total Commodity Over/(Under) Collection	Number of Months	Rate	Commodity Over/(Under) Collection Interest	Total Commodity Over/(Under) Collection
		(1)	(2)	(3 = 1 + 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)	(9 = 5 + 8)
		$	$	$	$	$				
	Reference:	Sch. 4, Pg. 2	Sch. 4, Pg. 3							
	Actuals through January 2024									
1	October, 2023	3,308,469	3,959	3,312,428	3,451,853	(139,425)	18 / 12	8.50%	(17,777)	(157,202)
2	November	6,624,551	16,508	6,641,060	10,445,283	(3,804,223)	17 / 12	8.50%	(458,092)	(4,262,315)
3	December	13,748,797	16,132	13,764,928	12,032,316	1,732,612	16 / 12	8.50%	196,363	1,928,975
4	January, 2024	15,973,630	18,797	15,992,426	21,592,044	(5,599,617)	15 / 12	8.50%	(594,959)	(6,194,576)
5	February	16,856,121	0	16,856,121	17,873,841	(1,017,719)	14 / 12	8.50%	(100,924)	(1,118,643)
6	March	13,950,191	0	13,950,191	14,081,919	(131,727)	13 / 12	8.50%	(12,130)	(143,857)
7	April	9,270,795	0	9,270,795	4,419,699	4,851,096	12 / 12	8.50%	412,343	5,263,439
8	May	4,275,763	0	4,275,763	1,905,441	2,370,322	11 / 12	8.50%	184,688	2,555,010
9	June	2,129,869	0	2,129,869	746,061	1,383,809	10 / 12	8.50%	98,020	1,481,829
10	July	1,354,490	0	1,354,490	690,858	663,632	9 / 12	8.50%	42,307	705,939
11	August	1,258,754	0	1,258,754	981,438	277,317	8 / 12	8.50%	15,715	293,032
12	September	1,321,410	0	1,321,410	1,141,696	179,714	7 / 12	8.50%	8,911	188,625
13	TOTAL	90,072,841	55,396	90,128,237	89,362,448	765,789			(225,535)	540,254

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF DEMAND OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

Line No.	Month	Total Demand Sales Revenue	Total Banking and Balancing Revenue	Total Standby Demand Revenue	NSS Capacity Release Revenue	Demand Purchased Gas Cost Recovery	Demand Cost of Fuel	Total Demand Over/(Under) Collection	Number of Months	Rate	Demand Over/(Under) Collection Interest	Total Demand Over/(Under) Collection
		(1)	(2)	(3)	(4)	(5 =1+2+3+4)	(6)	(7 = 5 - 6)	##	(9)	(10 = 7 x 8 x 9)	(11 = 7 + 10)
		$	$	$	$	$	$	$				
	Reference:	Sch. 4, Pg. 4	Sch. 4, Pg. 6	Sch. 4, Pg. 5	Sch. 4, Pg. 6							
	Actuals through January 2024											
1	October, 2023	2,524,237	63	57,768	26	2,582,094	8,272,949	(5,690,855)	18 / 12	8.50%	(725,584)	(6,416,439)
2	November	5,513,324	178	59,741	611	5,573,854	8,467,709	(2,893,855)	17 / 12	8.50%	(348,468)	(3,242,323)
3	December	11,291,123	173	78,846	788	11,370,930	8,630,796	2,740,134	16 / 12	8.50%	310,548	3,050,682
4	January, 2024	14,593,656	195	78,846	861	14,673,557	8,630,569	6,042,989	15 / 12	8.50%	642,068	6,685,057
5	February	17,025,376	0	78,636	0	17,104,013	8,744,230	8,359,783	14 / 12	8.50%	829,012	9,188,795
6	March	14,077,112	0	78,636	0	14,155,749	8,712,391	5,443,358	13 / 12	8.50%	501,243	5,944,601
7	April	9,362,137	0	78,636	0	9,440,774	6,503,335	2,937,439	12 / 12	8.50%	249,682	3,187,121
8	May	4,353,466	0	75,337	0	4,428,803	6,407,335	(1,978,532)	11 / 12	8.50%	(154,161)	(2,132,693)
9	June	2,195,178	0	75,337	0	2,270,515	6,407,335	(4,136,820)	10 / 12	8.50%	(293,025)	(4,429,845)
10	July	1,411,938	0	75,337	0	1,487,275	6,407,335	(4,920,060)	9 / 12	8.50%	(313,654)	(5,233,714)
11	August	1,315,453	0	76,242	0	1,391,695	6,407,335	(5,015,640)	8 / 12	8.50%	(284,220)	(5,299,860)
12	September	1,376,739	0	76,242	0	1,452,981	6,407,335	(4,954,354)	7 / 12	8.50%	(245,653)	(5,200,007)
13	TOTAL	85,039,739	610	889,605	2,286	85,932,239	89,998,654	(4,066,414)			167,788	(3,898,626)

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF COMMODITY GAS COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	SALES SUBJECT TO COMMODITY COST OF GAS	COMMODITY COST OF GAS	TOTAL COMMODITY COST RECOVERY
		(1)	(2)	(3 = 1 x 2)
		THERM	**$/THERM**	**$**
1	October, 2023 Est. Old	4,963,164	0.39968	1,983,677
2	October, 2023 Est. New	5,023,081	0.26939	1,353,168
3	September, 2023 Est.	(6,475,715)	0.39968	(2,588,214)
4	September, 2023 Act.	6,426,804	0.39968	2,568,665
5	September Act. Prior Period Adjustments		-	(8,828)
6	Total	9,937,334		3,308,469
7	November, 2023 Est. New	24,541,580	0.26939	6,611,256
8	October, 2023 Est. Old	(4,963,164)	0.39968	(1,983,677)
9	October, 2023 Est. New	(5,023,081)	0.26939	(1,353,168)
10	October, 2023 Act. Old	4,984,985	0.39968	1,992,399
11	October, 2023 Act. New	5,045,166	0.26939	1,359,117
12	October Act. Prior Period Adjustments	0	-	(1,375)
13	Total	24,585,485		6,624,551
14	December, 2023 Est.	51,103,716	0.26939	13,766,830
15	November, 2023 Est.	(24,541,580)	0.26939	(6,611,256)
16	November, 2023 Act.	24,471,890	0.26939	6,592,482
17	November Act. Prior Period Adjustments	0	-	740
18	Total	51,034,026		13,748,797
19	January, 2024 Est. Old	29,802,734	0.26939	8,028,559
20	January, 2024 Est. New	36,132,519	0.22053	7,968,304
21	December, 2023 Est.	(51,103,716)	0.26939	(13,766,830)
22	December, 2023 Act.	51,017,809	0.26939	13,743,688
23	December Act. Prior Period Adjustments	0	-	(91)
24	Total	65,849,346		15,973,630
25	February, 2024 Est. New	76,434,596	0.22053	16,856,121
26	January, 2024 Est. Old	0	-	0
27	January, 2024 Est. New	0	-	0
28	January, 2024 Act. Old	0	-	0
29	January, 2024 Act. New	0	-	0
30	January Act. Prior Period Adjustments	0	-	0
31	Total	76,434,596		16,856,121
32	March, 2024 Est.	63,257,568	0.22053	13,950,191
33	February, 2024 Est.	0	-	0
34	February, 2024 Act.	0	-	0
35	February Act. Prior Period Adjustments	0	-	0
36	Total	63,257,568		13,950,191

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF COMMODITY GAS COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	SALES SUBJECT TO COMMODITY COST OF GAS	COMMODITY COST OF GAS	TOTAL COMMODITY COST RECOVERY
		(1)	(2)	(3 = 1 x 2)
		THERM	**$/THERM**	**$**
1	April, 2024 Est. Old	42,038,700	0.22053	9,270,795
2	April, 2024 Est. New	0	-	0
3	March, 2024 Est.	0	-	0
4	March, 2024 Act.	0	-	0
5	March Act. Prior Period Adjustments	0	-	0
6	Total	42,038,700		9,270,795
7	May, 2024 Est.	19,388,576	0.22053	4,275,763
8	April, 2024 Est. Old	0	-	0
9	April, 2024 Est. New	0	-	0
10	April, 2024 Act. Old	0	-	0
11	April, 2024 Act. New	0	-	0
12	April Act. Prior Period Adjustments	0	-	0
13	Total	19,388,576		4,275,763
14	June, 2024 Est.	9,657,958	0.22053	2,129,869
15	May, 2024 Est.	0	-	0
16	May, 2024 Act.	0	-	0
17	May Act. Prior Period Adjustments	0	-	0
18	Total	9,657,958		2,129,869
19	July, 2024 Est. Old	6,141,977	0.22053	1,354,490
20	July, 2024 Est. New	0	-	0
21	June, 2024 Est.	0	-	0
22	June, 2024 Act.	0	-	0
23	June Act. Prior Period Adjustments	0	-	0
24	Total	6,141,977		1,354,490
25	August, 2024 Est.	5,707,860	0.22053	1,258,754
26	July, 2024 Est. Old	0	-	0
27	July, 2024 Est. New	0	-	0
28	July, 2024 Act. Old	0	-	0
29	July, 2024 Act. New	0	-	0
30	July Act. Prior Period Adjustments	0	-	0
31	Total	5,707,860		1,258,754
32	September, 2024 Est.	5,991,975	0.22053	1,321,410
33	August, 2024 Est.	0	-	0
34	August, 2024 Act.	0	-	0
35	August Act. Prior Period Adjustments	0	-	0
36	Total	5,991,975		1,321,410
37	TOTAL	380,025,401		90,072,841

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF NSS COMMODITY COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	RATE SCHEDULE NSS VOLUMES	RATE	NSS GAS COST RECOVERY
		(1)	(2)	(3=1*2)
		THERM	**$/THERM**	**$**
1	October, 2023 Est.	30,000	0.14096	4,229
2	September, 2023 Act.	20,860	0.12614	2,631
3	September, 2023 Est.	(23,000)	0.12614	(2,901)
4		27,860		3,959
5	November, 2023 Est.	71,000	0.21675	15,389
6	October, 2023 Act.	37,940	0.14096	5,348
7	October, 2023 Est.	(30,000)	0.14096	(4,229)
8		78,940		16,508
9	December, 2023 Est.	90,000	0.21161	19,045
10	November, 2023 Act.	57,560	0.21675	12,476
11	November, 2023 Est.	(71,000)	0.21675	(15,389)
12		76,560		16,132
13	January, 2024 Est.	98,000	0.21700	21,266
14	December, 2023 Act.	78,330	0.21161	16,575
15	December, 2023 Est.	(90,000)	0.21161	(19,045)
16		86,330		18,797
17	February, 2024 Est.	0	-	0
18	January, 2024 Act.	0	-	0
19	January, 2024 Est.	0	-	0
20		0		0
21	March, 2024 Est.	0	-	0
22	February, 2024 Act.	0	-	0
23	February, 2024 Est.	0	-	0
24		0		0
25	April, 2024 Est.	0	-	0
26	March, 2024 Act.	0	-	0
27	March, 2024 Est.	0	-	0
28		0		0
29	May, 2024 Est.	0	-	0
30	April, 2024 Act.	0	-	0
31	April, 2024 Est.	0	-	0
32		0		0
33	June, 2024 Est.	0	-	0
34	May, 2024 Act.	0	-	0
35	May, 2024 Est.	0	-	0
36		0		0
37	July, 2024 Est.	0	-	0
38	June, 2024 Act.	0	-	0
39	June, 2024 Est.	0	-	0
40		0		0
41	August, 2024 Est.	0	-	0
42	July, 2024 Act.	0	-	0
43	July, 2024 Est.	0	-	0
44		0		0
45	September, 2024 Est.	0	-	0
46	August, 2024 Act.	0	-	0
47	August, 2024 Est.	0	-	0
48		0		0
49	TOTAL	269,690		55,396

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF DEMAND GAS COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	VOLUMES SUBJ. TO DEMAND COST OF GAS	COST OF GAS	DEMAND COST RECOVERY
		(1)	(2)	(3 = 1 x 2)
		THERM	**$/THERM**	**$**
1	October, 2023 Est. Old	4,963,164	0.23621	1,172,349
2	October, 2023 Est. New	5,023,081	0.18843	946,499
3	October Choice - Est. Old	1,004,702	0.20935	210,334
4	October Choice - Est. New	984,807	0.15976	157,333
5	October Est. Priority One Transportation Old	117,169	0.23621	27,676
6	October Est. Priority One Transportation New	118,584	0.18843	22,345
7	September, 2023 Est.	(6,475,715)	0.23621	(1,529,629)
8	September 2023 Act.	6,426,804	0.23621	1,518,075
9	September Choice - Est.	(1,290,072)	0.20935	(270,077)
10	September Choice - Act.	1,296,516	0.20935	271,426
11	September Est. Priority One Transportation	(179,361)	0.23621	(42,367)
12	September Act. Priority One Transportation	170,490	0.23621	40,271
13	Total	12,160,169		2,524,237
14	November, 2023 Est. New	24,541,580	0.18843	4,624,370
15	November Choice - Est. New	4,831,434	0.15976	771,870
16	November Est. Priority One Transportation New	550,379	0.18843	103,708
17	October Est. Old	(4,963,164)	0.23621	(1,172,349)
18	October Est. New	(5,023,081)	0.18843	(946,499)
19	October Act. Old	4,984,985	0.23621	1,177,503
20	October Act. New	5,045,166	0.18843	950,661
21	October Choice - Est. Old	(1,004,702)	0.20935	(210,334)
22	October Choice - Est. New	(984,807)	0.15976	(157,333)
23	October Choice - Act. Old	1,010,107	0.20935	211,466
24	October Choice - Act. New	990,104	0.15976	158,179
25	October Est. Priority One Transportation Old	(117,169)	0.23621	(27,676)
26	October Est. Priority One Transportation New	(118,584)	0.18843	(22,345)
27	October Act. Priority One Transportation Old	122,048	0.23621	28,829
28	October Act. Priority One Transportation New	123,522	0.18843	23,275
29	Total	29,987,817		5,513,324
30	December, 2023 Est.	51,103,716	0.18843	9,629,473
31	December Choice - Est.	9,843,144	0.15976	1,572,541
32	December Est. Priority One Transportation	620,454	0.18843	116,912
33	November Est.	(24,541,580)	0.18843	(4,624,370)
34	November Act.	24,471,890	0.18843	4,611,238
35	November Choice - Est.	(4,831,434)	0.15976	(771,870)
36	November Choice - Act.	4,846,822	0.15976	774,328
37	November Est. Priority One Transportation	(550,379)	0.18843	(103,708)
38	November Act. Priority One Transportation	459,470	0.18843	86,578
39	Total	61,422,103		11,291,123
40	January, 2024 Est. Old	29,802,734	0.18843	5,615,729
41	January, 2024 Est. New	36,132,519	0.18738	6,770,511
42	January Choice - Est. Old	5,774,944	0.15976	922,605
43	January Choice - Est. New	6,945,197	0.15785	1,096,299
44	January Est. Priority One Transportation Old	414,682	0.18843	78,139
45	January Est. Priority One Transportation New	502,757	0.18738	94,207
46	December 2023 Est.	(51,103,716)	0.18843	(9,629,473)
47	December 2023 Act.	51,017,809	0.18843	9,613,286
48	December Choice - Est.	(9,843,144)	0.15976	(1,572,541)
49	December Choice - Act.	9,863,385	0.15976	1,575,774
50	December Est. Priority One Transportation	(620,454)	0.18843	(116,912)
51	December Act. Priority One Transportation	774,990	0.18843	146,031
52	Total	79,661,703		14,593,656

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF DEMAND GAS COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	VOLUMES SUBJ. TO DEMAND COST OF GAS	COST OF GAS	DEMAND COST RECOVERY
		(1)	(2)	(3 = 1 x 2)
		THERM	**$/THERM**	**$**
1	February, 2024 Est. New	90,860,158	0.18738	17,025,376
2	February Choice - Est. New	0	-	0
3	February Est. Priority One Transportation New	0	-	0
4	January Est. Old	0	-	0
5	January Est. New	0	-	0
6	January Act. Old	0	-	0
7	January Act. New	0	-	0
8	January Choice - Est. Old	0	-	0
9	January Choice - Est. New	0	-	0
10	January Choice - Act. Old	0	-	0
11	January Choice - Act. New	0	-	0
12	January Est. Priority One Transportation Old	0	-	0
13	January Est. Priority One Transportation New	0	-	0
14	January Act. Priority One Transportation Old	0	-	0
15	January Act. Priority One Transportation New	0	-	0
16	Total	90,860,158		17,025,376
17	March, 2024 Est.	75,126,012	0.18738	14,077,112
18	March Choice - Est.	0	-	0
19	March Est. Priority One Transportation	0	-	0
20	February Est.	0	-	0
21	February Act.	0	-	0
22	February Choice - Est.	0	-	0
23	February Choice - Act.	0	-	0
24	February Est. Priority One Transportation	0	-	0
25	February Act. Priority One Transportation	0	-	0
26	Total	75,126,012		14,077,112
27	April, 2024 Est. Old	49,963,375	0.18738	9,362,137
28	April, 2024 Est. New	0	-	0
29	April Choice - Est. Old	0	-	0
30	April Choice - Est. New	0	-	0
31	April Est. Priority One Transportation Old	0	-	0
32	April Est. Priority One Transportation New	0	-	0
33	March Est.	0	-	0
34	March Act.	0	-	0
35	March Choice - Est.	0	-	0
36	March Choice - Act.	0	-	0
37	March Est. Priority One Transportation	0	-	0
38	March Act. Priority One Transportation	0	-	0
39	Total	49,963,375		9,362,137
40	May, 2024 Est. New	23,233,357	0.18738	4,353,466
41	May Choice - Est. New	0	-	0
42	May Est. Priority One Transportation New	0	-	0
43	April Est. Old	0	-	0
44	April Est. New	0	-	0
45	April Act. Old	0	-	0
46	April Act. New	0	-	0
47	April Choice - Est. Old	0	-	0
48	April Choice - Est. New	0	-	0
49	April Choice - Act. Old	0	-	0
50	April Choice - Act. New	0	-	0
51	April Est. Priority One Transportation Old	0	-	0
52	April Est. Priority One Transportation New	0	-	0
53	April Act. Priority One Transportation Old	0	-	0
54	April Act. Priority One Transportation New	0	-	0
55	Total	23,233,357		4,353,466

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF DEMAND GAS COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	VOLUMES SUBJ. TO DEMAND COST OF GAS	COST OF GAS	DEMAND COST RECOVERY
		(1)	(2)	(3 = 1 x 2)
		THERM	**$/THERM**	**$**
1	June, 2024 Est.	11,715,115	0.18738	2,195,178
2	June Choice - Est.	0	-	0
3	June Est. Priority One Transportation	0	-	0
4	May Est.	0	-	0
5	May Act.	0	-	0
6	May Choice - Est.	0	-	0
7	May Choice - Act.	0	-	0
8	May Est. Priority One Transportation	0	-	0
9	May Act. Priority One Transportation	0	-	0
10	Total	11,715,115		2,195,178
11	July, 2024 Est. Old	7,535,157	0.18738	1,411,938
12	July, 2024 Est. New	0	-	0
13	July Choice - Est. Old	0	-	0
14	July Choice - Est. New	0	-	0
15	July Est. Priority One Transportation Old	0	-	0
16	July Est. Priority One Transportation New	0	-	0
17	June 2024 Est.	0	-	0
18	June 2024 Act.	0	-	0
19	June Choice - Est.	0	-	0
20	June Choice - Act.	0	-	0
21	June Est. Priority One Transportation	0	-	0
22	June Act. Priority One Transportation	0	-	0
23	Total	7,535,157		1,411,938
24	August, 2024 Est.	7,020,240	0.18738	1,315,453
25	August Choice - Est.	0	-	0
26	August Est. Priority One Transportation	0	-	0
27	July, 2023 Est. Old	0	-	0
28	July, 2023 Est. New	0	-	0
29	July 2023 Act. Old	0	-	0
30	July 2023 Act. New	0	-	0
31	July Choice - Est. Old	0	-	0
32	July Choice - Est. New	0	-	0
33	July Choice - Act. Old	0	-	0
34	July Choice - Act. New	0	-	0
35	July Est. Priority One Transportation Old	0	-	0
36	July Est. Priority One Transportation New	0	-	0
37	July Act. Priority One Transportation Old	0	-	0
38	July Act. Priority One Transportationn New	0	-	0
39	Total	7,020,240		1,315,453
40	September, 2024 Est.	7,347,310	0.18738	1,376,739
41	September Choice - Est.	0	-	0
42	September Est. Priority One Transportation	0	-	0
43	August Est.	0	-	0
44	August Act.	0	-	0
45	August Choice - Est.	0	-	0
46	August Choice - Act.	0	-	0
47	August Est. Priority One Transportation	0	-	0
48	August Act. Priority One Transportation	0	-	0
49	Total	7,347,310		1,376,739
50	TOTAL	456,032,516		85,039,739

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF STANDBY DEMAND COST RECOVERY
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

LINE NO.	MONTH	STANDBY VOLUMES	STANDBY DEMAND RATE	STANDBY GAS DEMAND RECOVERIES
		(1)	(2)	(3 = 1 x 2)
		THERM	**$/THERM**	**$**
1	October, 2023 Est.	0		0
2	September, 2023 Act.	53,940	1.07097	57,768
3	September, 2023 Est.	0	-	0
4		53,940		57,768
5	November, 2023 Est.	0	-	0
6	October, 2023 Act.	53,940	1.10754	59,741
7	October, 2023 Est.	0	-	0
8		53,940		59,741
9	December, 2023 Est.	0	-	0
10	November, 2023 Act.	71,190	1.10754	78,846
11	November, 2023 Est.	0	-	0
12		71,190		78,846
13	January, 2024Est.	0	-	0
14	December, 2023 Act.	71,190	1.10754	78,846
15	December, 2023 Est.	0	-	0
16		71,190		78,846
17	February, 2024 Est.	0	-	0
18	January, 2024 Act.	71,190	1.10460	78,636
19	January, 2024 Est.	0	-	0
20		71,190		78,636
21	March, 2024 Est.	0	-	0
22	February, 2024 Act.	71,190	1.10460	78,636
23	February, 2024 Est.	0	-	0
24		71,190		78,636
25	April, 2024	0	-	0
26	March, 2024 Act.	71,190	1.10460	78,636
27	March, 2024 Est.	0	-	0
28		71,190		78,636
29	May, 2024	0	-	0
30	April, 2024 Act.	71,190	1.05825	75,337
31	April, 2024 Est.	0	-	0
32		71,190		75,337
33	June, 2024	0	-	0
34	May, 2024 Act.	71,190	1.05825	75,337
35	May, 2024 Est.	0	-	0
36		71,190		75,337
37	July, 2024	0	-	0
38	June, 2024 Act.	71,190	1.05825	75,337
39	June, 2024 Est.	0	-	0
40		71,190		75,337
41	August, 2024	0	-	0
42	July, 2024 Act.	71,190	1.07097	76,242
43	July, 2024 Est.	0	-	0
44		71,190		76,242
45	September, 2024	0	-	0
46	August, 2024 Act	71,190	1.07097	76,242
47	August, 2024 Est.	0	-	0
48		71,190		76,242
49	TOTAL	819,780		889,605

COLUMBIA GAS OF OF PENNSYLVANIA, INC.

DETAIL OF NSS BANKING & BALANCING AND CAPACITY RELEASE REVENUE
OCTOBER, 2023 THROUGH SEPTEMBER, 2024

		NSS-BANKING & BALANCING			NSS-CAPACITY RELEASE		
LINE NO.	DESCRIPTION	VOLUME	RATE	AMOUNT	VOLUME	RATE	AMOUNT
		(1)	(2)	(3=1 x 2)	(4)	(5)	(6=4 x5)
		THERM	**$/THERM**	**$**	**THERM**	**$/THERM**	**$**
1	October, 2023 Est.	30,000	0.00226	68	30,000	0.00093	28
2	September, 2023 Act.	20,860	0.00226	47	20,860	0.00093	19
3	September, 2023 Est.	(23,000)	0.00226	(52)	(23,000)	0.00093	(21)
4		27,860		63	27,860		26
5	November, 2023 Est.	71,000	0.00226	160	71,000	0.00850	604
6	October, 2023 Act.	37,940	0.00226	86	37,940	0.00093	35
7	October, 2023 Est.	(30,000)	0.00226	(68)	(30,000)	0.00093	(28)
8		78,940		178	78,940		611
9	December, 2023 Est.	90,000	0.00226	203	90,000	0.01003	903
10	November, 2023 Act.	57,560	0.00226	130	57,560	0.00850	489
11	November, 2023 Est.	(71,000)	0.00226	(160)	(71,000)	0.00850	(604)
12		76,560		173	76,560		788
13	January, 2024 Est.	98,000	0.00226	221	98,000	0.00998	978
14	December, 2023 Act.	78,330	0.00226	177	78,330	0.01003	786
15	December, 2023 Est.	(90,000)	0.00226	(203)	(90,000)	0.01003	(903)
16		86,330		195	86,330		861
17	February, 2024 Est.	0	-	0	0	-	0
18	January, 2024 Act.	0	-	0	0	-	0
19	January, 2024 Est.	0	-	0	0	-	0
20		0		0	0		0
21	March, 2024 Est.	0	-	0	0	-	0
22	February, 2024 Act.	0	-	0	0	-	0
23	February, 2024 Est.	0	-	0	0	-	0
24		0		0	0		0
25	April, 2024 Est.	0	-	0	0	-	0
26	March, 2024 Act.	0	-	0	0	-	0
27	March, 2024 Est.	0	-	0	0	-	0
28		0		0	0		0
29	May, 2024 Est.	0	-	0	0	-	0
30	April, 2024 Act.	0	-	0	0	-	0
31	April, 2024 Est.	0	-	0	0	-	0
32		0		0	0		0
33	June, 2024 Est.	0	-	0	0	-	0
34	May, 2024 Act.	0	-	0	0	-	0
35	May, 2024 Est.	0	-	0	0	-	0
36		0		0	0		0
37	July, 2024 Est.	0	-	0	0	-	0
38	June, 2024 Act.	0	-	0	0	-	0
39	June, 2024 Est.	0	-	0	0	-	0
40		0		0	0		0
41	August, 2024 Est.	0	-	0	0	-	0
42	July, 2024 Act.	0	-	0	0	-	0
43	July, 2024 Est.	0	-	0	0	-	0
44		0		0	0		0
45	September, 2024 Est.	0	-	0	0	-	0
46	August, 2024 Act.	0	-	0	0	-	0
47	August, 2024 Est.	0	-	0	0	-	0
48		0		0	0		0
49	TOTAL	269,690		610	269,690		2,286

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEMAND PENALTY CREDITS/SUPPLIER REFUNDS RECEIVED OCTOBER 2023 - SEPTEMBER 2024
FROM VARIOUS SUPPLIERS

Line No.	Refund Type	Date Received	Total
1	Texas Eastern Transmission: Penalty Credit Docket No. RP-23-980	October 2023	4,067
2	Texas Eastern Transmission: Penalty Credit Docket No. RP-24-68	December 2023	485
3	Columbia Gas Transmission, LLC: Penalty Credit Docket No. RP-24-286	December 2023	510,386
4	Total Penalty Credits/Supplier Refunds to Pass Back		514,938
5	Interest Calculated on Schedule 5 Sheet 2 of 2		41,236
6	Total Penalty Credits/Supplier Refunds to Pass Back With Interest		556,174

COLUMBIA GAS OF PENNSYLVANIA, INC.
PENALTY CREDITS RECEIVED OCTOBER 2023 - SEPTEMBER 2024
PASSBACK INTEREST CALCULATION

Line No.	Month	Refund	Number of Months			Rate	Amount of Interest	Total
		(1)	(2)			(3)	(4 = 1 x 2 x 3)	(5 = 1 + 4)
		$				%	$	$
1	October, 2023	4,067	18	/	12	6.00%	366	4,433
2	November	0	17	/	12	6.00%	0	0
3	December	510,871	16	/	12	6.00%	40,870	551,741
4	January, 2024	0	15	/	12	6.00%	0	0
5	February	0	14	/	12	6.00%	0	0
6	March	0	13	/	12	6.00%	0	0
7	April	0	12	/	12	6.00%	0	0
8	May	0	11	/	12	6.00%	0	0
9	June	0	10	/	12	6.00%	0	0
10	July	0	9	/	12	6.00%	0	0
11	August	0	8	/	12	6.00%	0	0
12	September	0	7	/	12	6.00%	0	0
13	TOTAL	514,938					41,236	556,174

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
FEBRUARY, 2023 THROUGH JANUARY, 2024

Line No.	Month	TOTAL GAS COST RECOVERY FROM SALES	STANDBY DEMAND REVENUE	NSS CAPACITY/ BANKING REVENUE	PURCHASED GAS COST RECOVERY	COST OF FUEL	OVER (UNDER) COLLECTION
		(1)	(2)	(3)	(4 = 1+2+3)	(5)	(6 = 4 - 5)
		$	$	$	$	$	$
	Reference:	Schedule 1, Sheet 1a and 1b	Schedule 1 Sheet 1b	Schedule 1 Sheet 1b		Schedule 1, Sheet 1a and 1b	
1	February 2023	48,348,636	55,799	967	48,405,402	36,491,772	11,913,629
2	March	35,187,062	56,738	(98)	35,243,702	41,310,580	(6,066,879)
3	April	22,784,684	56,738	125	22,841,547	9,524,554	13,316,993
4	May	12,080,655	55,156	87	12,135,898	9,738,096	2,397,803
5	June	5,627,347	55,156	33	5,682,536	10,256,765	(4,574,229)
6	July	4,354,428	55,156	45	4,409,630	8,267,537	(3,857,907)
7	August	4,086,612	55,819	68	4,142,499	7,170,495	(3,027,996)
8	September	4,390,505	55,819	65	4,446,389	12,930,388	(8,483,999)
9	October	5,836,665	57,768	89	5,894,522	11,724,802	(5,830,280)
10	November	12,154,384	59,741	789	12,214,914	18,912,992	(6,698,078)
11	December	25,056,051	78,846	961	25,135,858	20,663,113	4,472,746
12	January 2024	30,586,082	78,846	1,056	30,665,984	30,222,612	443,371
13	TOTAL	210,493,111	721,581	4,188	211,218,880	217,213,706	(5,994,826)

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF COMMODITY OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
FEBRUARY, 2023 THROUGH JANUARY, 2024

Line No.	Month	Total Commodity Sales Revenue	Rate Schedule NSS Gas Cost Recovery	Total Commodity Purchase Gas Cost Recovery	Total Commodity Cost of Fuel	Total Commodity Over/(Under) Collection	Number of Months	Rate	Commodity Over/(Under) Collection Interest	Total Commodity Over/(Under) Collection
		(1)	(2)	(3 = 1 + 2)	(4)	(5 = 3 - 4)	(6)	(7)	(8 = 5 x 6 x 7)	(9 = 5 + 8)
			$	$	$	$			$	$
1	February 2023	35,478,472	17,305	35,495,777	28,201,626	7,294,150	14 / 12	8.50%	723,337	8,017,487
2	March	24,725,989	11,797	24,737,786	33,018,820	(8,281,034)	13 / 12	8.50%	(762,545)	(9,043,579)
3	April	15,019,864	5,325	15,025,189	3,468,234	11,556,955	12 / 12	8.50%	982,341	12,539,296
4	May	7,754,039	4,904	7,758,943	3,320,253	4,438,690	11 / 12	8.50%	345,848	4,784,538
5	June	3,583,319	1,151	3,584,470	4,032,397	(447,927)	10 / 12	8.50%	(31,728)	(479,655)
6	July	2,666,091	2,183	2,668,273	2,073,429	594,844	9 / 12	8.50%	37,921	632,765
7	August	2,378,517	2,662	2,381,179	979,367	1,401,812	8 / 12	8.50%	79,436	1,481,248
8	September	2,561,776	2,566	2,564,341	6,738,519	(4,174,177)	7 / 12	8.50%	(206,970)	(4,381,147)
9	October	3,308,469	3,959	3,312,428	3,451,853	(139,425)	18 / 12	8.50%	(17,777)	(157,202)
10	November	6,624,551	16,508	6,641,060	10,445,283	(3,804,223)	17 / 12	8.50%	(458,092)	(4,262,315)
11	December	13,748,797	16,132	13,764,928	12,032,316	1,732,612	16 / 12	8.50%	196,363	1,928,975
12	January 2024	15,973,630	18,797	15,992,426	21,592,044	(5,599,617)	15 / 12	8.50%	(594,959)	(6,194,576)
13	TOTAL	133,823,513	103,288	133,926,801	129,354,142	4,572,658			293,175	4,865,833

Exhibit 1-F
Schedule 1
Sheet 1b of 1
Demand

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF DEMAND OVER/(UNDER) COLLECTIONS FROM GAS COST RATE
FEBRUARY, 2023 THROUGH JANUARY, 2024

Line No.	Month	Total Demand Sales Revenue	Total Banking and Balancing Revenue	Total Standby Demand Revenue	NSS Capacity Release Revenue	Demand Purchased Gas Cost Recovery	Demand Cost of Fuel	Total Demand Over/(Under) Collection	Number of Months	Rate	Demand Over/(Under) Collection Interest	Total Demand Over/(Under) Collection
		(1)	(2)	(3)	(4)	(5 =1+2+3+4)	(6)	(7 = 5 - 6)	(8)	(9)	(10 = 7 x 8 x 9)	(11 = 7 + 10)
		$	$	$	$	$	$	$			$	$
1	February 2023	12,852,859	175	55,799	792	12,909,625	8,290,146	4,619,479	14 / 12	8.50%	458,098	5,077,577
2	March	10,449,276	122	56,738	(220)	10,505,916	8,291,760	2,214,155	13 / 12	8.50%	203,887	2,418,042
3	April	7,759,495	89	56,738	36	7,816,358	6,056,320	1,760,038	12 / 12	8.50%	149,603	1,909,641
4	May	4,321,712	62	55,156	25	4,376,955	6,417,842	(2,040,887)	11 / 12	8.50%	(159,019)	(2,199,906)
5	June	2,042,878	23	55,156	9	2,098,066	6,224,368	(4,126,302)	10 / 12	8.50%	(292,280)	(4,418,582)
6	July	1,686,155	33	55,156	13	1,741,356	6,194,108	(4,452,752)	9 / 12	8.50%	(283,863)	(4,736,615)
7	August	1,705,433	48	55,819	20	1,761,320	6,191,128	(4,429,808)	8 / 12	8.50%	(251,022)	(4,680,830)
8	September	1,826,164	46	55,819	19	1,882,048	6,191,870	(4,309,822)	7 / 12	8.50%	(213,695)	(4,523,517)
9	October	2,524,237	63	57,768	26	2,582,094	8,272,949	(5,690,855)	18 / 12	8.50%	(725,584)	(6,416,439)
10	November	5,513,324	178	59,741	611	5,573,854	8,467,709	(2,893,855)	17 / 12	8.50%	(348,468)	(3,242,323)
11	December	11,291,123	173	78,846	788	11,370,930	8,630,796	2,740,134	16 / 12	8.50%	310,548	3,050,682
12	January 2024	14,593,656	195	78,846	861	14,673,557	8,630,569	6,042,989	15 / 12	8.50%	642,068	6,685,057
13	TOTAL	76,566,310	1,207	721,581	2,981	77,292,079	87,859,564	(10,567,485)			(509,727)	(11,077,212)

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATEMENT OF OVER/UNDER COLLECTIONS FROM GAS COST RATE
FEBRUARY, 2023 THROUGH JANUARY, 2024

LINE NO.	MONTH	EXHIBIT 1-D SCHEDULE 1 SHEET 1 OF 3 SUMMARY OF PURCHASED GAS COSTS	EXHIBIT 1-F SCHEDULE 1 SHEET 1 OF 1 COST OF FUEL	DIFFERENCE
		(1)	(2)	(3 = 1 - 2)
		$	$	$
		1_/	2_/	
1	February 2023	39,317,547	36,491,772	2,825,775
2	March	43,120,064	41,310,580	1,809,483
3	April	11,731,705	9,524,554	2,207,151
4	May	10,365,283	9,738,096	627,187
5	June	7,878,593	10,256,765	(2,378,171)
6	July	6,917,688	8,267,537	(1,349,850)
7	August	7,309,555	7,170,495	139,060
8	September	5,854,751	12,930,388	(7,075,637)
9	October	11,440,128	11,724,802	(284,674)
10	November	19,831,181	18,912,992	918,189
11	December	22,626,707	20,663,113	1,963,594
12	January 2024	32,915,589	30,222,612	2,692,977
13	TOTAL	219,308,791	217,213,706	2,095,085

1_/ Per Financial Statements of Columbia Gas of Pennsylvania, Inc.
Includes Total Gas Purchased Expenses, excluding Account 805 Other Purchased Gas Expenses and Account 806 Exchange Gas & End User and Pipeline Imbalances.

2_/ Represents Gas Purchased Expenses - System Supply.

COLUMBIA GAS OF PENNSYLVANIA, INC.
RECONCILE COMMODITY 2023 1-D TO COMOODITY COST OF FUEL EXHIBIT 1-F, SCHEDULE 1, SHEET 1A
FEBRUARY, 2023 THROUGH JANUARY, 2024

LINE NO.	MONTH YEAR	TOTAL COMMODITY 2024 1307(F) 1-D SCHEDULES	OFF-SYSTEM SALES	OSS EXCHANGE	CHOICE EUB	TOTAL	TOTAL COMMODITY COST OF FUEL EXHIBIT 1-F SCHEDULE 1	DIFFERENCE	
		$	$	$	$	$	$	$	
		(a)	(b)	(e)	(f)	(a-b-c-d-e-f =g)	(h)	(i - g = f)	
1	February 2023	31,002,801	785,819	617,026	1,397,930	28,202,026	28,201,626	400	
2	March	34,803,461	378,063	437,045	969,969	33,018,384	33,018,820	(436)	
3	April	5,650,227	3,587,288	(1,146,587)	(259,146)	3,468,672	3,468,234	437	
4	May	3,922,441	1,529,190	0	(927,003)	3,320,253	3,320,253	(0)	
5	June	1,629,226	2,098,991	(3,573,320)	(928,842)	4,032,397	4,032,397	0	
6	July	698,580	454,130	92,516	(1,921,495)	2,073,429	2,073,429	0	
7	August	1,093,427	341,715	104,558	(332,213)	979,367	979,367	0	
8	September	(362,118)	730,974	(6,933,346)	(898,265)	6,738,519	6,738,519	0	
9	October	3,142,179	569,642	0	(879,316)	3,451,853	3,451,853	0	
10	November	11,338,472	7,750	0	885,439	10,445,284	10,445,283	0	
11	December	13,970,911	571,578	511,568	855,447	12,032,318	12,032,316	2	
12	January 2024	24,260,021	945,078	483,628	1,239,272	21,592,044	21,592,044	(0)	
13	Total	131,149,628	12,000,216	(9,406,913)	(798,221)	129,354,546	129,354,142	403	1/

1/ Correction from January 2023.

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PURCHASED GAS COSTS
BY TYPE BY MONTH

LINE NO.	MONTH	CITY GATE PURCHASES (SCHEDULE 2)	NON-LOCAL PURCHASES (SCHEDULE 3)	LOCAL PURCHASES (SCHEDULE 4)	GAS STORED UNDERGROUND (SCHEDULE 5)	TRANSPORTATION & GATHERING (SCHEDULE 6)	TOTAL SCHEDULES
		(1)	(2)	(3)	(4)	(5)	(6=1+2+3+4+5)
		$	$	$	$	$	$
1	FEBRUARY, 2023	0	2,944,842	38,301	30,119,724	6,215,080	39,317,947
2	MARCH	0	1,307,897	21,820	35,596,710	6,193,636	43,120,064
3	APRIL	471,150	10,111,135	20,675	(2,815,875)	3,944,620	11,731,705
4	MAY	950,477	8,768,764	14,123	(3,259,131)	3,891,050	10,365,283
5	JUNE	821,734	5,173,576	16,572	(2,042,739)	3,909,452	7,878,593
6	JULY	745,946	4,851,083	11,333	(2,564,182)	3,873,507	6,917,688
7	AUGUST	571,872	4,751,304	11,863	(1,899,730)	3,874,245	7,309,555
8	SEPTEMBER	293,868	2,496,743	10,141	(814,534)	3,868,534	5,854,751
9	OCTOBER	148,775	4,909,456	8,661	357,438	6,015,799	11,440,128
10	NOVEMBER	463,657	1,053,042	9,589	12,206,381	6,098,513	19,831,181
11	DECEMBER	971,478	6,133,133	12,266	9,241,423	6,268,407	22,626,707
12	JANUARY, 2024	1,886,059	7,832,941	12,657	16,833,595	6,350,338	32,915,589
13	TOTAL	7,325,015	60,333,915	188,001	90,959,080	60,503,181	219,309,192

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PURCHASED GAS COSTS
BY TYPE BY MONTH

LINE NO.	MONTH	CITY GATE PURCHASES (SCHEDULE 2) COMMODITY (1) $	NON-LOCAL PURCHASES (SCHEDULE 3) COMMODITY (2) $	NON-LOCAL PURCHASES (SCHEDULE 3) DEMAND (3) $	LOCAL PURCHASES (SCHEDULE 4) COMMODITY (4) $	GAS STORED UNDERGROUND (SCHEDULE 5) DEMAND (5) $	GAS STORED UNDERGROUND (SCHEDULE 5) COMMODITY (6) $	TRANSPORTATION & GATHERING (SCHEDULE 6) DEMAND (7) $	TRANSPORTATION & GATHERING (SCHEDULE 6) COMMODITY (8) $	TOTAL DEMAND (9=3+5+7) $	TOTAL COMMODITY (10=1+2+4+6+8) $	TOTAL SCHEDULES (11=9+10) $
1	FEBRUARY, 2023	0	2,944,842	0	38,301	2,203,206	27,916,518	6,111,940	103,140	8,315,146	31,002,801	39,317,947
2	MARCH	0	1,307,897	0	21,820	2,203,508	33,393,202	6,113,095	80,541	8,316,602	34,803,461	43,120,064
3	APRIL	471,150	10,111,135	0	20,675	2,203,508	(5,019,383)	3,877,970	66,650	6,081,478	5,650,227	11,731,705
4	MAY	950,477	8,768,764	0	14,123	2,588,255	(5,847,386)	3,854,587	36,463	6,442,842	3,922,441	10,365,283
5	JUNE	821,734	5,173,576	0	16,572	2,395,882	(4,438,620)	3,853,486	55,966	6,249,368	1,629,226	7,878,593
6	JULY	745,946	4,851,083	0	11,333	2,395,882	(4,960,064)	3,823,226	50,281	6,219,108	698,580	6,917,688
7	AUGUST	571,872	4,751,304	0	11,863	2,395,882	(4,295,612)	3,820,246	53,999	6,216,128	1,093,427	7,309,555
8	SEPTEMBER	293,868	2,496,743	0	10,141	2,395,882	(3,210,416)	3,820,988	47,546	6,216,870	(362,118)	5,854,751
9	OCTOBER	148,775	4,909,456	0	8,661	2,395,882	(2,038,444)	5,902,067	113,731	8,297,949	3,142,179	11,440,128
10	NOVEMBER	463,657	994,242	58,800	9,589	2,395,841	9,810,540	6,038,068	60,445	8,492,709	11,338,472	19,831,181
11	DECEMBER	971,478	6,074,333	58,800	12,266	2,395,841	6,845,583	6,201,156	67,251	8,655,796	13,970,911	22,626,707
12	JANUARY, 2024	1,886,059	7,774,141	58,800	12,657	2,395,841	14,437,754	6,200,928	149,409	8,655,569	24,260,021	32,915,589
13	TOTAL	7,325,015	60,157,515	176,400	188,001	28,365,406	62,593,674	59,617,758	885,423	88,159,564	131,149,628	219,309,192

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF PURCHASED GAS COSTS
BY TYPE BY MONTH

LINE NO.	MONTH	CITY GATE PURCHASES (SCHEDULE 2)	NON-LOCAL PURCHASES (SCHEDULE 3)	LOCAL PURCHASES (SCHEDULE 4)	GAS STORED UNDERGROUND (SCHEDULE 5)	TRANSPORTATION & GATHERING (SCHEDULE 6)	TOTAL
		(1)	(2)	(3)	(4)	(5)	(6=1+2+3+4+5)
		Dth	Dth	Dth	Dth	Dth	Dth
1	FEBRUARY, 2023	0	1,262,045	8,594	4,420,633	(21,611)	5,669,661
2	MARCH	0	607,974	8,339	5,309,382	(25,409)	5,900,286
3	APRIL	267,500	5,993,864	8,983	(3,013,326)	(87,834)	3,169,187
4	MAY	597,700	5,190,118	8,159	(3,622,687)	(91,659)	2,081,631
5	JUNE	569,200	3,694,544	8,985	(3,148,148)	(64,617)	1,059,964
6	JULY	449,140	3,267,631	7,130	(3,248,420)	(60,883)	414,598
7	AUGUST	437,380	3,327,717	7,186	(2,946,489)	(56,993)	768,801
8	SEPTEMBER	237,925	2,225,918	7,209	(2,838,198)	(60,948)	(428,094)
9	OCTOBER	110,000	3,590,281	7,717	(1,598,589)	(60,653)	2,048,756
10	NOVEMBER	254,700	491,052	6,705	3,829,487	(15,100)	4,566,844
11	DECEMBER	470,058	2,981,191	5,648	2,619,480	(52,945)	6,023,432
12	JANUARY, 2024	586,350	2,877,575	5,648	5,639,103	(58,198)	9,050,478
13	TOTAL	3,979,953	35,509,910	90,303	1,402,228	(656,850)	40,325,544

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF
CITY GATE GAS PURCHASES

LINE NO.	MONTH	VOLUME	RATE	TOTAL GAS COST
		(1)	(2)	(3=1x2)
		DTH	$/DTH	$
1	FEBRUARY, 2023	0	0.0000	0
2	MARCH	0	0.0000	0
3	APRIL	267,500	1.7613	471,150
4	MAY	597,700	1.5902	950,477
5	JUNE	569,200	1.4437	821,734
6	JULY	449,140	1.6608	745,946
7	AUGUST	437,380	1.3075	571,872
8	SEPTEMBER	237,925	1.2351	293,868
9	OCTOBER	110,000	1.3525	148,775
10	NOVEMBER	254,700	1.8204	463,657
11	DECEMBER	470,058	2.0667	971,478
12	JANUARY, 2024	586,350	3.1875	1,868,967
13	ADJUSTMENT	0	0.0000	17,092
14	TOTAL	3,979,953		7,325,015

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF CITY GATE PURCHASES
FROM COLONIAL ENERGY INC

LINE NO.	MONTH	VOLUME	RATE	TOTAL GAS COST
		(1)	(2)	(3=1x2)
		DTH	$/DTH	$
1	FEBRUARY, 2023	0	0.0000	0
2	MARCH	0	0.0000	0
3	APRIL	0	0.0000	0
4	MAY	0	0.0000	0
5	JUNE	0	0.0000	0
6	JULY	0	0.0000	0
7	AUGUST	0	0.0000	0
8	SEPTEMBER	0	0.0000	0
9	OCTOBER	0	0.0000	0
10	NOVEMBER	254,700	1.8204	463,657
11	DECEMBER	470,058	2.0667	971,478
12	JANUARY, 2024	555,350	2.6816	1,489,217
13	ADJUSTMENT	0	0.0000	17,092
14	TOTAL	1,280,108		2,924,352

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF CITY GATE PURCHASES
FROM NJR ENERGY SERVICES

LINE NO.	MONTH	VOLUME	RATE	TOTAL GAS COST
		(1)	(2)	(3=1x2)
		DTH	$/DTH	$
1	FEBRUARY, 2023	0	0.0000	0
2	MARCH	0	0.0000	0
3	APRIL	267,500	1.7613	471,150
4	MAY	597,700	1.5902	950,477
5	JUNE	569,200	1.4437	821,734
6	JULY	449,140	1.6608	745,946
7	AUGUST	437,380	1.3075	571,872
8	SEPTEMBER	237,925	1.2351	293,868
9	OCTOBER	110,000	1.3525	148,775
10	NOVEMBER	0	0.0000	0
11	DECEMBER	0	0.0000	0
12	JANUARY, 2024	0	0.0000	0
13	TOTAL	2,668,845		4,003,822

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF CITY GATE PURCHASES
FROM DTE ENERGY

LINE NO.	MONTH	VOLUME	RATE	TOTAL GAS COST
		(1) DTH	(2) $/DTH	(3=1x2) $
1	FEBRUARY, 2023	0	0.0000	0
2	MARCH	0	0.0000	0
3	APRIL	0	0.0000	0
4	MAY	0	0.0000	0
5	JUNE	0	0.0000	0
6	JULY	0	0.0000	0
7	AUGUST	0	0.0000	0
8	SEPTEMBER	0	0.0000	0
9	OCTOBER	0	0.0000	0
10	NOVEMBER	0	0.0000	0
11	DECEMBER	0	0.0000	0
12	JANUARY, 2024	31,000	12.2500	379,750
13	TOTAL	31,000		379,750

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM

LINE NO.	MONTH	VOLUME (1) Dth	TOTAL COMMODITY DOLLARS (2) $	TOTAL DEMAND DOLLARS (3) $	TOTAL DOLLARS (4=2+3) $
1	FEBRUARY, 2023	1,262,045	2,944,842	0	2,944,842
2	MARCH	607,974	1,307,897	0	1,307,897
3	APRIL	5,993,864	10,111,135	0	10,111,135
4	MAY	5,190,118	8,768,764	0	8,768,764
5	JUNE	3,694,544	5,173,576	0	5,173,576
6	JULY	3,267,631	4,851,083	0	4,851,083
7	AUGUST	3,327,717	4,751,304	0	4,751,304
8	SEPTEMBER	2,225,918	2,496,743	0	2,496,743
9	OCTOBER	3,590,281	4,909,456	0	4,909,456
10	NOVEMBER	491,052	994,242	58,800	1,053,042
11	DECEMBER	2,981,191	6,074,333	58,800	6,133,133
12	JANUARY, 2024	2,877,575	7,774,141	58,800	7,832,941
13	TOTAL	35,509,910	60,157,515	176,400	60,333,915

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
FEBRUARY 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	ASCENT RESOURCES - UTICA, LLC	494,431	1,279,617
3	BP ENERGY COMPANY	1,500	3,293
4	ELEVATION ENERGY GROUP (CARBONBETTER, LLC)	900	1,953
5	CASTLETON COMMODITIES MERCHANT TRADING L.P.	18,351	38,727
6	CIMA ENERGY LP (formerly CIMA ENERGY, LTD)	6,903	16,116
7	CITADEL ENERGY MARKETING LLC	59,400	124,884
8	DIRECT ENERGY BUSINESS MARKETING, LLC	13,800	30,000
9	DTE ENERGY TRADING, INC.	41,200	95,162
10	EDF TRADING NORTH AMERICA, LLC (EAGLE ENERGY)	7,500	20,288
11	EMERA ENERGY SERVICES, INC.	4,800	9,456
12	EQT ENERGY, LLC.	140,000	366,800
13	EQUINOR NATURAL GAS LLC (STATOIL)	5,000	13,450
14	GREYLOCK ENERGY, LLC	3,300	7,353
15	INTERSTATE GAS SUPPLY, INC.	14,100	32,379
16	NEXTERA ENERGY POWER MARKETING, LLC	59,700	122,202
17	SEQUENT ENERGY MANAGEMENT, LP	283,000	717,255
18	SPOTLIGHT ENERGY LLC	51,200	117,341
19	SOUTHWESTERN ENERGY SERVICES COMPANY	6,000	12,690
20	TC ENERGY MARKETING INC.	10,615	29,724
21	TENASKA GAS STORAGE, LLC	200	426
22	TRAILSTONE ENERGY MARKETING, INC.	7,500	18,750
23	TWIN EAGLE RESOURCE MANAGEMENT, LLC	4,000	12,540
24	TOTAL ESTIMATE	1,233,400	3,070,405
25	ADJUST TO ACTUAL		
26	GAS LOST DUE TO LINE HITS	(64)	(397)
27	ICE CHARGES	0	201
28	GAS SOLD TO SHIPPER (RADS 3.11)	(7,297)	(31,538)
29	GAS PURCHASED FROM SHIPPER (RADS 3.12)	37,609	80,818
30	OMO/OFO CHARGES (RADS 3.7, 3.8, 4.11)	0	(162,345)
31	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(157)
32	GAS LEFT ON FOR RECONNECT	(1,603)	(12,144)
33	TOTAL ADJUST TO ACTUAL	28,645	(125,563)
34	TOTAL SCHEDULE 3, SHEET 2	1,262,045	2,944,842

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
MARCH 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	BP ENERGY COMPANY	3,200	5,856
3	ELEVATION ENERGY GROUP (CARBONBETTER, LLC)	4,000	9,870
4	CASTLETON COMMODITIES MERCHANT TRADING L.P.	36,500	68,291
5	CHEVRON NATURAL GAS (CHEVRONTEXACO)	13,500	29,700
6	CIMA ENERGY LP (formerly CIMA ENERGY, LTD)	23,600	54,970
7	CITADEL ENERGY MARKETING LLC	129,299	281,431
8	CITIGROUP ENERGY INC.	20,000	45,513
9	CONOCOPHILLIPS COMPANY	5,000	11,850
10	DIRECT ENERGY BUSINESS MARKETING, LLC	34,500	80,826
11	DTE ENERGY TRADING, INC.	11,300	23,300
12	EQT ENERGY, LLC.	5,000	8,350
13	FREEPOINT COMMODITIES LLC	3,000	7,125
14	INTERSTATE GAS SUPPLY, INC.	28,000	60,818
15	MACQUARIE ENERGY LLC	10,000	21,550
16	MORGAN STANLEY CAPITAL GROUP INC.	1,500	3,600
17	NEXTERA ENERGY POWER MARKETING, LLC	73,910	152,732
18	NJR ENERGY SERVICES COMPANY	1,000	2,338
19	RANGE RESOURCES - APPALACHIA, LLC	24,500	52,900
20	SEQUENT ENERGY MANAGEMENT, LP	42,000	95,218
21	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	31,100	73,548
22	SPIRE MARKETING INC. (LACLEDE ENERGY)	400	965
23	SPOTLIGHT ENERGY LLC	38,200	83,613
24	TC ENERGY MARKETING INC.	15,000	33,638
25	TENASKA GAS STORAGE, LLC	2,900	4,930
26	TWIN EAGLE RESOURCE MANAGEMENT, LLC	29,500	65,730
27	VITOL INC. (VITOL S.A., INC.)	15,000	35,213
28	TOTAL ESTIMATE	601,909	1,313,873
29	ADJUST TO ACTUAL		
30	GAS LOST DUE TO LINE HITS	(7)	(42)
31	ICE CHARGES	0	370
32	GAS SOLD TO SHIPPER (RADS 3.11)	(1,361)	(4,354)
33	GAS PURCHASED FROM SHIPPER (RADS 3.12)	9,328	15,165
34	OMO/OFO CHARGES (RADS 3.7, 3.8, 4.11)	0	(2,657)
35	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(101)
36	GAS LEFT ON FOR RECONNECT	(1,895)	(14,357)
37	TOTAL ADJUST TO ACTUAL	6,065	(5,976)
38	TOTAL SCHEDULE 3, SHEET 3	607,974	1,307,897

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
APRIL 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	ARM ENERGY MANAGEMENT LLC	6,000	10,110
3	ELEVATION ENERGY GROUP (CARBONBETTER, LLC)	10,000	18,550
4	CASTLETON COMMODITIES MERCHANT TRADING L.P.	16,600	28,536
5	CITADEL ENERGY MARKETING LLC	121,000	195,880
6	CITIGROUP ENERGY INC.	600,000	1,030,500
7	CNX GAS COMPANY LLC	450,000	774,000
8	CONOCOPHILLIPS COMPANY	29,800	53,481
9	CONSTELLATION ENERGY SERVICES, INC. (INTEGRYS ENERGY)	900	1,436
10	DIRECT ENERGY BUSINESS MARKETING, LLC	26,000	39,120
11	DIVERSIFIED ENERGY MARKETING LLC (DEM)	5,000	9,150
12	DTE ENERGY TRADING, INC.	1,897,400	3,223,379
13	DXT COMMODITIES NORTH AMERICA INC.	7,100	9,930
14	EASTERN ENERGY FIELD SERVICES INC.	700	1,211
15	EMERA ENERGY SERVICES, INC.	5,000	8,475
16	EQT ENERGY, LLC.	1,099,326	1,827,654
17	GREYLOCK ENERGY, LLC	331,000	524,430
18	INTERSTATE GAS SUPPLY, INC.	18,600	34,215
19	JPMORGAN CHASE BANK, N.A.	600,000	1,032,000
20	KAISER MARKETING APPALACHIAN, LLC	15,000	26,050
21	MERCURIA ENERGY GAS TRADING LLC	371,000	623,407
22	NEXTERA ENERGY POWER MARKETING, LLC	60,900	110,519
23	NJR ENERGY SERVICES COMPANY	21,499	41,531
24	RANGE RESOURCES - APPALACHIA, LLC	65,000	107,675
25	SEQUENT ENERGY MANAGEMENT, LP	120,000	187,425
26	SIX ONE COMMODITIES	300	390
27	SOUTH JERSEY RESOURCES GROUP, LLC	5,000	9,425
28	SPARK ENERGY	100	195
29	SPOTLIGHT ENERGY LLC	43,500	78,668
30	SOUTHWESTERN ENERGY SERVICES COMPANY	5,600	9,282
31	TC ENERGY MARKETING INC.	20,086	34,840
32	TWIN EAGLE RESOURCE MANAGEMENT, LLC	21,400	32,782
33	TOTAL ESTIMATE	5,973,811	10,084,243
34	ADJUST TO ACTUAL		
35	GAS LOST DUE TO LINE HITS	(149)	(909)
36	ICE CHARGES	0	727
37	GAS SOLD TO SHIPPER (RADS 3.11)	(1,101)	(3,272)
38	GAS PURCHASED FROM SHIPPER (RADS 3.12)	22,664	38,087
39	CHOICE INTERIM CASH OUT	0	5
40	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(42)
41	GAS LEFT ON FOR RECONNECT	(1,361)	(7,705)
42	TOTAL ADJUST TO ACTUAL	20,053	26,892
43	TOTAL SCHEDULE 3, SHEET 4	5,993,864	10,111,135

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
MAY 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	BP ENERGY COMPANY	3,000	4,905
3	ELEVATION ENERGY GROUP (CARBONBETTER, LLC)	5,500	9,511
4	CASTLETON COMMODITIES MERCHANT TRADING L.P.	59,800	94,960
5	CIMA ENERGY LP (formerly CIMA ENERGY, LTD)	5,000	6,288
6	CITADEL ENERGY MARKETING LLC	341,800	541,031
7	CITIGROUP ENERGY INC.	469,000	833,900
8	CNX GAS COMPANY LLC	465,000	823,050
9	CONOCOPHILLIPS COMPANY	7,500	11,939
10	CONSTELLATION ENERGY SERVICES, INC. (INTEGRYS ENERGY)	1,500	2,393
11	DTE ENERGY TRADING, INC.	2,066,600	3,575,708
12	EMERA ENERGY SERVICES, INC.	2,000	3,020
13	EQT ENERGY, LLC.	1,021,450	1,700,880
14	GREYLOCK ENERGY, LLC	141,800	241,132
15	INTERSTATE GAS SUPPLY, INC.	10,000	16,125
16	JPMORGAN CHASE BANK, N.A.	1,000	1,715
17	KAISER MARKETING APPALACHIAN, LLC	18,100	29,543
18	KOCH ENERGY SERVICES, LLC	10,700	18,814
19	MERCURIA ENERGY GAS TRADING LLC	225,800	369,163
20	NEXTERA ENERGY POWER MARKETING, LLC	3,000	4,870
21	NJR ENERGY SERVICES COMPANY	400	590
22	RANGE RESOURCES - APPALACHIA, LLC	18,324	29,269
23	SEQUENT ENERGY MANAGEMENT, LP	217,900	316,838
24	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	1,500	2,475
25	SPIRE MARKETING INC. (LACLEDE ENERGY)	2,100	3,192
26	SPOTLIGHT ENERGY LLC	5,500	10,271
27	SPRAGUE OPERATING RESOURCES LLC (SPRAGUE ENER)	2,800	4,918
28	SOUTHWESTERN ENERGY SERVICES COMPANY	43,700	59,326
29	TENASKA GAS STORAGE, LLC	5,000	9,500
30	TWIN EAGLE RESOURCE MANAGEMENT, LLC	300	562
31	VITOL INC. (VITOL S.A., INC.)	24,500	37,955
32	WASHINGTON GAS LIGHT COMPANY	5,000	8,250
33	TOTAL ESTIMATE	5,185,574	8,772,089
34	ADJUST TO ACTUAL		
35	CITIGROUP ENERGY INC.	0	3,000
36	NJR ENERGY SERVICES COMPANY	0	(0)
37	TC ENERGY MARKETING INC.	0	(74)
38	TWIN EAGLE RESOURCE MANAGEMENT, LLC	0	90
39	GAS LOST DUE TO LINE HITS	(124)	(755)
40	ICE CHARGES	0	559
41	GAS SOLD TO SHIPPER (RADS 3.11)	(5,430)	(14,507)
42	GAS PURCHASED FROM SHIPPER (RADS 3.12)	11,146	15,019
43	OMO/OFO CHARGES (RADS 3.7, 3.8, 4.11)	0	0
44	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(726)
45	GAS LEFT ON FOR RECONNECT	(1,048)	(5,932)
46	TOTAL ADJUST TO ACTUAL	4,544	(3,325)
47	TOTAL SCHEDULE 3, SHEET 5	5,190,118	8,768,764

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
JUNE 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	BP ENERGY COMPANY	15,500	19,968
3	CLEARWATER ENTERPRISES, L.L.C.	5,000	6,625
4	CNX GAS COMPANY LLC	533,100	798,859
5	DIVERSIFIED ENERGY MARKETING LLC (DEM)	90,000	130,050
6	DTE ENERGY TRADING, INC. (COENERGY TRADING)	594,000	757,145
7	EDF TRADING NORTH AMERICA, LLC (EAGLE ENERGY)	20,000	25,850
8	EQT ENERGY, LLC. (EQUITABLE ENERGY, LLC)	695,000	901,250
9	GREYLOCK ENERGY, LLC (ENERGY CORPORATION OF AMERICA)	392,500	555,953
10	INTERSTATE GAS SUPPLY, INC.	690,000	1,032,125
11	JP MORGAN CHASE BANK, N.A.	300	404
12	KOCH ENERGY SERVICES, LLC	30,000	33,150
13	MORGAN STANLEY CAPITAL GROUP INC.	449,073	683,714
14	NEXTERA ENERGY MARKETING, LLC	25,000	32,150
15	PACIFIC SUMMIT ENERGY LLC	30,000	38,050
16	SEQUENT ENERGY MANAGEMENT, LP	50,000	70,600
17	SOUTHWESTERN ENERGY SERVICES COMPANY	29,400	35,574
18	TC ENERGY MARKETING INC.	20,000	27,988
19	TENASKA GAS STORAGE, LLC	19,972	25,464
20	TOTAL ESTIMATE	3,688,845	5,174,917
21	ADJUST TO ACTUAL		
22	GAS LOST DUE TO LINE HITS	(251)	(1,514)
23	ICE CHARGES	0	345
24	GAS SOLD TO SHIPPER (RADS 3.11)	(2,183)	(5,594)
25	GAS PURCHASED FROM SHIPPER (RADS 3.12)	8,804	9,262
26	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(15)
27	GAS LEFT ON FOR RECONNECT	(671)	(3,825)
28	TOTAL ADJUST TO ACTUAL	5,699	(1,341)
29	TOTAL SCHEDULE 3, SHEET 6	3,694,544	5,173,576

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
JULY 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	ASCENT RESOURCES - UTICA, LLC	310,000	489,025
3	BP ENERGY COMPANY	1,300	2,470
4	CITADEL ENERGY MARKETING LLC	295,500	395,500
5	CITIGROUP ENERGY INC.	30,000	41,025
6	DTE ENERGY TRADING, INC. (COENERGY TRADING)	235,700	319,715
7	EASTERN ENERGY FIELD SERVICES INC.	5,000	9,163
8	EMERA ENERGY SERVICES, INC.	2,500	3,075
9	EQT ENERGY, LLC	1,331,800	1,947,214
10	GREYLOCK ENERGY, LLC	420,000	689,930
11	KAISER MARKETING APPALACHIAN, LLC	58,500	100,755
12	MERCURIA ENERGY GAS TRADING LLC	7,500	12,075
13	RANGE RESOURCES - APPALACHIA, LLC	50,000	82,550
14	SEQUENT ENERGY MANAGEMENT, LP	343,000	475,358
15	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	155,000	241,025
16	SOUTHWESTERN ENERGY SERVICES COMPANY	6,400	8,960
17	SYMMETRY ENERGY	4,000	6,000
18	TOTAL ESTIMATE	3,256,200	4,823,839
19	ADJUST TO ACTUAL		
20	INTERSTATE GAS SUPPLY, INC.	0	20,125
21	TENASKA	0	(0)
22	GAS LOST DUE TO LINE HITS	(110)	(661)
23	ICE CHARGES	0	122
24	GAS SOLD TO SHIPPER (RADS 3.11)	(157)	(355)
25	GAS PURCHASED FROM SHIPPER (RADS 3.12)	12,525	13,397
26	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(81)
27	GAS LEFT ON FOR RECONNECT	(828)	(5,302)
28	TOTAL ADJUST TO ACTUAL	11,431	27,244
29	TOTAL SCHEDULE 3, SHEET 7	3,267,631	4,851,083

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
AUGUST 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	ASCENT RESOURCES - UTICA, LLC	620,000	830,800
3	BP ENERGY COMPANY	1,500	1,920
4	CITADEL ENERGY MARKETING LLC	617,293	830,259
5	CONSTELLATION ENERGY SERVICES, INC. (INTEGRYS ENERGY)	8,600	11,035
6	DIVERSIFIED ENERGY MARKETING LLC (DEM)	10,000	12,225
7	DTE ENERGY TRADING, INC. (COENERGY TRADING)	340,600	384,710
8	EDF TRADING NORTH AMERICA, LLC (EAGLE ENERGY)	15,000	13,050
9	EMERA ENERGY SERVICES, INC.	1,100	1,502
10	EQT ENERGY, LLC	387,500	399,125
11	EQUINOR NATURAL GAS LLC (STATOIL)	42,000	42,105
12	FREEPOINT COMMODITIES LLC	10,000	12,200
13	GREYLOCK ENERGY, LLC	322,000	407,950
14	INTERSTATE GAS SUPPLY, INC.	1,700	2,017
15	KOCH ENERGY SERVICES, LLC	28,000	27,825
16	NEXTERA ENERGY MARKETING, LLC	28,000	31,605
17	NJR ENERGY SERVICES COMPANY	400	500
18	RANGE RESOURCES - APPALACHIA, LLC	271,700	362,328
19	SEQUENT ENERGY MANAGEMENT, LP	283,000	307,735
20	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	7,800	10,362
21	SOUTH JERSEY RESOURCES GROUP, LLC	9,100	12,639
22	SPRAGUE OPERATING RESOURCES LLC (SPRAGUE ENER)	15,200	17,290
23	SOUTHWESTERN ENERGY SERVICES COMPANY	5,300	6,758
24	TC ENERGY MARKETING INC.	8,900	9,248
25	VITOL INC. (VITOL S.A., INC.)	31,400	42,003
26	TOTAL ESTIMATE	3,066,093	3,777,190
27	ADJUST TO ACTUAL		
28	GAS LOST DUE TO LINE HITS	(91)	(548)
29	ICE CHARGES	0	236
30	GAS SOLD TO SHIPPER (RADS 3.11)	(97)	(243)
31	GAS PURCHASED FROM SHIPPER (RADS 3.12)	16,773	19,990
32	CHOICE ANNUAL CASH OUT	245,856	960,216
33	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(335)
34	GAS LEFT ON FOR RECONNECT	(818)	(5,200)
35	TOTAL ADJUST TO ACTUAL	261,624	974,115
36	TOTAL SCHEDULE 3, SHEET 8	3,327,717	4,751,304

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
SEPTEMBER 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	CASTLETON COMMODITIES MERCHANT TRADING L.P.	15,000	16,650
3	CITADEL ENERGY MARKETING LLC	581,866	731,130
4	CNX GAS COMPANY LLC	300,000	318,000
5	DIVERSIFIED ENERGY MARKETING LLC (DEM)	5,000	7,725
6	DTE ENERGY TRADING, INC. (COENERGY TRADING)	435,000	453,270
7	EQT ENERGY, LLC	502,000	484,035
8	GREYLOCK ENERGY, LLC	10,000	16,450
9	KOCH ENERGY SERVICES, LLC	10,000	16,250
10	MERCURIA ENERGY GAS TRADING LLC	44,992	46,819
11	MORGAN STANLEY CAPITAL GROUP INC.	7,000	10,850
12	NEXTERA ENERGY MARKETING, LLC	10,000	8,000
13	SEQUENT ENERGY MANAGEMENT, LP	73,000	76,240
14	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	5,000	5,750
15	SOUTHWESTERN ENERGY SERVICES COMPANY	208,900	291,603
16	TC ENERGY MARKETING INC.	2,500	3,075
17	VITOL INC. (VITOL S.A., INC.)	13,000	20,150
18	TOTAL ESTIMATE	2,223,258	2,505,997
19	ADJUST TO ACTUAL		
20	TC ENERGY	0	13
21	GAS LOST DUE TO LINE HITS	(682)	(4,112)
22	ICE CHARGES	0	324
23	GAS SOLD TO SHIPPER (RADS 3.11)	(6,909)	(14,123)
24	GAS PURCHASED FROM SHIPPER (RADS 3.12)	9,867	9,437
25	CHOICE ANNUAL CASH OUT	1,318	5,146
26	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(4)
27	GAS LEFT ON FOR RECONNECT	(933)	(5,936)
28	TOTAL ADJUST TO ACTUAL	2,660	(9,255)
29	TOTAL SCHEDULE 3, SHEET 9	2,225,918	2,496,743

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
OCTOBER 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS
		(1)	(2)
1	ESTIMATE	Dth	$
2	BP ENERGY COMPANY	232,496	336,925
3	CARBONBETTER, LLC	4,000	8,660
4	CASTLETON COMMODITIES MERCHANT TRADING L.P.	171,696	241,455
5	CITADEL ENERGY MARKETING LLC	1,091,083	1,599,003
6	CONOCOPHILLIPS COMPANY	15,000	17,450
7	CONSTELLATION ENERGY SERVICES, INC. (INTEGRYS ENERGY)	10,000	12,300
8	CONSTELLATION NEWENERGY - GAS DIVISION, LLC	5,000	6,575
9	DIVERSIFIED ENERGY MARKETING LLC (DEM)	77,500	93,575
10	DTE ENERGY TRADING, INC. (COENERGY TRADING)	552,500	798,818
11	EQT ENERGY, LLC	640,447	853,275
12	FREEPOINT COMMODITIES LLC	15,000	17,513
13	INTERSTATE GAS SUPPLY, INC.	10,000	11,800
14	KAISER MARKETING APPALACHIAN, LLC	30,100	35,296
15	KOCH ENERGY SERVICES, LLC	155,000	195,300
16	MACQUARIE ENERGY LLC	31,000	33,893
17	MERCURIA ENERGY GAS TRADING LLC	265,500	338,378
18	NEXTERA ENERGY MARKETING, LLC	95,794	95,925
19	RADIATE ENERGY LLC	2,900	3,625
20	SEQUENT ENERGY MANAGEMENT, LP	14,626	14,913
21	SNYDER BROTHERS INC.	6,500	7,479
22	SOUTH JERSEY RESOURCES GROUP, LLC	5,700	6,238
23	SPIRE MARKETING INC. (LACLEDE ENERGY)	300	877
24	SOUTHWESTERN ENERGY SERVICES COMPANY	72,000	88,993
25	TC ENERGY MARKETING INC.	34,000	42,508
26	TENASKA GAS STORAGE, LLC	5,000	6,325
27	TWIN EAGLE RESOURCE MANAGEMENT, LLC	4,500	4,830
28	VITOL INC. (VITOL S.A., INC.)	21,000	26,413
29	TOTAL ESTIMATE	3,568,642	4,898,337
30	ADJUST TO ACTUAL		
31	KOCH	0	(1,250)
32	GAS LOST DUE TO LINE HITS	(27)	(161)
33	ICE CHARGES	0	304
34	GAS SOLD TO SHIPPER (RADS 3.11)	(2,135)	(4,528)
35	GAS PURCHASED FROM SHIPPER (RADS 3.12)	25,502	24,584
36	CHOICE INTERIM CASH OUT	0	0
37	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(64)
38	GAS LEFT ON FOR RECONNECT	(1,701)	(7,767)
39	TOTAL ADJUST TO ACTUAL	21,639	11,118
40	TOTAL SCHEDULE 3, SHEET 10	3,590,281	4,909,456

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
NOVEMBER 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS	TOTAL DEMAND DOLLARS	TOTAL DOLLARS
		(1)	(2)	(3)	(4=2+3)
1	ESTIMATE	Dth	$	$	$
2	BP ENERGY COMPANY	3,000	6,855	0	6,855
3	CASTLETON COMMODITIES MERCHANT TRADING L.P.	6,000	14,713	0	14,713
4	CNX GAS COMPANY LLC	15,000	31,700	0	31,700
5	COLONIAL ENERGY, INC	3,000	5,381	0	5,381
6	CONSTELLATION ENERGY SERVICES, INC. (INTEGRYS ENERGY)	2,000	5,240	0	5,240
7	DTE ENERGY TRADING, INC. (COENERGY TRADING)	330,000	693,375	0	693,375
8	EQT ENERGY, LLC	4,000	9,600	0	9,600
9	MACQUARIE ENERGY LLC	5,000	10,250	0	10,250
10	MERCURIA ENERGY GAS TRADING LLC	11,100	21,931	0	21,931
11	MORGAN STANLEY CAPITAL GROUP INC.	23,500	55,451	0	55,451
12	NEXTERA ENERGY MARKETING, LLC	5,700	10,432	0	10,432
13	RANGE RESOURCES - APPALACHIA, LLC	2,500	4,844	0	4,844
14	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	2,000	4,585	0	4,585
15	SOUTHWESTERN ENERGY SERVICES COMPANY	29,000	66,680	0	66,680
16	TC ENERGY MARKETING INC.	2,000	5,140	0	5,140
17	VITOL INC. (VITOL S.A., INC.)	14,000	33,260	58,800	92,060
18	TOTAL ESTIMATE	457,800	979,437	58,800	1,038,237
19	ADJUST TO ACTUAL				
20	GAS LOST DUE TO LINE HITS	(200)	(1,188)	0	(1,188)
21	ICE CHARGES	0	51	0	51
22	GAS SOLD TO SHIPPER (RADS 3.11)	(3,469)	(6,795)	0	(6,795)
23	GAS PURCHASED FROM SHIPPER (RADS 3.12)	39,827	36,111	0	36,111
24	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(56)	0	(56)
25	GAS LEFT ON FOR RECONNECT	(2,906)	(13,318)	0	(13,318)
26	TOTAL ADJUST TO ACTUAL	33,252	14,805	0	14,805
27	TOTAL SCHEDULE 3, SHEET 11	491,052	994,242	58,800	1,053,042

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
DECEMBER 2023

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS	TOTAL DEMAND DOLLARS	TOTAL DOLLARS
		(1)	(2)	(3)	(4=2+3)
1	ESTIMATE	Dth	$	$	$
2	ASCENT RESOURCES - UTICA, LLC	40,000	82,400	0	82,400
3	BP ENERGY COMPANY	800	1,460	0	1,460
4	CARBONBETTER, LLC	2,000	4,030	0	4,030
5	CASTLETON COMMODITIES MERCHANT TRADING L.P.	235,600	539,524	0	539,524
6	CITIGROUP ENERGY INC.	22,400	44,400	0	44,400
7	CNX GAS COMPANY LLC	310,000	626,200	0	626,200
8	COLONIAL ENERGY, INC	56,900	115,643	0	115,643
9	CONOCOPHILLIPS COMPANY	17,000	38,548	0	38,548
10	DTE ENERGY TRADING, INC. (COENERGY TRADING)	1,529,000	3,124,080	0	3,124,080
11	EDF TRADING NORTH AMERICA, LLC (EAGLE ENERGY)	24,200	49,210	0	49,210
12	EQT ENERGY, LLC	248,000	513,360	0	513,360
13	INTERSTATE GAS SUPPLY, INC.	20,000	41,050	0	41,050
14	KAISER MARKETING APPALACHIAN, LLC	5,000	10,000	0	10,000
15	KOCH ENERGY SERVICES, LLC	93,000	187,860	0	187,860
16	MERCURIA ENERGY GAS TRADING LLC	341,500	637,343	0	637,343
17	MORGAN STANLEY CAPITAL GROUP INC.	3,000	6,195	0	6,195
18	NEXTERA ENERGY MARKETING, LLC	300	636	0	636
19	NRG	2,000	4,060	0	4,060
20	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	1,000	1,900	0	1,900
21	SOUTH JERSEY RESOURCES GROUP, LLC	2,300	4,564	0	4,564
22	TC ENERGY MARKETING INC.	4,700	8,789	0	8,789
23	UNITED ENERGY TRADING, LLC	10,000	20,925	0	20,925
24	VITOL INC. (VITOL S.A., INC.)	18,500	35,969	58,800	94,769
25	TOTAL ESTIMATE	2,987,200	6,098,144	58,800	6,156,944
26	ADJUST TO ACTUAL				
27	CNX	0	(50)	0	(50)
28	COLONIAL	0	172	0	172
29	GAS LOST DUE TO LINE HITS	(75)	(444)	0	(444)
30	ICE CHARGES	0	186	0	186
31	GAS SOLD TO SHIPPER (RADS 3.11)	(4,670)	(13,247)	0	(13,247)
32	GAS PURCHASED FROM SHIPPER (RADS 3.12)	1,538	2,425	0	2,425
33	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	(32)	0	(32)
34	GAS LEFT ON FOR RECONNECT	(2,802)	(12,822)	0	(12,822)
35	TOTAL ADJUST TO ACTUAL	(6,009)	(23,811)	0	(23,811)
36	TOTAL SCHEDULE 3, SHEET 12	2,981,191	6,074,333	58,800	6,133,133

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS PURCHASES
NON-LOCAL, SHORT & LONG TERM
JANUARY 2024

LINE NO.	SUPPLIER	VOLUMES	TOTAL COMMODITY DOLLARS	TOTAL DEMAND DOLLARS	TOTAL DOLLARS
		(1)	(2)	(3)	(4=2+3)
1	ESTIMATE	Dth	$	$	$
2	BP ENERGY COMPANY	40,000	203,560	0	203,560
3	CASTLETON COMMODITIES MERCHANT TRADING L.P.	251,000	589,780	0	589,780
4	CITADEL ENERGY MARKETING LLC	780,000	1,647,763	0	1,647,763
5	CNX GAS COMPANY LLC	310,000	654,100	0	654,100
6	COLONIAL ENERGY, INC	16,000	33,784	0	33,784
7	CONSTELLATION ENERGY SERVICES, INC. (INTEGRYS ENERGY)	17,600	46,965	0	46,965
8	DTE ENERGY TRADING, INC. (COENERGY TRADING)	51,450	148,197	0	148,197
9	EQT ENERGY, LLC	250,000	541,455	0	541,455
10	INTERSTATE GAS SUPPLY, INC.	2,800	5,600	0	5,600
11	KOCH ENERGY SERVICES, LLC	582,778	1,237,100	0	1,237,100
12	MERCURIA ENERGY GAS TRADING LLC	159,000	463,130	0	463,130
13	MORGAN STANLEY CAPITAL GROUP INC.	12,000	33,190	0	33,190
14	NEXTERA ENERGY MARKETING, LLC	31,000	63,374	0	63,374
15	RADIATE ENERGY LLC	4,800	68,424	0	68,424
16	REPSOL ENERGY NORTH AMERICA CORPORATION	3,400	8,525	0	8,525
17	SEQUENT ENERGY MANAGEMENT, LP	5,200	8,957	0	8,957
18	SHELL ENERGY NORTH AMERICA (US), L.P. (CORAL)	8,000	93,680	0	93,680
19	SOUTH JERSEY RESOURCES GROUP, LLC	36,300	409,305	0	409,305
20	SPOTLIGHT ENERGY LLC	34,500	83,835	0	83,835
21	SPRAGUE OPERATING RESOURCES LLC (SPRAGUE ENER)	2,000	5,390	0	5,390
22	SOUTHWESTERN ENERGY SERVICES COMPANY	34,300	123,745	0	123,745
23	TWIN EAGLE RESOURCE MANAGEMENT, LLC	1,000	2,700	0	2,700
24	VITOL INC. (VITOL S.A., INC.)	241,500	1,327,638	58,800	1,386,438
25	TOTAL ESTIMATE	2,874,628	7,800,196	58,800	7,858,996
26	ADJUST TO ACTUAL				
27	COLONIAL	0	501	0	501
28	GAS LOST DUE TO LINE HITS	(3,786)	(16,557)	0	(16,557)
29	ICE CHARGES	0	132	0	132
30	GAS SOLD TO SHIPPER (RADS 3.11)	(3,786)	(13,453)	0	(13,453)
31	GAS PURCHASED FROM SHIPPER (RADS 3.12)	10,920	16,713	0	16,713
32	CHOICE INTERIM CASH OUT	2,174	3,231	0	3,231
33	OMO/OFO CHARGES (RADS 3.7, 3.8, 4.11)	0	(6,116)	0	(6,116)
34	CHOICE NON-COMPLIANCE CHARGES (RADS 4.12)	0	0	0	0
35	GAS LEFT ON FOR RECONNECT	(2,576)	(10,506)	0	(10,506)
36	TOTAL ADJUST TO ACTUAL	2,947	(26,056)	0	(26,056)
37	TOTAL SCHEDULE 3, SHEET 13	2,877,575	7,774,141	58,800	7,832,941

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF GAS PURCHASES
FROM LOCAL PRODUCERS

LINE NO.	MONTH	VOLUME	TOTAL DOLLARS
		(1)	(2)
		DTH	$
1	FEBRUARY, 2023	8,594	38,301
2	MARCH	8,339	21,820
3	APRIL	8,983	20,675
4	MAY	8,159	14,123
5	JUNE	8,985	16,572
6	JULY	7,130	11,333
7	AUGUST	7,186	11,863
8	SEPTEMBER	7,209	10,141
9	OCTOBER	7,717	8,661
10	NOVEMBER	6,705	9,589
11	DECEMBER	5,648	12,266
12	JANUARY, 2024	5,648	12,657
13	TOTAL	90,303	188,001

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS
APPLICABLE TO NET
GAS STORED UNDERGROUND

LINE NO.	MONTH	VOLUMES	DEMAND DOLLARS	COMMODITY DOLLARS	TOTAL DOLLARS
		(1) DTH	(2) $	(3) $	(4=2+3) $
1	FEBRUARY, 2023	4,420,633	2,203,206	27,916,518	30,119,724
2	MARCH	5,309,382	2,203,508	33,393,202	35,596,710
3	APRIL	(3,013,326)	2,203,508	(5,019,383)	(2,815,875)
4	MAY	(3,622,687)	2,588,255	(5,847,386)	(3,259,131)
5	JUNE	(3,148,148)	2,395,882	(4,438,621)	(2,042,739)
6	JULY	(3,248,420)	2,395,882	(4,960,064)	(2,564,182)
7	AUGUST	(2,946,489)	2,395,882	(4,295,612)	(1,899,730)
8	SEPTEMBER	(2,838,198)	2,395,882	(3,210,416)	(814,534)
9	OCTOBER	(1,598,589)	2,395,882	(2,038,444)	357,438
10	NOVEMBER	3,829,487	2,395,841	9,810,540	12,206,381
11	DECEMBER	2,619,480	2,395,841	6,845,583	9,241,423
12	JANUARY, 2024	5,639,103	2,395,841	14,437,754	16,833,595
13	TOTAL	1,402,228	28,365,406	62,593,674	90,959,080

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
APPLICABLE TO NET GAS STORED UNDERGROUND
BLACKHAWK FACILITY

LINE NO.	MONTH	VOLUME INJECTED	RATE	AMOUNT	VOLUME WITHDRAWN	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	0	2.6871	0	0	6.1891	0
2	ADJUSTMENT	0	2.6871	0	67	6.1891	415
3	ADJUSTMENT	0	2.6871	0	0	6.1891	(415)
4	MARCH	0	3.5279	0	0	6.1866	0
5	ADJUSTMENT	0	3.5279	0	67	6.1866	415
6	ADJUSTMENT	0	3.5279	0	0	6.1866	(415)
7	APRIL	0	1.7837	0	704	4.6934	3,304
8	ADJUSTMENT	0	1.7837	0	67	4.6934	314
9	ADJUSTMENT	0	1.7837	0	0	4.6934	(314)
10	MAY	0	1.7299	0	0	3.8010	0
11	ADJUSTMENT	0	1.7299	0	67	3.8010	255
12	ADJUSTMENT	0	1.7299	0	0	3.8010	(255)
13	JUNE	0	1.4280	0	0	3.3219	0
14	ADJUSTMENT	0	1.4280	0	67	3.3219	223
15	ADJUSTMENT	0	1.4280	0	0	3.3219	(223)
16	JULY	0	1.5445	0	0	3.0151	0
17	ADJUSTMENT	0	1.5445	0	67	3.0151	202
18	ADJUSTMENT	0	1.5445	0	0	3.0151	(202)
19	AUGUST	0	1.4775	0	0	2.8068	0
20	ADJUSTMENT	0	1.4775	0	67	2.8068	188
21	ADJUSTMENT	0	1.4775	0	0	2.8068	(188)
22	SEPTEMBER	0	1.1544	0	0	2.6155	0
23	ADJUSTMENT	0	1.1544	0	67	2.6155	175
24	ADJUSTMENT	0	1.1544	0	0	2.6155	(175)
25	OCTOBER	0	1.4446	0	0	2.5353	0
26	ADJUSTMENT	0	1.4446	0	67	2.5353	170
27	ADJUSTMENT	0	1.4446	0	0	2.5353	(170)
28	NOVEMBER	0	2.1263	0	0	2.5347	0
29	ADJUSTMENT	0	2.1263	0	67	2.5347	170
30	ADJUSTMENT	0	2.1263	0	0	2.5347	(170)
31	DECEMBER	0	2.1541	0	0	2.5335	0
32	ADJUSTMENT	0	2.1541	0	67	2.5335	170
33	ADJUSTMENT	0	2.1541	0	0	2.5335	(170)
34	JANUARY, 2024	0	2.9682	0	0	2.5362	0
35	ADJUSTMENT	0	2.9682	0	67	2.5362	170
36	ADJUSTMENT	0	2.9682	0	0	2.5362	(170)
37	TOTAL	0		0	1,508		3,303

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
APPLICABLE TO NET GAS STORED UNDERGROUND
COLUMBIA GAS TRANSMISSION - FSS

LINE NO.	MONTH	VOLUME INJECTED	RATE	AMOUNT	VOLUME WITHDRAWN	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	(1,055)	2.6871	(2,835)	4,029,847	6.1891	24,941,126
2	ADJUSTMENT	(23,844)	2.6871	(64,071)	(6,089)	6.1891	(37,685)
3	MARCH	0	3.5279	0	4,618,632	6.1866	28,573,629
4	ADJUSTMENT	(10,351)	3.5279	(36,517)	(33,078)	6.1866	(204,640)
5	APRIL	(2,463,144)	1.7837	(4,393,510)	55,305	4.6934	259,568
6	ADJUSTMENT	(7,799)	1.7837	(13,911)	(9,863)	4.6934	(46,291)
7	MAY	(3,314,440)	1.7299	(5,733,650)	160,424	3.8010	609,772
8	ADJUSTMENT	538	1.7299	931	439	3.8010	1,669
9	JUNE	(2,652,561)	1.4280	(3,787,857)	0	3.3219	0
10	ADJUSTMENT	8,685	1.4280	12,402	(2,425)	3.3219	(8,056)
11	JULY	(2,805,745)	1.5445	(4,333,473)	0	3.0151	0
12	ADJUSTMENT	121	1.5445	187	(5,987)	3.0151	(18,051)
13	AUGUST	(2,468,544)	1.4775	(3,647,274)	0	2.8068	0
14	ADJUSTMENT	(26,908)	1.4775	(39,757)	827	2.8068	2,321
15	SEPTEMBER	(2,423,123)	1.1544	(2,797,253)	0	2.6155	0
16	ADJUSTMENT	266	1.1544	307	9,594	2.6155	25,093
17	OCTOBER	(1,420,926)	1.4446	(2,052,670)	227,747	2.5353	577,407
18	ADJUSTMENT	(5,394)	1.4446	(7,792)	(14,491)	2.5353	(36,739)
19	NOVEMBER	0	2.1263	0	3,092,165	2.5347	7,837,711
20	ADJUSTMENT	(41,448)	2.1263	(88,131)	43,266	2.5347	109,666
21	DECEMBER	(68,768)	2.1541	(148,133)	2,002,928	2.5335	5,074,418
22	ADJUSTMENT	(1,602)	2.1541	(3,451)	74,585	2.5335	188,961
23	JANUARY, 2024	(125,729)	2.9682	(373,189)	5,053,159	2.5362	12,815,822
24	ADJUSTMENT	5,507	2.9682	16,346	31,142	2.5362	78,982
25	TOTAL	(17,846,264)		(27,493,301)	19,328,127		80,744,682

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
APPLICABLE TO NET GAS STORED UNDERGROUND
EASTERN GAS TRANSMISSION AND STORAGE

LINE NO.	MONTH	VOLUME INJECTED	RATE	AMOUNT	VOLUME WITHDRAWN	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	(17,397)	2.6871	(46,747)	201,528	6.1891	1,247,277
2	ADJUSTMENT	0	2.6871	0	(1,242)	6.1891	(7,687)
3	MARCH	0	3.5279	0	303,581	6.1866	1,878,134
4	ADJUSTMENT	(172)	3.5279	(607)	(277)	6.1866	(1,714)
5	APRIL	(305,505)	1.7837	(544,929)	0	4.6934	0
6	MAY	(244,509)	1.7299	(422,976)	0	3.8010	0
7	ADJUSTMENT	3,115	1.7299	5,389	0	3.8010	0
8	JUNE	(251,952)	1.4280	(359,787)	0	3.3219	0
9	ADJUSTMENT	(906)	1.4280	(1,294)	0	3.3219	0
10	JULY	(195,294)	1.5445	(301,632)	0	3.0151	0
11	ADJUSTMENT	352	1.5445	544	2,585	3.0151	7,794
12	AUGUST	(208,400)	1.4775	(307,911)	0	2.8068	0
13	ADJUSTMENT	68	1.4775	100	0	2.8068	0
14	SEPTEMBER	(190,522)	1.1544	(219,939)	0	2.6155	0
15	ADJUSTMENT	2,763	1.1544	3,190	0	2.6155	0
16	OCTOBER	(214,957)	1.4446	(310,527)	0	2.5353	0
17	NOVEMBER	(1,137)	2.1263	(2,418)	248,667	2.5347	630,296
18	ADJUSTMENT	4,924	2.1263	10,470	0	2.5347	0
19	DECEMBER	0	2.1541	0	307,068	2.5335	777,957
20	ADJUSTMENT	0	2.1541	0	(666)	2.5335	(1,687)
21	JANUARY, 2024	0	2.9682	0	346,617	2.5362	879,090
22	ADJUSTMENT	0	2.9682	0	0	2.5362	0
23	TOTAL	(1,619,529)		(2,499,074)	1,407,861		5,409,460

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
APPLICABLE TO NET GAS STORED UNDERGROUND
EQUITRANS

LINE NO.	MONTH	VOLUME INJECTED	RATE	AMOUNT	VOLUME WITHDRAWN	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	0	2.6871	0	284,900	6.1891	1,763,275
2	MARCH	0	3.5279	0	491,495	6.1866	3,040,683
3	APRIL	(217,050)	1.7837	(387,152)	0	4.6934	0
4	MAY	(224,285)	1.7299	(387,991)	0	3.8010	0
5	JUNE	(217,050)	1.4280	(309,947)	0	3.3219	0
6	JULY	(224,285)	1.5445	(346,408)	0	3.0151	0
7	AUGUST	(224,285)	1.4775	(331,381)	0	2.8068	0
8	SEPTEMBER	(217,050)	1.1544	(250,563)	0	2.6155	0
9	OCTOBER	(164,455)	1.4446	(237,572)	0	2.5353	0
10	NOVEMBER	0	2.1263	0	485,046	2.5347	1,229,446
11	DECEMBER	0	2.1541	0	347,076	2.5335	879,317
12	JANUARY, 2024	0	2.9682	0	354,505	2.5362	899,096
13	TOTAL	(1,488,460)		(2,251,014)	1,963,022		7,811,816

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
APPLICABLE TO NET GAS STORED UNDERGROUND
NATIONAL FUEL

LINE NO.	MONTH	VOLUME INJECTED	RATE	AMOUNT	VOLUME WITHDRAWN	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	0	2.6871	0	9,391	6.1891	58,122
2	ADJUSTMENT	0	2.6871	0	(1,699)	6.1891	(10,515)
3	MARCH	0	3.5279	0	11,182	6.1866	69,179
4	ADJUSTMENT	0	3.5279	0	(46)	6.1866	(285)
5	APRIL	0	1.7837	0	9,870	4.6934	46,324
6	ADJUSTMENT	0	1.7837	0	(367)	4.6934	(1,722)
7	MAY	0	1.7299	0	7,471	3.8010	28,397
8	ADJUSTMENT	0	1.7299	0	(2,958)	3.8010	(11,243)
9	JUNE	(19,141)	1.4280	(27,333)	0	3.3219	0
10	ADJUSTMENT	0	1.4280	0	(2,580)	3.3219	(8,571)
11	JULY	(13,039)	1.5445	(20,139)	0	3.0151	0
12	ADJUSTMENT	6	1.5445	9	0	3.0151	0
13	AUGUST	(12,974)	1.4775	(19,169)	0	2.8068	0
14	ADJUSTMENT	149	1.4775	220	0	2.8068	0
15	SEPTEMBER	(13,342)	1.1544	(15,402)	0	2.6155	0
16	ADJUSTMENT	147	1.1544	170	0	2.6155	0
17	OCTOBER	(196)	1.4446	(283)	0	2.5353	0
18	ADJUSTMENT	237	1.4446	342	0	2.5353	0
19	NOVEMBER	0	2.1263	0	11,868	2.5347	30,082
20	ADJUSTMENT	1,139	2.1263	2,422	0	2.5347	0
21	DECEMBER	0	2.1541	0	14,093	2.5335	35,705
22	ADJUSTMENT	0	2.1541	0	496	2.5335	1,257
23	JANUARY, 2024	0	2.9682	0	14,154	2.5362	35,897
24	ADJUSTMENT	0	2.9682	0	(142)	2.5362	(360)
25	TOTAL	(57,014)		(79,163)	70,733		272,266

COLUMBIA GAS OF PENNSYLVANIA, INC
SUMMARY OF HISTORICAL GAS VOLUMES
RETAINAGE BY PIPELINE FOR STORAGE ACTIVITY

LINE NO.	MONTH	TCO - FSS TOTAL (1) DTH
1	FEBRUARY, 2023	(53,774)
2	MARCH	(71,651)
3	APRIL	(75,544)
4	MAY	(8,549)
5	JUNE	(10,285)
6	JULY	(7,201)
7	AUGUST	(6,489)
8	SEPTEMBER	(6,998)
9	OCTOBER	(6,221)
10	NOVEMBER	(15,070)
11	DECEMBER	(55,797)
12	JANUARY, 2024	(40,177)
13	TOTAL	(357,756)

NOTE: THESE VOLUMES REPRESENT RETAINAGE BY THE PIPELINE.

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
STORAGE DEMAND CHARGES
COLUMBIA GAS TRANSMISSION CORPORATION

LINE NO.	MONTH	MDSQ VOLUME (1) DTH	MDSQ RATE (2) $/DTH	MDSQ AMOUNT (3=1x2) $	SCQ VOLUME (4) DTH	SCQ RATE (5) $/DTH	SCQ AMOUNT (6=4x5) $
1	FEBRUARY, 2023	395,714	2.5920	1,025,691	21,948,692	0.0467	1,025,004
2	MARCH	395,714	2.5920	1,025,691	21,948,692	0.0467	1,025,004
3	APRIL	395,714	2.5920	1,025,691	21,948,692	0.0467	1,025,004
4	MAY	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
5	ADJUSTMENT	0	0.0000	91,410	0	0.0000	100,964
6	JUNE	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
7	JULY	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
8	AUGUST	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
9	SEPTEMBER	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
10	OCTOBER	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
11	NOVEMBER	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
12	DECEMBER	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
13	JANUARY, 2024	395,714	2.8230	1,117,101	21,948,692	0.0513	1,125,968
14	TOTAL	4,748,568		13,222,388	263,384,304		13,309,687

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
STORAGE DEMAND CHARGES
EASTERN GAS TRANSMISSION AND STORAGE

LINE NO.	MONTH	MDSQ VOLUME (1) DTH	MDSQ RATE (2) $/DTH	MDSQ AMOUNT (3=1x2) $	SCQ VOLUME (4) DTH	SCQ RATE (5) $/DTH	SCQ AMOUNT (6=4x5) $
1	FEBRUARY, 2023	28,800	2.6784	77,138	2,111,176	0.0258	54,468
2	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
3	MARCH	28,800	2.6784	77,138	2,111,176	0.0258	54,468
4	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
5	APRIL	28,800	2.6784	77,138	2,111,176	0.0258	54,468
6	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
7	MAY	28,800	2.6784	77,138	2,111,176	0.0258	54,468
8	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
9	JUNE	28,800	2.6784	77,138	2,111,176	0.0258	54,468
10	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
11	JULY	28,800	2.6784	77,138	2,111,176	0.0258	54,468
12	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
13	AUGUST	28,800	2.6784	77,138	2,111,176	0.0258	54,468
14	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
15	SEPTEMBER	28,800	2.6784	77,138	2,111,176	0.0258	54,468
16	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
17	OCTOBER	28,800	2.6784	77,138	2,111,176	0.0258	54,468
18	ADJUSTMENT	(4,800)	2.6784	(12,856)	(240,000)	0.0258	(6,192)
19	NOVEMBER	28,800	2.6749	77,037	2,111,176	0.0258	54,468
20	ADJUSTMENT	(4,800)	2.6749	(12,840)	(240,000)	0.0258	(6,192)
21	DECEMBER	28,800	2.6749	77,037	2,111,176	0.0258	54,468
22	ADJUSTMENT	(4,800)	2.6749	(12,840)	(240,000)	0.0258	(6,192)
23	JANUARY, 2024	28,800	2.6749	77,037	2,111,176	0.0258	54,468
24	ADJUSTMENT	(4,800)	2.6749	(12,840)	(240,000)	0.0258	(6,192)
25	TOTAL	288,000		771,127	22,454,112		579,316

EXHIBIT 1-D
SCHEDULE 5
SHEET 10 OF 15

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
STORAGE DEMAND CHARGES
EQUITRANS

LINE NO.	MONTH	STORAGE DEMAND VOLUME	STORAGE DEMAND RATE	STORAGE DEMAND AMOUNT	STORAGE CAPACITY VOLUME	STORAGE CAPACITY RATE	STORAGE CAPACITY AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	19,130	1.5000	28,695	2,000,000	0.0260	52,000
2	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
3	MARCH	19,130	1.5000	28,695	2,000,000	0.0260	52,000
4	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
5	APRIL	19,130	1.5000	28,695	2,000,000	0.0260	52,000
6	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
7	MAY	19,130	1.5000	28,695	2,000,000	0.0260	52,000
8	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
9	JUNE	19,130	1.5000	28,695	2,000,000	0.0260	52,000
10	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
11	JULY	19,130	1.5000	28,695	2,000,000	0.0260	52,000
12	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
13	AUGUST	19,130	1.5000	28,695	2,000,000	0.0260	52,000
14	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
15	SEPTEMBER	19,130	1.5000	28,695	2,000,000	0.0260	52,000
16	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
17	OCTOBER	19,130	1.5000	28,695	2,000,000	0.0260	52,000
18	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
19	NOVEMBER	19,130	1.5000	28,695	2,000,000	0.0260	52,000
20	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
21	DECEMBER	19,130	1.5000	28,695	2,000,000	0.0260	52,000
22	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
23	JANUARY, 2024	19,130	1.5000	28,695	2,000,000	0.0260	52,000
24	ADJUSTMENT	(14,348)	1.5000	(21,522)	(1,500,000)	0.0260	(39,000)
25	TOTAL	57,384		86,076	6,000,000		156,000

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
STORAGE DEMAND CHARGES
NATIONAL FUEL

LINE NO.	MONTH	STORAGE DEMAND VOLUME (1) DTH	STORAGE DEMAND RATE (2) $/DTH	STORAGE DEMAND AMOUNT (3=1x2) $	STORAGE CAPACITY VOLUME (4) DTH	STORAGE CAPACITY RATE (5) $/DTH	STORAGE CAPACITY AMOUNT (6=4x5) $
1	FEBRUARY, 2023	2,429	2.7576	6,698	267,143	0.0501	13,384
2	ADJUSTMENT	0	0.0000	(302)	0	0.0000	0
3	MARCH	2,429	2.7576	6,698	267,143	0.0501	13,384
4	APRIL	2,429	2.7576	6,698	267,143	0.0501	13,384
5	MAY	2,429	2.7576	6,698	267,143	0.0501	13,384
6	JUNE	2,429	2.7576	6,698	267,143	0.0501	13,384
7	JULY	2,429	2.7576	6,698	267,143	0.0501	13,384
8	AUGUST	2,429	2.7576	6,698	267,143	0.0501	13,384
9	SEPTEMBER	2,429	2.7576	6,698	267,143	0.0501	13,384
10	OCTOBER	2,429	2.7576	6,698	267,143	0.0501	13,384
11	NOVEMBER	2,429	2.7643	6,714	267,143	0.0502	13,411
12	DECEMBER	2,429	2.7643	6,714	267,143	0.0502	13,411
13	JANUARY, 2024	2,429	2.7643	6,714	267,143	0.0502	13,411
14	TOTAL	29,148		80,126	3,205,716		160,687

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF GAS
INJECTION/WITHDRAWAL CHARGES
COLUMBIA GAS TRANSMISSION CORPORATION

LINE		WITHDRAWAL CHARGES			INJECTION CHARGES		
NO.	MONTH	VOLUME	RATE	AMOUNT	VOLUME	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	4,061,202	0.0153	62,136	1,060	0.0153	16
2	ADJUSTMENT	175,280	0.0153	2,675	3,013	0.0153	46
3	ADJUSTMENT	0	0.0000	498	0	0.0000	(72)
4	MARCH	4,603,030	0.0153	70,427	0	0.0000	0
5	ADJUSTMENT	(63,818)	0.0153	(975)	2,084	0.0153	32
6	ADJUSTMENT	0	0.0000	(19)	0	0.0000	(51)
7	APRIL	55,305	0.0153	846	2,449,275	0.0153	37,474
8	ADJUSTMENT	0	0.0000	(66)	675	0.0153	10
9	ADJUSTMENT	0	0.0000	0	0	0.0000	10
10	MAY	160,424	0.0153	2,454	3,314,440	0.0153	50,711
11	ADJUSTMENT	(2,018)	0.0153	(31)	17,071	0.0153	261
12	ADJUSTMENT	0	0.0000	(30)	0	0.0000	11
13	JUNE	0	0.0000	0	2,652,561	0.0153	40,584
14	ADJUSTMENT	111	0.0153	2	7,490	0.0153	115
15	ADJUSTMENT	0	0.0000	67	0	0.0000	3
16	JULY	0	0.0000	0	2,805,745	0.0153	42,928
17	ADJUSTMENT	0	0.0000	(7)	8,676	0.0153	153
18	AUGUST	0	0.0000	0	2,468,544	0.0153	37,769
19	ADJUSTMENT	0	0.0000	(34)	11,764	0.0153	180
20	ADJUSTMENT	0	0.0000	0	0	0.0000	301
21	SEPTEMBER	0	0.0000	0	2,423,124	0.0153	37,074
22	ADJUSTMENT	0	0.0000	(0)	2,402	0.0153	37
23	ADJUSTMENT	0	0.0000	0	0	0.0000	92
24	OCTOBER	38,064	0.0153	582	1,426,703	0.0153	21,829
25	ADJUSTMENT	0	0.0000	0	18,080	0.0153	277
26	ADJUSTMENT	0	0.0000	0	0	0.0000	(58)
27	NOVEMBER	3,092,165	0.0153	47,310	0	0.0000	0
28	ADJUSTMENT	0	0.0000	3,286	0	0.0000	581
29	DECEMBER	2,032,671	0.0153	31,100	69,048	0.0153	1,056
30	ADJUSTMENT	76,530	0.0153	1,171	0	0.0000	37
31	ADJUSTMENT	0	0.0000	12	0	0.0000	0
32	JANUARY, 2024	4,944,907	0.0153	75,657	126,241	0.0153	1,931
33	ADJUSTMENT	0	0.0000	351	0	0.0000	(98)
34	TOTAL	19,173,853		297,412	17,807,996		273,237

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF GAS
INJECTION/WITHDRAWAL CHARGES
EASTERN GAS TRANSMISSION AND STORAGE

LINE		WITHDRAWAL CHARGES			INJECTION CHARGES		
NO.	MONTH	VOLUME	RATE	AMOUNT	VOLUME	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	0	0.0000	0	0	0.0000	0
2	ADJUSTMENT	385,113	0.0274	10,552	0	0.0000	0
3	ADJUSTMENT	0	0.0000	(651)	0	0.0000	0
4	MARCH	0	0.0000	0	0	0.0000	0
5	ADJUSTMENT	183,682	0.0273	5,018	0	0.0000	0
6	ADJUSTMENT	0	0.0000	(378)	0	0.0000	0
7	APRIL	0	0.0000	0	334,153	0.0396	13,232
8	ADJUSTMENT	397,696	0.0210	8,334	0	0.0000	(1,234)
9	ADJUSTMENT	0	0.0000	(553)	0	0.0000	0
10	MAY	0	0.0000	0	262,756	0.0396	10,405
11	ADJUSTMENT	0	0.0000	(1)	0	0.0000	(1,258)
12	ADJUSTMENT	0	0.0000	0	0	0.0000	(918)
13	JUNE	0	0.0000	0	289,770	0.0396	11,475
14	ADJUSTMENT	0	0.0000	0	(17,341)	0.0396	(687)
15	ADJUSTMENT	0	0.0000	0	0	0.0000	(836)
16	ADJUSTMENT	0	0.0000	0	0	0.0000	(540)
17	JULY	0	0.0000	0	212,520	0.0396	8,416
18	ADJUSTMENT	0	0.0000	0	(38,170)	0.0396	(1,512)
19	ADJUSTMENT	0	0.0000	0	0	0.0000	147
20	AUGUST	0	0.0000	0	242,069	0.0396	9,586
21	ADJUSTMENT	0	0.0000	(782)	(17,294)	0.0396	(685)
22	ADJUSTMENT	0	0.0000	0	0	0.0000	(97)
23	SEPTEMBER	0	0.0000	0	227,700	0.0396	9,017
24	ADJUSTMENT	0	0.0000	(1,384)	(36,432)	0.0396	(1,443)
25	ADJUSTMENT	0	0.0000	0	0	0.0000	(429)
26	OCTOBER	0	0.0000	0	242,928	0.0396	9,620
27	ADJUSTMENT	0	0.0000	0	(37,178)	0.0396	(1,472)
28	ADJUSTMENT	0	0.0000	0	0	0.0000	(1,800)
29	NOVEMBER	0	0.0000	0	0	0.0000	0
30	ADJUSTMENT	0	0.0000	0	0	0.0000	(1,302)
31	ADJUSTMENT	0	0.0000	0	0	0.0000	126
32	DECEMBER	55,600	0.0256	1,423	0	0.0000	0
33	ADJUSTMENT	0	0.0000	5,273	0	0.0000	0
34	ADJUSTMENT	0	0.0000	0	0	0.0000	0
35	JANUARY, 2024	79,642	0.0256	2,039	0	0.0000	0
36	ADJUSTMENT	0	0.0000	(1,849)	0	0.0000	0
37	ADJUSTMENT	0	0.0000	6,769	0	0.0000	0
38	TOTAL	1,101,733		33,811	1,665,481		57,813

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF GAS
INJECTION/WITHDRAWAL CHARGES
EQUITRANS

LINE NO.	MONTH	WITHDRAWAL CHARGES VOLUME	RATE	AMOUNT	INJECTION CHARGES VOLUME	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	284,900	0.0069	1,966	0	0.0000	0
2	ADJUSTMENT	(213,674)	0.0069	(1,474)	0	0.0000	0
3	MARCH	491,495	0.0069	3,391	0	0.0000	0
4	ADJUSTMENT	(368,620)	0.0069	(2,543)	0	0.0000	0
5	APRIL	0	0.0000	0	217,050	0.0069	1,498
6	ADJUSTMENT	0	0.0000	0	(162,788)	0.0069	(1,123)
7	MAY	0	0.0000	0	224,285	0.0069	1,548
8	ADJUSTMENT	0	0.0000	0	(168,214)	0.0069	(1,161)
9	JUNE	0	0.0000	0	217,050	0.0069	1,498
10	ADJUSTMENT	0	0.0000	0	(162,788)	0.0069	(1,124)
11	JULY	0	0.0000	0	224,285	0.0069	1,548
12	ADJUSTMENT	0	0.0000	0	(168,214)	0.0069	(1,161)
13	AUGUST	0	0.0000	0	224,285	0.0069	1,548
14	ADJUSTMENT	0	0.0000	0	(168,214)	0.0069	(1,161)
15	SEPTEMBER	0	0.0000	0	217,050	0.0069	1,498
16	ADJUSTMENT	0	0.0000	0	(162,788)	0.0069	(1,123)
17	OCTOBER	0	0.0000	0	164,455	0.0069	1,135
18	ADJUSTMENT	0	0.0000	0	(123,341)	0.0069	(851)
19	NOVEMBER	485,046	0.0069	3,347	0	0.0000	0
20	ADJUSTMENT	(363,785)	0.0069	(2,510)	0	0.0000	0
21	DECEMBER	347,076	0.0069	2,395	0	0.0000	0
22	ADJUSTMENT	(260,307)	0.0069	(1,796)	0	0.0000	0
23	JANUARY, 2024	354,505	0.0069	2,446	0	0.0000	0
24	ADJUSTMENT	(265,879)	0.0069	(1,835)	0	0.0000	0
25	TOTAL	490,758		3,386	372,115		2,567

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF GAS
INJECTION/WITHDRAWAL CHARGES
NATIONAL FUEL

LINE NO.	MONTH	WITHDRAWAL CHARGES VOLUME	RATE	AMOUNT	INJECTION CHARGES VOLUME	RATE	AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)
		DTH	$/DTH	$	DTH	$/DTH	$
1	FEBRUARY, 2023	0	0.0000	0	0	0.0000	0
2	ADJUSTMENT	12,005	0.0473	568	0	0.0000	0
3	MARCH	0	0.0000	0	0	0.0000	0
4	ADJUSTMENT	9,300	0.0473	440	0	0.0000	0
5	APRIL	0	0.0000	0	0	0.0000	0
6	ADJUSTMENT	10,753	0.0473	509	0	0.0000	0
7	MAY	6,882	0.0473	326	0	0.0000	0
8	JUNE	4,860	0.0473	230	21,894	0.0473	1,036
9	ADJUSTMENT	0	0.0000	0	0	0.0000	0
10	JULY	0	0.0000	0	15,314	0.0473	724
11	ADJUSTMENT	0	0.0000	0	(2,759)	0.0473	(131)
12	AUGUST	0	0.0000	0	15,391	0.0473	728
13	ADJUSTMENT	0	0.0000	0	(2,424)	0.0473	(115)
14	SEPTEMBER	0	0.0000	0	16,002	0.0473	757
15	ADJUSTMENT	0	0.0000	0	(2,386)	0.0473	(113)
16	OCTOBER	0	0.0000	0	5,610	0.0472	265
17	ADJUSTMENT	0	0.0000	0	(2,897)	0.0473	(137)
18	NOVEMBER	300	0.0472	14	0	0.0000	0
19	ADJUSTMENT	4,767	0.0000	225	(1,705)	0.0472	(80)
20	DECEMBER	0	0.0000	0	0	0.0000	0
21	ADJUSTMENT	12,055	0.0472	569	(14)	0.0471	(1)
22	JANUARY, 2024	13,951	0.0472	658	0	0.0000	0
23	ADJUSTMENT	0	0.0000	0	0	0.0000	0
24	TOTAL	74,873		3,538	62,026		2,933

COLUMBIA GAS OF PENNSYLVANIA, INC.
SUMMARY OF HISTORIC COST OF GAS
TRANSPORTATION CHARGES

LINE NO.	MONTH	TRANSPORTATION SHRINKAGE VOLUMES 1/	TOTAL DEMAND COSTS	TOTAL COMMODITY COSTS	TOTAL TRANSPORTATION COSTS
		(1)	(2)	(3)	(4=2+3)
		Dth	$	$	$
1	FEBRUARY, 2023	(21,611)	6,111,940	103,140	6,215,080
2	MARCH	(25,409)	6,113,095	80,541	6,193,636
3	APRIL	(87,834)	3,877,970	66,650	3,944,620
4	MAY	(91,659)	3,854,587	36,463	3,891,050
5	JUNE	(64,617)	3,853,486	55,966	3,909,452
6	JULY	(60,883)	3,823,226	50,281	3,873,507
7	AUGUST	(56,993)	3,820,246	53,999	3,874,245
8	SEPTEMBER	(60,948)	3,820,988	47,546	3,868,534
9	OCTOBER	(60,653)	5,902,067	113,731	6,015,799
10	NOVEMBER	(15,100)	6,038,068	60,445	6,098,513
11	DECEMBER	(52,945)	6,201,156	67,251	6,268,407
12	JANUARY, 2024	(58,198)	6,200,928	149,409	6,350,338
13	TOTAL	(656,850)	59,617,758	885,423	60,503,181

1/ THESE VOLUMES REPRESENT RETAINAGE BY THE PIPLINES.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DETAIL OF HISTORIC COST OF GAS
COLUMBIA GAS TRANSMISSION CORPORATION
RATE SCHEDULE FTS - TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	BILLING RATE	AMOUNT	CAPACITY RELEASE 1/	TOTAL FTS AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5=3+4)
		Dth	$/Dth	$	$	$
1	FEBRUARY, 2023	134,931	9.8500	1,329,070	(193,799)	1,135,272
2	ADJUSTMENT				(51,368) 2/	(51,368)
3	MARCH	134,931	9.8500	1,329,070	(196,242)	1,132,829
4	ADJUSTMENT				(51,368) 2/	(51,368)
5	APRIL	134,931	10.3790	1,400,449	(207,601)	1,192,848
6	ADJUSTMENT				(54,126) 2/	(54,126)
7	MAY	134,931	10.2800	1,387,091	(206,217)	1,180,874
8	ADJUSTMENT				(53,610) 2/	(53,610)
9	JUNE	134,931	10.2800	1,387,091	(207,810)	1,179,280
10	ADJUSTMENT				(53,610) 2/	(53,610)
11	JULY	134,931	10.1850	1,374,272	(206,909)	1,167,363
12	ADJUSTMENT				(53,115) 2/	(53,115)
13	AUGUST	134,931	10.1850	1,374,272	(208,865)	1,165,407
14	ADJUSTMENT				(53,115) 2/	(53,115)
15	SEPTEMBER	134,931	10.1850	1,374,272	(210,912)	1,163,360
16	ADJUSTMENT				(53,115) 2/	(53,115)
17	OCTOBER	134,931	10.1850	1,374,272	(215,994)	1,158,278
18	ADJUSTMENT				(53,115) 2/	(53,115)
19	NOVEMBER	134,931	10.1850	1,374,272	(214,568)	1,159,704
20	ADJUSTMENT				(53,115) 2/	(53,115)
21	DECEMBER	134,931	10.1690	1,372,113	(216,702)	1,155,412
22	ADJUSTMENT				(53,031) 2/	(53,031)
23	JANUARY, 2024	134,931	10.1690	1,372,113	(217,007)	1,155,107
24	ADJUSTMENT				(53,031) 2/	(53,031)
25	TOTAL	1,619,172		16,448,359	(3,138,344)	13,310,015

1/ INCLUDES CAPACITY ALLOCATED TO SUPPLIERS PARTICIPATING IN COLUMBIA'S CHOICE PROGRAM.
2/ AMOUNT REPRESENTS 5,215 DTH OF CAPACITY 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.
DETAIL OF HISTORIC COST OF GAS
COLUMBIA GAS TRANSMISSION CORPORATION
RATE SCHEDULE SST - TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	BILLING RATE	AMOUNT	CAPACITY RELEASE	TOTAL SST AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5=3+4)
		Dth	$/Dth	$	$	$
1	FEBRUARY, 2023	395,714	9.7310	3,850,693	(44,296)	3,806,397
2	ADJUSTMENT				44,296	44,296
3	MARCH	395,714	9.7310	3,850,693	0	3,850,693
4	APRIL	197,857	10.2600	2,030,013	(3,600)	2,026,413
5	ADJUSTMENT				3,600	3,600
6	MAY	197,857	10.1610	2,010,425	(56,458)	1,953,967
7	ADJUSTMENT				56,458	56,458
8	JUNE	197,857	10.1610	2,010,425	(5,700)	2,004,725
9	ADJUSTMENT				5,700	5,700
10	JULY	197,857	10.0660	1,991,629	(5,580)	1,986,049
11	ADJUSTMENT				5,580	5,580
12	AUGUST	197,857	10.0660	1,991,629	(8,820)	1,982,809
13	ADJUSTMENT				8,820	8,820
14	SEPTEMBER	197,857	10.0660	1,991,629	0	1,991,629
15	OCTOBER	395,714	10.0660	3,983,257	0	3,983,257
16	NOVEMBER	395,714	10.0660	3,983,257	0	3,983,257
17	DECEMBER	395,714	10.0500	3,976,926	(33,279)	3,943,647
18	ADJUSTMENT				33,279	33,279
19	JANUARY, 2024	395,714	10.0500	3,976,926	(64,279)	3,912,647
20	ADJUSTMENT				64,279	64,279
21	TOTAL	3,561,426		35,647,500	0	35,647,500

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
COLUMBIA GAS TRANSMISSION CORPORATION
RATE SCHEDULE FTS -TRANSPORTATION COMMODITY CHARGES

LINE NO.	MONTH	FTS COMMODITY VOLUME	FTS BILLING RATE	FTS AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	150,668	0.0129	1,944
2	ADJUSTMENT	0	0.0000	(0)
3	MARCH	253,969	0.0129	3,276
4	APRIL	734,516	0.0147	10,797
5	MAY	705,137	0.0147	10,366
6	ADJUSTMENT	0	0.0000	(0)
7	JUNE	697,710	0.0147	10,256
8	ADJUSTMENT	4,244	0.0147	62
9	JULY	821,780	0.0147	12,080
10	ADJUSTMENT	0	0.0000	(1)
11	AUGUST	708,725	0.0147	10,418
12	ADJUSTMENT	0	0.0000	(4)
13	SEPTEMBER	445,052	0.0147	6,542
14	ADJUSTMENT	0	0.0000	0
15	OCTOBER	406,503	0.0146	5,935
16	ADJUSTMENT	0	0.0000	(0)
17	NOVEMBER	46,977	0.0146	686
18	ADJUSTMENT	0	0.0000	(0)
19	DECEMBER	377,474	0.0146	5,511
20	JANUARY, 2024	113,817	0.0146	1,662
21	ADJUSTMENT	0	0.0000	(0)
22	TOTAL	5,466,572		79,532

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
COLUMBIA GAS TRANSMISSION CORPORATION
RATE SCHEDULE SST -TRANSPORTATION COMMODITY CHARGES

		SST		
LINE NO.	MONTH	COMMODITY VOLUME	BILLING RATE	SST AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	3,718,126	0.0129	47,964
2	ADJUSTMENT			(3,212)
3	MARCH	4,161,206	0.0129	53,680
4	ADJUSTMENT			(7,175)
5	APRIL	2,468,328	0.0147	36,284
6	ADJUSTMENT			(7,090)
7	MAY	2,683,555	0.0147	39,448
8	ADJUSTMENT			(515)
9	JUNE	1,480,713	0.0147	21,766
10	ADJUSTMENT			777
11	JULY	1,215,519	0.0147	17,868
12	ADJUSTMENT			(139)
13	AUGUST	1,139,379	0.0147	16,749
14	ADJUSTMENT			(107)
15	SEPTEMBER	1,630,815	0.0147	23,973
16	ADJUSTMENT			(95)
17	OCTOBER	1,667,766	0.0146	24,349
18	ADJUSTMENT			(258)
19	NOVEMBER	3,097,547	0.0146	45,224
20	ADJUSTMENT			2,512
21	DECEMBER	3,329,264	0.0146	48,607
22	ADJUSTMENT			(4,281)
23	JANUARY, 2024	6,013,980	0.0146	87,804
24	ADJUSTMENT			(3,625)
25	TOTAL	32,606,198		440,510

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
EASTERN GAS TRANSMISSION AND STORAGE
RATE SCHEDULE FT and FTNN - TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	BILLING RATE	AMOUNT	CAPACITY RELEASE 1/	TOTAL FTNN AMOUNT
		(1)	(2)	(3=1x2)	(4)	(5=3+4)
		Dth	$/Dth	$	$	$
1	FEBRUARY, 2023	34,055	5.9674	203,220	(3,264)	199,956
2	ADJUSTMENT			(19,233)		(19,233)
3	MARCH	34,055	5.9674	203,220	(3,300)	199,920
4	ADJUSTMENT			(19,233)		(19,233)
5	APRIL	27,055	5.9674	161,448	(3,366)	158,082
6	ADJUSTMENT			(18,744)		(18,744)
7	MAY	27,055	5.9674	161,448	(3,384)	158,064
8	ADJUSTMENT			(19,233)		(19,233)
9	JUNE	27,055	5.9674	161,448	(3,348)	158,100
10	ADJUSTMENT			(18,744)		(18,744)
11	JULY	27,055	5.9674	161,448	(3,234)	158,214
12	ADJUSTMENT			(18,744)		(18,744)
13	AUGUST	27,055	5.9674	161,448	(3,211)	158,238
14	ADJUSTMENT			(18,744)		(18,744)
15	SEPTEMBER	27,055	5.9674	161,448	(3,258)	158,190
16	ADJUSTMENT			(18,744)		(18,744)
17	OCTOBER	27,055	5.9674	161,448	(3,312)	158,136
18	ADJUSTMENT			(18,744)		(18,744)
19	NOVEMBER	34,055	5.9493	202,603	(3,308)	199,295
20	ADJUSTMENT			(18,687)		(18,687)
21	DECEMBER	34,055	5.9493	202,603	(3,498)	199,105
22	ADJUSTMENT			(18,687)		(18,687)
23	JANUARY, 2024	34,055	5.9493	202,603	(3,421)	199,182
24	ADJUSTMENT			(18,687)		(18,687)
25	TOTAL	359,660		1,918,165	(39,904)	1,878,262

1/ INCLUDES CAPACITY ALLOCATED TO SUPPLIERS PARTICIPATING IN COLUMBIA'S CHOICE PROGRAM.

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
EASTERN GAS TRANSMISSION AND STORAGE
RATE SCHEDULE FT and FTNN - TRANSPORTATION COMMODITY CHARGES

LINE NO.	MONTH	COMMODITY VOLUME	BILLING RATE	TOTAL FTNN AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	294,385	0.0108	3,179
2	ADJUSTMENT			115
3	ADJUSTMENT			(268)
4	MARCH	303,875	0.0108	3,282
5	ADJUSTMENT			(492)
6	ADJUSTMENT			644
7	APRIL	371,460	0.0108	4,012
8	ADJUSTMENT			(63)
9	ADJUSTMENT			(149)
10	MAY	297,228	0.0108	3,210
11	ADJUSTMENT			(3,326)
12	ADJUSTMENT			(103)
13	JUNE	323,640	0.0108	3,495
14	ADJUSTMENT			(2,697)
15	ADJUSTMENT			(850)
16	JULY	247,612	0.0108	2,674
17	ADJUSTMENT			(2,740)
18	ADJUSTMENT			(141)
19	AUGUST	278,600	0.0108	3,009
20	ADJUSTMENT			(2,145)
21	ADJUSTMENT			(76)
22	SEPTEMBER	260,640	0.0108	2,815
23	ADJUSTMENT			(2,264)
24	ADJUSTMENT			(453)
25	OCTOBER	308,744	0.0107	3,304
26	ADJUSTMENT			(2,099)
27	ADJUSTMENT			1
28	NOVEMBER	317,429	0.0112	3,555
29	ADJUSTMENT			(2,292)
30	ADJUSTMENT			638
31	DECEMBER	318,109	0.0112	3,563
32	ADJUSTMENT			(165)
33	ADJUSTMENT			(629)
34	JANUARY, 2024	514,527	0.0112	5,763
35	ADJUSTMENT			(885)
36	ADJUSTMENT			(172)
37	TOTAL	3,836,249		21,250

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
EQUITRANS
RATE SCHEDULE FTS - TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	BILLING RATE	TOTAL FTS AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	55,000	7.6569	421,130
2	ADJUSTMENT			(77,080)
3	MARCH	55,000	7.6569	421,130
4	ADJUSTMENT			(77,080)
5	APRIL	32,000	8.0000	256,000
6	ADJUSTMENT			(39,264)
7	MAY	20,000	8.0000	160,000
8	ADJUSTMENT			(39,264)
9	JUNE	20,000	8.0000	160,000
10	ADJUSTMENT			(39,264)
11	JULY	20,000	8.0000	160,000
12	ADJUSTMENT			(39,264)
13	AUGUST	20,000	8.0000	160,000
14	ADJUSTMENT			(39,264)
15	SEPTEMBER	20,000	8.0000	160,000
16	ADJUSTMENT			(39,264)
17	OCTOBER	32,000	8.0000	256,000
18	ADJUSTMENT			(39,264)
19	NOVEMBER	55,000	7.6569	421,130
20	ADJUSTMENT			(110,960)
21	DECEMBER	55,000	7.6569	421,130
22	ADJUSTMENT			(75,112)
23	JANUARY, 2024	55,000	7.6569	421,130
24	ADJUSTMENT			(75,112)
25	TOTAL	439,000		2,727,458

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
EQUITRANS
TRANSPORTATION COMMODITY CHARGES

LINE NO.	MONTH	COMMODITY VOLUME	BILLING RATE	AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	417,592	0.0115	4,802
2	ADJUSTMENT	0	0.0000	(465)
3	ADJUSTMENT	0	0.0000	(3,253)
4	MARCH	483,027	0.0115	5,555
5	ADJUSTMENT	0	0.0000	(416)
6	ADJUSTMENT	0	0.0000	(3,854)
7	APRIL	368,550	0.0115	4,238
8	ADJUSTMENT	0	0.0000	(716)
9	ADJUSTMENT	0	0.0000	(2,641)
10	MAY	380,835	0.0115	4,380
11	ADJUSTMENT	0	0.0000	2
12	ADJUSTMENT	0	0.0000	(3,286)
13	JUNE	368,550	0.0115	4,238
14	ADJUSTMENT	0	0.0000	2
15	ADJUSTMENT	0	0.0000	(3,180)
16	JULY	380,835	0.0115	4,380
17	ADJUSTMENT	0	0.0000	3
18	ADJUSTMENT	0	0.0000	(3,287)
19	AUGUST	380,835	0.0115	4,380
20	ADJUSTMENT	0	0.0000	2
21	ADJUSTMENT	0	0.0000	(3,287)
22	SEPTEMBER	368,550	0.0115	4,238
23	ADJUSTMENT	0	0.0000	3
24	ADJUSTMENT	0	0.0000	(3,181)
25	OCTOBER	319,889	0.0114	3,647
26	ADJUSTMENT	0	0.0000	6
27	ADJUSTMENT	0	0.0000	(2,739)
28	NOVEMBER	490,456	0.0114	5,591
29	ADJUSTMENT	0	0.0000	(4,300)
30	ADJUSTMENT	0	0.0000	143
31	DECEMBER	584,822	0.0114	6,667
32	ADJUSTMENT	0	0.0000	(455)
33	ADJUSTMENT	0	0.0000	(4,659)
34	JANUARY, 2024	818,166	0.0489	39,990
35	ADJUSTMENT	0	0.0000	(5,556)
36	ADJUSTMENT	0	0.0000	(462)
37	TOTAL	5,362,107		46,528

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TENNESSEE GAS PIPELINE CORPORATION
RATE SCHEDULE FTA - TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	BILLING RATE	TOTAL FTA AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	23,600	4.7112	111,184
2	MARCH	23,600	4.7112	111,184
3	APRIL	23,600	4.7112	111,184
4	MAY	23,600	4.7112	111,184
5	JUNE	23,600	4.7112	111,184
6	JULY	23,600	4.7112	111,184
7	AUGUST	23,600	4.7112	111,184
8	SEPTEMBER	23,600	4.7112	111,184
9	OCTOBER	23,600	4.7112	111,184
10	NOVEMBER	23,600	4.7117	111,196
11	DECEMBER	30,600	4.6638	142,711
12	JANUARY, 2024	30,600	4.6638	142,711
13	TOTAL	297,200		1,397,276

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TENNESSEE GAS PIPELINE CORPORATION
RATE SCHEDULE FTA - TRANSPORTATION COMMODITY CHARGES

LINE NO.	MONTH	COMMODITY VOLUME	BILLING RATE	TOTAL FTA AMOUNT
		(1) Dth	(2) $/Dth	(3=1x2) $
1	FEBRUARY, 2023	354,066	0.0253	8,975
2	MARCH	330,993	0.0261	8,637
3	APRIL	251,098	0.0256	6,416
4	MAY	267,518	0.0227	6,083
5	ADJUSTMENT	0	0.0000	35
6	JUNE	179,304	0.0275	4,931
7	ADJUSTMENT	0	0.0000	(0)
8	JULY	185,348	0.0261	4,846
9	ADJUSTMENT	0	0.0000	(0)
10	AUGUST	116,428	0.0361	4,207
11	ADJUSTMENT	0	0.0000	(3)
12	SEPTEMBER	173,400	0.0273	4,728
13	ADJUSTMENT	0	0.0000	(3)
14	OCTOBER	264,540	0.0223	5,903
15	ADJUSTMENT	0	0.0000	(3)
16	NOVEMBER	325,178	0.0244	7,948
17	ADJUSTMENT	0	0.0000	(0)
18	DECEMBER	367,311	0.0271	9,968
19	ADJUSTMENT	0	0.0000	(0)
20	JANUARY, 2024	480,341	0.0263	12,619
21	ADJUSTMENT	0	0.0000	0
22	TOTAL	3,295,525		85,286

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TEXAS EASTERN TRANSMISSION CORPORATION
TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	TOTAL CDS AND FT1 DEMAND 1/
		(1)
		$
1	FEBRUARY, 2023	502,780
2	MARCH	502,780
3	APRIL	303,765
4	ADJUSTMENT	(104,041)
5	MAY	295,933
6	ADJUSTMENT	(45)
7	JUNE	295,933
8	JULY	295,933
9	AUGUST	302,671
10	SEPTEMBER	304,090
11	ADJUSTMENT	1,418
12	OCTOBER	304,090
13	NOVEMBER	304,090
14	DECEMBER	410,545
15	JANUARY, 2024	410,545
16	TOTAL	4,130,486

1/ CDS AND FT1 DEMAND CHARGES ARE DETAILED ON SHEETS 13-14.

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TEXAS EASTERN TRANSMISSION CORPORATION
TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	CDS CONTRACT # 800387 RATE	AMOUNT	DEMAND VOLUME	CDS CONTRACT # 910463 RATE	AMOUNT	DEMAND VOLUME	CDS CONTRACT # 910464 RATE	AMOUNT	TOTAL AMOUNT CDS
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)	(7)	(8)	(9=7x8)	(10=3+6+9)
		Dth	$/Dth	$	Dth	$/Dth	$	Dth	$/Dth	$	$
1	FEBRUARY, 2023	5,390	12.7725	68,844	364	12.7653	4,647	9,951	12.6675	126,054	199,544
2	MARCH	5,390	12.7725	68,844	364	12.7653	4,647	9,951	12.6675	126,054	199,544
3	APRIL	5,390	10.2296	55,137	364	10.2241	3,722	9,951	10.0698	100,205	159,064
4	ADJUSTMENT	0	0.0000	(13,706)	0	0.0000	(925)	0	0.0000	(25,849)	(40,480)
5	MAY	5,390	10.2296	55,137	364	10.2241	3,722	9,951	10.0698	100,205	159,064
6	JUNE	5,390	10.2296	55,137	364	10.2241	3,722	9,951	10.0698	100,205	159,064
7	JULY	5,390	10.2296	55,137	364	10.2241	3,722	9,951	10.0698	100,205	159,064
8	AUGUST	5,390	10.1880	54,914	364	10.1827	3,706	9,951	9.9714	99,225	157,845
9	SEPTEMBER	5,390	10.2427	55,208	364	10.2372	3,726	9,951	10.0823	100,329	159,264
10	ADJUSTMENT	0	0.0000	294	0	0.0000	20	0	0.0000	1,104	1,418
11	OCTOBER	5,390	10.2427	55,208	364	10.2372	3,726	9,951	10.0823	100,329	159,264
12	NOVEMBER	5,390	10.2427	55,208	364	10.2372	3,726	9,951	10.0823	100,329	159,264
13	DECEMBER	5,390	10.2144	55,056	364	10.2090	3,716	9,951	10.0497	100,004	158,776
14	JANUARY, 2024	5,390	10.2144	55,056	364	10.2090	3,716	9,951	10.0497	100,004	158,776
15	TOTAL	64,680		675,474	4,368		45,592	119,412		1,228,403	1,949,469

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TEXAS EASTERN TRANSMISSION CORPORATION
TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	FT-1 CONTRACT # 830049 RATE	AMOUNT	DEMAND VOLUME	FT-1 CONTRACT # 910951 RATE	AMOUNT	DEMAND VOLUME	FT-1 CONTRACT # 911660 RATE	AMOUNT	DEMAND VOLUME	FT-1 CONTRACT # 911831-R1 RATE	AMOUNT	DEMAND VOLUME	FT-1 CONTRACT # 911923 RATE	AMOUNT	TOTAL AMOUNT FT-1	TOTAL CDS AND FT-1 DEMAND
		(11) Dth	(12) $/Dth	(13=11x12) $	(14) Dth	(15) $/Dth	(16=14x15) $	(17) Dth	(18) $/Dth	(19=17x18) $	(20) Dth	(21) $/Dth	(22=20x21) $	(23) Dth	(24) $/Dth	(25=23x24) $	(26=16+19+22) $	(27=10+26) $
1	FEBRUARY, 2023	10,000	12.0660	120,660	15,335	11.2529	172,563	100	2.0650	207	1,200	8.1720	9,806	0	0.0000	0	303,236	502,780
2	MARCH	10,000	12.0660	120,660	15,335	11.2529	172,563	100	2.0650	207	1,200	8.1720	9,806	0	0.0000	0	303,236	502,780
3	APRIL	0	0.0000	0	15,335	8.9148	136,708	100	2.0650	207	1,200	0.0000	7,787	0	0.0000	0	144,701	303,765
4	ADJUSTMENT	0	0.0000	(25,640)	0	0.0000	(35,855)	0	0.0000	(45)	0	0.0000	(2,020)	0	0.0000	0	(63,560)	(104,041)
5	MAY	0	0.0000	0	15,335	8.9148	136,708	100	1.6120	161	1,200	0.0000	7,787	0	0.0000	0	136,869	295,933
6	ADJUSTMENT	0	0.0000	0	0	0.0000	0	0	0.0000	(45)	0	0.0000	0	0	0.0000	0	(45)	(45)
7	JUNE	0	0.0000	0	15,335	8.9148	136,708	100	1.6120	161	1,200	6.4890	7,787	0	0.0000	0	136,869	295,933
8	ADJUSTMENT	0	0.0000	0	0	0.0000	0	0	0.0000	0	0	0.0000	0	0	0.0000	0	0	0
9	JULY	0	0.0000	0	15,335	8.9148	136,708	100	1.6120	161	1,200	6.4890	7,787	0	0.0000	0	136,869	295,933
10	ADJUSTMENT	0	0.0000	0	0	0.0000	0	0	0.0000	0	0	0.0000	0	0	0.0000	0	0	0
11	AUGUST	0	0.0000	0	15,335	8.9252	136,868	100	1.6120	161	1,200	6.4970	7,796	0	0.0000	0	144,826	302,671
12	SEPTEMBER	0	0.0000	0	15,335	8.9252	136,868	100	1.6120	161	1,200	6.4970	7,796	0	0.0000	0	144,826	304,090
13	ADJUSTMENT																	1,418
14	OCTOBER	0	0.0000	0	15,335	8.9252	136,868	100	1.6120	161	1,200	6.4970	7,796	0	0.0000	0	144,826	304,090
15	NOVEMBER	0	0.0000	0	15,335	8.9252	136,868	100	1.6120	161	1,200	6.4970	7,796	0	0.0000	0	144,826	304,090
16	DECEMBER	10,000	9.4690	94,690	15,335	8.8846	136,245	100	1.6120	161	1,200	6.4600	7,752	2,000	6.4600	12,920	251,769	410,545
17	JANUARY, 2024	10,000	9.4690	94,690	15,335	8.8846	136,245	100	1.6120	161	1,200	6.4600	7,752	2,000	6.4600	12,920	251,769	410,545
18	TOTAL	40,000		405,060	184,020		1,676,067	1,200		1,980	14,400		95,430	4,000		25,840	2,181,017	4,130,486

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TEXAS EASTERN TRANSMISSION CORPORATION
TRANSPORTATION COMMODITY CHARGES

LINE NO.	MONTH	COMMODITY VOLUME	BILLING RATE	TOTAL FT1 COMMODITY	COMMODITY VOLUME	BILLING RATE	TOTAL CDS COMMODITY	TOTAL FT1 CDS
		(1)	(2)	(3=1x2)	(4)	(5)	(6=4x5)	(7=3+6)
		Dth	$/Dth	$	Dth	$/Dth	$	$
1	FEBRUARY, 2023	202,788	0.0568	11,517	172,791	0.1168	20,182	31,699
2	ADJUSTMENT	0	0.0000	(0)	0	0.0000	0	(0)
3	MARCH	246,637	0.0663	16,360	3,663	0.1168	428	16,787
4	ADJUSTMENT	0	0.0000	(243)	0	0.0000	0	(243)
5	APRIL	277,779	0.0490	13,611	29,760	0.1195	3,556	17,168
6	ADJUSTMENT	0	0.0000	391	0	0.0000	10	400
7	MAY	446,115	0.0490	21,860	29,300	0.1195	3,501	25,361
8	ADJUSTMENT	0	0.0000	(0)	0	0.0000	0	(0)
9	JUNE	294,079	0.0490	14,410	14,880	0.1195	1,778	16,188
10	ADJUSTMENT	0	0.0000	(0)	0	0.0000	0	(0)
11	JULY	368,496	0.0490	18,056	16,250	0.1195	1,942	19,998
12	ADJUSTMENT	0	0.0000	(0)	0	0.0000	0	0
13	AUGUST	384,734	0.0490	18,852	15,376	0.1196	1,839	20,691
	ADJUSTMENT	0	0.0000	0	0	0.0000	0	0
15	SEPTEMBER	218,847	0.0490	10,724	2,970	0.1196	355	11,079
16	ADJUSTMENT	0	0.0000	1	0	0.0000	0	1
17	OCTOBER	169,560	0.0489	8,292	92,644	0.1195	11,071	19,363
18	ADJUSTMENT	0	0.0000	(0)	0	0.0000	0	(0)
19	NOVEMBER	0	0.0000	0	0	0.0000	0	0
20	ADJUSTMENT	0	0.0000	(0)	0	0.0000	(0)	(0)
21	DECEMBER	28,382	0.0760	2,157	0	0.0000	0	2,157
22	JANUARY, 2024	149,669	0.0746	11,164	0	0.0000	0	11,164
23	ADJUSTMENT	0	0.0000	(122)	0	0.0000	0	(122)
24	TOTAL	2,787,086		147,028	377,634		44,663	191,691

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
NATIONAL FUEL GAS SUPPLY
RATE SCHEDULE FT - TRANSPORTATION DEMAND CHARGES

LINE NO.	MONTH	DEMAND VOLUME	BILLING RATE	TOTAL FT AMOUNT
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	8,304	5.0867	42,240
2	MARCH	8,304	5.0867	42,240
4	APRIL	8,304	5.0867	42,240
4	MAY	8,304	5.0867	42,240
5	JUNE	8,304	5.0867	42,240
6	JULY	8,304	5.0867	42,240
7	AUGUST	8,304	5.0867	42,240
8	SEPTEMBER	8,304	5.0867	42,240
9	OCTOBER	8,304	5.0867	42,240
10	NOVEMBER	8,304	5.0768	42,158
11	DECEMBER	8,304	5.0768	42,158
12	JANUARY, 2024	8,304	5.0768	42,158
14	TOTAL	99,648		506,630

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
NATIONAL FUEL GAS SUPPLY
TRANSPORTATION COMMODITY CHARGES

LINE NO.	MONTH	COMMODITY VOLUME	BILLING RATE	TOTAL FT COMMODITY
		(1)	(2)	(3=1x2)
		Dth	$/Dth	$
1	FEBRUARY, 2023	50,297	0.0155	780
2	ADJUSTMENT			218
3	MARCH	45,815	0.0155	710
4	ADJUSTMENT			150
5	APRIL	25,191	0.0155	391
6	ADJUSTMENT			251
7	MAY	23,310	0.0155	361
8	ADJUSTMENT			88
9	JUNE	28,406	0.0161	458
10	ADJUSTMENT			36
11	JULY	22,477	0.0160	361
12	ADJUSTMENT			(322)
13	AUGUST	23,617	0.0160	378
14	ADJUSTMENT			(215)
15	SEPTEMBER	24,403	0.0160	391
16	ADJUSTMENT			(229)
17	OCTOBER	27,659	0.0156	430
18	ADJUSTMENT			(207)
19	NOVEMBER	46,720	0.0154	720
20	ADJUSTMENT			21
21	DECEMBER	50,957	0.0154	785
22	ADJUSTMENT			182
23	JANUARY, 2024	65,339	0.0154	1,006
24	ADJUSTMENT			224
25	TOTAL	434,191		6,968

COLUMBIA GAS OF PENNSYLVANIA, INC
DETAIL OF HISTORIC COST OF GAS
TRANSPORTATION SHRINKAGE VOLUMES AND OPERATIONAL BALANCING CHARGES
AND OTHER COMMODITY CHARGES

			DEMAND	COMMODITY	COMMODITY	
LINE NO.	MONTH	TRANSPORTATION SHRINKAGE VOLUMES	OPERATIONAL BALANCING CHARGES	CASH IN/ CASH OUT EXCHANGE FEES	OTHER COMPLIANCE	TOTAL COMMODITY
		(1)	(2)	(3)	(4)	(5=3+4)
		Dth	$	$	$	$
1	FEBRUARY, 2023	(21,611)	(3,633)	10,725	(62)	10,664
2	MARCH	(25,409)	0	0	0	0
3	APRIL	(87,834)	13	0	(2,646)	(2,646)
4	MAY	(91,659)	233	0	(45,641)	(45,641)
5	JUNE	(64,617)	155	482	0	482
6	JULY	(60,883)	0	0	(5,300)	(5,300)
7	AUGUST	(56,993)	0	0	0	0
8	SEPTEMBER	(60,948)	0	0	0	0
9	OCTOBER	(60,653)	5	0	56,099	56,099
10	NOVEMBER	(15,100)	0	0	0	0
11	DECEMBER	(52,945)	0	0	0	0
12	JANUARY, 2024	(58,198)	0	0	0	0
13	TOTAL	(656,850)	(3,228)	11,207	2,451	13,658

§53.64(c)(1) A complete list in schedule format of each spot and each long term source of gas supply, production, transportation, and storage used in the past 12 months, which 12-month period shall end 2 months prior to the date of the tariff filing, separately setting forth on a monthly basis the quantity and price of gas delivered, produced, transported or stored, maximum daily quantity levels, maximum annual quantity levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and copies of Federal tariffs and contract provisions relating to the purchases—including demand and commodity components. With regard to each contemplated future source of supply, production, transportation or storage during each of the next 20 months, for each source, provide the name of the source, the maximum daily quantity, the maximum annual quantity, the minimum take levels, a detailed description of warrantee or penalty provisions, including liquidated damages, take or pay provisions or minimum bill or take provisions of the purchases, balancing provisions and contractual or tariffed terms of the purchases, copies of applicable Federal tariffs, the expiration date of each contract, the date when each contract was most recently negotiated and the details of such negotiation – such as meeting held, offers made, and changes in contractual obligation-- and whether current proceedings, negotiations or renegotiations are pending before the Federal Energy Regulatory Commission, and the like, to modify the price, quantity or another condition of purchase, and if so, the details of the proceedings, negotiations or renegotiations. Gas supply sources which individually represent less than 3% of the total system supply may be shown collectively, such as other local gas purchases.

Response:

Sources of gas supply and prices of gas used in the twelve months ended January 31, 2023 are set forth on Exhibit No. 1-D; projected volumes and prices for the next twenty (20) months, October 2023 through September 2024, and February 2023 through September 2023, are shown on Exhibit Nos. 1-B and 1-C, respectively. Copies of the individual, currently effective contracts and service agreements are available for review at the offices of local counsel, Post & Schell, 17 North Second Street, Harrisburg, Pennsylvania 17101-1601, and at the Commercial Operations Department of NiSource Corporate Services located at 290 W. Nationwide Blvd, Columbus, Ohio 43215.

CPA has contracts for firm transportation capacity with several interstate pipelines and negotiates separate gas supply agreements with Marketing Companies and Producers for volumes to be transported on each pipeline.

1. Affiliate Purchases - Interstate Gas
   See Exhibit No. 8-A.

2. Interstate Acquisition for System Supply

A comprehensive Request for Proposal (RFP) process for firm gas supply acquisition is initiated in the spring of each year and completed prior to the winter period. The RFP included a request for firm service natural gas supplies to Texas Eastern Zone M-3 delivery points at Texas Eastern M-2 zone index prices. Gas suppliers were selected based on their reliability, capability and pricing structure. Requests for Proposals (RFPs) were sent to natural gas suppliers for gas to be delivered into Columbia Gas Transmission, Eastern Gas Transmission and Storage, National Fuel Gas Supply Corporation, Tennessee Gas Pipeline, Texas Eastern Transmission and Equitrans Midstream Corporation.

Proposals were requested for varying term lengths, nomination flexibility, and innovative pricing options. CPA received proposals that provided various levels of nomination flexibility, term lengths from three months to twelve months, with prices based on gas market indices. In this process, CPA identifies the best proposals and then negotiates specific contract terms and conditions.

Supply reliability is a critically important element of CPA's supply portfolio contracting strategy; CPA fully expects its suppliers to deliver on a firm basis and the contracts contain conditions and consequences related to failure to perform.

Flexibility is another important attribute of CPA's contracts. CPA negotiates for a combination of seasonal, monthly, and daily gas supplies, which provides for the flexibility needed to meet customer demands under varying temperatures. CPA achieves part of this flexibility by contracting for winter only supplies.

As a result of the RFP process, effective for the contract period of April 2023 through March 2024, CPA entered into ten new term gas supply purchase agreements. None of these term agreements are with affiliated companies. The resulting gas supply contract portfolio, along with monthly and daily firm supply purchases, results in winter firm gas supplies flowing under FTS capacity, which when added to volumes available from storage, are sufficient to serve CPA's firm daily demand in the winter heating season.

A list of the firm gas purchase contracts that are presently in effect during the period under review is provided in Attachment 1 to this Exhibit 1-D-1. In addition to the agreements listed in Attachment 1, CPA purchases spot gas from both the term contract suppliers and a multitude of other suppliers. These spot purchases are for gas that is received for a period between one day and one month in duration. The price is negotiated based on market conditions at the time of purchase.

3. Local Gas Supply Acquisition for System Supply

CPA purchases Pennsylvania gas delivered directly into its system under contracts with various initial terms and various renewal terms. In these agreements the gas price is tied to either an index price or a CPA posted price. In addition to these direct local gas purchases, CPA buys significant quantities of gas at supply points known as Aggregation Pools and at a supply point known as the Columbia Gas Transmission Appalachian Pool ("TCO Pool"). The gas delivered into Aggregation Pools represents local Appalachian production within the defined geographic area of the Aggregation Pool while gas delivered into the TCO pool originates from many physical locations that include multiple interstate pipeline interconnects with TCO as well as from Appalachian gas production. Though a portion of the gas in the TCO Pool has been produced in Pennsylvania, it is impossible for CPA to determine the amount of Pennsylvania production that CPA purchases at the TCO Pool.

COLUMBIA GAS OF PENNSYLVANIA, INC.

FIRM GAS PURCHASE AGREEMENTS - FEBRUARY 1, 2023 THROUGH JANUARY 31, 2024

SELLER	AGREE MENT DATE	EFFECTIVE DATE	INITIAL CONTRACT TERMINATION DATE	DATE TERMINATED	MONTHS AVAILABLE	QUANTITY DTH/DAY 11/2021-10/2022	QUANTITY DTH/DAY 11/2022-10/2023	DELIVERY POINT	TOTAL DEMAND CHARGE	MUST TAKE
ASCENT RESOURCES - UTICA, LLC	7/25/2022	12/01/2022	02/28/2023	02/28/2023	DEC-FEB	10,000		COLUMBIA GAS TRANSMISSION TCO POOL	0	Y
ASCENT RESOURCES - UTICA, LLC	8/3/2022	12/01/2022	02/28/2023	02/28/2023	DEC-FEB	7,600		TENNESSEE GAS PIPELINE 200 LINE POOL	0	Y
EQT ENERGY, LLC	10/11/2022	12/01/2022	02/28/2023	02/28/2023	DEC-FEB	5,000		EQUITRANS - BRADEN RUN	0	Y
EQT ENERGY, LLC	10/11/2022	12/01/2022	02/28/2023	02/28/2023	DEC-FEB	31,000 Daily Call		EQUITRANS - BRADEN RUN	$15,500	N
COLONIAL ENERGY	10/3/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		23,535 Baseload + Daily Call	TETCO- VARIOUS	$0	Y
CASTLETON COMMODITIES	8/25/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		4,305 Daily Call	LEIDY TRANSCO INTO NAT. FUEL	0	N
BP ENERGY	8/15/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		4,000 Daily Call	LEIDY TRANSCO INTO EASTERN GAS	0 0	N
EQT ENERGY, LLC	8/16/2023	12/01/2023	02/29/2024	02/29/2024	DEC-FEB		8,000	EQUITRANS - BRADEN RUN	0	Y
VITOL INC.	9/19/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		28,000 Daily Call	EQUITRANS - BRADEN RUN	$294,000	N
DTE ENERGY TRADING	8/21/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		255 Daily Call	EASTERN GAS - LOUDON	$0	N
DTE ENERGY TRADING	8/21/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		1,100 Daily Call	EASTERN GAS - PLEASANT GAP	$0	N
CNX GAS CO LLC	8/8/2023	12/01/2023	02/29/2024	02/29/2024	DEC-FEB		10,000	COLUMBIA GAS TRANSMISSION TCO POOL	$0	Y
CASTLETON COMMODITIES	8/25/2023	12/01/2023	02/29/2024	02/29/2024	DEC-FEB		7,600	TENNESSEE GAS PIPELINE 200 LINE POOL	0	Y
DTE ENERGY TRADING	9/6/2023	11/01/2023	03/31/2024	03/31/2024	NOV-MAR		5,500 Daily Call	EASTERN GAS - VARIOUS	$0	N

§53.64(c)(1) A complete list in schedule format of each spot and each long term source of gas supply, production, transportation and storage, used in the past twelve (12) months, ... separately setting forth ... a detailed description of warrantee or penalty provisions, including liquidated damages, take-or-pay provisions or minimum bill or take provisions of the purchases...

Response:

For the twelve-month period ending January 31, 2024, CPA did not purchase gas supplies under any contract containing a take-or-pay provision. As shown in Exhibit 1-D-1, CPA did execute two gas supply contracts with demand/reservation fees, payable irrespective of whether or not CPA calls on any of this daily gas supply.

In Section II of Exhibit No. 1-D-1 CPA describes its term gas purchase process. Attachment 1 to Exhibit 1-D-1 lists CPA's current term contracts. All of these agreements contain penalty provisions to promote a high degree of supplier reliability while maintaining price competitiveness. Exhibit 1-D, Schedule 3 lists all purchases by month by supplier made by CPA for system supply. Exhibit 1-D-3 provides a listing of the transportation and storage contracts utilized during this time period.

§53.64(c)(1) A complete list in schedule format of each ... transportation and storage, used in the past 12 months ... separately setting forth ... maximum daily quantity levels, maximum annual quantity levels. With regard to each contemplated future source of ... transportation or storage, during each of the next 20 months for each source, provide the name of source, the maximum daily quantity, the maximum annual quantity ...

Response:

Please see Attachment 1 to this Exhibit 1-D-3 for a list of Columbia's firm capacity contracts listing maximum daily and seasonal levels.

COLUMBIA GAS OF PENNSYLVANIA, INC.

FIRM GAS TRANSPORTATION AND STORAGE AGREEMENTS - FEBRUARY 1, 2023 THROUGH JANUARY 31, 2024

FIRM GAS TRANSPORTATION AGREEMENTS

TRANSPORTER	CONTRACT NUMBER	RATE SCHEDULE	MONTHS AVAILABLE	QUANTITY DTH/DAY 2/23 - 3/23	QUANTITY DTH/DAY 4/23 - 10/23	QUANTITY DTH/DAY 11/23 - 1/24	DELIVERY POINT
COLUMBIA GAS	50675	FTS	NOV-OCT	13,334	13,334	13,334	CPA OP-8 AND OP-4
COLUMBIA GAS	56741	FTS	NOV-OCT	11,666	11,666	11,666	CPA OP-4
COLUMBIA GAS	56742	FTS	NOV-OCT	10,000	10,000	10,000	CPA OP-4
COLUMBIA GAS	80136	FTS	NOV-OCT	60,551	60,551	60,551	CPA OP-8 AND OP-4
COLUMBIA GAS	82610	SST	OCT-MAR	395,714	395,714	395,714	CPA OP-8 AND OP-4
			APR-SEPT	197,857	197,857	197,857	CPA OP-8 AND OP-4
COLUMBIA GAS	256937	FTS	NOV-OCT	39,380	39,380	39,380	CPA OP-8
EASTERN GAS *	700034	FTNN-GSS	NOV-MAR	6,000		6,000	CPA @ WARRENDALE/DARLINGTON
EASTERN GAS *	200539	FT	NOV-MAR	3,000		3,000	CPA @ WARRENDALE
			APR-OCT		2,000		CPA @ WARRENDALE
EASTERN GAS *	100121	FTNN	NOV-OCT	4,800	4,800	4,800	CPA @ PLEASANT GAP
EASTERN GAS *	100122	FTNN	NOV-OCT	15,000	15,000	15,000	CPA @ PLEASANT GAP
EASTERN GAS *	200687	FT	NOV-OCT	5,000	5,000	5,000	CPA @ PLEASANT GAP
EASTERN GAS *	200754	FT	NOV-OCT	255	255	255	CPA @ Centre Hall
EQUITRANS	1588	FTS	NOV-MAR	18,870	18,870	18,870	CPA @ SPARTAN
EQUITRANS	1590	NOFT	NOV-MAR	36,130		36,130	CPA @ SPARTAN
			APRIL		32,000		CPA @ SPARTAN
			MAY-SEPT		20,000		CPA @ SPARTAN
			OCTOBER		32,000		CPA @ SPARTAN
NATIONAL FUEL	F02091	FT	NOV-OCT	4,304	4,304	4,304	CPA @ WARREN
NATIONAL FUEL	E12637	EFT	NOV-OCT	4,000	4,000	4,000	CPA@FINDLAY TWNSHP
TENNESSEE	345027	FT-A	NOV-OCT	16,000	16,000	16,000	CPA @ NEW CASTLE
TENNESSEE	63409	FT-A	NOV-OCT	7,600	7,600	7,600	CPA @ PITT TERMINAL
TENNESSEE	390907	FT-A	Dec-Feb			7,000	CPA @ PITT TERMINAL
TEXAS EASTERN	800387R3	CDS	NOV-OCT	2,342	2,342	2,342	VARIOUS CPA CITY GATES
TEXAS EASTERN	910951R2	FT-1	NOV-OCT	14,835	14,835	14,835	TCO @ DELMONT/UNIONTOWN
TEXAS EASTERN	830049R1	FT	DEC-MAR	10,000		10,000	CPA @ PLEASANT GAP/ROCKWOOD
TEXAS EASTERN	910464R1	CDS	NOV-OCT	5,000	5,000	5,000	VARIOUS CPA CITY GATES
TEXAS EASTERN	910463R1	CDS	NOV-OCT	158	158	158	CPA @ CHAMBERSBURG
TEXAS EASTERN	911660R1	FT-1	NOV-OCT	100	100	100	MARIETTA EXTENSION
TEXAS EASTERN	911831R1	FT-1	NOV-OCT	1,200	1,200	1,200	CPA@NEMACOLIN
TEXAS EASTERN	911923	FT-1	NOV-OCT			2,000	CPA@UNIONTOWN

FIRM GAS STORAGE AGREEMENTS

TRANSPORTER	CONTRACT NUMBER	RATE SCHEDULE	MDQ/SCQ	QUANTITY DTH/DAY 2/22 - 3/22	QUANTITY DTH/DAY 4/22 - 10/22	QUANTITY DTH/DAY 11/22 - 1/23
COLUMBIA GAS	82512	FSS	MDQ	395,714	395,714	395,714
			SCQ	21,948,692	21,948,692	21,948,692
EASTERN GAS *	600037	GSS	MDQ	9,000	9,000	9,000
			SCQ	941,176	941,176	941,176
EASTERN GAS *	300195	GSS	MDQ	4,800	4,800	4,800
			SCQ	240,000	240,000	240,000
EASTERN GAS *	300206	GSS	MDQ	15,000	15,000	15,000
			SCQ	930,000	930,000	930,000
EQUITRANS	1589	115SS	MDQ	19,130	19,130	19,130
			SCQ	2,000,000	2,000,000	2,000,000
NATIONAL FUEL	G12636	ESS	MDQ		2,429	2,429
			SCQ		267,143	267,143

*Eastern Gas Transmission and Storage, Inc. (formerly Dominion Transmission, Inc.)

§53.64(c)(3) A complete listing of sources of gas supply transportation or storage and their costs, including shut-in and curtailed sources of supply, both inside and outside this Commonwealth considered by or offered to the utility but not chosen for use during the past 12 months, which 12-month period shall end 2 months prior to the date of the tariff filing, and the reasons why the gas supply, transportation or storage was not selected for use as a part of the utility's supply mix. A similar listing of gas sources, transportation or storage and associated projected costs offered or considered but not chosen to meet supply for the next 20 months, along with reasons for nonselection.

Response:

1. Pennsylvania Production - CPA continues to work with local producers who have natural gas wells in close proximity to CPA's pipelines and who desire to sell that gas either to CPA or to a third party involved in CPA's gas transportation program. Working with the producer, a determination is made as to whether or not the expected delivery volume can support the expense of new facilities, and if CPA's market where the production is located is able to receive the new supply without backing off previously connected local gas production in the vicinity. CPA has continued its practice to purchase such quantities of local gas offered that economically and physically can be safely received, so long as it meets CPA's gas quality standards. Opportunities to acquire such supplies are limited, and result in deliveries that are relatively small compared to CPA's overall gas supply requirements.

2. Spot Market Interstate Supplies - Prior to each month CPA determines an estimated requirement for spot market gas supplies. The determination is made utilizing CPA's monthly planning process. Once a spot requirement is determined a dynamic purchasing process takes place. CPA negotiates and completes the spot purchases based upon the best obtainable price under then existing market conditions during the purchasing period.

3. Transportation or Storage Capacity - For the twelve-month period ending January 31, 2024, CPA was offered services, as additions to its existing capacity that were reviewed and rejected. Attachment 2-A lists the services offered and rejected, as well as the reasons for the non-selection.

COLUMBIA GAS OF PENNSYLVANIA, INC.

STORAGE AND TRANSPORTATION SERVICES OFFERED AND REJECTED DURING LAST 12 MONTHS

SERVICE PROVIDER	SERVICE	OFFER	DELIVERY LOCATION	ANNUAL DEMAND COST ($/DTH PEAK DAY CAPACITY)	REASONS FOR REJECTION / ACCEPTANCE
National Fuel	Firm Transportation (FT)	Open Season - OS314	NFGDC - Mineral Springs	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS321	Transco - Leidy	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS328	TGP - East Aurora, TCPL - Niagara	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS329	Area near EGTS - Ellisburg , TGP - Rose Lake	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS331	TGP - Rose Lake	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS334	TGP - Rose Lake	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS335	TGP - Mercer	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Storage Service (FSS) and Firm Storage Transportation (FST)	Open Season - OS336	TGP - Rose Lake, Transco - Wharton, Millennium - Independence, Empire - Tuscarora	Recourse Rates	Project did not effectively serve CPA markets
National Fuel	Firm Transportation (FT)	Open Season - OS342	TGP - East Aurora or TCPL - Niagra	Recourse Rates	Project did not effectively serve CPA markets

§ 53.64(c)(4) An annotated listing of Federal Energy Regulatory Commission or other relevant non-Commission proceedings, including legal action necessary to relieve the utility from existing contract terms which are or may be adverse to the interest of its ratepayers, which affect the cost of the utility's gas supply, transportation or storage or which might have an impact on the utility's efforts to provide its customers with reasonable gas service at the lowest price possible. This list shall include docket numbers and shall summarize what has transpired in the cases, and the degree of participation, if any, which the utility has had in the cases. The initial list filed under this paragraph shall include cases for the past 3 years. Subsequent lists need only update prior lists and add new cases.

Response:

Please see the attached annotated listing of relevant proceedings before the Federal Energy Regulatory Commission ("FERC") that Columbia reviewed during 2021 in the utility's efforts to provide its customers with reliable gas service at the lowest possible cost. The listing describes both generic FERC proceedings involving industry-wide issues and individual interstate pipeline filings of particular interest to Columbia.

In generic proceedings involving industry-wide issues, Columbia normally participates through its trade association, the American Gas Association ("AGA").

In individual pipeline proceedings affecting Columbia, the Columbia Distribution Companies ("CDC")[1] which includes Columbia, has intervened, monitored and/or participated in many of these dockets to protect its interests and those of its customers. Attachment A to this response shows both cases that have been concluded with the issuance of a final order and those that remain open. Sheets 1-35 include cases in which Columbia participated (either through CDC or AGA), and Sheets 36-60 list FERC proceedings reviewed by Columbia wherein no action was required.

[1] Sometimes also referred to as "NiSource Gas Distribution" or "NGD".

FERC
DOE – Grid Reliability and Resiliency
RM18-1, AD18-7

Sep 28, 2017
Pursuant to section 403 of the Department of Energy Organization Act, the Secretary of Energy released a proposed rule for final action by the Federal Energy Regulatory Commission.
Interested persons were invited to submit comments regarding the Proposal. Comments were due on or before October 23, 2017, and Reply Comments were due on or before November 7, 2017.

Dec 7, 2017
In a letter to the Secretary of the Department of Energy (DOE), the new FERC Chairman, Kevin McIntyre, requested a 30 day extension in the rule making. He stated that the Commission has received over 1,500 comments in response to the NOPR; and in addition, the Commission has sworn in two new members within previous last two weeks. Hence the FERC needed more time to respond to the DOE.

Jan 8, 2018
The FERC terminated the rule making proceeding.
The Commission stated that it places a priority on grid resilience and issued an order initiating a new proceeding (Docket No. AD18-7-000) to "holistically examine the resilience of the bulk power system".
Additionally, the Commission directed operators of the regional wholesale power markets to provide information, within 60 days, as to whether FERC and the markets need to take additional action on resilience of the bulk power system. The goals are to develop a common understanding among the Commission, industry and others of what resilience of the bulk power system means and requires; to understand how each regional transmission organization and independent system operator assesses resilience in its geographic footprint; and to use this information to evaluate whether additional Commission action regarding resilience is appropriate. FERC expects to review the additional material in the near future.

Feb 7, 2018
The Foundation for Resilient Societies, a New Hampshire non-profit, requested a rehearing of the FERC Order issued in this docket.

Mar 8, 2018
Given an absence of Commission action within 30 days from date of filing the appeal, the rehearing request would be regarded as being denied.

Sep 19, 2019
In response to a letter from the South Carolina PSC, Chairman of the FERC stated, in part, "My colleagues and I are reviewing this matter. However, as the Commission determines a path forward to continue to promote the reliability and resilience of the electric system, I note that several regions are concurrently taking action to improve reliability and resilience such as introducing new products and services, and developing market rule changes."

Nov 20, 2020
In a letter to FERC Chairman James Danly, West Virginia Congressman David McKinley urged all parties involved to revisit the issue and act in an urgent and thorough fashion regarding the ongoing issue of electric grid resilience.

Feb 18, 2021
FERC issued Order Addressing Arguments Raised on Rehearing. Deputy Secretary, Nathaniel Davis, responses to Resilient Societies' request for rehearing and sustain the results of the January 2018 Order.

Mar 31, 2021
FERC issues response to several U.S. House of Representatives requesting an update on Grid Reliability and Resilience Pricing and Grid Resilience in Regional Transmission Organizations (AD18-7).

2022
No issuances.

2023
No issuances.

FERC

Security Investments For Energy Infrastructure
AD19-12

Feb 4, 2019
The FERC issued a Notice that, along with United States Department of Energy (DOE), it will co-host a Security Investments for Energy Infrastructure Technical Conference on March 28, 2019. The purpose of the conference was to discuss current cyber and physical security practices used to protect energy infrastructure and will explore how federal and state authorities can provide incentives and cost recovery for security investments in energy infrastructure, including the natural gas sector. The conference aimed to address two high-level topics:

1. Current and emerging cyber and physical security threats, and
2. How Federal and State authorities can facilitate investments to improve the cyber/ physical security of energy infrastructure.

May 28, 2019
Following the Technical Conference, NiSource participated in preparing comments by the AGA, which are summarized here:

A. State and Federal Entities have a vested interest in facilitating energy infrastructure security investments.
B. Further coordination is needed between the various agencies that oversee security.
C. Federal standards or guidelines that designate an energy facility as a high-risk or critical may create certain challenges.
D. Financial or accounting incentives should be considered for prudent cyber security investments.
E. States should ensure that cost recovery options exist for costs related to participating in voluntary federal programs and other expenditures related to addressing security threats.
F. Federal and State authorities should not attempt to prioritize specific incentives for security investments.

July 8, 2020
TCO filed a request for a three-year extension of time, until July 19, 2023. On August 25,

2020
FERC accepted the request

2021
No Submittals or issuances.

2022
No Submittals or issuances.

2023
No Submittals or issuances.

Texas Eastern (TETCO)
Lilly Compressor Station Project
CP20-37

Jan 10,2020
Texas Eastern requests authorization for its Lilly Compressor Units Replacement Project. Texas Eastern is requesting authorization to replace the four existing compressor units at the Lilly Compressor Station located in Cambria County, Pennsylvania, with two new, more efficient gas turbines to comply with future air emission reduction requirements in Pennsylvania on this portion of Texas Eastern's system.

Feb 7, 2020
Given that Columbia Gas of Pennsylvania is a firm transportation and storage customer of TETCO, and that this project may impact their customers, CPA filed an intervention in this docket.

Feb 13, 2020
FERC issued an Environmental Information Report request.

July 16, 2020
FERC issued an order granting the requested authorization for the replacement project.

Oct 20, 2021
FERC granted the request of Texas Eastern to place facilities associated with Lilly Compressor Units Replacements Project into service.

2022-2023
Texas Eastern submits quarterly Status Reports.

Columbia Gas Transmission (TCO)
Section 4 Rate Case
RP20-1060

Jul 31, 2020
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 February 1, 2021.

TCO updated its cost-of-service and proposed to change its rates for its services accordingly. The proposed unit rate for Rate Schedule FTS transportation service reflects a 78 percent increase over the existing Rate Schedule FTS base unit rate including the 2020 Capital Cost Recovery Mechanism. The proposed Rate Schedule FSS storage service unit rate reflects a 134 percent increase over the existing Rate Schedule FSS storage service unit rate. The proposed rate changes for FTS, FSS, and SST are as follows:

TCO is also making certain changes to its Tariff related to penalties. First, in order to ensure that shippers have an incentive to schedule accurately, TCO is proposing to revise Section 19.4 of its GT&C to include a new nominal Daily Scheduling Penalty equal to one (1) times the applicable Rate Schedule ITS maximum rate on any difference greater than 10 percent between daily scheduled quantities and actual deliveries at a physical delivery point.

Second, TCO is proposing to broaden the application of existing, substantive, Critical Day penalties within the GT&C to violations of interruption orders, OFOs, and unauthorized withdrawal limitations within Rate Schedules FSS and FSS-M. The current penalties for violations of interruption orders, OFOs, and unauthorized withdrawals on Critical Days under Rate Schedules FSS and FSS-M include a price per Dth penalty level equal to three times the midpoint of the range of prices reported for "TCO Gas, Appalachia". The proposed change is to make the penalty level the higher of either: (1) a price per Dth equal to three times the midpoint of the range of prices reported for "TCO Gas, Appalachia" as published in Platts Gas Daily price survey; or (2) a price per Dth equal to 150 percent of the highest midpoint posting for either: Mich Con City-gate, Transco, Zone 6 Non-N.Y., or Texas Eastern, M-2 Receipts as published in Platts Gas Daily price survey. The second penalty option will only be assessed on days in which the daily spot price of gas exceeds three times the midpoint of the range of prices reported for "TCO Gas, Appalachia."

Third, TCO is proposing to broaden its confiscation rights when shippers exceed stated volume limitations in these rate schedules. Currently, to ensure the integrity and operational efficiency of its storage fields, TCO establishes thresholds for the amounts of gas that may be kept in storage at specific times throughout the year. Specifically, Rate Schedules FSS and FSS-M place volume limits relative to a shipper's Storage Contract Quantity ("SCQ") during injection and withdrawal periods as follows:

- 60% of a shipper's SCQ on June 30 (Rate Schedules FSS/FSS-M at Section 3(d));
- 85% of a shipper's SCQ on August 31 (Rate Schedules FSS/FSS-M at Section 3(d));
- 65% of a shipper's SCQ on February 1 (Rate Schedules FSS/FSS-M at Section 4(d));
- 25% of a shipper's SCQ on April 1 (Rate Schedules FSS/FSS-M at Section 4(d)).

Currently, TCO is permitted to confiscate any shipper's gas above 25 percent of the shipper's SCQ that remains in storage effective April 1 of each year. TCO is proposing to add the same confiscation provisions for shippers exceeding the limits on February 1, June 30, and August 31, consistent with the forfeiture provisions that are already included in the Tariff for April 1.

Aug 12, 2020
Given that Columbia Distribution Companies (CDCs) are firm transportation and storage customers of TCO, and that this rate increase will impact their customers, the CDCs filed a protest in this docket. The CDCs included comments in its protest, stating:

- CDCs serve more than 2.3 million residential, commercial, and industrial customers. In order to meet their service obligations, each of these companies relies on significant purchases of firm transportation and storage services from TCO.
- CDCs submit that neither the proposed increases in rates, the proposed MCRM, nor the other proposed tariff modifications have been shown to be just and reasonable.
- TCO proposes to re-functionalize certain low-pressure gathering systems as transmission facilities, and to engage in substantial modernization of those systems at an estimated cost of

$1.68 billion. This proposal has not been shown to be just and reasonable, and should not be approved without a thorough investigation of the anticipated costs and benefits.

Aug 31, 2020
FERC issued an order stating that the proposed tariff records have not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory, or otherwise unlawful. Accordingly, and as described in this order, we shall accept such tariff records for filing and suspend their effectiveness for five months, to be effective February 1, 2021, subject to refund. Hearing procedures to follow. Furthermore, the Commission ordered:

A. The tariff records referenced in Appendix A are accepted and suspended for five months, to be effective upon motion February 1, 2021, subject to refund.
B. The language of the pro forma tariff records for the Preferred Case is set for hearing.
C. Upon its motion to place suspended rates into effect, TCO must remove facilities not placed into service before the effective date.

Aug 31, 2020
FERC issued an order establishing time standards for the hearing, which require that the hearing be convened within 42 weeks (June 23, 2021) and the initial decision issued within 63 weeks (November 17, 2021) of the issuance of this Order.

Sep 8, 2020
FERC issued an order for a prehearing conference to be scheduled for 10:00 a.m., on October 7, 2020, via WebEx.

Oct 8, 2020
FERC issued an order adopting the proposed schedule below:

Oct 30, 2020
The Commission ordered that a public hearing shall be held to determine the justness and reasonableness of TCO's proposed tariff records.

Dec 1, 2020
The Commission issued an order scheduling the first settlement conference via Webex conferencing on January 13, 2021 at 10:00 am ET.
The Commission issued order of scheduling the settlement conference via Webex conferencing on July 15, 2021.

Aug 4, 2021
The Commission issued an uncontested partial settlement. TCO withdrew revised tariff records: (i) establishing a new nominal Daily Scheduling Penalty; (ii) expanded application of substantive Critical Day penalties to violations of interruption orders, operational flow orders and unauthorized storage withdrawals; (iii) broadened TCO's rights to confiscate gas when exceed stated storage limits; and (iv) revised the treatment of hourly takes exceeding 1/24th of Maximum Daily Delivery Obligations or Daily Delivery Quantity.

Oct 7, 2021
Report of Settlement Judge issued, recommends to continuation of settlement procedures.

Oct 29, 2021
TCO submits motion to place Interim Settlements Rates into effect and waive answer period.

Nov 12, 2021
TCO submits tariff filing per 385.602: Renewed Motion to Place Interim Settlement Rate into effect December 1, 2021. The Revised Rates for FTS, FSS, and SST are as follows:

Nov 18, 2021
The Commission approved TCO's October 22, 2021 filing of tariff records to implement, in part, the terms of the stipulation and agreement of partial settlement filed.

Dec 7, 2021
Status Report is issued by the Settlement Judge to the Commission and the Chief Judge.

Dec 17, 2021
Certification of Uncontested Settlement issued to the Commission by Presiding Administrative Law Judge.

Dec 21, 2021
Final Status Report issued to the Commission and the Chief Judge by the Settlement Judge, recommends the termination of settlement negotiations.

Feb 25, 2022
The Commission ordered Settlement with Modification and Stipulation and Agreement of Settlement.

May 13, 2022
Columbia Gas Transmission filed Settlement Refund Report pursuant to Article VI.D Stipulation and Agreement Settlement.

Jun 2, 2022
The Commission accepted Columbia's May 13, 2022 Settlement Refund Report.

Mar 6, 2023
Columbia Gas Transmission March 6, a revised tariff records to reflect the Period II Settlement rates in accordance with Commission October 29, 2021 uncontested Stipulation and Agreement of Settlement.

Mar 31, 2023
The Commission accepted Columbia Gas Transmission March 6 2023 revised tariff record filing.

Columbia Gas Transmission Period II - Base Tariff Rates

FTS	Reservation Charge	$9.197
	Commodity Max/Min	¢0.63
	Overrun	¢30.87

SST	Reservation Charge	$9.078
	Commodity Max/Min	¢0.63
	Overrun	¢30.48

FSS	Reservation Charge	$2.567
	Capacity	¢4.63
	Injection	¢1.53
	Withdrawal	¢1.53
	Overrun	¢17.57

Texas Eastern Transmission
Section 4 Rate Case
RP21-1188

Sep 30, 2021
Texas Eastern Transmission filed revised tariff records effectuate changes in the rates and other rate-related tariff provisions. Rate changes are for returns on capital investments made as part of ongoing efforts to modernize its system and enhance the integrity, reliability, and safety of system operations. Texas Eastern proposed an effective date of November 1, 2021.

The filing reflected changes to Texas Eastern's transportation and storage rates under firm and interruptible rate schedules. The underlying costs for the rates filed is $2,218,359,340 excluding costs that are recovered through tracker mechanisms. Texas Eastern seeks an overall rate of return of 10.876% (ROE), with an allowed rate of return on equity (ROE) of 14.50%.

Columbia Gas of Pennsylvania contracts Firm Transportation Services (FTS) with Texas Eastern. Noted below is the requested changes to FTS:

Oct 8, 2021
Due to the financial impact on its customers, Columbia Gas of Pennsylvania filed an intervention in this docket on the customers' behalf.

Oct 29, 2021
The Commission order accepting and suspending tariff records, subject to refund, conditions and establishing hearing procedures.
The effective date of tariff records in Appendix A will be April 1, 2022, subject to refund and the outcome of the hearing.

Nov 2, 2021
Order of Chief Judge designation presiding administrative law judge and establishing Track III schedule. Hearing to be convened within 42 weeks (August 23, 2022) and initial decision issued with 63 weeks (January 17, 2023).

Dec 29, 2021
The Commission order adopting procedural schedule, uniform hearing rules, electronic hearing rules, and remote hearing guidance:

Jan 21, 2022
The Commission released transcript of the November 29, 2021 prehearing conference.

Feb 14, 2022
Chief Judge ordered consolidating of dockets. Consolidation order was given to end RP21-1001 and proceedings captured with Docket No. RP21-1188.

Mar 31, 2022
Texas Eastern submits tariff records into effect April 1, 2022. These tariffs removed facilities not in service as of March 31, 2022. By the Order of Paragraph (D) of the October 29 Order.

May-Oct, 2022
Several hearings are held with Chief Judge and Settlement Status Reports are issued by Texas Eastern.

Sep 9, 2022
Texas Eastern submitted a Stipulation and Agreement Settlement. This settlement also included related materials that resolved the issues set in past hearings.

Oct 24, 2022
Settlement Judge certified an uncontested offer of settlement to the Commission, which if approved, would resolve all issues in the proceedings.

Nov 30, 2022
The Commission issued a letter approving Texas Eastern Transmission's September 8, 2022 filing of stipulation and agreement:

1. *On September 8, 2022, Texas Eastern Transmission, LP (Texas Eastern) filed a stipulation and agreement (Settlement) pursuant to Rule 602 of the Commission's Rules of Practice and Procedure.1 Texas Eastern states that the Settlement resolves the issues set for hearing in the consolidated dockets. The comments filed in the proceeding support or do not oppose the Settlement. On October 20, 2022, the Settlement Judge certified the Settlement to the Commission as an uncontested settlement.2 As discussed below, we approve the Settlement, and direct Texas Eastern to file actual tariff records consistent with the terms of the Settlement.*

2. *On August 31, 2021, in RP21-1001-001, the Commission rejected revised tariff records filed by Texas Eastern as an NGA section 4 rate case. Subsequently, on October 29, 2021, in RP21-1188-000, the Commission accepted and suspended revised tariff records comprising a new NGA section 4 rate case filed by Texas Eastern. On January 20, 2022, the Commission, on rehearing, modified its decision in RP21-1001-001 by accepting the previously rejected tariff records, subject to refund and the outcome of hearing procedures. Both dockets were consolidated on February 14, 2022.*

3. *The Settlement details base rates, provides that the transportation and storage rates contained in the pro forma tariff records reflect the base rates and factor in the tracked costs in effect as of **August 1, 2022**, and details pro forma textual tariff record changes. The Settlement further provides that Texas Eastern shall issue refunds owed to "each customer paying Motion Rates no later than the end of the month in which the invoice reflecting the Base Rate refunds is issued,"4 and that Texas Eastern shall apply a **13.5%** return on equity when calculating the return component and allowance for funds used during construction for expansion projects.*

4. *Texas Eastern states that the Settlement establishes a rate case moratorium and section 5 **moratorium** through **January 1, 2024**, with a **comeback provision** that states that Texas Eastern shall file a general section 4 rate case requesting a rate effective date that is no later than **September 1, 2026**. Texas Eastern further states that the "standard of review for any changes to the terms of this Settlement during the term of this Settlement shall be the just and reasonable standard and not the public interest standard."*

5. *We find that the uncontested Settlement appears to be fair and reasonable and in the public interest. The Settlement is supported or not opposed by all parties to the proceeding. Therefore, we approve the Settlement as proposed. We direct Texas Eastern to file actual tariff records consistent with the Settlement in eTariff format as required by Order No. 714.6 The Commission's approval of the Settlement does not constitute approval of, or precedent regarding, any principle or issue in this proceeding.*

Jan 30, 2023

Texas Eastern submits compliance filing – Revised Tariff Records, in accordance with November 30, 2022 FERC order.

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, EIGHTH REVISED VOLUME NO. 1

FT-1
RESERVATION
CHARGES

Pursuant to Sections 3.2(A), 3.3(A), and 3.5 of Rate Schedule FT-1:

	FT-1 RESERVATION CHARGE* $/dth		FT-1 RESERVATION CHARGE ADJUSTMENT $/dth	
ACCESS AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
STX-AAB	9.9560	0.0000	0.3273	0.0000
WLA-AAB	4.7390	0.0000	0.1558	0.0000
ELA-AAB	2.9360	0.0000	0.0965	0.0000
ETX-AAB	3.1590	0.0000	0.1038	0.0000
STX-STX	6.3460	0.0000	0.2086	0.0000
STX-WLA	8.0420	0.0000	0.2644	0.0000
STX-ELA	9.4630	0.0000	0.3111	0.0000
STX-ETX	9.4640	0.0000	0.3111	0.0000
WLA-WLA	3.1390	0.0000	0.1032	0.0000
WLA-ELA	4.5600	0.0000	0.1499	0.0000
WLA-ETX	4.5270	0.0000	0.1488	0.0000
ELA-ELA	2.8640	0.0000	0.0942	0.0000
ETX-ETX	3.0740	0.0000	0.1011	0.0000
ETX-ELA	2.8660	0.0000	0.0942	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.6080	0.0000	0.1187	0.0000
M1-M2	8.7350	0.0000	0.2872	0.0000
M1-M3	16.8530	0.0000	0.5541	0.0000
M2-M2	6.5680	0.0000	0.2159	0.0000
M2-M3	14.6870	0.0000	0.4829	0.0000
M3-M3	9.5620	0.0000	0.3144	0.0000

CURRENTLY EFFECTIVE SERVICE RATES APPLICABLE TO OPEN ACCESS, PART 284, RATE SCHEDULES IN FERC GAS TARIFF, EIGHTH REVISED VOLUME NO. 1

FT-1
USAGE
CHARGES

ZONE RATE
$/dth

Pursuant to Sections 3.2(A) and 3.3(A) of Rate Schedule FT-1:

	STX	WLA	ELA	ETX	M1	M2	M3
USAGE-1 - MAXIMUM							
from STX	0.0222	0.0257	0.0429	0.0429	0.0658	0.1124	0.1817
from WLA	0.0257	0.0099	0.0277	0.0277	0.0506	0.0972	0.1665
from ELA	0.0429	0.0277	0.0214	0.0214	0.0443	0.0909	0.1602
from ETX	0.0429	0.0277	0.0214	0.0214	0.0443	0.0909	0.1602
from M1	0.0658	0.0506	0.0443	0.0443	0.0229	0.0695	0.1388
from M2	0.1124	0.0972	0.0909	0.0909	0.0695	0.0495	0.1194
from M3	0.1817	0.1665	0.1602	0.1602	0.1388	0.1194	0.0729
USAGE-1 - MINIMUM							
from STX	0.0192	0.0227	0.0399	0.0399	0.0598	0.1064	0.1757
from WLA	0.0227	0.0069	0.0248	0.0248	0.0447	0.0913	0.1606
from ELA	0.0399	0.0248	0.0185	0.0185	0.0384	0.0850	0.1543
from ETX	0.0399	0.0248	0.0185	0.0185	0.0384	0.0850	0.1543
from M1	0.0598	0.0447	0.0384	0.0384	0.0199	0.0665	0.1358
from M2	0.1064	0.0913	0.0850	0.0850	0.0665	0.0465	0.1164
from M3	0.1757	0.1606	0.1543	0.1543	0.1358	0.1164	0.0699
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0208						
from WLA		0.0094					
from ELA			0.0201				
from ETX				0.0201			
from M1				0.0435	0.0221		
from M2				0.0882	0.0668	0.0476	
from M3						0.1142	0.0696
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0178						
from WLA		0.0064					
from ELA			0.0172				
from ETX				0.0172			
from M1				0.0376	0.0191		
from M2				0.0823	0.0638	0.0446	
from M3						0.1112	0.0666
USAGE-2	0.2204	0.2204	0.2204	0.2204	0.3619	0.5771	0.9133

Apr 3, 2023
The Commission issued an order accepting Texas Eastern Tariff Records (Jan 30, 2023) and denied EQT's protest.

May 12, 2023
Texas Eastern submits Base Rate Refund Report pursuant to the terms of the Settlement Agreement.

Jun 9, 2023
The Commission accepted Refund Report.

Eastern Gas Transmission
Section 4 Rate Case
RP21-1187

Sep 30, 2021
Eastern Gas Transmission and Storage filed tariff records which reflected changes in its rates. The proposed rates are to be effective on November 1, 2021. Eastern Gas proposed rates reflect a return of equity (ROE) of 14.75%. Noted are the changes to FT, FTNN, GSS rate schedules:

Oct 12, 2021
NiSource Gas Distribution (NGD) companies are firm transportation and storage customers of Eastern Gas Transmission, and given that the operational transactions support NGD's operations, an intervention and protest was filed in this docket on behalf of its customers. NiSource requested the Commission:

1. Issue an order permitting it to intervene.
2. Suspend any proposed increases in rates for the max. period permitted.
3. Any proposed increases in rates to take effect only subject to refund, should the suspension period expire prior to the time this proceeding is concluded.
4. Request a full and complete investigation of the proposed rates and tariff changes.
5. To set the matter for evidentiary hearing.
6. Grant NiSource relief as may be necessary to protect its interests and the interests of the retail customers which it serves.

Oct 29, 2021
The Commission issued order accepting and suspending tariff records, subject to refund and conditions, establishing hearing procedures and directing to show cause. The Commission found ten rate schedules contained rate decreases. The Commission accepted the proposed rate deductions. Suspension of rates set in Appendix A set to be effective April 1, 2022.

Nov 2, 2021
Order of Chief Judge designating presiding administrative law judge and establishing Track III schedule. Hearing to be convened within 42 weeks (August 23, 2022) and initial decision on January 17, 2023.

Nov 9, 2021
Eastern Gas Transmission filed revised tariff records in compliance with the Commission order issued October 29, 2021.

Nov 18, 2021
Order of Chief Judge extending Track III deadlines to September 20, 2022 and February 14, 2023, respectively.

2022
Various Issuances and Submittals on hearing schedules, service list, questions and answers.

Nov 30, 2022
The Commission issued approval of the uncontested settlement. Eastern is ordered to file tariff records consistent with Settlement. Article VIII sets a 12.59% return on equity component solely for calculating the return. Article IX established a rate case moratorium through December 31, 2025.

Dec 15, 2022
Eastern Gas submitted tariff filing with compliance with the uncontested settlement issued on November 30, 2022.

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [3] Surcharge (6)	EPCA [4] Surcharge (7)	Other Adj. (8)	Current Rate [5] (9)	FERC ACA (10)
FT, FTNN [2]									
	RESERVATION CHARGE:								
	(Maximum Rate)	$5.6792	$0.2182	$0.0032	($0.0008)	($0.0010)	-	$5.8988	-
	(Minimum Rate)	$0.0000	-	-	-	-	-	$0.0000	-
	USAGE CHARGE:								
	(Maximum Rate)	$0.0065	$0.0009	$0.0021	($0.0008)	($0.0003)	-	$0.0084	[6]
	(Minimum Rate)	$0.0065	-	-	-	-	-	$0.0065	[6]
	CAPACITY RELEASE (Vol. Charge):								
	(Maximum Rate)	$0.1867	$0.0072	$0.0001	$0.0000	$0.0000	-	$0.1940	-
FT(SC), FTNN(SC) [2]									
	(Maximum Rate)	$0.3799	$0.0152	$0.0023	($0.0009)	($0.0004)	-	$0.3961	[6]
	(Minimum Rate)	$0.0065	-	-	-	-	-	$0.0065	[6]

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate Schedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [5] Surcharge (6)	EPCA [6] Surcharge (7)	Current Rate [7] (8)	FERC ACA (9)
GSS [2], [3]								
	Maximum							
	Storage Demand	$2.6065	$0.0604	$0.0041	($0.0026)	($0.0028)	$2.6656	-
	Storage Capacity	$0.0258	-	-	-	-	$0.0258	-
	Injection Charge	$0.0252	-	$0.0106	$0.0000	($0.0001)	$0.0357	-
	Withdrawal Charge	$0.0252	-	-	$0.0000	($0.0001)	$0.0251	[8]
	GSS-TE Surcharge	-	-	-	($0.0002)	-	($0.0002)	-
	From Customers Balance	$0.7282	$0.0126	$0.0008	($0.0005)	($0.0007)	$0.7404	[8]
	Minimum							
	Storage Demand	$0.0000	-	-	-	-	$0.0000	-
	Storage Capacity	$0.0000	-	-	-	-	$0.0000	-
	Injection Charge	$0.0252	-	-	-	-	$0.0252	-
	Withdrawal Charge	$0.0252	-	-	-	-	$0.0252	[8]
	GSS-TE Surcharge	$0.0000	-	-	-	-	$0.0000	-
	From Customers Balance	$0.7282	$0.0126	$0.0008	($0.0005)	($0.0007)	$0.7404	[8]
GSS-E [2], [3]								
	Maximum							
	Storage Demand	$2.4565	$0.0604	$0.0041	($0.0026)	($0.0028)	$2.5156	-
	Storage Capacity	$0.0409	-	-	-	-	$0.0409	-
	Injection Charge	$0.0252	-	$0.0106	$0.0000	($0.0001)	$0.0357	-
	Withdrawal Charge	$0.0252	-	-	$0.0000	($0.0001)	$0.0251	[8]
	Authorized Overruns	$1.4160	$0.0126	$0.0008	($0.0005)	($0.0007)	$1.4282	[8]
	Minimum							
	Storage Demand	$0.0000	-	-	-	-	$0.0000	-
	Storage Capacity	$0.0000	-	-	-	-	$0.0000	-
	Injection Charge	$0.0252	-	-	-	-	$0.0252	-
	Withdrawal Charge	$0.0252	-	-	-	-	$0.0252	[8]
	Authorized Overruns	$1.4160	$0.0126	$0.0008	($0.0005)	($0.0007)	$1.4282	[8]

Jan 10, 2023
The Commission issued a letter accepting Eastern Gas tariff filing (Dec 15, 2022) to comply with the uncontested settlement.

Feb 28, 2023
Eastern Gas submits tariff filing – Refund Report.

Mar 28, 2023
The Commission issue a letter accepting Eastern Gas's Refund Report (Feb 28, 2023).

Equitrans
Truittsburg Well Conversion
CP22-24

Dec 2, 2021
Equitrans request authorization to convert two existing observation wells to injection/withdrawal wells in the Truittsuburg Storage Field (Clarion County, PA). In addition, to sell excess cushion gas resulting from conversion. Equitrans proposes to add approximately 1,119 feet of well lines to convert the two observation wells. Project in service date is projected April 2022. The resultant working gas capacity will increase 1,634 MMcf to 1,829 MMcf.

Equitrans states that the conversion of the wells will enhance system flexibility and reliability on the Equitran's Allegheny Valley Connector System. The project is estimated to cost approximately $739,000.

Jan 6, 2022
Given that Columbia Gas of Pennsylvania is a firm transportation and storage customer of Equitrans, and that this project may impact their customers, CPA filed an intervention in this docket.

2022
Repeated issuances and submittals between the Commission and Equitrans on data requests.

2023
Equitrans submits bi-weekly construction and status reports.

Equitrans
Ohio Valley Connector Expansion
CP22-44

Jan 28, 2022
Equitrans submits application requesting authorization for the Ohio Valley Connector Expansion Project. The project consists of: acquisition of Cygrymus Compressor Station (Greene County, PA), construction of two turbines and one additional compressor unit, and approximately 5.5 miles of pipeline.

The requested project would create approximately 350, 000 Dth/d of incremental firm gas on its Mainline System.

Feb 22, 2022

As a customer of Equitrans, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

2022-2023
Various issuances and Submittals between the Commission, Equitrans, and third parties on environmental concerns.

Jul 31, 2023
The Commission grants approval for Equitrans to start construction.

Equitrans
Abandonment of 5 wells
CP22-162

Apr 12, 2022
Equitrans filed an application to abandon five injection/withdrawal wells in the Swarts Complex, located in Greene County, Pennsylvania. This is part of the agreement, in September 2018, with CONSOL Coal Company to abandon certain storage facilities (Docket No. CP18-549-000).

Apr 28, 2022
As a customer of Equitrans, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Apr-Dect, 2022
Various Issuances and Submittals on environmental information.

Jan 26, 2023
The Commission order approving amendment to abandonment.

2023
Equitrans files monthly status reports.

Texas Eastern
Looping 2 miles
CP22-486

Jul 7, 2022
Texas Eastern submitted Appalachia to Market II (A2M II) and Armagh & Entriken HP Replacement Projects to the Commission for approval. The A2M II Project is designed to provide up to 55,000 dekatherms per

day of additional firm natural gas from the Appalachia basin (SW Pennsylvania) to local distribution customers in New Jersey.

The A2M II and HP Replacement projects have overlapping facilities are collective referred as the Project. The Project facilities include 2 miles of 36-inch diameter looping pipeline in Lebanon County, Pennsylvania. Two compression stations are included in overlapping facilities, located in Indiana and Hunting Counties, Pennsylvania. The Project has an estimated cost of $368 million.

Texas Eastern request authorization on or before November 15, 2023, to allow for construction to begin in January 2024. Completion is expected to be prior to the start of 2025/2026 winter heating season.

Jul 14, 2022
As a customer of Texas Eastern, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Jul-Dec, 2022
Various Issuances and Submittals involving Environmental impacts and data requests.

2023
Various Issuances and Submittals involving Environmental impacts and data requests.

Columbia Gas Transmission
Replacement on Line 1360
CP23-8

Oct 31, 2022
Columbia Gas Transmission filed request authorization to replace a segment of its existing Line 1360 and related facilities located in Beaver County, PA. The project consists of 2.78 miles of 16-inch diameter bare steel 1940’s vintage.

The project cost is approximately $18 million with a like size replacement. No new capacity will be created as the result of replacing the Line 1360 facilities. Construction is proposed for Spring 2023 and will be completed by September 2023.

Nov 14, 2022
Given that Columbia Gas of Pennsylvania is a firm transportation and storage customer of TCO, and that this project may impact their customers, CPA filed an intervention in this docket.

Dec, 2022
Columbia Gas Transmission submittal additional environmental information.

2023
TCO submits weekly construction status reports.

Columbia Gas Transmission
Penalty Revenue Credit Report 2022
RP23-318

Dec 30, 2022
Columbia Gas Transmission filed a Penalty Revenue Crediting Report for resulting penalty revenue credits for each month for the twelve-month period ending October 31, 2022. The Report shows Non-Penalized shippers penalty revenue credits including interest.

Penalty revenue credits for contract months November 2021 thru October 2022 for Columbia Gas of Pennsylvania amounted to $50,736.40.

Jan 10, 2023
NiSource filed an intervention in this docket due to a financial impact on its customers.

Please note that the FERC does not issue any receipts of routine reports.

National Fuel Gas Supply
2023 Annual Retainage Adjustment
RP23-441

Feb 15, 2023
National Fuel submits revised tariff Annual Retainage Adjustment filing. The proposed adjustments included a decrease in Transportation Fuel and Company Use Retention ("TFUR") from 0.79% to 0.72% and a decrease in the Transportation LAUF Retention 0.36% to 0.10%. Also a decrease in the SOLAR from 0.46% to 0.45%. The NA2015 fuel rate will decrease from 1.10% to 1.09%. The proposed effective date is April 1, 2023.

Feb 23, 2023
As a customer of Nation Fuel, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Mar 1, 2023
The FERC issued an Order accepting National Fuel's tariff filing, effective April 1, 2023 as requested.

Texas Eastern
OFO Penalty Disbursement Report
RP23-451

Feb 21, 2023
Texas Eastern filed an operational flow order (OFO) penalty disbursement report, pursuant to section 4.3 (GT&C) of its tariff.

This section of the tariff also requires Texas Eastern to file an annual OFO penalty disbursement report within 60 days of the month in which Texas Eastern collects over $1,000,000 in OFO penalty revenue.

In the instant filing, Texas Eastern states that it collected OFO penalty revenue from October 2021 to November 2022.

Mar 2, 2023
Due to the impact of this tariff on its customers, Columbia Gas of Pennsylvania filed an intervention in this docket.

Mar 7, 2023
The FERC accepted the OFO penalty disbursement report.

Equitrans
AVC Storage Loss Retainage Factor
RP23-490

Feb 28, 2023
Equitrans files actual fuel and unaccounted for gas experienced to operate the storage facilities Allegheny Valley Connector ("AVC") system. The revised AVC Storage Loss Retainage Factor has been calculated at 5.81% for 2022. The purpose of the calculation is the Storage Retention Rate True-up Volumes as required by Section 6.31 [6].

Mar 8, 2023
As a firm transportation and storage customers of Equitrans, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Mar 23, 2023
The FERC accepted the proposed Allegheny Valley Connector (AVC) Storage Loss retainage Factor for 2022 as requested. The tariff record is effective April 1, 2023.

Columbia Gas Transmission (TCO)
Annual Electric Power Costs Adjustments (EPCA) 2023
RP23-501

Feb 28, 2023
Columbia Gas Transmission submits Electric Power Costs Adjustments (“EPCA”) for the annual period beginning April 1, 2023.

TCO is authorized to make annual filings to revise its EPCA rates to take into account both prospective changes in Electric Power Costs (“Current EPCA Rate”) and unrecovered Electric Power Costs from the preceding twelve-month period (“Unrecovered EPCA Surcharge”).

Under the current EPCA Rate, for the twelve-month period beginning April 1, 2023, TCO had proposed to collect $29,275,900.

Mar 13, 2023
As firm transportation and storage customers of TCO, NiSource Gas Distribution filed an intervention in this docket on behalf of its customers.

Mar 23, 2023
The FERC issued an Order accepting TCO’s tariff record, effective April 1, 2023.

Columbia Gas Transmission (TCO)
Annual Transportation Costs Adjustment (TCRA) 2023
RP23-502

Feb 28, 2023
TCO filed revised tariffs reflecting its Transportation Costs Rate Adjustment (“TCRA”) for the annual period beginning April 1, 2023.

Under its tariff, TCO is authorized to make annual filings to revise its TCRA rates to reflect estimated prospective Operational 858 Costs for the 12-month period commencing April 1, 2023, and unrecovered past Operational 858 Costs for the period January 1, 2022, through December 31, 2022.

The estimated prospective Operational 858 Costs for the twelve-month period commencing April 1, 2023 are $76,399,304 compared to $75,399,304 of estimated prospective Operational 858 Costs, included in TCO’s 2022 Periodic TCRA Filing.

Mar 13, 2023
Due to the financial impact on its customers, Columbia Distribution Companies filed an intervention in this docket on the customers’ behalf.

Mar 31, 2023
The Commission issued an Order accepting the tariff records to be effective April 1, 2023.

Columbia Gas Transmission (TCO)
Annual Retainage Adjustment Mechanism (RAM) 2023
RP23-503

Feb 28, 2023
TCO filed revised tariff to adjust the Retainage Adjustment Mechanism (RAM) percentages partly based on unrecovered retainage for the period of January 1, 2022 through December 31, 2022; and account for prospective changes permitting new allocation methodology for TCO's gathering system. The effective date is April 1, 2023.

	Current Retainage Percentage	Proposed Retainage Percentage
Transportation	1.831%	2.132%
Transportation – FT-C	0.423%	0.763%
Gathering	0.423%	0.763%
Storage Losses	0.436%	0.405%
Ohio Storage Expansion	0.450%	0.559%

Mar 13, 2023
As firm transportation and storage customers of TCO, NiSource Gas Distribution filed an intervention in this docket on behalf of its customers.

Mar 31, 2023
The FERC issued an Order accepting TCO's tariff record, effective April 1, 2023.

Tennessee Gas
Annual Fuel Tracker 2023
RP23-522

Mar 1, 2023
Tennessee Gas Pipeline filed revised tariff to adjust the Annual Fuel Adjustment Mechanism effective April 1, 2023.

These reflect Tennessee's proposed recovery of (i) Fuel and Losses for the prospective year based on quantities incurred by Tennessee during the twelve month period ending December 31, 2018 and (ii) the balances as of the end of the Base Period in the applicable Deferred F&LR subaccounts.

Mar 13, 2023
As firm transportation customers of TGP, the NiSource Distribution Companies filed an intervention in this docket on behalf of its customers.

Mar 30, 2023
The Commission ordered acceptance and suspending tariff records subject to hearing outcome.

Columbia Gas Transmission (TCO)
Annual Capital Cost Recovery Mechanism (CCRM) 2023
RP23-524

Mar 1, 2023
Columbia Gas Transmission filed proposed revision to its Capital Cost Recovery Mechanism (CCRM) Rate to be effective April 1, 2023.

TCO is filing to establish a CCRM-T Daily Rate of $0.0141, applicable to Rate Schedules FTS, NTS, NTS-S, and SST.

TCO is also establishing a CCRM-T Daily Rate of $0.0282 for Rate Schedule GTS, $0.0129 for Rate Schedule OPT-30 Day, $0.0118 for Rate Schedule OPT-60 Day, $0.0141 for Rate Schedule ITS-Winter, and $0.0094 for Rate Schedule ITS-Summer. TCO also filed a CCRM-S Daily Reservation Charge Rate of $0.0084 and Capacity Charge Rate of $0.0050, applicable to Rate Schedule FSS, FSS-M, and FBS.

Mar 13, 2023
As firm transportation and storage customers of TCO, NiSource Gas Distribution filed an intervention in this docket on behalf of its customers.

Mar 31, 2023
The FERC issued an Order accepting TCO's tariff record, effective April 1, 2023.

Eastern Gas Transmission
Interim Fuel Retention Percentage
RP23-627

Mar 31, 2023
Eastern Gas filed revised tariff to adjust its annual fuel retainage factors, effective May 1, 2023.

Table 1 – Fuel Retention Percentages

Description	Current	Proposed
General System - Transportation	1.67%	1.21%
General System - Storage	1.43%	1.44%
Steuben - Transportation	0.00%	0.40%
Leidy South Surcharge - Transportation[4]	0.63%	0.59%

Apr 10, 2023
As a customer of Eastern Gas Transmission, Columbia Gas of Pennsylvania filed intervention in this docket on behalf of its customers.

Apr 19, 2023
The FERC issued an Order accepting Eastern Gas's tariff record, effective May 1, 2023.

Columbia Gas Transmission (TCO)
2023 Summer Operational Transactions Report Adjustment (OTRA)
RP23-662

Mar 31, 2023
TCO filed its Operational Transaction Rate Adjustment ("OTRA") for the upcoming 2023 summer season, requesting it to become effective May 1, 2023.

In this filing, TCO is proposed to increase its OTRA monthly reservation rate for the 2023 summer season to $0.107 per Dth for Rate Schedule FTS/NTS, TPS and SST service from the existing 2022 winter season rate of $0.206 per Dth.

The decrease reflected in current OTRA surcharge costs of approximately $12 million.

Apr 10, 2023
NiSource Gas Distribution (NGD) companies are firm transportation and storage customers of TCO, and given that the operational transactions support NGD's operations, an intervention was filed in this docket on behalf of its customers.

Apr 19, 2023
The FERC issued an Order accepting TCO's surcharge for costs associated with the summer OTRA period (April 2023 – October 2023), effective May 1, 2023.

Columbia Gas Transmission (TCO)
Amendment to OTRA (RP23-662)
RP23-766

May 9, 2023
TCO filed amendment to correct a minor error in the one proposed tariff sections submitted as part of TCO's March 31, 2023 Operational Transaction Rate Adjustment (OTRA) docket no. RP23-662. Section V.5 rate schedule GTS proposed rate $0.71 was corrected to $0.071.

	Base Tariff Rate 1/ 2/	TCRA Rates	EPCA Rates	OTRA Rates	CCRM-T Rates	Total Effective Rate 2/ 3/	Daily Rate 2/ 3/
Rate Schedule GTS							
Commodity							
Maximum $	1.2563	0.0326	0.0103	0.0071~~0.7100~~	0.0282	1.3345~~2.0374~~	1.3345~~2.0374~~
Minimum $	0.0103	0.0009	0.0060	0.00	0.00	0.0172	0.0172
MFCC $	1.2460	0.0317	0.0043	0.0071~~0.7100~~	0.0282	1.3173~~2.0202~~	1.3173~~2.0202~~

May 11, 2023
NiSource Gas Distribution (NGD) companies are firm transportation and storage customers of TCO, and given that the operational transactions support NGD's operations, an intervention was filed in this docket on behalf of NiSource Distribution customers.

May 23, 2023
The FERC issued an Order accepting TCO's revised tariff OTRA, effective May 1, 2023.

Columbia Gas Transmission (TCO)
TCRA Filing – REVISED refund from Texas Eastern
RP23-824

Jun 1, 2023
TCO filed revised tariff sections for the previously filed Annual Transportation Cost Rate Adjustment (TCRA) filing February 28, 2023 docket no. RP23-502. This revised filing reflects the impact of refund from Texas Eastern Settlement Order (RP21-1001 and RP21-1188) September 8, 2022.

The proposed tariff rate effective date, July 1, 2023.

May 13, 2023
NiSource Gas Distribution (NGD) companies are firm transportation and storage customers of TCO, and given that the operational transactions support NGD's operations, an intervention was filed in this docket on behalf of NiSource Distribution customers.

Jun 30, 29023
The FERC granted TCO's revised tariff and waiver request. Tariff records effective July 1, 2023.

Eastern Gas
2023 Overrun and Penalty Revenue Distribution
RP23-860

Jun 30, 2023
Eastern Gas filed a distribution report to reflect revenue distribution and billing adjustments resulting from Eastern Gas collection of unauthorized overrun charges and penalty revenues for the twelve-month period ending March 31, 2023.

Credits of Unauthorized Overrun Charge and Penalty Revenues, amounting to a net revenue inclusive of interest, were $968,697.63, and were distributed to non-offending customers on June 30, 2023.

Jul 11, 2023
Columbia Gas of Pennsylvania filed an intervention in this docket due to a financial impact on its customers.

Please note that the FERC does not issue any receipts of routine reports.

Texas Eastern
Electric Power Cost (EPC) Aug 2023
RP23-862

Jun 30, 2023
Texas Eastern tendered for filing, revised tariffs to establish new semi-annual EPC rates and surcharges for its Electric Power Cost ("EPC") Adjustment, effective August 1, 2023.

Texas Eastern is basing its electric power cost projections on the latest actual twelve months of electric power costs and the actual throughput quantities during the twelve month period ending April 2023.

Jul 11, 2023
As a customer of Texas Eastern, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Jul 24, 2023
The Commission accepted the tariff record as requested, effective August 1, 2023.

Tennessee Gas
New tariff – firm hourly transportation rate (Powerserve) FT-PS
RP23-863

Jun 30, 2023
Tennessee Gas filed a new tariff rate schedule FT-PS (PowerServe). The proposed PowerServe is a new hourly firm transportation service with an optional no-notice service component. The new tariff will allow interested shippers to nominate and receive deliveries of gas from Tennessee at an hourly rate that exceeds an uniform hourly flow rate.

"Under Rate Schedule FT-PS, Tennessee will transport natural gas on a firm basis for a shipper up to the Transportation Quantity ("TQ") and up to the Maximum Hourly Quantity ("MHQ") stated in such shipper's FT-PS PowerServe agreement. The MHQ can range between the TQ divided by 8 and the TQ divided by 24. In other words, a shipper can elect to receive its entire daily entitlement in as little as eight hours or as many as twenty-four hours, representing a uniform hourly flow profile."

Tennessee request proposed tariff records effective date of October 1, 2023.

Jul 12, 2023
NiSource Gas Distribution (NGD) companies are firm transportation Tennessee Gas, and given that the operational transactions support NGD's operations, an intervention was filed in this docket on behalf of NiSource Distribution customers.

Sep 29, 2023
The Commission issues an Order certificates and accepting tariff records effective October 1, 2023. Subject to Tennessee filing revised tariff record to incorporate the modified tariff language within 30 days.

Equitrans
Abandon wells Swarts and Hunters Well Replacement – Greene County, PA
CP23-507

Jun 30, 2023
Equitrans requests authorization to abandon by sale injection/withdrawel wells in the existing Hunter Cave Storage Field and Swarts Complex. The project replace the capacity and capabilities of the of the storage fields which was lost to the CONSOL coal company. When there is active mining proximate to gas storage operations, Pennsylvania law requires storage field operator to either modernize or plug all wells.

CONSOL plans to commence long wall mining proximate to the Hunters Cave Field in February 2024.

Well Number	Planned Abandonment Date	Total Deliverability Decrease to Date	Working Gas Decrease to Date
600483	February 2024	5%	2%
600482	March 2024	10%	4%
602692	April 2024	11%	4%
603724	May 2024	12%	5%
603922	May 2024	13%	5%
603725	June 2024	17%	8%
603722	June 2024	19%	8%
602729	July 2024	37%	28%
600484	August 2024	46%	40%
602721	October 2024	58%	55%
602681	December 2024	76%	77%
603622	January 2025	77%	77%
602796	June 2025	83%	82%
602702	October 2025	84%	83%
602923	May 2026	96%	96%
603921	February 2028	97%	97%
603918	January 2042	99%	97%
603668	August 2042	100%	100%
603919	January 2043	100%	100%

Aug 4, 2023
Given that Columbia Gas of Pennsylvania is a firm transportation and storage of Equitrans, and given that the operational transactions support Columbia Gas of Pennsylvania operations, an intervention was filed in this docket on behalf of its customers.

Aug-Dec 2023
Various Issuances and Submittals on environmental information request.

National Fuel
Abandon storage wells Swede Hill - McKean County, PA
CP23-496

Jun 9, 2023
National Fuel requests authorization to abandon five storage wells and associated well lines in its Swede Hills Storage Field located in Hamilton Township, McKean County, Pennsylvania. National Fuel has completed routine well evaluations and determined five wells contain significant downhole localized corrosion. The corrosion location and current configuration of the wells has deemed reworking of the wells not feasible, plugging and abandoning the wells is the only prudent course of action. National Fuel stated no impact to existing customers or storage operations.

Aug 4, 2023
Given that Columbia Gas of Pennsylvania is a firm transportation and storage of National Fuel, and given that the operational transactions support Columbia Gas of Pennsylvania operations, an intervention was filed in this docket on behalf of its customers.

Aug 14, 2023
The Commission issues completed Environmental Assessment Report on the proposed project.

Columbia Gas Transmission (TCO)
Creditworthiness Tariff Clarification
RP23-949

Aug 1, 2023
TCO filed proposed update to its creditworthiness provisions and make general housekeeping edits within its tariff.

"Columbia is proposing to update the creditworthiness provisions in Sections 9.6 (Creditworthiness of Shipper) and Section 10 (Billing and Payment) of its Tariff to make credit-related modifications as further described below. The proposed revisions will mutually serve both Columbia and its Shippers through the implementation of clear and concise creditworthiness requirements that will assist in streamlining the evaluation of creditworthiness for a new and existing Shippers. Further, Columbia's proposed changes are consistent with the Commission's June 16, 2005 Policy Statement on Creditworthiness Issues for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding issued under Docket Nos. PL05-8-000 and RM04-4-000 ("Creditworthiness Policy Statement").3

As discussed below, the proposed creditworthiness modifications: 1) modify the creditworthiness standard to an unenhanced senior unsecured debt rating of either BBB- by S&P Global Market Intelligence LLC ("S&P") or Baa3 by Moody's Investors Service, Inc. ("Moody's"); 2) remove the stable or positive outlook opinion and tangible net worth requirements 2) modify the other information Columbia may consider in making its creditworthiness determination; 3) update financial assurance descriptions and requirements and present such requirements for all services in an organized table format; 4) update and clarify the notice provisions for a shipper's failure to meet creditworthiness; and 5) clarify and/or modify certain provisions and references affected by the foregoing creditworthiness proposal."
TCO proposed September 1, 2023 effective date.

Aug 10, 2023
NiSource Gas Distribution (NGD) companies are firm transportation and storage customers of TCO, and given that the operational transactions support NGD's operations, an intervention was filed in this docket on behalf of NiSource Distribution customers.

Aug 31, 2023
The Commission issued order to accept proposed tariff changes on creditworthiness provisions, effective September 1, 2023.

National Fuel
Section 4 Rate Case 2023
RP23-929

Jul 31, 2023
National Fuel Gas Supply filed revised tariff record, and includes changes rates, effective September 1, 2023. National Fuel requested that the Commission suspend the tariff sections for the full five-month suspension period, so effective date would be February 1, 2024.

"National Fuel states that its last rate case was filed in Docket No. RP19-1426-000 on July 31, 2019. The Commission approved an uncontested Stipulation and Agreement (2020 Stipulation) of that proceeding on June 1, 2020.5 The 2020 Stipulation provides that National Fuel shall file an NGA section 4 rate case for rates to be effective February 1, 2024."

"National Fuel proposes a cost of service of $385,418,269 and a total rate base of $1,321,145,984 using data for the base period consisting of 12 months ending March 31, 2023, as adjusted for known and measurable changes through December 31, 2023. 7 National Fuel's proposed rates reflect a 43.46% debt and 56.54% equity capital structure, and a 15.12% return on equity (ROE), for an overall rate of return of 10.70%.8 National also proposes changes to its annual depreciation rates and negative salvage rates."

Jul 14, 2023
Columbia Gas of Pennsylvania is firm transportation and storage customers of National Fuel, and given that the operational transactions support, an intervention and protest was filed in this docket on behalf of its customers. Columbia Gas of Pennsylvania requested the Commission:

1. Issue an order permitting it to intervene.
2. Suspend any proposed increases in rates for the max. period permitted.
3. Any proposed increases in rates to take effect only subject to refund, should the suspension period expire prior to the time this proceeding is concluded.
4. Request a full and complete investigation of the proposed rates and tariff changes.
5. To set the matter for evidentiary hearing.
6. Grant Columbia Gas of Pennsylvania relief as may be necessary to protect its interests and the interests of the retail customers which it serves.

Aug 31, 2023
The Commission issued an order accepting and suspending tariff records, subject to refund and establishing hearing procedures. The Commission orders:

A. The tariffs records are accepted and suspended for five months, to be effective upon motion February 1, 2024, subject to refund and the outcome of the hearing established.
B. A public hearing shall be held to determine the justness and reasonableness of National Fuel's proposed tariff records.
C. A Presiding Administrative Law Judge, to be designated by the Chief Administrative Law Judge, shall, with 45 days convene a prehearing conference in these proceedings.
D. Upon its motion to place suspended rates into effect, National Fuel must remove facilities not placed in service before the effective date.

Sep 20, 2023
The Chief Judge issues presiding administrative law judge and establishes Track III procedural time standards.

Sep 2023-Jan 2024
Settlement Judge facilitated five conference proceedings.

Jan 30 2024
National Fuel submitted to place suspended and revised tariffs records into effect. The effective date of February 1, 2024, pursuant to Section 154.206(a) of the Commission's regulations and the August 31 Order.

RATES FOR TRANSPORTATION SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	Current Rate [2/] (6)
FT/FT-S						
	Reservation	(Max)	$8.2087~~8.6126~~	-	-	$8.2087~~8.6126~~ ~~[4/]~~
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0068	-	-	$0.0068 plus ACA [3/]
		(Min)	0.0068	-	-	$0.0068 plus ACA [3/]
	Overrun	(Max)	0.2767~~2900~~	-	-	$0.2767~~2900~~ plus ACA [3/]
		(Min)	0.0068	-	-	$0.0068 plus ACA [3/]
EFT	Reservation	(Max)	$8.4880~~8.8833~~	0.0000	0.0000	$8.4880~~8.8833~~ ~~[4/]~~
		(Min)	0.0000	0.0000	0.0000	$0.0000
	Commodity	(Max)	0.0223	0.0000	0.0000	$0.0223 plus ACA[3/]
		(Min)	0.0223	0.0000	0.0000	$0.0223 plus ACA[3/]
	Overrun	(Max)	0.3014~~3144~~	-	-	$0.3014~~3144~~ plus ACA[3/]
		(Min)	0.0223	-	-	$0.0223 plus ACA[3/]

National Fuel
Abandon 2 Storage Wells – Allegany County New York
CP23-506

Jun 29, 2023
National Fuel filed blanket certificate authority requesting abandon two storage wells and associated well lines in its Beech Hill Storage Field located in Allegany County, New York.

Sep 5, 2023
Given that Columbia Gas of Pennsylvania is a firm transportation and storage of National Fuel, and given that the operational transactions support Columbia Gas of Pennsylvania operations, an intervention was filed in this docket on behalf of its customers.

Sep 5, 2023
The Commission issues completed Environmental Assessment Report on the proposed project.

Texas Eastern
August 2023 Penalty Disbursement Report
RP23-980

Aug 25, 2023
Texas Eastern Transmission filed Penalty Disbursement Report to the Commission. Texas Eastern is required to file penalty disbursement report within sixty days of August 31 or sixty days after the end of the month for which OFO order penalty revenue collected exceeds $1,000,000.

Sep 6, 2023
As a customer of Texas Eastern, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Sep 21, 2023
The Commission accepted the Penalty Disbursement Report.

Texas Eastern
Changes to Action Alert Penalty Provision
RP23-1091

Sep 28, 2023
Texas Eastern Transmission filed proposal to modify its tariff to allow for more flexibility, as operational conditions permit, to the amounts assessed for action alert penalties. This proposed change would give more flexibility to Texas Eastern's customers.

Oct 10, 2023
As a customer of Texas Eastern, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Oct 31, 2023
The Commission accepted the tariff record as requested, effective November 1, 2023.

Eastern Gas Transmission
2023 Annual Electric Power Cost Rate Adjustment (EPCA)
RP23-1094

Sep 29, 2023

Eastern Gas Transmission filed an updated Electric Power Cost Adjustment (EPCA). The EPCA would recover costs associated with 105.4 million kWh of electric power passed on annual period ending June 30, 2023.

Oct 6, 2023
As a customer of Eastern Gas Transmission, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Oct 19, 2023
The Commission accepted the tariff record as requested, effective November 1, 2023.

Eastern Gas Transmission
2023 Annual Transportation Cost Rate Adjustment (TCRA)
RP23-1095

Sep 29, 2023
Eastern Gas Transmission filed an updated Transportation Cost Rate Adjust (TCRA). The proposed TCRA and EPCA rate changes are noted below.

Combined Effect of both EPCA and TCRA Filings			
Rate Component	**Proposed Rate**	**Current Rate**	**Difference**
FT/FTNN Reservation	$5.9493	$5.9674	($0.0181)
FT/FTNN Usage	$0.0098	$0.0093	$0.0005
IT	$0.2045	$0.2046	($0.0001)
GSS Demand Rate	$2.6749	$2.6784	($0.0035)
GSS Injection Rate	$0.0393	$0.0396	($0.0003)
GSS Withdrawal Rate	$0.0256	$0.0262	($0.0006)

Oct 6, 2023
As a customer of Eastern Gas Transmission, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Oct 19, 2023
The Commission accepted the tariff record as requested, effective November 1, 2023.

National Fuel
Pipeline Safety and Greenhouse Gas Cost Adjustments
RP23-1097

Sep 29, 2023
National Fuel Gas Supply filed updated tariff cost recovery mechanism for cost associated with Pipeline Safety and Greenhouse Gas Costs (PS/GHG). National Fuel proposed an effective date of November 1, 2023.

"National Fuel notes that its Total Cost of Service under the mechanism is $4.17 million, which exceeds the pro-rated $1.25 million limit applicable to the PS/GHG Mechanism. See Exhibit 1, Page 1. National Fuel's filing therefore proposes to recover $1.25 million between November 1, 2023 and January 31, 2024, subject to rates under National Fuel's 2023 Rate Case becoming effective on February 1, 2024. 9 To the extent rates were to become effective at some later date the mechanism and the associated surcharges proposed herein would continue until such date."

Oct 10, 2023
Columbia Gas of Pennsylvania filed an intervention in this docket due to a financial impact on its customers.

Oct 24, 2023
The Commission issued an Order accepting the revised tariffs effective November 1, 2023, as requested.

Tennessee Gas Pipeline
Pipeline Safety and Greenhouse Gas Cost Adjustments
RP23-1103

Sep 29, 2023
Tennessee Gas Pipeline filed updated tariff cost recovery mechanism for cost associated with Pipeline Safety and Greenhouse Gas Costs (PS/GHG) pursuant to Article XXXVIII of the General Terms and Conditions of Tennessee's tariff. Tennessee Gas proposed an effective date of November 1, 2023.

Oct 10, 2023
Columbia Gas of Pennsylvania filed an intervention in this docket due to a financial impact on its customers.

Oct 25, 2023
The Commission issued an Order accepting the revised tariffs effective November 1, 2023, as requested.

Texas Eastern
October 2023 Penalty Disbursement Report
RP24-68

Oct 27, 2023
Texas Eastern Transmission filed an operational flow order (OFO) penalty disbursement report, pursuant to Section4.3 (GT&C) of its tariff.

This section of the tariff also requires Texas Eastern to file an annual OFO penalty disbursement report within 60 days of the month in which Texas Eastern collects over $1,000,000 in OFO penalty revenue.

System / Zone	Production Month	Penalty Amount Collected
TETLP / ETX	May 2023	$86,886.41
TETLP / M1	June 2023	$3,689.60
TETLP / M3	June 2023	$8.22
TETLP / WLA	June 2023	$5,552.37
TETLP / M2	July 2023	$91,995.75
TETLP / M3	July 2023	$70,633.13
TETLP / M3	August 2023	$111,485.40

Nov 7, 2023
Columbia Gas of Pennsylvania filed an intervention in this docket due to a financial impact on its customers.

Nov 15, 2023
The Commission issued an Order accepting the filing of penalty disbursement.

Texas Eastern
PCB December 2023 Filing
RP24-82

Oct 30, 2023
Texas Eastern filed tariff records to implement new rates set forth in the PCB Settlement extension, approved by the Commission in Docket No. RP17-964, effective December 1, 2023, through November 30, 2024.

The tariff sections reflect Texas Eastern’s estimate of its Year 7 Eligible PCB-Related Costs of $4,599,481 of which $2,644,701 is recoverable by Texas Eastern pursuant to the Settlement.

Nov 7, 2023
Columbia Gas of Pennsylvania filed an intervention in this docket due to a financial impact on its customers.

Nov 17, 2023

The Commission accepted Texas Eastern's filing of tariff records to comply with the Joint Settlement Extension Agreement approved in October 17, 2017.

Columbia Gas Transmission
Abandon 5 wells Donegal Storage, Washington PA
CP24-11

Oct 23, 2023
Columbia Gas Transmission filed a request for authorization to abandon five injection/withdrawal wells located in its Donegal Storage Field in Washington County, Pennsylvania.

Donegal Wells 4075, 4090, 4111, 42230, and 4836 are proposed for abandonment. Columbia commenced storage operations at the Donegal Storage Field in 1940. The proposed wells to be abandon are part of an underground coal mine currently being developed in the Pittsburgh Coal Seam.

Nov 6, 2023
Columbia Gas of Pennsylvania filed motion to intervene.

Texas Eastern
Applicable Shrinkage Adjustment (ASA)
RP24-102

Oct 31, 2023
Texas Eastern filed proposed tariff to make changes to the Applicable Shrinkage Adjustment (ASA) and clear the net balance in the deferred account. Texas Eastern also proposed revisions in the ASA Percentages and ASA Surcharges, as well as the lost and unaccounted for ("LAUF") percentages, for various incremental projects, as required by prior FERC orders.

The filing reflects an increase in the annual average ASA Percentage for typical long-haul service of 0.16%, and an increase in ASA Surcharge of 0.0036 cents per dekatherm. For those system customers accessing the Market Area zones, this filing on average increase fuel by 0.07%. The rate would be effective December 1, 2023.

Nov 13, 2023
Columbia Gas of Pennsylvania filed an intervention in this docket due to a financial impact on its customers.

Nov 20, 2023
The Commission accepted the tariff records on Annual Tracker Filing.

Columbia Gas Transmission
Operational Transaction Rate Adjustments (OTRA) Winter 2023
RP24-121

Nov 1, 2023
Columbia Gas Transmission proposes to collect costs associated with the upcoming OTRA winter season of November 2023 through March 2024 in the amount of $9,569,661. Additionally, TCO is proposing to include $1,077,696 of over-recoveries from the previous OTRA period in its calculation of the OTRA True-Up Surcharge.

"On February 25, 2022, in Docket Nos. RP20-1060 et al., the Commission issued an order approving Columbia's Modernization Settlement, which by its terms extended Columbia's OTRA mechanism through the term of the Settlement. 6 Columbia's OTRA mechanism allows Columbia to adjust its OTRA rates for both a summer season and a winter season each year The seasonal filings address both prospective changes in OTRA costs, as well as prior period over- or under-recoveries."

Nov 13, 2023
As firm transportation and storage customers of TCO, NiSource Gas Distribution filed an intervention in this docket on behalf of its affiliates and their customers.

Nov 20, 2023
The Commission accepted tariff records to reflect semi-annual Operational Transaction Rate Adjustment.

Texas Eastern
Electric Power Cost Adjustment Filing
RP24-271

Dec 28, 2023
Texas Eastern tendered for filing, revised tariffs to establish new semi-annual EPC rates and surcharges for its Electric Power Cost ("EPC") Adjustment, effective February 1, 2024.

Texas Eastern is basing its electric power cost projections on the latest actual twelve months of electric power costs and the actual throughput quantities during the twelve month period ending October 2023.

Jan 9, 2024
As a customer of Texas Eastern, Columbia Gas of Pennsylvania filed an intervention in this docket on behalf of its customers.

Jan 23, 2024
The Commission accepted tariff records to reflect the new EPC rates.

Columbia Gas Transmission
Penalty Revenue Credit Report 2023
RP24-284

Dec 29, 2023
Columbia Gas Transmission filed a Penalty Revenue Crediting Report for resulting penalty revenue credits for each month for the twelve-month period ending October 31, 2023. The Report shows Non-Penalized shippers penalty revenue credits including interest.

Penalty revenue credits for contract months November 2022 thru October 2023 for Columbia Gas of Pennsylvania amounted to $510,385.

Jan 9, 2024
NiSource filed an intervention in this docket due to a financial impact on its customers.

Combined List of FERC pipeline filings reviewed

JANUARY 2023

Jan 3, 2023 Equitrans negotiated rate capacity release agreements effective January 1, 2023, RP23-332; reviewed/OK; FERC approved January 26, 2023, as requested.

Jan 3, 2023 Texas Eastern Transmission negotiated rates – various releases effective January 1, 2023, RP23-334; reviewed/OK; FERC approved January 19, 2023, as requested.

Jan 3, 2023 NEXUS Gas Transmission negotiated rates – various releases effective January 1, 2023, RP23-338; reviewed/OK; FERC approved January 27, 2023, as requested.

Jan 3, 2023 Texas Eastern Transmission negotiated rates – NextEra Energy effective January 1, 2023, RP23-340; reviewed/OK; FERC approved January 26, 2023, as requested.

Jan 3, 2023 Texas Eastern Transmission negotiated rates – Venture Global effective January 1, 2023, RP23-341; reviewed/OK; FERC approved January 26, 2023, as requested.

Jan 5, 2023 Transcontinental Gas Pipe Line Rate Schedule S-2 OFO Refund Report, RP23-344; reviewed/OK; FERC has not issued an Order in this docket.

Jan 5, 2023 Rockies Express Pipeline (REX) negotiated rate agreements effective January 5, 2023, RP23-346; reviewed/OK; FERC approved January 26, 2023, as requested.

Jan 6, 2023 Tennessee Gas Pipeline rate filing PAL NRA KM Gas Marking & Wells Fargo effective February 1, 2023; RP23-348; reviewed/OK; FERC approved January 23, 2023, as requested.

Jan 6, 2023 Rockies Express Pipeline (REX) negotiated rate agreement and amendments effective January 6, 2023, RP23-351; reviewed/OK; FERC approved January 27, 2023, as requested.

Jan 9, 2023 Columbia Gas of Maryland filed tariff record effective December 9, 2022, PR23-21; FERC approved February 14, 2023, as requested.

Jan 9, 2023 Texas Eastern Transmission non-conforming agreement – Venture Global effective January 1, 2023, RP23-353; reviewed/OK; FERC approved January 24, 2023, as requested.

Jan 10, 2023 NEXUS Gas Transmission FOSA signature block update effective February 10, 2023, RP23-354; reviewed/OK; FERC approved January 31, 2023, as requested.

Jan 11, 2023 Equitrans amended negotiated rate agreement effective January 10, 2023, RP23-355; reviewed/OK; FERC approved January 31, 2023, as requested.

Jan 17, 2023 Rockies Express Pipeline (REX) negotiated rate agreement and amendments effective January 18, 2023, RP23-359; reviewed/OK; FERC approved January 31, 2023, as requested.

Jan 19, 2023 Transcontinental Gas Pipe Line rate schedule GSS/LSS tracker filing Eastern Gas Transmission settlement effective April 1, 2022, RP23-361; reviewed, January 26, 2023, Columbia Gas of Virginia filed motion to intervene; FERC approved February 13, as requested.

Jan 20, 2023 Equitrans negotiated rate agreement effective January 20, 2023, RP23-362; reviewed/OK; FERC approved February 3, 2023, as requested.

Jan 26, 2023 Eastern Gas Transmission negotiated rate agreement effective February 1, 2023, RP23-371; reviewed/OK; FERC approved February 10, 2023, as requested.

Jan 26, 2023 Columbia Gas of Maryland rate effective January 1, 2023, PR23-26; April 5, 2023, CMD submits tariff amendment, effective January 1, 2023.

Jan 31, 2023 Transcontinental Gas Pipe Line negotiated rate – Cherokee AGL replacement shippers effective February 1, 2023, RP23-380; reviewed/OK; FERC approved February 23, 2023, as requested.

Jan 31, 2023 Rockies Express Pipeline (REX) negotiated rate agreement effective February 1, 2023, RP23-387; reviewed/OK; FERC approved February 24, 2023, as requested.

Jan 31, 2023 Saltville Gas Storage Company address change effective August 1, 2023, RP23-388; reviewed/OK; FERC approved March 3, 2023, as requested.

Jan 31, 2023 Egan Hub Storage address change effective August 1, 2023, RP23-392; reviewed/OK; FERC approved March 3, 2023, as requested.

Jan 31, 2023 NEXUS address change effective August 1, 2023, RP23-394; reviewed/OK; FERC approved March 3, 2023, as requested.

Jan 31, 2023 Texas Eastern Transmission address change effective August 1, 2023; RP23-395; reviewed/OK; FERC approved March 3, 2023, as requested.

Jan 31, 2023 Texas Eastern Transmission negotiated rates – Nextera NRA effective February 1, 2023, RP23-403; reviewed/OK; FERC approved February 23, 2023, as requested.

Jan 31, 2023 NEXUS Gas Transmission negotiated rate – EAP rate EAP Ohio to Citadal effective January 27, 2023, RP23-404; reviewed/OK; FERC approved February 24, 2023, as requested.

Jan 31, 2023 Columbia Gas Transmission rate filing Antero release to MU Marketing effective February 1, 2023, RP23-405; reviewed/OK; FERC approved February 23, 2023, as requested.

February 2023

Feb 1, 2023 Equitrans negotiated rate capacity releases agreements effective February 1, 2023, RP23-414; reviewed/OK; FERC approved February 24, 2023, as requested.

Feb 1, 2023 NEXUS Gas Transmission negotiated rates various releases effective February 1, 2023; RP23-415; reviewed/OK; FERC approved February 24, 2023, as requested.

Feb 2, 2023 Texas Eastern Transmission non-conforming agreements – NextEra effective February 2, 2023; RP23-419; reviewed/OK; FERC approved February 17, 2023, as requested.

Feb 3, 2023 Equitrans compliance filing Penalty Revenue Crediting Report, RP23-420; reviewed/OK; FERC approved February 22, 2023, as requested.

Feb 6, 2023 Columbia Gas Transmission non-conforming – Columbia Gas of Virginia effective February 1, 2023, RP23-430; reviewed/OK; FERC approved March 2, 2023, as requested.

Feb 8, 2023 Rockies Express Pipeline (REX) negotiated rate agreements amendments effective February 9, 2023; RP23-431; reviewed/OK; FERC approved February 28, 2023, as requested.

Feb 9, 2023 Trunkline Gas Company updated GT&C Section effective March 9, 2023; RP23-433; reviewed/OK; FERC approved February 24, 2023, as requested.

Feb 10, 2023 Midwestern Gas Transmission housekeeping updated effective March 13, 2023; RP23-434; reviewed/OK; FERC approved March 16, 2023, as requested.

Feb 10, 2023 Panhandle Eastern Pipe Line updated GT&C Section 28 effective March 10, 2023; RP23-435; reviewed/OK; FERC approved February 24, 2023, as requested.

Feb 15, 2023 National Fuel Gas Supply Fuel Tracker Filing effective April 1, 2023; RP23-441; reviewed, February 23, 2023 Columbia Gas of Pennsylvania filed motion to intervene; FERC approved March 1, 2023, as requested.

Feb 16, 2023 Texas Eastern Transmission negotiated rates NJN 910185 clean up effective March 18, 2023: RP23-444; reviewed/OK; FERC approved March 3, 2023, as requested.

Feb 21, 2023 Rockies Express Pipeline (REX) negotiated rate agreement amendments effective February 21, 2023; RP23-450; reviewed/OK; FERC approved March 13, 2023, as requested.

Feb 21, 2023 Texas Eastern Transmission February 2023 Penalty Disbursement Report; RP23-451; reviewed, March 2, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved March 7, 2023, as requested.

Feb 23, 2023 Equitrans formula based negotiated rates effective March 1, 2023; RP23-454; reviewed/OK; FERC approved March 8, 2023, as requested.

Feb 23, 2023 Columbia Gas Transmission compliance filing Annual Report on Operational Transactions 2023; RP23-456; reviewed/OK; FERC has not issued an Order in this docket.

Feb 23, 2023 Crossroads Pipeline compliance filing Annual Report on Operational Transactions 2023; RP23-457; reviewed/OK; FERC has not issued an Order in this docket.

Feb 24, 2023 Columbia Gas of Virginia Application for a Certificate of Public Convenience and Necessity to transport and sell natural gas in interstate commerce as though intrastate pipeline. CP23-77; FERC issued blanket certificate, August 30, 2023.

Feb 27, 2023 Midwestern Gas Transmission Annual Fuel Retention Percentage Adjustment 2023 Rate effective April 1, 2023; RP23-468; reviewed, March 13, 2023 NIPSCO filed motion to intervene; FERC approved March 16, 2023, as requested.

Feb 28, 2023 Eastern Gas Transmission nonconforming service agreements effective April 1, 2023; RP23-473; reviewed/OK; FERC approved March 23, 2023, as requested.

Feb 28, 2023 NEXUS Gas Transmission ASA Filing effective April 1, 2023; RP23-478; reviewed, March 13, 2023 NIPSCO filed motion to intervene; FERC approved March 20, 2023, as requested.

Feb 28, 2023 Transcontinental Gas Pipe Line negotiated rates – Cherokee replacement shippers effective March 1, 2023; RP23-482; reviewed/OK; FERC approved March 23, 2023, as requested.

Feb 28, 2023 Transcontinental Gas Pipe Line 2023 Annual Transco Fuel Tracker effective April 1, 2023; RP23-488; reviewed, March 8, 2023, Columbia Gas of Virginia filed motion to intervene; FERC approved March 22, 2023, as requested.

Feb 28, 2023 Equitrans AVC storage loss retainage factor updated – 2023 effective April 1, 2023; RP23-490; reviewed, March 8, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved March 23, 2023, as requested.

Feb 28, 2023 Rockies Express Pipeline Fuel and L&U Reimbursement Percentages and Power Cost Charges; RP23-491; reviewed, March 13, 2023, Columbia Gas of Ohio filed motion to intervene; FERC approved March 30, 2023, as requested.

Feb 28, 2023 Tennessee Gas Pipeline rate filing Citadel Energy Marketing SP378772 effective March 1, 2023, RP23-500; reviewed/OK; FERC approved March 16, 2023, as requested.

Feb 28, 2023 Columbia Gas Transmission EPCA 2023 effective April 1, 2023, RP23-501; reviewed, March 13, 2023 NiSource filed motion to intervene; FERC approved March 23, 2023, as requested.

Feb 28, 2023 Columbia Gas Transmission TCRA 2023 effective April 1, 2023, RP23-502; reviewed, March 13, 2023 NiSource filed motion to intervene; FERC approved March 31, 2023, as requested.

Feb 28, 2023 Columbia Gas Transmission RAM 2023 effective April 1, 2023, RP23-503; reviewed, March 13, 2023 NiSource filed motion to intervene; FERC approved March 31, 2023, as requested.

March 2023

Mar 1, 2023 Texas Eastern Transmission negotiated rate – Sequent K911825 effective April 1, 2023; RP23-508; reviewed/OK; FERC approved March 24, 2023, as requested.

Mar 1, 2023 NEXUS Gas Transmission negotiated rates – various release effective March 1, 2023, RP23-510; reviewed/OK; FERC approved March 24, 2023, as requested.

Mar 1, 2023 Panhandle Eastern Pipe Line Fuel Filing effective April 1, 2023, RP23-514; reviewed, March 13, 2023 NiSource filed motion to intervene; FERC approved March 17, 223, as requested.

Mar 1, 2023 Trunkline Gas Company Fuel Filing effective April 1, 2023, RP23-515; reviewed/OK; FERC approved March 22, 2023, as requested.

Mar 1, 2023 Texas Eastern Transmission negotiated rates – Con ED to Direct Energy effective March 1, 2023, RP23-519; reviewed/OK; FERC approved March 27, 2023, as requested.

Mar 1, 2023 Tennessee Gas Pipeline 2023 Fuel Tracker Filing effective April 1, 2023, RP23-522; March 13, 2023 NiSource filed motion to intervene; FERC issued an order on April 4, 2023, Track II procedural time line.

Mar 1, 2023 Transcontinental Gas Pipe Line Annual Electric Power Tracker Filing effective April 1, 2023, RP23-523; March 13, 2023 NiSource filed motion to intervene; FERC approved March 24, 2023, as requested.

Mar 1, 2023 Columbia Gas Transmission CCRM 2023 effective April 1, 2023, RP23-524; March 13, 2023 NiSource filed motion to intervene; FERC approved March 31, 2023, as requested.

Mar 1, 2023 Equitrans negotiated rate capacity release agreements effective March 1, 2023, RP23-527; reviewed/OK; FERC approved March 27, 2023, as requested.

Mar 1, 2023 ANR Pipeline Company 2023 Fuel and EPC filing effective April 1, 2023, RP23-543; reviewed, March 13, 2023 NIPSCO filed motion to intervene; FERC approved March 24, 2023, as requested.

Mar 1, 2023 Crossroads Pipeline Company TRA 2023 filing effective April 1, 2023, RP23-545; reviewed; March 13, 2023 Columbia Gas of Ohio filed motion to intervene. FERC approved March 30, 2023, as requested.

Mar 16, 2023 Transcontinental Gas Pipeline rate filing SS-12, Firm, and Interruptible transportation fuel percentages tracker filing effective April 1, 2023, RP23-575; reviewed, March 28, 2023 Columbia Gas of Virginia filed motion to intervene; FERC approved March 31, 2023, as requested.

Mar 17, 2023 Rockies Express Pipeline (REX) negotiated rate agreements amendments effective March 18, 2023, RP23-579; reviewed/OK; FERC approved April 5, 2023, as requested.

Mar 23, 2023 Rockies Express Pipeline (REX) compliance filing – Annual Purchase and Sales Report, RP23-585; reviewed/OK; FERC has not issued an Order in this docket.

Mar 23, 2023 Equitrans rate filing updated initial retainage rate effective April 1, 2023, RP23-586; reviewed/OK; FERC approved April 10, 2023, as requested.

Mar 24, 2023 Transcontinental Gas Pipe Line rate filing Schedule S-2 tracker filing effective February 1, 2023, RP23-588; reviewed/OK; FERC approved April 18, 2023, as requested.

Mar 24, 2023 Natural Gas Pipeline Company of America negotiated rate agreement filing – BP Energy/Eco-Energy effective March 31, 2023, RP23-589; reviewed/OK; FERC approved April 18, 2023, as requested.

Mar 24, 2023 Transcontinental Gas Pipe Line Company rate filing list of non-conforming services agreements effective April 24, 2023, RP23-590; reviewed/OK; FERC approved April 13, 2023, as requested.

Mar 27, 2023 Natural Gas Pipeline Company of America rate filing negotiated rate agreement filing – other shippers effective April 1, 2023, RP23-594; reviewed/OK; FERC approved April 20, 2023, as requested.

Mar 28, 2023 Natural Gas Pipeline Company of America rate filing negotiated rate agreement filing multiple shippers effective April 1, 2023, RP23-599; reviewed/OK; FERC approved April 24, 2023, as requested.

Mar 28, 2023 Transcontinental Gas Pipe Line rate filing negotiated rates – ESS – Spire Alabama effective April 1, 2023, RP23-600; reviewed/OK; FERC approved April 21, 2023, as requested.

Mar 29, 2023 Trunkline Gas Company rate filing non-conforming NRA and FP&L effective April 1, 2023, RP23-604; reviewed/OK; FERC approved April 19, 2023, as requested.

Mar 29, 2023 Trunkline Gas Company rate filing non-conforming list update FP&L effective April 1, 2023, RP23-605; reviewed/OK; FERC approved April 19, 2023, as requested.

Mar 30, 2023 Equitrans rate filing amended negotiated rate agreement effective April 1, 2023, RP23-613; reviewed/OK; FERC approved April 14, 2023, as requested.

Mar 30, 2023 Equitrans rate filing negotiated rate agreement effective April 1, 2023; RP23-614; reviewed/OK; FERC approved April 14, 2023, as requested.

Mar 30, 2023 Tennessee Gas Pipeline Company rate filing Volume No. 2 – XTO Energy Inc. & GDF Suez effective April 1, 2023, RP23-619; reviewed/OK; FERC approved April 21, 2023, as requested.

Mar 31, 2023 Columbia Gas of Ohio rate filing rate effective March 1, 2023, PR23-41; FERC approved May 11, 2023, as requested.

Mar 31, 2023 East Tennessee Natural Gas Fuel Filing effective May 1, 2023, RP23-624; reviewed; FERC approved April 20, 2023, as requested.

Mar 31, 2023 East Tennessee Natural Gas 2021-2022 Cashout Report, RP23-625; reviewed/OK; FERC approved April 18, 2023, as requested.

Mar 31, 2023 Eastern Gas Transmission and Storage negotiated rate agreements effective April 1, 2023; RP23-626; reviewed/OK; FERC approved April 14, 2023, as requested.

Mar 31, 2023 Eastern Gas Transmission and Storage Interim Fuel Retention Percentage effective May 1, 2023, RP23-627; reviewed, April 10, 2023 Columbia Gas of Virginia file motion to intervene; FERC approved April 19, 2023, as requested.

Mar 31, 2023 Panhandle Eastern Pipe Line compliance filing Through of Penalty Revenues Report, RP23-633; reviewed/OK; FERC has not issued an Order in this docket.

Mar 31, 2023 Panhandle Eastern Pipe Line compliance filing Through of Cash-Out Revenues Report, RP23-634; reviewed/OK; FERC has not issued an Order in this docket.

Mar 31, 2023 Columbia Gas Transmission negotiated rate agreements effective April 1, 2023, RP23-646; reviewed/OK; FERC approved April 18, 2023, as requested.

Mar 31, 2023 Tennessee Gas Pipeline Company rate filing Volume No. 2 Mex Gas and Morgan Stanley effective April 1, 2023, RP23-648; reviewed/OK; FERC approved April 21, 2023, as requested.

Mar 31, 2023 Transcontinental Gas Pipe Line negotiated rates – Cherokee AGL replacement shippers effective April 1, 2023, RP23-650; reviewed/OK; FERC approved April 20, 2023, as requested.

Mar 31, 2023 Rockies Express Pipeline (REX) negotiated rate agreement and amendments effective April 1, 2023, RP23-653; reviewed/OK; FERC approved April 24, 2023, as requested.

Mar 31, 2023 ANR Pipeline rate filing Vitol 138868 negotiated rate agreement effective April 1, 2023, RP23-656; reviewed/OK; FERC approved April 20, 2023, as requested.

Mar 31, 2023 Columbia Gas Transmission rate filing OTRA Summer 2023 effective May 1, 2023, RP23-662; reviewed; April 10, 2023, NiSource filed motion to intervene; FERC approved April 14, 2023, as requested.

Mar 31, 2023 NEXUS Gas Transmission negotiated rate – various releases effective April 1, 2023, RP23-663; reviewed/OK; FERC approved April 20, 2023, as requested.

Mar 31, 2023 Texas Eastern Transmission March 2023 Penalty Disbursement Report, RP23-664; reviewed/OK; FERC approved April 18, 2023, as requested.

Mar 31, 2023 Tennessee Gas Pipeline rate filing Volume No. 2 Koch Energy Services SP385736 effective April 1, 2023, RP23-666; reviewed/OK; FERC approved April 21, 2023, as requested.

April 2023

Apr 3, 2023 NEXUS Gas Transmission rate filing negotiated rate – Enbridge Gas DTE 963130 effective April 2, 2023, RP23-668; reviewed/OK; FERC approved April 26, 2023, as requested.

Apr 3, 2023 Equitrans rate filing negotiated rate capacity release agreements effective April 1, 2023, RP23-669; reviewed/OK; FERC approved April 26, 2023, as requested.

Apr 3, 2023 Texas Eastern Transmission negotiated rate agreements – Castleton effective April 1, 2023, RP23-671; reviewed/OK; FERC approved April 21, 2023, as requested.

Apr 3, 2023 Texas Eastern Transmission negotiated rate agreements – Vitol effective April 1, 2023, RP23-672; reviewed/OK; FERC approved April 27, 2023, as requested.

Apr 4, 2023	Texas Eastern Transmission negotiated rate release from Morgan Stanley effective April 1, 2023, RP23-673; reviewed/OK; FERC approved April 27, 2023, as requested.
Apr 5, 2023	Transcontinental Gas Pipe Line Company rate schedule S-2 compliance filing January 1, 2023; RP23-676; reviewed/OK; FERC approved April 27, 2023, as requested.
Apr 6, 2023	Transcontinental Gas Pipe Line Company settlement flow through refund to rate schedules GSS and LSS customers, RP23-677; reviewed/OK; FERC approved April 27, 2023, as requested.
Apr 13, 2023	Natural Gas Pipeline Company of America rate filing negotiated agreement – Macquarie Energy effective April 14, 2024, RP23-682; reviewed/OK; FERC approved April 27, 2023, as requested.
Apr 13, 2023	Egan Hub Storage – Tres Palacios Holdings acquisition notification, RP23-683; reviewed/OK; FERC approved May 15, 2023, as requested.
Apr 20, 2023	Equitrans clean up filing – April 2023 effective May 21, 203, RP23-693; reviewed/OK; FERC approved May 3, 2023, as requested.
Apr 20, 2023	Equitrans FOSA update – April 2023 effective May 21, 2023, RP23-694; reviewed/OK; FERC approved May 19, 2023, as requested.
Apr 24, 2023	ANR Pipeline Company 2023 Operational Purchases and Sales Report, RP23-700; reviewed/OK; FERC has not issued an Order in this docket.
Apr 24, 2023	ANR Storage Company 2023 Operational Purchases and Sales Report, RP23-701; reviewed/OK; FERC has not issued an Order in this docket.
Apr 24, 2023	Transcontinental Gas Pipe Line rate schedule GSS/LSS fuel retention percentage tracker filing effective May 1, 2023, RP23-702; reviewed, April 27, 2023, Columbia Gas of Virginia filed motion to intervene; FERC approved May 10, 2023, as requested.
Apr 27, 2023	Transcontinental Gas Pipe Line compliance filing rate schedule S-2 OFO flow through refund report April 2023, RP23-711; reviewed/OK; FERC approved May 19, 2023, as requested.
Apr 27, 2023	Transcontinental Gas Pipe Line negotiated rates – Cherokee replacement shippers effective May 1, 2023; RP23-719; reviewed/OK; FERC approved May 10, 2023, as requested.
Apr 28, 2023	Columbia Gas of Ohio rate filing effective March 30, 2023, PR23-49; FERC approved May 26, 2023, as requested.
Apr 28, 2023	ANR Pipeline Company rate filing Cashout Surcharge 2023 effective June 1, 2023, RP23-732; reviewed/OK; FERC approved May 25, 2023, as requested.

Apr 28, 2023 Tennessee Gas Pipeline rate filing Mex Gas SP384402 effective May 1, 2023, RP23-738; reviewed/OK; FERC approved May 15, 2023, as requested.

May 2023

May 1, 2023 Texas Eastern Transmission rate filing negotiated rates – various releases effective May 1, 2023, RP23-745; reviewed/OK; FERC approved May 30, 2023, as requested.

May 1, 2023 NEXUS Gas Transmission rate filing negotiated rates – various releases effective May 1, 2023, RP23-746; reviewed/OK; FERC approved May 24, 203, as requested.

May 1, 2023 Equitrans rate filing negotiated rate capacity release agreements effective May 1, 2023, RP23-750; reviewed/OK; FERC approved May 25, 2023, as requested.

May 2, 2024 Texas Eastern Transmission negotiated rates – Nextera to TVA effective May1, 2023, RP23-757; reviewed/OK; FERC approved May 18, 2023, as requested.

May 3, 2023 Transcontinental Gas Pipe Line rate schedule S-2 flow through general rate refund report, RP23-759; reviewed/OK; FERC approved May 31, 2023, as requested.

May 8, 2023 Columbia Gas of Ohio rate filing SOC Rates effective May 1, 2023, PR23-50; FERC approved June 9, 2023, as requested.

May 8, 2023 Columbia Gas Transmission rate filing OTRA Summer 2023 – GTS Rate Amendment effective May 1, 2023, RP23-766; reviewed, May 11, 2023 NiSource filed motion to intervene; FERC approved May 23, 2023; as requested.

May 15, 2023 Equitrans rate filing negotiated rate agreements effective May 15, 2023, RP23-770; reviewed/OK; FERC approved June 1, 2023, as requested.

May 17, 2023 Equitrans rate filing negotiated rate agreements effective May 17, 2023, RP23-771; reviewed/OK; FERC approved June 5, 2023, as requested.

May 17, 2023 Equitrans rate filing negotiated rate agreements effective May 17, 2023, RP23-772; reviewed/OK; FERC approved June 1, 2023, as requested.

May 18, 2023 Columbia Gas of Maryland rate filing SOC change effective January 1, 2023, PR23-52; FERC issued and Order on June 15, 2023.

May 19, 2023 Equitrans rate filing negotiated rate agreement effective May 20, 2023, RP23-774; reviewed/OK; FERC approved June 8, 2023, as requested.

May 23, 2023 Transcontinental Gas Pipe Line compliance filing rate schedule S-2 OFO refund report May 2023, RP23-776; reviewed/OK; FERC has not issued an Order in this docket.

May 25, 2023 ANR Pipeline compliance filing VXP – request for tariff waiver, RP23-787; reviewed/OK; FERC approved July 13, 2023, as requested.

May 26, 2023 Equitrans rate filing negotiated rate agreement effective May 27, 2023, RP23-791; reviewed/OK; FERC approved June 20, 2023, as requested.

May 26, 2023 Rockies Express Pipeline (REX) compliance filing Annual Penalty Charge Reconciliation, RP23-792; reviewed/OK; FERC has not issued an Order in this docket.

May 31, 2023 Rockies Express Pipeline (REX) negotiated rate agreements effective June 1, 2023, RP23-804; reviewed/OK; FERC approved June 22, 2023, as requested.

June 2023

Jun 1, 2023 Equitrans rate filing negotiated rate agreement effective June 1, 2023, RP23-807; reviewed/OK; FERC approved June 23, 2023, as requested.

Jun 1, 2023 NEXUS Gas Transmission rate filing negotiated rates various releases effective June 1, 2023, RP23-810; reviewed/OK; FERC approved June 22, 2023, as requested.

Jun 1, 2023 Columbia Gas Transmission negotiated rate agreements effective June 1, 2023; RP23-814; reviewed/OK; FERC approved June 15, 2023, as requested.

Jun 1, 2023 Texas Eastern Transmission negotiated rates various releases effective June 1, 2023, RP23-816; reviewed/OK; FERC approved June 22, 2023, as requested.

Jun 1, 2023 Equitrans rate filing negotiated rate capacity release agreements effective June 1, 2023, RP23-818; reviewed/OK; FERC approved June 23, 2023, as requested.

Jun 1, 2023 Natural Gas Pipeline Company of America rate filing negotiated rate agreement filing Kiowa effective June 1, 2023, RP23-820; reviewed/OK; FERC approved June 26, 2023, as requested.

Jun 1, 2023 Transcontinental Gas Pipe Line Company rate filing negotiated rates Cherokee AGL replacement shippers effective June 1, 2023, RP23-821; reviewed/OK; FERC approved June 23, 2023, as requested.

Jun 1, 2023 Columbia Gas Transmission rate filing TCRA Filing – Texas Eastern Refund effective July 1, 2023; RP23-824; reviewed, June 13, 2023, NiSource filed motion to intervene; FERC granted waiver and accepted, June 30, 2023.

Jun 1, 2023 Equitrans compliance filing notice regarding non-certificated gathering facilities, RP23-829; reviewed/OK; FERC approved July 5, 2023, as requested.

Jun 1, 2023 Columbia Gas Transmission rate filing negotiated rate and non-conforming agreement – Antero effective July 1, 2023, RP23-830; reviewed/OK; FERC approved June 16, 2023, as requested.

Jun 13, 2023 Columbia Gas of Maryland rate filing CMD rates effective May 1, 2023, PR23-55; FERC approved August 8, 2023, as requested.

Jun 16, 2023 Equitrans compliance filing gathering system abandonment project effective July 17, 2023, RP23-839; reviewed/OK; FERC approved July 18, 2023, as requested.

Jun 16, 2023 Transcontinental Gas Pipe Line tariff filing per 154.204 market-based rates Washington Storage effective July 17, 2023, RP23-840; reviewed/OK; FERC approved, December 15, 2023.

Jun 27, 2023 Texas Eastern Transmission negotiated rates – DTE effective July 1, 2023, RP23-847; reviewed/OK; FERC approved July 21, 2023, as requested.

Jun 28, 2023 Natural Gas Pipeline Company of America negotiated rates – Macquarie effective July 1, 2023, RP23-852; reviewed/OK; FERC approved July 21, 2023, as requested.

Jun 30, 2023 Equitrans clean-up filing June 2023 effective August 1, 2023, RP23-858; reviewed/OK; FERC approved July28, 2023, as requested.

Jun 30, 2023 Eastern Gas Transmission and Storage 2023 Overrun and Penalty Revenue Distribution, RP23-860; reviewed; July 11, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC has not issued an Order in this docket.

Jun 30, 2023 Columbia Gas Transmission negotiated rate amendment – Macquarie effective July 1, 2023, RP23-861; reviewed/OK; FERC approved July 24, 2023, as requested.

Jun 30, 2023 Texas Eastern Transmission rate filing Electric Power Cost (EPC) August 2023 Filing effective August 1, 2023, RP23-862; reviewed, July 11, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved July 24, 2023, as requested.

Jun 30, 2023 Tennessee Gas Pipeline Powerserve hourly rate effective August 1, 2023, RP23-863; reviewed, July 12, 2023 NiSource filed motion to intervene; FERC accepted amended tariff record, September 29, 2023.

Jun 30, 2023 Transcontinental Gas Pipe Line negotiated rates – Cherokee AGL – replacement shippers effective July 1, 2023, RP23-869; reviewed/OK; FERC approved July 17, 2023, as requested.

Jun 30, 2023 Texas Eastern Transmission negotiated rates – BU to Enhanced Energy effective July 1, 2023, RP23-875; reviewed/OK; FERC approved July 21, 2023, as requested.

Jun 30, 2023 Columbia Gas of Ohio rate filing rates effective May 31, 2023, PR23-59; FERC approved August 8, 2023, as requested.

July 2023

Jul 3, 2023 NEXUS Gas Transmission negotiated rates – various releases effective July 1, 2023, RP23-878; reviewed/OK; FERC approved July 21, 2023, as requested.

Jul 3, 2023 Equitrans negotiated rate capacity release agreements effective July 1, 2023, RP23-879; reviewed/OK; FERC approved July 27, 2023, as requested.

Jul 3, 2023 NEXUS Gas Transmission negotiated rates Columbia to Symmetry effective July 4, 2023, RP23-880; reviewed/OK; FERC approved July 21, 2023, as requested.

Jul 5, 2023 East Tennessee Natural Gas – July 2023 name change clean-up filing effective August 5, 2023, RP23-882; reviewed/OK; FERC approved July 27, 2023, as requested.

Jul 7, 2023 Texas Eastern Transmission rate filing negotiated rates Colonial effective July 7, 2023, RP23-885; reviewed/OK; FERC approved July 27, 2023, as requested.

Jul 7, 2023 Transcontinental Gas Pipe Line Company compliance filing – Pro Forma – IT feeder to FT McMullen Lateral, RP23-886; reviewed/OK; FERC issued an Order August 22, 2023, accepted the proposed language subject to actual tariff revision.

Jul 10, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial effective July 8, 2023, RP23-888; reviewed/OK; FERC approved August 8, 2023, as requested.

Jul 11, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial effective July 12, 2023, RP23-891; reviewed/OK; FERC approved July 28, 2023, as requested.

Jul 12, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial effective July 13, 2023, RP23-894; reviewed/OK; FERC approved July 27, 2023, as requested.

Jul 17, 2023 Texas Eastern Transmission negotiated rates – July 2023 Cleanup Filing effective August 17, 2023, RP23-899; reviewed/OK; FERC approved August 9, 2023, as requested.

Jul 17, 2023 NEXUS Gas Transmission negotiated rates – July 2023 Cleanup Filing effective August 17, 2023, RP23-901; reviewed/OK; FERC approved August 9, 2023, as requested.

Jul 17, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial effective July 18, 2023, RP23-902; reviewed/OK; FERC approved August 1, 2023, as requested.

Jul 19, 2023 Columbia Gas of Ohio rate filing effective June 29, 2023, PR23-61; FERC accepted August 17, 2023, as requested.

Jul 19, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial 8984439 effective July 19, 2023, RP23-905; reviewed/OK; FERC approved August 1, 2023, as requested.

Jul 20, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial 8984456 effective July 20, 2023, RP23-906; reviewed/OK; FERC approved August 3, 2023, as requested.

Jul 21, 2023 Texas Eastern Transmission negotiated rates – UGI to Colonial 8984486 effective July 22, 2023, RP23-908; reviewed/OK; FERC approved August 4, 2023, as requested.

Jul 26, 2023 Transcontinental Gas Pipe Line tariff filing Rate Schedule GSS and LSS Eastern Gas Penalty Flow Through Refund, RP23-911; reviewed, August 4, 2023, Columbia Gas of Virginia filed motion to intervene. FERC has not issued an Order in this docket.

Jul 28, 2023 Tennessee Gas Pipeline Company Producer Certified Gas Informational Report for the 12 months period ending June 30, 2023, RP22-921; reviewed/OK; FERC approved August 18, 2023, as requested.

Jul 31, 2023 Equitrans removed expired negotiated rate agreements effective August 1, 2023, RP23-924; reviewed/OK; FERC approved August 22, 2023, as requested.

Jul 31, 2023 National Fuel Gas Supply Rate Case 2023 effective September 1, 2023, RP23-929; reviewed; August 14, 2023, Columbia Gas of Pennsylvania filed protest intervention. FERC issued order August 31, 2023, accepted and suspended – subject to hearing outcome.

Jul 31, 2023 Saltville Gas Storage Company General Section 4 Rate Case effective September 1, 2023, RP23-930; reviewed; August 14, 2023 Columbia Gas of Virginia filed protest intervention. FERC issued order August 30, 2023, accepted and suspended – subject to hearing outcome.

Jul 31, 2023 Transcontinental Gas Pipe Line Rate Schedule S-2 Tracker Filing effective August 1, 2023, RP23-934; reviewed/OK; FERC approved August 16, 2023, as requested.

Jul 31, 2023 National Gas Pipeline Company of America negotiated rate agreement – La Frontera effective August 1, 2023, RP23-935; reviewed/OK; FERC approved August 24, 2023, as requested.

Jul 31, 2023 Transcontinental Gas Pipe Line negotiated rates – Cherokee AGL – replacement shippers effective August 1, 2023, RP23-936; reviewed/OK; FERC approved August 24, 2023, as requested.

Jul 31, 2023 Rockies Express Pipeline negotiated rate agreements effective August 1, 2023, RP23-937; reviewed/OK; FERC approved September 5, 2023, as requested.

August 2023

Aug 1, 2023 Equitrans negotiated rate capacity releases agreements effective August 1, 2023, RP23-939; reviewed/OK; FERC approved August 17, 2023, as requested.

Aug 1, 2023 NEXUS Gas Transmission negotiated rates – various releases effective Aug 1, 2023, RP23-948; reviewed/OK; FERC approved August 24, 2023, as requested.

Aug 1, 2023 Columbia Gas Transmission Creditworthiness cleanup effective September 1, 2023, RP23-949; reviewed, August 10, 2023, NiSource filed motion to intervene. FERC accepted tariff records filed, August 31, 2023.

Aug 2, 2023 Equitrans negotiated rate agreement effective August 2, 2023, RP23-954; reviewed/OK; FERC approved August 16, 2023, as requested.

Aug 2, 2023 Columbia Gas Transmission Direct Energy to NRG name change – capacity release amendment effective August 1, 2023, RP23-955; reviewed/OK; FERC approved August 28, 2023, as requested.

Aug 3, 2023 Rockies Express Pipeline negotiated rate agreement effective August 4, 2023, RP23-956; reviewed/OK; FERC approved September 5, 2023, as requested.

Aug 4, 2023 Equitrans amended negotiated rate agreement effective August 5, 2023, RP23-959; reviewed/OK; FERC approved August 17, 2023, as requested.

Aug 9, 2023 Equitrans negotiated rate agreement effective August 9, 2023, RP23-961; reviewed/OK; FERC approved August 30, 2023, as requested.

Aug 9, 2023 Equitrans negotiated rate agreement effective August 10, 2023, RP23-964; reviewed/OK; FERC approved August 23, 2023, as requested.

Aug 15, 2023 Enbridge (East Tennessee, Egan Hub, NEXUS Gas, Saltville Gas Storage, Texas Eastern) compliance filing LINK system maintenance request waivers, RP23-967; reviewed/OK; FERC has not issued an Order so far.

Aug 18, 2023 Equitrans rate filing negotiated rate agreement effective August 19, 2023, RP23-970; reviewed/OK; FERC approved August 31, 2023, as requested.

Aug 24, 2023 Texas Eastern Transmission compliance filing termination of rate schedules X-6, X-57, and X-75 effective September 2, 2023, RP23-977; reviewed/OK; FERC approved September 11, 2023, as requested.

Aug 25, 2023 Texas Eastern Transmission compliance filing August 2023 Penalty Disbursement Report, RP23-980; reviewed, September 6, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved September 21, 2023, as requested.

Aug 28, 2023 Texas Eastern Transmission compliance filing 2023 Operational Entitlements Filing, RP23-981; reviewed/OK; FERC approved September 22, 2023, as requested.

Aug 29, 2023 Columbia Gas of Ohio rate filing rate change effective July 31, 2023, PR23-66; FERC approved October 12, 2023, as requested.

Aug 30, 2023 Transcontinental Gas Pipe Line rate filing 2023 ACA Tracker Filing – GSS, LSS, SS-2, and S-2 effective October 1, 2023, RP23-985; reviewed, September 6, 2023, Columbia Gas of Virginia filed motion to intervene. FERC approved September 19, 2023, as requested.

Aug 31, 2023 Eastern Gas Transmission and Storage negotiated rate agreements effective September 1, 2023, RP23-996; reviewed/OK; FEC approved September 25, 2023, as requested.

Aug 31, 2023 Texas Eastern Transmission negotiated rate – various releases effective September 1, 2023, RP23-998; reviewed/OK; FERC approved September 14, 2023, as requested.

Aug 31, 2023 Transcontinental Gas Pipe Line Company negotiated rates – Cherokee AGL – Replacement shippers effective September 1, 2023, RP23-1003; reviewed/OK; FERC approved September 26, 203, as requested.

Aug 31, 2023 Equitrans removed expired negotiated rate agreements effective September 1, 2023, RP23-1007; reviewed/OK; FERC approved September 18, 2023, as requested.

Aug 31, 2023 Equitrans negotiated rate agreements effective September 1, 2023, RP23-1012; reviewed/OK; FERC approved September 21, 2023, as requested.

Aug 31, 2023 Rockies Express Pipeline (REX) negotiated rate agreement effective September 1, 2023, RP23-1014; reviewed/OK; FERC approved September 25, 2023, as requested.

Aug 31, 2023 NEXUS Gas Transmission negotiated rates – various releases effective September 1, 2023, RP23-1015; reviewed/OK; FERC approved September 14, 2023, as requested.

September 2023

Sep 1, 2023 Equitrans rate filing payment method update effective October 1, 2023, RP23-1019; reviewed/OK; FERC approved September 21, 2023, as requested.

Sep 1, 2023 Equitrans rate filing negotiated rate capacity release agreement effective September 1, 2023, RP23-1022; reviewed/OK; FERC approved September 22, 2023, as requested.

Sep 1, 2023 Natural Gas Pipeline Company of America amendments to Non-Conforming Agreements – Devon, EOG, Targa effective September 1, 2023, RP23-1029; reviewed/OK; FERC approved September 25, 2023, as requested.

Sep 5, 2023 Columbia Gas of Ohio rate effective August 29, 2023, PR23-71; FERC approved October 12, 2023, as requested.

Sep 6, 2023 Equitrans rate filing formula based negotiated rate October 1, 2023 update effective October 1, 2023, RP23-1033; reviewed/OK; FERC approved September 19, 2023, as requested.

Sep 12, 2023 Equitrans compliance filing – Operational Purchase and Sales 2023, RP23-1034; reviewed/OK; FERC has not issued an Order in this docket

Sep 12, 2023 Transcontinental Gas Pipe Line Company initial rate filing – Regional Energy Access Enhancement Project effective October 15, 2023, RP23-1035; reviewed/OK; FERC approved September 28, 2023, as requested.

Sep 13, 2023 Northern Indiana Public Service Company rate filing statement of operating conditions effective September 13, 2023, PR23-72; FERC has not issued an Order in this docket.

Sep 14, 2023 Transcontinental Gas Pipe Line Company rate filing Non-Conforming – REA interim firm service – various shippers effective October 15, 2023, RP23-1038; reviewed/OK; FERC approved September 28, 2023, as requested.

Sep 20, 2023 Equitrans negotiated rate agreement effective September 20, 2023, RP23-1040; reviewed/OK; FERC approved October 16, 2023, as requested.

Sep 22, 2023 Natural Gas Pipeline Company of America compliance filing Penalty Revenue Crediting Report from January – June 2023, RP23-1048; reviewed, September 29, 2023, NIPSCO filed motion to intervene; FERC has not issued an Order in this docket.

Sep 22, 2023 Transcontinental Gas Pipe Line compliance filing Annual Cash-Out Report Period Ending July 31, 2023, RP23-1049; reviewed, October 3, 2023, Columbia Gas of Virginia filed motion to intervene; FERC has not issued an Order in this docket.

Sep 22, 2023 ANR Pipeline Company rate filing Freepoint 139395 negotiated rate agreement effective September 23, 2023, RP23-1052; reviewed/OK; FERC approved October 16, 2023, as requested.

Sep 25, 2023 Transcontinental Gas Pipe Line Company non-conforming – REA Interim Firm Service – OS Shippers effective October 15, 2023, RP23-1055; reviewed/OK; FERC approved October 16, 2023, as requested.

Sep 25, 2023 Rockies Express Pipeline rate filing REX 2023-09-25 negotiated rate agreement effective September 26, 2023; RP23-1057; reviewed/OK; FERC approved October 12, 2023, as requested.

Sep 28, 2023 Tennessee Gas Pipeline Company rate filing SWN SP359400 and National Fuel SP92985 effective November 1, 2023, RP23-1087; reviewed/OK; FERC approved October 12, 2023, as requested.

Sep 29, 2023 Texas Eastern Transmission negotiated rate Nextera NRA effective October 1, 2023, RP23-1090; reviewed/OK; FERC approved October 25, 2023, as requested.

Sep 29, 2023 Texas Eastern Transmission rate filing Action Alert Penalty Provision Modification effective November 1, 2023, RP23-1091; reviewed, October 10, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved October 31, 2023, as requested.

Sep 29, 2023 Equitrans negotiated rate agreements effective October 1, 2023, RP23-1092; reviewed/OK; FERC approved October 20, 2023, as requested.

Sep 29, 2023 Eastern Gas Transmission and Storage 2023 Annual Electric Power Cost Adjustment (EPCA) Filing effective November 1, 2023, RP23-1094; reviewed, October 6, 2023, Columbia Gas of Pennsylvania and Virginia filed motion to intervene; FERC approved October 19, 2023, as requested.

Sep 29, 2023 Eastern Gas Transmission and Storage 2023 Annual Transportation Cost Rate Adjustment (TCRA) Filing effective November 1, 2023, RP23-1095; reviewed, October 6, 2023 Columbia Gas of Pennsylvania and Virginia filed motion to intervene; FERC approved October 19, 2023, as requested.

Sep 29, 2023 National Fuel Gas Supply Pipeline Safety and Greenhouse Gas Cost Adjustments effective November 1, 2023, RP23-1097; reviewed, October 10, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved October 24, 2023, as requested.

Sep 29, 2023 Tennessee Gas Pipeline Company Pipeline Safety Greenhouse Gas Cost Adjustments effective November 1, 2023, RP23-1103; reviewed, October 10, 2023, NiSource filed motion to intervene; FERC approved October 25, 2023, as requested.

Sep 29, 2023 Trunkline Gas Company rate filing Fuel Filing effective November 1, 2023, RP23-1104; reviewed, October 10, 2023, Columbia Gas of Ohio filed motion to intervene; FERC approved November 17, 2023, as requested.

Sep 29, 2023 Trunkline Gas Company Annual Report of Flow Through, RP23-1108; reviewed/OK; FERC has not issued an Order for this docket.

Sep 29, 2023 NEXUS negotiated rates various releases effective October 1, 2023, RP23-1110; reviewed/OK; FERC approved October 20, 2023, as requested,

Sep 29, 2023 Transcontinental Gas Pipe Line Company negotiated rates – Cherokee AGL – replacement shippers effective October 1, 2023, RP23-1114; reviewed/OK; FERC approved October 12, 2023, as requested.

Sep 29, 2023 Saltville Gas Storage Company 2023 Fuel Filing effective November 1, 2023, RP23-1121; reviewed, October 10, 2023, Columbia Gas of Virginia filed motion to intervene; FERC approved October 19, 2023, as requested.

Sep 29, 2023 Transcontinental Gas Pipe Line Company non-conforming – McMullen Supply Enhancement effective November 1, 2023, RP23-1123; reviewed/OK; FERC approved October 26, 2023, as requested.

Sep 29, 2023 Natural Gas Pipeline Company of America negotiated rate agreement filing effective October 1, 2023, RP23-1124; reviewed/OK; FERC approved October 20, 203, as requested.

Sep 29, 2023 Transcontinental Gas Pipe Line non-conforming – Leidy Southeast – Piedmont Superseding effective November 1, 2023, RP23-1125; reviewed/OK; FERC approved October 26, 2023, as requested.

Sep 29, 2023 Rockies Express Pipeline negotiated rate agreement effective October 1, 2023, RP23-1130; reviewed/OK; FERC approved October 19, 2023, as requested.

Sep 29, 2023 Columbia Gas Transmission NR NC agreement – EQT 287537 effective October 1, 2023, RP23-1131; reviewed/OK; FERC approved October 18, 2023, as requested.

Sep 29, 2023 Transcontinental Gas Pipe Line Tariff Title Page – contact info – effective November 1, 2023, RP23-1132; reviewed/OK; FERC approved October 12, 2023, as requested.

Sep 29, 2023 Transcontinental Gas Pipe Line Cash Out Surcharge Annual Update Filing 2023 effective November 1, 2023, RP23-1134; reviewed, October 10, 2023, Columbia Gas of Virginia filed motion to intervene; FERC approved October 17, 2023, as requested.

Sep 29, 2023 Transcontinental Gas Pipe Line Tariff Title Page – contract info – effective November 1, 2023, RP23-1135; reviewed/OK; FERC approved October 13, 2023, as requested.

Sep 29, 2023 Transcontinental Gas Pipe Line Tariff Title Page – contract info – effective November 1, 2023, RP23-1136; reviewed/OK; FERC approved October 13, 2023, as requested.

Sep 29, 2023 Panhandle Eastern Pipe Line Company Fuel Filing effective November 1, 2023, RP23-1137; reviewed/OK; FERC approved October 17, 2023, as requested.

October 2023

Oct 2, 2023 Equitrans negotiated rate capacity release agreements effective October 1, 2023, RP24-1; reviewed/OK; FERC approved October 19, 2023, as requested.

Oct 2, 2023 Texas Eastern Transmission negotiated rates – various releases effective October 1, 2023, RP24-2; reviewed/OK; FERC approved October 19, 2023, as requested.

Oct 3, 2023 ANR Pipeline Company OFO Penalty changes effective November 3, 2023, RP24-20; reviewed, October 16, 2023, NIPSCO filed motion to intervene; FERC approved November 2, 2023, subject to conditions.

Oct 5, 2023 Columbia Gas of Ohio rate filing effective September 28, 2023, PR24-2; FERC approved November 2, 2023, as requested.

Oct 6, 2023 Tennessee Gas Pipeline volume 2 – Consolidated Edison Company SP3960134 effective November 1, 2023, RP24-27; reviewed/OK; FERC approved October 25, 2023, as requested.

Oct 6, 2023 Tennessee Gas Pipeline East 300 upgrade project – recourse rate effective November 1, 2023, RP24-28; reviewed/OK; FERC approved October 31, 2023, as requested.

Oct 10, 2023 ANR Pipeline Company compliance filing Penalty Revenue Crediting Report 2023, RP24-33; reviewed, October 23, 2023, NIPSCO filed motion to intervene; FERC has not issued an Order for this docket.

Oct 17, 2023 Equitrans rate filing negotiated rate agreements effective November 17, 2023, RP24-42; reviewed/OK; FERC approved November 7, 2023, as requested.

Oct 19, 2023 Eastern Gas Transmission administrative changes effective November 20, 2023, RP24-45; reviewed/OK; FERC approved November 9, 2023, as requested.

Oct 19, 2023 Equitrans amended negotiated rate agreement effective October 19, 2023, RP24-48, reviewed/OK; FERC approved November 13, 2023, as requested.

Oct 24, 2023 Panhandle Eastern Pipe Line negotiated rate filing effective March 1, 2023, RP24-54; reviewed/OK; FERC approved November 15, 2023, as requested.

Oct 26, 2023 Transcontinental Gas Pipe Line compliance filing Annual Penalty Revenue Sharing 2023, RP24-57; reviewed, November 7, 2023, Columbia Gas of Virginia filed motion to intervene; FERC has not issued an Order for this docket.

Oct 26, 2023 Texas Eastern Transmission rate filing negotiated rates effective November 1, 2023, RP24-59; reviewed/OK; FERC approved November 8, 2023, as requested.

Oct 26, 2023 Transcontinental Gas Pipe Line rate schedule GSS, LSS, SS-2 Tracker Filing effective November 1, 2023, RP24-61; reviewed, November 7, 2023, Columbia Gas of Virginia filed motion to intervene; FERC approved November 20, 2023, as requested.

Oct 27, 2023 Texas Eastern Transmission October 2023 Penalty Disbursement Report, RP24-68; reviewed, November 7, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved November 15, 2023, as requested.

Oct 27, 2023 Tennessee Gas Pipeline Company negotiated rate agreements various shippers effective November 1, 2023, RP24-77; reviewed/OK; FERC approved November 16, 2023, as requested.

Oct 30, 2023 Transcontinental Gas Pipe Line non-conforming – Adelphia West Ridge Interconnection 2023 effective December 1, 2023, RP24-81; reviewed/OK; FERC approved November 21, 2023, as requested.

Oct 30, 2023 Texas Eastern Transmission PCB December 2023 Rate Filing effective December 1, 2023, RP24-82; reviewed, November 7, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved November 17, 2023, as requested.

Oct 31, 2023 Equitrans negotiated rate agreements effective November 1, 2023, RP24-83; reviewed/OK; FERC approved November 21, 2023, as requested.

Oct 31, 2023 Trunkline Gas Company compliance filing Annual Interruptible Storage Revenue Credit Report, RP24-87; reviewed/OK; FERC approved November 28, 2023, as requested.

Oct 31, 2023 Trunkline Gas Company negotiated rate filing – NextEra Energy & Ford effective November 1, 2023, RP24-89; reviewed/OK; FERC approved November 28, 2023, as requested.

Oct 31, 2023 Tennessee Gas Pipeline non-conforming agreement (TC Energy 382826) effective November 1, 2023, RP24-91; reviewed/OK; FERC approved November 14, 2023, as requested.

Oct 31, 2023 Rockies Express Pipeline System Map URL effective December 1, 2023, RP24-92; reviewed/OK; FERC approved November 20, 2023, as requested.

Oct 31, 2023 Tennessee Gas Pipeline negotiated rate agreement (Con Ed 389644) effective November 1, 2023, RP24-95; reviewed/OK; FERC approved November 16, 2023, as requested.

Oct 31, 2023 Texas Eastern Transmission negotiated rate agreement Con Ed 910950 releases effective November 1, 2023; RP24-100; reviewed/OK; FERC approved November 21, 2023, as requested.

Oct 31, 2023 Texas Eastern Transmission Applicable Shrinkage Adjustment (ASA) effective December 1, 2023, RP24-102; reviewed, November 13, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved November 20, 2023, as requested.

Oct 31, 2023 Natural Gas Pipeline Company of America negotiated rate agreement effective November 1, 2023, RP24-103; reviewed/OK; FERC approved November 20, 2023, as requested.

Oct 31, 2023 Rockies Express Pipeline (REX) negotiated rate agreement effective RP24-105; reviewed/OK; FERC approved November 20, 2023, as requested.

Oct 31, 2023 NEXUS Gas Transmission negotiated rates – Union Gas effective November 1, 2023, RP24-106; reviewed/OK; FERC approved November 20, 2023, as requested.

Oct 31, 2023 Texas Eastern Transmission negotiated rates effective November 1, 2023, RP24-107; RP24-107; reviewed/OK; FERC approved November 20, 2023, as requested.

November 2023

Nov 1, 2023 Texas Eastern Transmission negotiated rates – Keyspan effective November 1, 2023, RP24-113; reviewed/OK; FERC approved November 21, 2023, as requested.

Nov 1, 2023 Columbia Gas Transmission Operational Transaction Rate Adjustments (OTRA) Winter 2023, RP24-121; reviewed, November 13, 2023, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved November 20, 2023, as requested.

Nov 1, 2023 NEXUS Gas Transmission negotiated various releases effective November 1, 2023, RP24-122; reviewed/OK; FERC approved November 27, 2023, as requested.

Nov 1, 2023 Equitrans negotiated capacity release agreement effective November 1, 2023, RP24-126; reviewed/OK; FERC approved November 21, 2023, as requested.

Nov 1, 2023 Columbia Gas Transmission MXP negotiated rate agreement effective November 1, 2023, RP24-130; reviewed/OK; FERC approved November 28, 2023, as requested.

Nov 1, 2023 Texas Eastern Transmission negotiated rates – various releases effective November 1, 2023, RP24-135; reviewed/OK; FERC approved November 20, 2023, as requested.

Nov 1, 2023 Columbia Gas Transmission negotiated rate agreements effective November 1, 2023, RP24-136; reviewed/OK; FERC approved November 28, 2023, as requested.

Nov 1, 2023 ANR Pipeline Company negotiated rate agreement effective November 1, 2023, RP24-137; reviewed/OK; FERC approved November 21, 2023, as requested.

Nov 2, 2023 Equitrans negotiated rate capacity release agreement effective November 1, 2023, RP24-141; reviewed/OK; FERC approved November 28, 2023, as requested.

Nov 3, 2023 NEXUS Gas Transmission negotiated rates – DTE Gas effective November 1, 2023, RP24-142; reviewed/OK; FERC approved December 5, 2023, as requested.

Nov 3, 2023 Transcontinental Gas Pipe Line Company rate schedule S-2 OFO Refund Report November 2023, RP24-143; reviewed/OK; FERC has not issued an Order for this docket.

Nov 3, 2023	Columbia Gas Transmission Vitol negotiated rate agreement effective November 3, 2023, RP24-144; reviewed/OK; FERC approved November 21, 2023, as requested.
Nov 6 2023	Transcontinental Gas Pipe Line list of non-conforming service agreements effective December 7, 2023; RP24-145; reviewed/OK; FERC approved November 28, 2023, as requested.
Nov 11, 2023	Transcontinental Gas Pipe Line negotiated rate – Cherokee AGL – replacement shippers effective December 14, 2023, RP24-152; reviewed/OK; FERC approved December 6, 2023, as requested.
Nov 14, 2023	Equitrans negotiated rate agreements effective November 15, 2023, RP24-154; reviewed/OK; FERC approved November 30, 2023, as requested.
Nov 16, 2023	National Fuel Gas Supply correction of Metadata effective November 1, 2023, RP24-161; reviewed/OK; FERC approved November 30, 2023, as requested.
Nov 16, 2023	National Fuel Gas Supply TSCA – Informational filing effective November 1, 2023, RP24-162; reviewed/OK; FERC approved November 30, 2023, as requested.
Nov 21, 2023	Transcontinental Gas Pipe Line non-conforming – Carolina Market Link – PEG effective January 1, 2024, RP24-165; reviewed/OK; FERC approved December 12, 2023, as requested.
Nov 29, 2023	Tennessee Gas Pipeline compliance filing Cashout Report 2022-2023, RP24-176; reviewed, December 6, 2023, Columbia Gas Ohio filed motion to intervene; FERC has not issued an Order for this docket.
Nov 29, 2023	Columbia Gas of Pennsylvania rate filing Statement of Operating Conditions to be effective November 29, 2023, PR24-15; FERC has not issued an Order for this docket.
Nov 29, 2023	Columbia Gas of Virginia rate filing Statement of Operating Conditions to be effective November 29, 2023, PR24-16; FERC has not issued an Order for this docket.
Nov 30, 2023	Equitrans negotiated rate agreement effective date December 1, 2023, RP24-183; reviewed/OK; FERC approved December 14, 2023, as requested.
Nov 30, 2023	Texas Eastern Transmission negotiated rates – various releases effective December 1, 2023, RP24-196; reviewed/OK; FERC approved December 19, 2023, as requested.
Nov 30, 2023	Rockies Express Pipeline (REX) negotiated rate agreements effective December 1, 2023, RP24-198; reviewed/OK; FERC approved December 15, 2023, as requested.

Nov 30, 2023 Tennessee Gas Pipeline negotiated rate agreements filing effective December 1, 2023, RP24-202; reviewed/OK; FERC approved December 18, 2023, as requested.

December 2023

Dec 1, 2023 Equitrans negotiated rate capacity release agreements effective December 1, 2023, RP24-209; reviewed/OK; FERC approved December 15, 2023, as requested.

Dec 1, 2023 NEXUS Gas Transmission negotiated rates – various releases effective December 1, 2023, RP24-211; reviewed/OK; FERC approved December 18, 2023, as requested.

Dec 1, 2023 Texas Eastern Transmission negotiated rates – December 2023 Clean Up Filing effective January 1, 2024, RP24-212; reviewed/OK; FERC approved December 18, 2023, as requested.

Dec 1, 2023 Rockies Express Pipeline (REX) negotiated rate agreements effective December 2, 2023, RP24-220; reviewed/OK; FERC approved December 15, 2023, as requested.

Dec 1, 2023 NEXUS Gas Transmission negotiated rates – DTE Electric 860002 effective December 1, 2023, RP24-221; reviewed/OK; FERC approved December 21, 203, as requested.

Dec 1, 2023 Texas Eastern Transmission negotiated rates – effective December 1, 2023, RP24-224; reviewed/OK; FERC approved December 15, 2023, as requested.

Dec 1, 2023 Transcontinental Gas Pipe Line rate schedule S-2 tracker filing (PCB/ASA) effective December 1, 2023, RP24-225; reviewed/OK; FERC approved December 14, 2023, as requested.

Dec 7, 2023 East Tennessee Natural Gas December 2023 Terminated Agreements Cleanup effective January 7, 2024, RP24-229; reviewed/OK; FERC approved January 2, 2024, as requested.

Dec 8, 2023 Natural Gas Pipeline Company of America negotiated agreements filing – MRP Elgin effective December 8, 2023, RP24-233; reviewed/OK; FERC approved January 2, 2024, as requested.

Dec 13, 2023 Eastern Gas Transmission Administrative Changes filing effective January 16, 2024, RP24-241; reviewed/OK; FERC approved January 8, 2024, as requested.

Dec 14, 2023 Rockies Express Pipeline (REX) negotiated rate agreement amendments effective December 15, 2023, RP24-245; reviewed/OK; FERC approved January 8, 2024, as requested.

Dec 19, 2023 Transcontinental Gas Pipe Line compliance filing rate schedule S-2 OFO Refund Report December 2023, RP24-254; reviewed/OK; FERC has not issued an Order for this docket.

Dec 20, 2023 Columbia Gas Transmission rate filing discount type adjustment – revision to GT&C Section 46 effective January 20, 2024; RP24-257; reviewed, January 2, 2024, NiSource filed motion to intervene; FERC approved January 11, 2024, as requested.

Dec 27, 2023 Transcontinental Gas Pipe Line Cash Out Surcharge True Up Filing 2024 effective February 1, 2024; RP24-264; reviewed, January 8, 2024, Columbia Gas of Virginia filed motion to intervene; FERC approved January 24, 2024, as requested.

Dec 28, 2023 Trunkline Gas Company non-conforming NRA with BP Energy Company effective January 1, 2024, RP24-266; reviewed/OK; FERC approved January 22, 2024, as requested.

Dec 28, 2023 Trunkline Gas Company non-conforming list update – BP Energy effective January 1, 2024, RP24-267; reviewed/OK; FERC approved January 22, 2024, as requested.

Dec 28, 2023 Texas Eastern Transmission Electric Power Cost (EPC) rate filing effective February 1, 2024, RP24-271; reviewed, January 9, 2024, Columbia Gas of Pennsylvania filed motion to intervene; FERC approved January 23, 2024, as requested.

Dec 28, 2023 Tennessee Gas Pipeline Company negotiated rate agreements effective January 1, 2024, RP24-273; reviewed/OK; FERC approved January 18, 2024, as requested.

Dec 29, 2023 Rockies Express Pipeline (REX) negotiated rate agreements and amendment effective January 1, 2024; RP24-280; reviewed/OK; FERC approved January 19, 2024, as requested.

Dec 29, 2023 Columbia Gas Transmission Penalty Revenue Crediting Report 2023, RP24-284; reviewed, January 9, 2024, NiSource filed motion to intervene; FERC has not issued an Order for this docket.

§53.64(c)(5) A listing and updating, if necessary, of projections of gas supply and demand provided to this Commission for any purpose – see §59.67 (relating to formats). In addition, provide an accounting of the difference between reported gas supply available and gas supply deliverable- including storage – from the utility to its customers under various circumstances and time periods.

Response:

Exhibit 4 Attachment 1 provides actual calendar year supply and requirements data for calendar year 2023 and estimated supply and requirements for calendar years 2024 through 2026.

The estimated supply and demand projections are based upon normal weather. Columbia's capacity portfolio provides sufficient flexibility to satisfy customer requirements under a wide range of weather conditions.

Sheet 1 of Exhibit 4 Attachment 2 compares gas supply and requirements projections for calendar year 2024 as included in Exhibit No. 4 in Columbia's 2023 and 2024 gas cost recovery filings. Supply and Requirements total volumes in the 2024 filing are 747 MDth higher than in the 2023 filing.

Sheet 2 of Exhibit 4 Attachment 2 reflects the reconciliation of the 2023 actual supply and requirements data to the estimated 2023 data contained in Columbia's 2023 Exhibit No. 4. Contrasting total actual requirements for 2023 versus the estimated total requirements yields a negative variance of 7,896 MDth or 20 percent. This difference is the result of warmer than normal weather. The total actual degree days for calendar year 2023 were 18 percent less than normal degree days that served as the basis for the 2023 estimate.

COLUMBIA GAS OF PENNSYLVANIA, INC.

GAS SUPPLY AND DEMAND

		Calendar Years			
GAS SUPPLY - MDth		**2023 Actual**	**2024 Est.**	**2025 Est.**	**2026 Est.**
1.	Pipeline Contracts	0	0	0	0
2.	Underground Storage Withdrawal	20,828	20,586	21,456	21,515
3.	LNG Purchases - Columbia LNG	0	0	0	0
4.	LNG Storage Withdrawal	0	0	0	0
5.	Propane A/	0	0	0	0
6.	SNG Purchases - Columbia LNG	0	0	0	0
7.	Natural Gas Production	0	0	0	0
8.	Local and Appalachian Purchases(net of Exchanges)	19,890	18,947	20,611	17,750
9.	Displaced Gas	0	0	0	0
10.	Other (Non-Local) Purchases	13,403	21,384	20,487	23,144
11.	Customer Choice / CAP Supply	6,300	6,895	6,714	6,477
12	Subtotal	60,420	67,813	69,268	68,886
DEDUCTIONS - MDth					
13	Curtailments	0	0	0	0
14	Underground Storage Injections B/	20,956	20,603	22,231	21,831
15	LNG Liquefaction	0	0	0	0
16	Sales to other utilities	0	0	0	0
17	Total Deductions	20,956	20,603	22,231	21,831
18	Net Gas Supply (13-19)	39,464	47,210	47,037	47,055
REQUIREMENTS - MDth					
FIRM REQUIREMENTS					
19	Residential	26,761	30,044	30,208	30,437
20	Commercial	8,399	9,092	9,090	9,093
21	Industrial	323	375	457	473
22	Propane Service	0	0	0	0
23	Unaccounted For/Unbilled	-2,455	604	457	464
24	Company Use	135	127	127	127
25	Other	0	0	0	0

26	Subtotal	33,164	40,242	40,339	40,594
27	Customer Choice / Cap	6,300 C/	6,968	6,698	6,461
28	Total	39,464	47,210	47,037	47,055

		Calendar Years			
INTERRUPTIBLE REQUIREMENT - MDth		**2023 Actual**	**2024 Est.**	**2025 Est.**	**2026 Est.**
29	Retail	0	0	0	0
30	Company's Own Plants	0	0	0	0
31	Subtotal	0	0	0	0
32	Total Gas Requirements (28 + 31)	39,464	47,210	47,037	47,055
33	Surplus or (Deficiency) (18 - 32)	0	0	0	0
STORAGE DATA (MDth)					
34	Underground Storage	28,286	25,797	25,797	25,797
35	Capacity - 12/31				
36	Underground Inventory, 12/31	18,534	18,137	18,461	18,335
37	Underground inventory change from Prior Year	-199	-396	323	-126
WEATHER DATA					
38	Weighted average for Pittsburgh, Bradford, & Harrisburg, PA, and Morgantown & Martinsburg, WV. Balance point temp of 65 F.				
	Billing	4,731	5,218	5,218	5,218
	Calendar	4,547	5,244	5,244	5,244

Notes:
Utilities should report by footnote in which category apartment houses are included and breakpoints for change in category, if any.

Units that are individually metered within apartment houses are classified as Residential. Where apartment houses are master metered, they are classified as Commercial.

A/ Propane purchased for propane service. All propane volumes are stated in MDth equivalent.
B/ Includes volumes injected but retained by pipelines for transportation retainage.
C/ 2023 customer choice volumes were as follows:

Residential	3,582	MDth
Commercial	2,718	MDth
	6,300	

COLUMBIA GAS OF PENNSYLVANIA, INC.

Comparison of 2024 Calendar Year Estimate per Current Form 1 Filing to the 2024 Estimate in the Previous Form 1 Filing (Volumes in MDth)

Estimate Report Line	Description	Current Year Estimate for Calendar Year 2024		Prior Year Estimate for Calendar Year 2024
	SUPPLY:			
1	Pipeline Contracts	0		0
2	Underground Storage Withdrawal	20,586		22,182
5	Propane	0		0
8	Local and Appalachian Purchases	18,947		22,506
10	Other (Non-Local) Purchases	21,384		19,103
11	Customer Choice Supply	6,895		6,675
12	Subtotal	67,813		70,467
14	Deduct Storage Injection	20,603		22,510
18	Net Gas Supply			
		47,210		47,957
	REQUIREMENTS:			
19	Residential	30,044		30,787
20	Commercial	9,092		9,380
21	Industrial	375		348
22	Propane Service	0		0
23	Unaccounted For/Unbilled	604		656
24	Company Use	127		135
25	Other	0		0
26	Subtotal	40,242		41,306
29	Retail (Interruptible Requirement)	0		0
27	Customer Choice	6,968	B/	6,651
32	Total Requirements	47,210		47,957

COLUMBIA GAS OF PENNSYLVANIA, INC.

Actual Compared to Estimate 2023 Calendar Year (Volumes in MDth)

Estimate Report Line	Description	2023 Actual	Estimate per 2023 Report
	SUPPLY:		

1	Pipeline Contracts	0		0
2	Underground Storage Withdrawal	20,828		21,453
5	Propane	0		0
8	Local and Appalachian Purchases	19,890		21,692
10	Other (Non-Local) Purchases	13,403		19,760
11	Customer Choice Supply	6,300		6,850
12	Subtotal	60,420		69,754
14	Deduct Storage Injection	20,956	A/	22,394
18	Net Gas Supply			
		39,464		47,360
	REQUIREMENTS:			
19	Residential	26,761		30,346
20	Commercial	8,399		9,233
21	Industrial	323		289
22	Propane Service	0		0
23	Unaccounted For/Unbilled	-2,455		535
24	Company Use	135		135
25	Other	0		0
26	Subtotal	33,164		40,538
29	Retail (Interruptible Requirement)	0		0
27	Customer Choice	6,300	B/	6,822
32	Total Requirements	39,464		47,360

1/ Includes volumes injected but retained by pipelines for transportation retainage.

§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 20-year history is also used to develop colder and warmer weather scenarios.

The colder weather scenario reflects an increase in total winter season degree days based on a 1 in 10 or 10 percent risk level for winter season degree days. The 10 percent risk level 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 risk level. The 10 percent risk level 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 2024 – September 2025 (Mdth)

	Colder	**Normal**	**Warmer**
Sales Excluding CHOICE℠ :			
Residential	29,634	27,704	25,771
Commercial	9,723	9,090	8,455
Industrial	459	440	424
Other	543	543	543
Subtotal	40,359	37,776	35,194
CHOICE℠	9,867	9,244	8,620
Total	50,226	47,020	43,814

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 2015 and the 2023 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 2014/15 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.

<u>Design Day Demand and Date</u>

CPA utilizes multivariable linear regression analysis to determine Design Day Demand. CPA's methodology is discussed in its 2023 Design Day Forecast, which is included in this filing as Exhibit No. 13. Table 1 shows the 2023 Design Day Forecast for the 2024-2025 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 2024-25. The Design Day Demand excludes standby and EBS volumes.

Winter Season 2024-25 Design Day Demand (MDth/Day)

	Sales and CHOICE^{SM}	GDS	Total
Residential	452.6	0	452.6
Commercial	171.5	96.6	268.1
Industrial	2.0	97.2	99.2
Other	1.5	0	1.5
Total:			
Volume	627.6	193.8	821.4
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 2024-2025 and 2025-2026. The Design Day Demand excludes standby and EBS volumes.

Winter Season 2024-2025 and 2025-2026 Design Day Demand (MDth/Day)

	Sales and CHOICE^{SM}	GDS	Total
2024 – 2025	627.6	193.8	821.4
2025 – 2026	629.0	194.5	823.5

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 1950 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 2023 DDF and firm capacity for the next four winter seasons.

Firm Peak Day Capacity and Demand (MDth/Day)

	Contract Year			
	2024-25	2025-26	2026-27	2027-28
Demand of Sales and Choice Customers				
Residential	452.6	453.7	456.0	458.4
Commercial	171.5	171.8	172.1	172.5
Industrial	2.0	2.0	2.0	2.0
Other	1.5	1.5	1.5	1.5
Total	627.6	629.0	631.6	634.4
Max Hour Adjustment	9.8	9.8	9.8	9.9
Total Demand	**637.4**	**638.8**	**641.4**	**644.3**
Capacity				
Firm Transportation				
TCO	134.9	134.9	134.9	134.9
Less Marketed Capacity Releases	(5.2)	(5.2)	(4.4)	(5.2)
Net TCO	129.7	129.7	130.5	129.7
EGTS	5.2	5.2	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)				3.0
National Fuel Gas Supply Corp.	5.8	5.8	5.8	5.8
Subtotal, net of releases and assign	218.4	218.4	219.2	221.4
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	451.2	451.2	451.2	451.2
Local Direct	0.7	0.7	0.7	0.7
Total Firm Capacity				
Gross	670.3	670.3	671.2	673.4
Less Capacity to provide Standby	(5.1)	(5.1)	(5.1)	(5.1)
Less Capacity to provide EBS	(12.6)	(12.6)	(12.6)	(12.6)
Net Capacity	**652.6**	**652.6**	**653.5**	**655.7**
Difference: Capacity less Demand	15.2	13.8	12.0	11.4

Firm Peak Day Capacity and Demand (MDth/Day)

CPA's available capacity is approximately 101.8 percent of projected firm demand adjusted for a maximum hour design for contract year 2027-28, the highest projected design day firm requirements in CPA's 2023 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 71 percent of CPA's winter season and about 84 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. This 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 a second FT contract for 5,000 Dth that expires 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. It was determined that an additional 2,000 Dth a day was required to meet the needs of these markets. As a result, CPA contracted with TETCO for a new firm transportation contract in this amount effective December 1, 2023, with an expiration date of November 30, 2024.

CPA solicited bids for replacement capacity for contract 910951 and none were received. As a result, in October 2023, CPA renewed contract 910951 through October 31, 2024, 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. 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 new capacity is projected to be on-line in November of 2027. 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 7,000 Dth/day of additional firm capacity to satisfy these needs. This capacity was a winter only contract from December 1, 2023 through February 29, 2024. This capacity may be renewed in the future or additional options may be pursued.

CPA also has a contract with National Fuel Gas Supply Corporation (National) consisting 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. 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, 2024.

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℠ 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.

<u>Expiration of an Existing Contract and Request for Proposal (RFP) to Natural Gas Suppliers (NGSs)</u>

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, 2023, CPA issued an RFP for capacity to replace the

National Fuel capacity, effective November 1, 2023. 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 2024-25 and therefore will not seek additional capacity from NGSs serving CHOICE^{SM} customers through the ACRR process for contract year 2024-25. CPA will review its Design Day supply balance again before the 2025-26 winter season to determine if capacity will be sought through the ACRR process for the 2025-26 contract year.

OPERATION OF TCO STORAGE

Operation Guidelines

As noted on Table 4, approximately 71 percent of CPA's Design Day capacity is provided by storage. In addition, CPA relies upon storage to provide approximately 58 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.

<u>Tariff Restrictions</u>

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 2023-24. 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	5	February 17	80 percent
Second		>= 20 percent	80 percent	12	February 27	65 percent
Third		>= 10 percent	65 percent	19	March 12	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 6° Fahrenheit or warmer. CPA manages storage activity to delay the first ratchet until days with average daily temperatures of 5° Fahrenheit and colder have less than a 10 percent probability of occurrence. Based on historical temperature data since 1949**,** the latest occurrence of a 5° Fahrenheit or colder average day temperature, with a 1 in 10 risk of a later occurrence, is February 17th. CPA plans to maintain storage inventory above 30 percent of the Storage Contract Quantity (“SCQ”) until February 17th, 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^{SM} 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^{SM} 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^{SM} 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 entered into 2 sales transactions with Columbia Gas of Ohio in May 2023.

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 serves low-income customers in its Customer Assistance Program ("CAP") through an aggregation process under which licensed Natural Gas Suppliers competitively bid for the right to supply commodity to CAP customers. There are approximately 23,200 customers enrolled in the CAP Program. CPA utilizes an RFP process in an effort to secure the most competitively priced gas commodity for the CAP customers. CPA currently does not have a CAP supplier and will not be sending out another RFP until around April 2024 with bids being due on or before May 31st, 2024.

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 2023.

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.

§53.64(c)(6) Each Section 1307(f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning ... its participation in capacity and release programs ...

Response:

CAPACITY RELEASE

During CPA's pre-month strategy meetings, procurement recommendations are finalized that lead to the determination of the level of capacity that can be released on a recallable and on a non-recallable basis, by pipeline.

Once it has been determined that capacity is available for release, CPA provides widespread notice of the availability of such capacity to CPA's capacity customer list via facsimile, telephone, email, or such other method as may be available and deemed appropriate. Included in the notice is a deadline date and time to respond. Once the bids are received, they are reviewed and awarded on a prearranged basis.

The capacity is then posted on the respective Electronic Bulletin Boards (EBB) for each pipeline as applicable. The posted releases establish the requirements for each individual release relating to the term of the release, quantities, receipt and delivery points, minimal acceptable bid, the bid criteria utilized by the pipeline in choosing the best bid, and the right to recall the capacity. The bidding and awarding procedures then follow the procedures of the pipeline's tariff with a contract being submitted to the assignee by the pipeline prior to the nomination deadline.

CPA has rights to firm transportation and/or storage capacity on Eastern Gas Transmission and Storage (formally Dominion Transmission), Equitrans, National Fuel, Texas Eastern, Tennessee, and Columbia Gas Transmission.

§53.64(c)(6) Each Section 1307(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 ...

Response:

CPA's fuel procurement activities are conducted by its Energy Supply and Optimization (ES&O) Department. ES&O is located in Columbus, Ohio and is dedicated to serving the gas supply management needs of CPA and its affiliated LDCs as part of the NiSource Corporate Services Company.

Karl E. Stanley is Vice President, Supply & Optimization. The positions under ES&O have been actively involved in the direct acquisition of gas supplies since the beginning of open access transportation in the late 1980s. Summaries of the job descriptions for those Manager, Director and Gas Trader positions in the Columbus office associated with CPA's fuel procurement activities are provided below.

Director – Supply Development

To direct the planning, development, procurement and scheduling functions related to the implementation of the "least-cost" supply for firm customers and the Strategic Gas Supply Plans for each of the Columbia distribution companies. To direct back office operations related to payment of invoices, billing of trading partners, management of contracts and the negotiation of pipeline and supply contracts. To direct involvement in and evaluation of activities related to the Federal Regulatory Commission. To direct economic feasibility studies to formulate the optimal gas supply and capacity mix; to recommend solutions to peak day and seasonal gas supply deficiencies; to enable each distribution company to achieve the company goals of reliability balanced with the least cost objective; to consult with marketers and other stakeholders in designing Customer CHOICE: to ensure that the distribution companies are properly evaluating and selecting their "least-cost" gas supply utilization options within the scope of each distribution company of Columbia's established business objectives; to direct the implementation of daily operations within the terms of each distribution company's contractual arrangements; and to plan, develop and direct the forecasting of daily and seasonal market requirements (core and non-core) under various gas operations planning scenarios, inclusive of the design peak day(s).

Director of Portfolio and Optimization

To oversee the asset management function related to least-cost commodity procurement and utilization of NiSource's natural gas and electric assets. Execute transactions that support daily operations for both firm, CHOICE and large transportation customers. Maintain compliance with all industry standards as well operate within state and federal approved tariff limits. Develop seasonal and long-term volatility mitigation strategies as well as execute various financial transactions that support the customer approved programs. Provide market perspective input into the development of a diverse and balanced supply approach that ensures overall safe and reliable delivery of energy.

Manager – Planning

To plan, develop and oversee the preparation of Strategic Gas Supply Plans for the distribution companies and the economic feasibility studies to formulate the optimal gas supply and capacity mix for each distribution company in order to achieve the goals and objectives of the Strategic Gas Supply Plan; to evaluate, and recommend as appropriate, alternative gas supply sources and projects to achieve the company goals of reliability balanced with the least cost objective; to analyze the impact of Customer CHOICE programs on the Company's gas supply portfolio; to design and implement Customer CHOICE programs; to monitor and evaluate the potential impact of changing federal and state regulations, as well as supply availability and deliverability; to recommend gas supply strategies that enable each distribution company to continue to achieve its "least-cost" purchasing policy by securing and delivering competitively priced, reliable gas supplies.

Manager - Engineering Services

To plan, develop and oversee engineering activities supporting development of a least cost supply portfolio; to initiate and evaluate distribution systems' supply absorption capabilities; to coordinate city gate capacity requirements with upstream pipelines and District operational personnel; to recommend capacity changes to meet customer requirements; and to determine operational requirements for Customer CHOICE marketers in specific market areas.

Manager – Scheduling and Accounting

To manage the reconciliation and approval for payment of gas supply, pipeline transportation, and storage invoices from numerous pipelines and suppliers; to manage the reconciliation, negotiation, and resolution of pipeline and supplier imbalances to minimize financial exposure; to provide General Accounting, Financial Planning, and Regulatory Services with information and advice necessary for proper accounting, cash forecasting and recovery of costs associated with these gas supplies; and to develop and maintain computer systems which track purchasing, movement and accounting of gas activity.

Gas Trader

To negotiate long- and short-term gas purchase agreements required to meet customer demand in a reliable, cost effective manner and to negotiate the purchase of spot gas supplies from natural gas producers and marketers.

Nominations

To schedule long- and short-term gas purchases and storage injections/withdrawals on upstream pipelines and/or storage facilities; verify and balance nominations, storage inventories and pipeline imbalances; post capacity releases on pipeline and storage websites; confirm daily city-gate nominations for system supply, transportation customers and Choice suppliers; support month end closing process.

§53.64 (c)(7) A list of off system sales, including transportation, storage, or capacity releases by the utility at less than the weighted average price of gas, or at less than the original contract cost of transportation, storage or capacity supplied to the utility for its own customers.

Response:

Columbia did not sell gas at prices below the weighted average price of gas in the review period. Columbia did, however, sell gas below the commodity purchase price on 17 instances. The need for these sales was brought about by the abnormally warm winter days. The overall effect caused a difficult supply balance scenario that required CPA to make several adjustments to avoid potential imbalance and cash out penalties associated with exceeding CPA's FSS daily contract quantity. CPA also completed several capacity releases at prices below the maximum allowed pipeline tariff rates. This is the normal nature of the secondary transportation capacity market. These releases are listed in Attachment 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.
Marketed Capacity Release Activity - February 2023 through January 2024

Parcel Number	Flow Month	Pipeline	Rate Schedule	Release Rate ($/Dth)	Demand Rate ($/Dth)	Release Quantity (Dth)
25993606	Feb-23	TCO	SST	$2.8000	$9.7310	364,500
25993800	Feb-23	TCO	SST	$2.8000	$9.7310	37,050
25994603	Feb-23	TCO	SST	$3.3600	$9.7310	34,506
122712	Mar-23	EASTERN TR	FT	$4.1850	$5.9674	124,000
115693	Mar-23	TETCO	CDS	$3.4100	$20.0409	31,000
123399	Apr-23	EASTERN TR	FT	$3.0000	$5.9674	120,000
26003774	Apr-23	TCO	SST	$4.5000	$10.2600	13,500
26003775	Apr-23	TCO	SST	$3.0000	$10.2600	2,250
26007687	Apr-23	TCO	SST	$1.5000	$10.2600	27,000
116381	Apr-23	TETCO	FT-1	$0.5250	$9.2152	60,000
116382	Apr-23	TETCO	CDS	$0.9000	$20.0409	60,000
124108	May-23	EASTERN TR	FT	$3.1000	$5.9674	124,000
26007613	May-23	TCO	SST	$1.5500	$10.1610	170,500
26007690	May-23	TCO	SST	$3.1000	$10.1610	2,325
26007691	May-23	TCO	SST	$1.5500	$10.1610	930,000
26010448	May-23	TCO	SST	$1.5500	$10.1610	24,000
117014	May-23	TETCO	CDS	$0.5580	$20.0409	62,000
125242	Jun-23	EASTERN TR	FT	$5.5200	$5.9674	120,000
26010535	Jun-23	TCO	SST	$1.5000	$10.1610	90,000
26013300	Jun-23	TCO	SST	$1.5000	$10.1610	24,000
117837	Jun-23	TETCO	FT-1	$0.9000	$9.2152	90,000
117843	Jun-23	TETCO	CDS	$1.5000	$20.0409	60,000
125680	Jul-23	EASTERN TR	FT	$5.7350	$5.9674	124,000
26013318	Jul-23	TCO	SST	$1.2400	$10.0660	139,500
118337	Jul-23	TETCO	CDS	$1.2400	$20.0409	62,000
126451	Aug-23	EASTERN TR	FT	$2.0150	$5.9674	124,000
26015038	Aug-23	TCO	SST	$1.2400	$10.0660	170,500
26018911	Aug-23	TCO	SST	$1.2400	$10.0660	50,000
118949	Aug-23	TETCO	CDS	$3.1000	$20.0659	62,000
126749	Sep-23	EASTERN TR	FT	$1.3500	$5.9674	120,000
119497	Sep-23	TETCO	CDS	$1.6800	$20.0659	21,000
119498	Sep-23	TETCO	CDS	$1.3500	$20.0659	21,000
119499	Sep-23	TETCO	CDS	$1.7400	$20.0659	21,000
127516	Oct-23	EASTERN TR	FT	$1.8600	$5.9674	124,000
26021600	Oct-23	TCO	SST	$3.1000	$10.0660	6,200
120064	Oct-23	TETCO	CDS	$0.6510	$20.0659	62,000
128151	Nov-23	EASTERN TR	FT	$2.5500	$5.9493	120,000
26026717	Dec-23	TCO	SST	$3.2550	$10.0500	21,700
26026721	Dec-23	TCO	SST	$3.1000	$10.0500	310,000
26028968	Jan-24	TCO	SST	$3.2550	$10.0500	21,700
26028969	Jan-24	TCO	SST	$3.1000	$10.0500	310,000
26028970	Jan-24	TCO	SST	$3.1000	$10.0500	310,000

Note: January 2024 is estimated.

Columbia Gas of Pennsylvania, Inc.
Off-System Sales At Less Than The Commodity Purchase Price
February 2023 through January 2024

Sale ID	Month	Volume (Dth)	Purchase Rate	Sales Price	Point of Sale
S0262691	Feb-23	140,000	$2.6060 1)	$2.5550	TCO Pool
S0263400	Apr-23	10,000	$1.7200	$1.5600	TCO Pool
S0263401	Apr-23	200	$1.7200	$1.5600	TCO Pool
S0263402	Apr-23	5,300	$1.7200	$1.5600	TCO Pool
S0263403	Apr-23	5,000	$1.7200	$1.5550	TCO Pool
S0263404	Apr-23	13,500	$1.7200	$1.5575	TCO Pool
S0263410	Apr-23	10,000	$1.7200	$1.5550	TCO Pool
S0263419	Apr-23	12,000	$1.7200	$1.4300	TCO Pool
S0263420	Apr-23	75,000	$1.7200	$1.4300	TCO Pool
S0263421	Apr-23	31,500	$1.7200	$1.4300	TCO Pool
S0263424	Apr-23	25,200	$1.7200	$1.4300	TCO Pool
S0263435	Apr-23	30,000	$1.7200	$1.4850	TCO Pool
S0263548	Apr-23	3,000	$1.6325	$1.5850	Eastern Trans
S0263383	Apr-23	14,400	$1.7200	$1.7100	TCO Pool
S0263397	Apr-23	6,600	$1.7200	$1.5650	TCO Pool
S0263398	Apr-23	4,500	$1.7200	$1.5600	TCO Pool
S0264612	Sep-23	10,000	$1.6450	$1.6150	TCO Pool

1) Purchase rate was adjusted to include transportaion costs.

§53.64 (c) (8) 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 the transportation.

Response:

Presently, Columbia Gas of Pennsylvania is not transporting any volumes for other utilities or pipelines. However, Columbia continues to be heavily involved in transportation service for jurisdictional customers.

The requirements of this section are addressed in Exhibit No. 9. Exhibit No. 9 reflects both the throughput and the rate schedule that applies to each traditional end-user transportation customer. Exhibit No. 9 also reflects the customers served under the Choice Program summarized by rate schedule by month.

§53.65 Whenever a gas utility under 66 Pa.C.S. § 1307(f) (relating to sliding scale of rates; adjustments) purchases gas, transportation or storage from an affiliated interest, as defined at 66 Pa.C.S. § 2101 (relating to definitions of affiliated interest), it shall, in addition to the normal submission expected of a gas utility under 66 Pa.C.S. § 1307(f) file evidence to meet its burden under 66 Pa.C.S. § 1317(b) (relating to regulation of natural gas costs). The evidence, to be filed 60 days prior to the filing of a tariff under 66 Pa.C.S. § 1307(f), shall include statements regarding:

(1) The costs of the affiliated gas, transportation or storage as compared to the average market price of other gas, transportation or storage and the price of other sources of gas, transportation or storage.

Response:

Columbia Gas of Pennsylvania, Inc. ("CPA") did not purchase gas, transportation or storage from an affiliated interest during the historical period of this filing.

§53.65 (2) Estimates of the quantity of gas, transportation or storage available to the utility from all sources.

Response:

Sources of supply and quantities available for CPA are identified within Exhibit No. 5, §53.64(c)(6) and Exhibit No. 1-D-1. Firm transportation and storage capacity contracts, and the applicable maximum daily and seasonal levels, are shown in Attachment 1 to Exhibit 1-D-3.

§53.65 (3) Efforts made by the utility to obtain gas, transportation or storage from nonaffiliated interests.

Response:

With regard to gas supplies, CPA's policy is to purchase gas from reliable sources of supply at the lowest cost. In accordance with that policy, CPA has structured its supply plan such that its supply mix provides reliable supplies to meet customer demand during periods of colder-than-normal weather while simultaneously remaining flexible enough to reduce purchases during warmer-than-normal periods. CPA designs this flexibility to have a minimal price impact and to take advantage of lower cost supplies from any accessible supplier. To the extent that affiliated interests from time to time offer CPA gas supplies under competitive terms and conditions, CPA will consider those supplies like all others in accordance with its policy of purchasing gas supplies from reliable sources at the lowest cost.

All transportation and storage capacity services are provided to CPA from non-affiliated pipeline companies. Each one of these pipelines provides delivery in specific areas of CPA's system and is required in order to meet CPA's customer requirements. Although there are many things to consider when contracting for capacity such as price, term, flexibility and reliability, it is delivery to the point into CPA's system where needed that is the determining factor.

Columbia Gas of Pennsylvania, Inc.
Exhibit No. 8-D

§53.65 (4) The specific reasons why the utility has purchased gas, transportation or storage from an affiliated interest and demonstration that the purchases are consistent with a least cost fuel procurement policy.

Response:

Columbia Gas of Pennsylvania, Inc. has not purchased gas, transportation or storage from an affiliated interest during the historical period of this filing.

§53.65 (5) The sources and amounts of gas, transportation or storage which have been withheld from the market by the utility or affiliated interest and the reasons why the gas, transportation or storage has been withheld.

Response:

During the twelve month period ending January 31, 2024, Columbia did not withhold from the market any gas supply or transportation or storage capacity, other than for purposes of retaining sufficient call upon those assets to assure reliable supply and balancing services for its customers under colder than normal weather conditions as they may be encountered throughout the winter season.

No gas offered to Columbia by affiliated companies was withheld that should have been used as part of a least cost procurement strategy.

Neither Columbia nor any affiliate intends to withhold gas in the Application Period that should be used as part of a least cost purchase strategy, consistent with Columbia's obligation to provide safe and adequate service.

§53.64 (c) (9) A schedule depicting historic monthly end-user transportation throughput by customer. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to § 5.423 (relating to orders to limit availability of proprietary information).

Response:

The historic monthly transportation throughput by customer by rate schedule is shown on the attached schedules. Schedule 1 reflects Choice Service Customers while Schedule 2 reflects Traditional Transportation End-User Customers. Due to the large number of Choice Service Customers, the customers are summarized by rate schedule by month.

COLUMBIA GAS OF PENNSYLVANIA, INC
1307(F) - 2024

Exhibit 9 Schedule 1

Transportation Volumes - Twelve Months Ended January 31, 2024

Choice Service Customers

	Number of Customers	Rate Schedule	Dth February	March	April	May	June	July	August	September	October	November	December	January	Total
	48,647	RTC	641,329.3	531,124.7	395,443.7	214,785.7	95,675.9	69,030.2	61,673.7	62,896.4	104,577.4	270,804.5	552,195.9	705,688.3	3,705,225.7
	7,071	SCC	228,169.7	157,629.4	126,160.3	61,851.4	26,980.9	21,588.0	18,967.1	20,155.2	30,600.5	84,230.2	188,840.0	258,603.0	1,223,775.7
	1,186	SC2	227,293.8	203,486.3	157,709.3	95,363.6	59,910.8	43,639.9	43,962.0	46,602.8	64,848.2	129,667.6	245,243.8	309,545.6	1,627,273.7
Total Month	56,904	(1)	1,096,792.8	892,240.4	679,313.3	372,000.7	182,567.6	134,258.1	124,602.8	129,654.4	200,026.1	484,702.3	986,279.7	1,273,836.9	6,556,275.1

(1) Average Number of Customers for the Twelve Months Ended January 31, 2024

53.64(c) (10) A schematic system map, locating and identifying by name, the pressure and capacity of all interstate or intrastate transmission pipeline connections, compressor stations, utility transmission or distribution mains 6 inch or larger in size, storage facilities, including maximum daily injection and withdrawal rates, production fields, and each individual supply or transportation customer which represents 5% or more of total system throughput in a month. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to § 5.423.

Response:

The schematic "Pipeline Connections, Supply Points and Storage Locations" provides an overview of Columbia Gas of Pennsylvania's (CPA) supply configuration. The following responses and related exhibits reference the schematic by unique numeric codes and more fully address the points of interest detailed in question 10.

1) Supply Pipelines - see Exhibit No. 10.1

Supply pipeline companies are coded on the schematic and identified by name and a unique numeric code in Exhibit 10.1. Compressor stations are owned and operated by the respective transmission companies. As a result, compressor station operating pressures and capacities are unknown to CPA. CPA does own and operate one compressor at its Blackhawk peak shaving storage facility (see item 4).

2) Supply Connections - see Exhibits No. 10.2 A-B

3) Significant Distributions Mains (6 inch or larger) - see Exhibit No. 10.3 A-F

CPA provides the energy needs of over 420,000 residential, commercial and industrial customers located in over 70 isolated natural gas distribution systems, or markets (see Exhibit 10.2) located throughout Pennsylvania. Many, if not all, of these distribution systems contain 6 inch pipe operating at various approved pressures. Providing detailed operating maps for these distribution systems would be a considerable task, both in terms of the number of maps required, and the difficulty in organizing them in a meaningful and understandable manner. However, a distribution main's significance is not only a function of its size, but also its operating pressure and its location within the system. A 6 inch high pressure main (for CPA a pressure greater than 60 psig) can deliver considerably more gas than a 6 inch low pressure main. In addition, a high pressure main is typically used to distribute natural gas from a supply point(s) to lower pressure sub-systems within a given geographic region. Therefore, we are providing market drawings, which show significant distribution mains for CPA's major distribution systems. These drawings are from CPA's Supervisory Control and Data Acquisition system (SCADA).

4) Storage - see Exhibit 10.4

CPA owns and operates the Blackhawk underground storage facility located in Beaver County, Pennsylvania. It historically acted as a peak shaving facility for CPA. Due to the age, condition, and the upgrades/betterment required, CPA plans to retire Blackhawk from service over the next few years. Other underground storage supply is obtained through contracts noted in Exhibit 10.4.

5) Supply Connections Satisfying the 5% Condition - see Exhibit 10.5

6) CPA Customers Satisfying the 5% Condition - see Exhibit 10.6

Note that customers #17 & 29 are dual purpose customers. The meter acts as a supply point from the transmission company to CPA and as a delivery point from CPA to the customer. No other customers are served through these points.

EXHIBIT 10.1
CPA DIRECT TRANSMISSION SUPPLY POINTS

1. EQUITRANS GAS TRANSMISSION (EQ)
2. EASTERN GAS TRANSMISSION AND STORAGE (EGT&S)
   (FORMERLY DOMINION–(DETI))
3. COLUMBIA GAS TRANSMISSION (TCO)
4. TEXAS EASTERN TRANSMISSION (TET)
5. TENNESSEE GAS PIPELINE (TGP)
6. TRANSCONTINENTAL GAS PIPE LINE (TRANSCO)
   (SHOWN ON MAP BUT DOES NOT SERVE CPA)
7. NATIONAL FUEL GAS SUPPLY CORP (NFG)

EXHIBIT 10.2 A
CPA DIRECT TRANSMISSION SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET		SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
ROCHESTER	20325	(16) TGP / KOPPEL	0	0
STATE COLLEGE	21305	(25) EGT&S / PLEASANT GAP	24,800	0
STATE COLLEGE	21357	EGT&S / CENTRE HALL	395	0
UNIONTOWN	70056	(26) TET / UNIONTOWN	11,753	0
UNIONTOWN	70579	(13) TET / ROCKWOOD	9,000	0
YORK	71219	(11) TET / EMIGSVILLE	2,342	0
STATE COLLEGE	71363	(12) TET / PLEASANT GAP	7,800	0
YORK	73200	TET / CHAMBERSBURG	200	0
YORK	73918	TET / SOUTH YORK	100	0
ROCHESTER	314673	NFG / FINDLAY TOWNSHIP	4,000	0
WARREN	329621	(27) NFG / WARREN	4,218	0
ROCHESTER	420062	(14) TGP / NEW CASTLE	16,000	0
ROCHESTER	420306	(15) TGP / BRADFORD WOODS	7,600	0
ROCHESTER	514010	(18) EGT&S / WARRENDALE	9,000	0
ROCHESTER	516110	(19) EGT&S / DARLINGTON	6,000	0
ROCHESTER	535317	(24) EQUITRANS / SPARTAN	55,000	0
YORK	600054	(8) NORTH YORK	36,293	175
YORK	600055	YORK ST. HANOVER	1,541	300
YORK	600056	BALTIMORE ST., HANOVER	990	200
YORK	600057	RIDGE AVE HANOVER	9,402	300
YORK	600058	BECKMILL ROAD	9,272	200
YORK	600059	MCSHERRYSTOWN	361	75
YORK	600061	GLEN ROCK	3,309	75
YORK	600062	SHREWSBURY	3,777	75
YORK	600063	(9) EMIGSVILLE	40,126	550
YORK	600064	(10) ADMIRE	29,117	300
BRADFORD	600183	TUNA CROSS ROADS	400	75
BRADFORD	600184	DERRICK CITY	379	75
BRADFORD	600185	RED ROCK	165	75
BRADFORD	600186	LAFFERTY HOLLOW	2,432	75
BRADFORD	600187	CORWIN LANE	196	35
BRADFORD	600188	LEWIS RUN	2,008	75
NEW BETHLEHEM	600191	SUMMERVILLE	402	75
NEW BETHLEHEM	600192	WASH. & PENN NEW BETHLEHEM	506	60
NEW BETHLEHEM	600193	COL PA PIPE YARD NEW BETHLEHEM	451	60
NEW BETHLEHEM	600197	WEST MONTERY ROAD	362	50
NEW BETHLEHEM	600198	CHURCH YARD RIMERSBURG	252	50
EMLENTON	600199	FAIRVIEW MEASURING STATION	3,853	100
ROCHESTER	600202	ENON VALLEY	87	100
ROCHESTER	600203	WAMPUM WEST	618	75

EXHIBIT 10.2 A
CPA DIRECT TRANSMISSION SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET		SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
ROCHESTER	600205	CHEWTON VILLAGE	206	200
ROCHESTER	600206	CHEWTON	22,093	200
ROCHESTER	600208	NEW CASTLE ROAD	700	200
ROCHESTER	600216	BISCUP LANE LINE D-272	1,316	150
ROCHESTER	600217	SULLIVAN PLAN	1,086	200
ROCHESTER	600218	HALL FARM	6,046	100
ROCHESTER	600219	(23) AMBRIDGE STA.	19,920	140
ROCHESTER	600221	CLINTON	2,300	75
WASHINGTON	600222	PARIS	286	50
WASHINGTON	600223	MIDWAY	853	50
MT LEBANON	600224	(20) MCCANDLESS	7,475	200
MT LEBANON	600226	T-P NOBLESTOWN	2,382	75
WASHINGTON	600228	(21) CECIL GREENTREE	36,964	300
WASHINGTON	600229	PATTERSON MILLS	252	50
WASHINGTON	600230	AVELLA	205	50
WASHINGTON	600231	HICKORY LINE D-4	1,954	100
WASHINGTON	600232	SHARP FARM	11,546	250
WASHINGTON	600233	(22) TANNEHILL	47,689	300
WASHINGTON	600234	HOUSTON	862	75
WASHINGTON	600235	LINDEN	7,000	100
WASHINGTON	600236	MCMURRAY	984	100
WASHINGTON	600237	HIXON WALLACE	6,318	100
WASHINGTON	600238	GOAT HILL	20,288	100
WASHINGTON	600240	WEST ALEXANDER	376	75
WASHINGTON	600241	RUFFS CREEK	184	50
WASHINGTON	600242	WATER ST WAYNESBURG	205	5
UNIONTOWN	600243	SOUTH JEANETTE	15,974	225
UNIONTOWN	600244	NORTH JEANNETTE	1,980	75
UNIONTOWN	600245	ADAMSBURG	9,831	225
UNIONTOWN	600246	ARMBURST(STARASKS)	0	0
UNIONTOWN	600247	WIGLE HILL	150	75
UNIONTOWN	600248	FISHER HIGHTS	3,828	75
UNIONTOWN	600249	KINDER FARM	6,626	50
UNIONTOWN	600250	ALLENPORT	8,000	60
WASHINGTON	600251	BEALLSVILLE	2,600	60
WASHINGTON	600252	MARIANA	972	75
UNIONTOWN	600254	WHITELY CREEK LINE D-8500	13,099	180
UNIONTOWN	600255	GRIMES FARM	941	150
UNIONTOWN	600257	RT219 (SOMERSET)	3,200	125
GREENCASTLE	600259	OAKS LEASE GREENCASTLE	1,393	90

EXHIBIT 10.2 A
CPA DIRECT TRANSMISSION SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET		SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
GREENCASTLE	600260	SHADY GROVE	1,860	90
GREENCASTLE	600261	NUNNERY	166	110
GREENCASTLE	600262	KNEPPER	155	110
GREENCASTLE	600263	MONT ALTO	2,729	110
GREENCASTLE	600264	CASHTOWN	391	90
YORK	600265	FAIRFIELD	700	90
YORK	600266	ARENDTSVILLE	368	90
YORK	600267	GETTYSBURG	9,262	165
YORK	600268	TWO TAVERNS	546	90
YORK	600269	LITTLESTOWN	1,813	90
YORK	600270	ABBOTTSTOWN	1,851	90
YORK	600271	EAST BERLIN	571	90
YORK	600277	CROSS KEYS	7,336	200
STATE COLLEGE	600279	(28) SNOWSHOE	979	420
ROCHESTER	600447	GEORGETOWN	110	20
WASHINGTON	600451	BOWER HILL	92	100
ROCHESTER	600452	NERO PLAN	162	100
NEW BETHLEHEM	600453	EMERICKVILLE	478	55
ROCHESTER	600454	GLASGOW	44	20
EMLENTON	600457	YOUNG RIMERSBURG	64	50
ROCHESTER	600460	BIRNESSER	93	200
UNIONTOWN	600461	PRESTIGE FURNITURE JEANNETTE	201	75
BRADFORD	600462	DALLAS CITY	32	75
WASHINGTON	600463	BARTON WAYNESBURG	39	5
NEW BETHLEHEM	600466	FAIRMONT.MT.SAVAGE REFRACTORY.	193	60
NEW BETHLEHEM	600467	OAKRIDGE	104	60
NEW BETHLEHEM	600469	CLAIRION ROAD HAWTHRONE	181	5
NEW BETHLEHEM	600471	KOLLERSBURG ROAD OAKLAND	90	10
NEW BETHLEHEM	600472	VAULT WORKS OAKLAND	152	10
NEW BETHLEHEM	600473	SEMAN S BETHLEHEM	111	10
NEW BETHLEHEM	600475	BLACKWELL N BETHLEHEM	58	60
NEW BETHLEHEM	600476	SMITH HAWTHRONE	160	5
WASHINGTON	600478	GARDENER FARM	171	50
NEW BETHLEHEM	600479	PLEASANT HILLS	239	50
NEW BETHLEHEM	600480	MAPLE GROVE	61	50
NEW BETHLEHEM	600482	COTTAGE HILL NEW BETHLEHEM	95	60
WASHINGTON	600484	WEST MIDDLETOWN	110	50
WASHINGTON	600486	ROUTE 22	79	50
WASHINGTON	600492	THOMAS	146	100
WASHINGTON	600493	MERCHANT FARM	89	100

EXHIBIT 10.2 A
CPA DIRECT TRANSMISSION SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET		SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
WASHINGTON	600494	BULGER	135	75
WASHINGTON	600495	CROSS CREEK	86	50
WASHINGTON	600498	SPARTA	13	50
WASHINGTON	600499	WAYNESBURG C S YARD	65	25
WASHINGTON	600502	RODGERSVILLE	123	5
WASHINGTON	600503	SUGAR RUN	116	50
WASHINGTON	600505	HICKORY	192	100
ROCHESTER	600506	MCCALISTER CROSSROADS	206	75
WASHINGTON	600508	SCENERY HILL EAST	32	100
UNIONTOWN	600509	VICTORY HILL	163	75
UNIONTOWN	600510	CENTERVILLE	181	75
UNIONTOWN	600513	MORRIS CROSSROADS	92	150
WASHINGTON	600516	WINDRIDGE	110	5
WASHINGTON	600519	LAIRD FARM	70	75
WASHINGTON	600530	EIGHTY FOUR	250	100
EMLENTON	600531	WEST SUNBURY	117	100
WASHINGTON	600535	SCENERY HILL WEST	132	100
EMLENTON	602280	F R BARTOE-CODY	0	0
UNIONTOWN	602281	N A BATYKEFER-WOODWARD	0	0
WASHINGTON	602405	FORDYCE-WILSON	0	0
UNIONTOWN	602484	C R LOWSTUTER-BERRYMAN	0	0
ROCHESTER	602525	PEOPLES NATURAL BAER	0	0
EMLENTON	602598	R R WALKER-MCANALLEN	0	0
GREENCASTLE	603308	MERCERSBURG	1,200	140
ROCHESTER	604062	NIXON FARM	8,634	150
WASHINGTON	604583	WESTLAND	132	100
BRADFORD	604745	HIGHLAND. WARREN LINE D-4005	50	150
UNIONTOWN	617891	FILIPS WELL NO. 582	0	0
ROCHESTER	618370	SLIPPERY ROCK REQUIREMENTS	1,800	75
WASHINGTON	618774	GRAYSVILLE	146	5
ROCHESTER	619688	MONACA	24,298	200
UNIONTOWN	619856	PRODUCTION CHECK METER&CPA SAL	0	0
ROCHESTER	620184	CRESTMONT VILLAGE	336	100
BRADFORD	620746	MT ALTA,LINE 4226	137	75
ROCHESTER	630212	KANE HEIGHTS	240	100
YORK	630930	DILLSBURG CPA	500	300
WASHINGTON	634428	BURNSVILLE	49	75
UNIONTOWN	635710	CPA-REDD FARM	5,000	75
NEW BETHLEHEM	639213	SINCLAIR S BETHLEHEM REPLACE	142	35
ROCHESTER	640029	WASHINGTON MEADOWLANDS TROTTI	1,828	200

EXHIBIT 10.2 A
CPA DIRECT TRANSMISSION SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET		SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
ROCHESTER	640299	ELLWOOD CITY 2	5,500	200
YORK	640464	CPA BERMUDIAN	600	400
YORK	640478	CPA-EISERHOWER FARM	55	165
EMLENTON	640549	HETRICK ROAD	0	0
NEW BETHLEHEM	642758	PENNS STATION	0	0
EMLENTON	642788	CALUMET KARNS CITY	145	0
YORK	642857	VILLA VISTA	375	300
YORK	643009	PARADISE	100	500
NEW BETHLEHEM	643028	CPA-KNOX EMLENTON	3,313	110
WASHINGTON	643031	ROBINSON RUN ROAD	200	100
ROCHESTER	643048	PEOPLES UNMEASURED	0	0
ROCHESTER	643083	BEATTY FARM	305	150
ROCHESTER	643152	ROBINSON HIGHWAY	291	75
ROCHESTER	643213	HIGHLAND ROCHESTER	4,140	200
NEW BETHLEHEM	643391	SPAULDING ROAD-CLYMER	970	60
GREENCASTLE	648599	COLONIAL DRIVE	125	75
GREENCASTLE	648703	GRANITE STATION RD.	270	75

* PRESSURES THAT MAY EXIST IN THE PIPELINE FROM TIME TO TIME.

EXHIBIT 10.2 B
CPA DUAL PURPOSE SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET	SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
TEXAS EASTERN TRANS. LINE	72942	1,200	*
TCO PIPELINE	600284	1,849	100
TCO PIPELINE	600285	100	90
TCO PIPELINE	600287	0	60
HUPP FARM - INDUSTRIAL PARK	600289	62	150
TCO PIPELINE	600291	63	100
TCO PIPELINE	600292	18	90
TCO PIPELINE	600293	12,937	225
TCO PIPELINE	600294	400	90
TCO PIPELINE	600295	1,031	100
PITT METALS - SR980	600296	50	75
ORRTANNA	600297	71	90
TCO PIPELINE	600616	11	20
PENN HILLS	600637	41	75
TCO PIPELINE	600646	17	75
TCO PIPELINE	600931	135	60
TCO PIPELINE	600933	21	60
TCO PIPELINE	600945	18	5
TCO PIPELINE	600996	154	50
TCO PIPELINE	601046	26	30
TCO PIPELINE	601083	84	5
TCO PIPELINE	601162	21	5
TCO PIPELINE	601251	77	5
TCO PIPELINE	601273	105	50
LUZERNE TWP - ELEM. SCHOOL	601275	44	5
TCO PIPELINE	601335	143	150
GLADHILL	601476	51	90
TCO PIPELINE	601493	183	90
TCO PIPELINE	601511	684	90
TCO PIPELINE	603124	12	100
DENORA - HERCULES POWDER - D	603295	200	75
CLAD METALS - SR519	603296	83	100
TCO PIPELINE	603304	444	50
LONE PITT	603311	15	100
DENORA - HERCULES POWDER - D	603323	74	75
TCO PIPELINE	604339	16	90
TCO PIPELINE	604246	0	75
HUPP FARM - INDUSTRIAL PARK	604247	60	200

EXHIBIT 10.2 B
CPA DUAL PURPOSE SUPPLY POINTS
COLUMBIA GAS TRANSMISSION SUPPLY POINTS UNLESS OTHERWISE NOTED

CPA MARKET	SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
TCO PIPELINE	604339	16	90
INDIANA CO. - INDUSTRIAL PARK	604394	95	265
TCO PIPELINE	604420	5	50
TCO PIPELINE	604502	102	100
TCO PIPELINE	604540	50	100
TCO PIPELINE	614446	101	100
HUPP FARM - INDUSTRIAL PARK	614465	144	200
TCO PIPELINE	614624	0	300
TCO PIPELINE	614635	392	450
TCO PIPELINE	614666	1,394	620
TCO PIPELINE	630310	0	*
CENTRAL GREENE SCHOOLS	634498	10	*
TARCO	635239	0	100
PENN DOT	640519	12	20
KEYSTONE LIME	642997	15	75
TCO PIPELINE	643009	100	500
TCO PIPELINE	645180	0	*
TCO PIPELINE	645561	0	*
MENALLEN TWP - UPPER MIDDLET	645819	0	*
TCO PIPELINE	645872	0	*
CENTRAL GREENE SCHOOLS	647605	50	5
JERR-DAN CORP	648084	6	0
TCO PIPELINE	648785	0	*
TCO PIPELINE	648868	1	75

EXHIBIT 10.4
CPA STORAGE CONTRACTS - CITY GATE QUANTITIES

TRANSMISSION PIPELINE	RATE SCHEDULE	STORAGE QUANTITY DTH	MAXIMUM WITHDRAWAL DTH/DAY	MAXIMUM INJECTION DTH/DAY
COLUMBIA GAS TRANSMISSION	FSS	21,948,709	395,714	175,590
EQUITRANS	115SS	2,000,000	19,130	10,000
EASTERN GAS TRANSMISSION & STORAGE	GSS	2,111,176	28,800	11,730

EXHIBIT 10.5
CPA DIRECT TRANSMISSION SUPPLY POINTS
SUPPLY POINTS SATISFYING THE 5% CONDITION
COLUMBIA GAS TRANSMISSION SUPPLY POINT UNLESS OTHERWISE NOTED

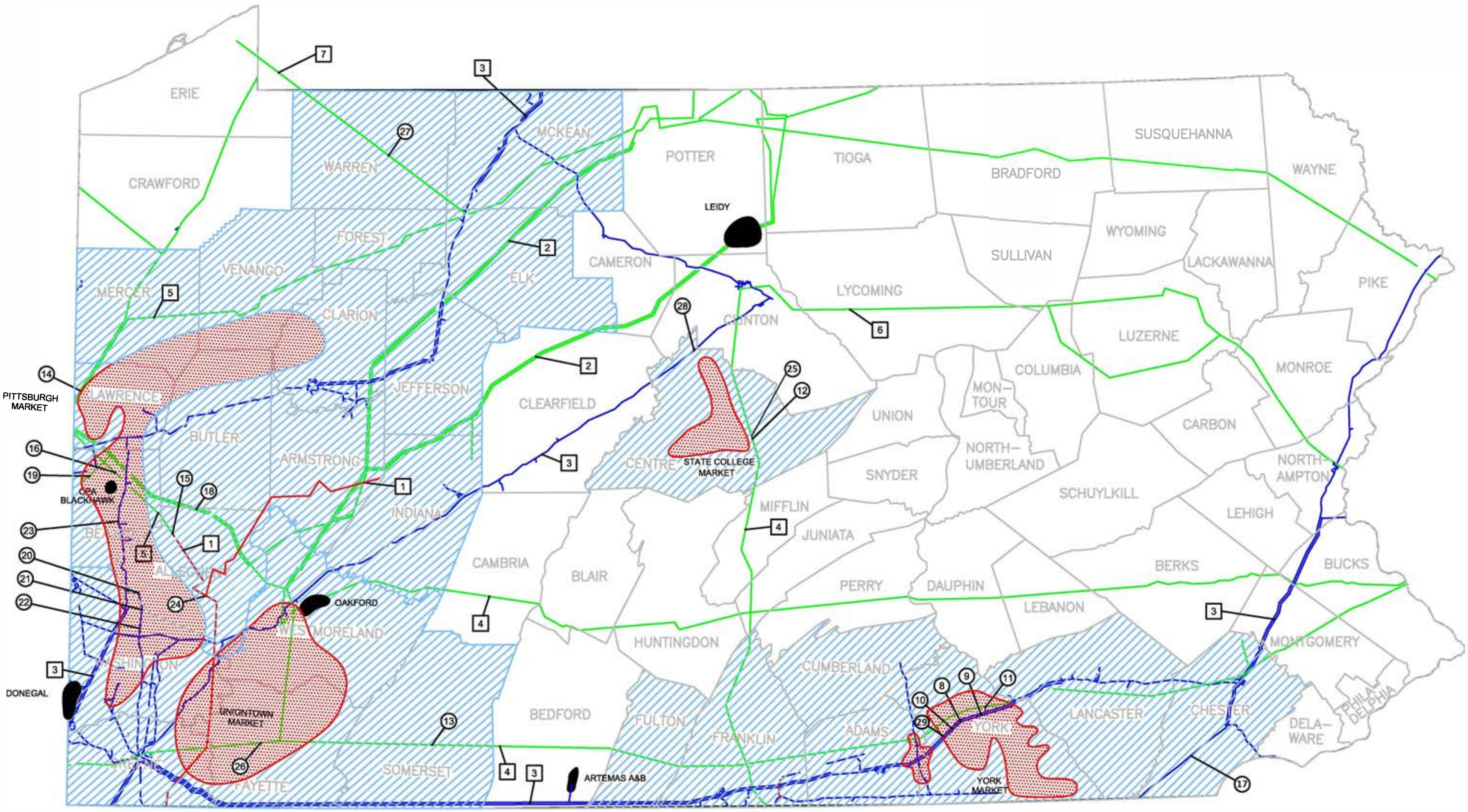
CPA MARKET	POD	SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
WASHINGTON	600233	TANNEHILL (22)	25,008	300
YORK	600063	EMIGSVILLE (9)	21,998	550
YORK	600064	ADMIRE (10)	20,617	300
YORK	600054	NORTH YORK (8)	19,383	175
STATE COLLEGE	21305	PLEASANT GAP (25)	19,211	*
ROCHESTER	535317	SPARTAN (24)	18,842	*
MT LEBANON	600224	MCCANDLESS (20)	12,130	200

* PRESSURES THAT MAY EXIST IN THE PIPELINE FROM TIME TO TIME.

EXHIBIT 10.6
CPA CUSTOMERS SATISFYING THE 5% CONDITION

CPA MARKET	SUPPLY PT (SCHEMATIC ID)	CAPACITY Dth/Day	PRESSURE PSIG
CLEVELAND CLIFF (LUKENS STEEL)	600293 (17)	6,427	225
PIXELLE SPECIALITES (GLATFELTER)	643009 (29)	6,434	500

COLUMBIA GAS OF PENNSYLVANIA, INC.
PIPELINE INTERCONNECTS, SUPPLY POINTS AND STORAGE LOCATIONS



TRANSMISSION PIPELINES

1 Equitrans Gas Transmission (EQ)
2 Eastern Gas Tranmission & Storage (EGT&S)
3 Columbia Gas Transmission (TCO)
4 Texas Eastern Transmission (TET)
5 Tennessee Gas Pipeline (TGP)
6 Transcontinental Gas Pipeline (TRANSCO)
7 National Fuel Gas Supply (NFG)

MAJOR INTERCONNECTS SERVING PA

8 (TCO) North York
9 (TCO) Emigsville
10 (TCO) Admire
11 (TET) Emigsville
12 (TET) Pleasant Gap
13 (TET) Rockwood
14 (TGP) New Castle
15 (TGP) Bradford Woods
16 (TGP) Koppel
17 Cleveland Cliffs
18 (EGT&S) Warrendale
19 (EGT&S) Darlington
20 (TCO) McCandless
21 (TCO) Cecil Greentree
22 (TCO) Tannehill
23 (TCO) Ambridge
24 (EQ) Spartan
25 (EGT&S) Pleasant Gap
26 (TET) Uniontown
27 (NFG) Warren
28 (TCO) Snowshoe
29 Pixelle Specialties (Glatfelter)

LEGEND

CPA Service Areas
CPA Major Markets
Storage Fields

Exhibit 10.1

EXHIBIT 10.3A

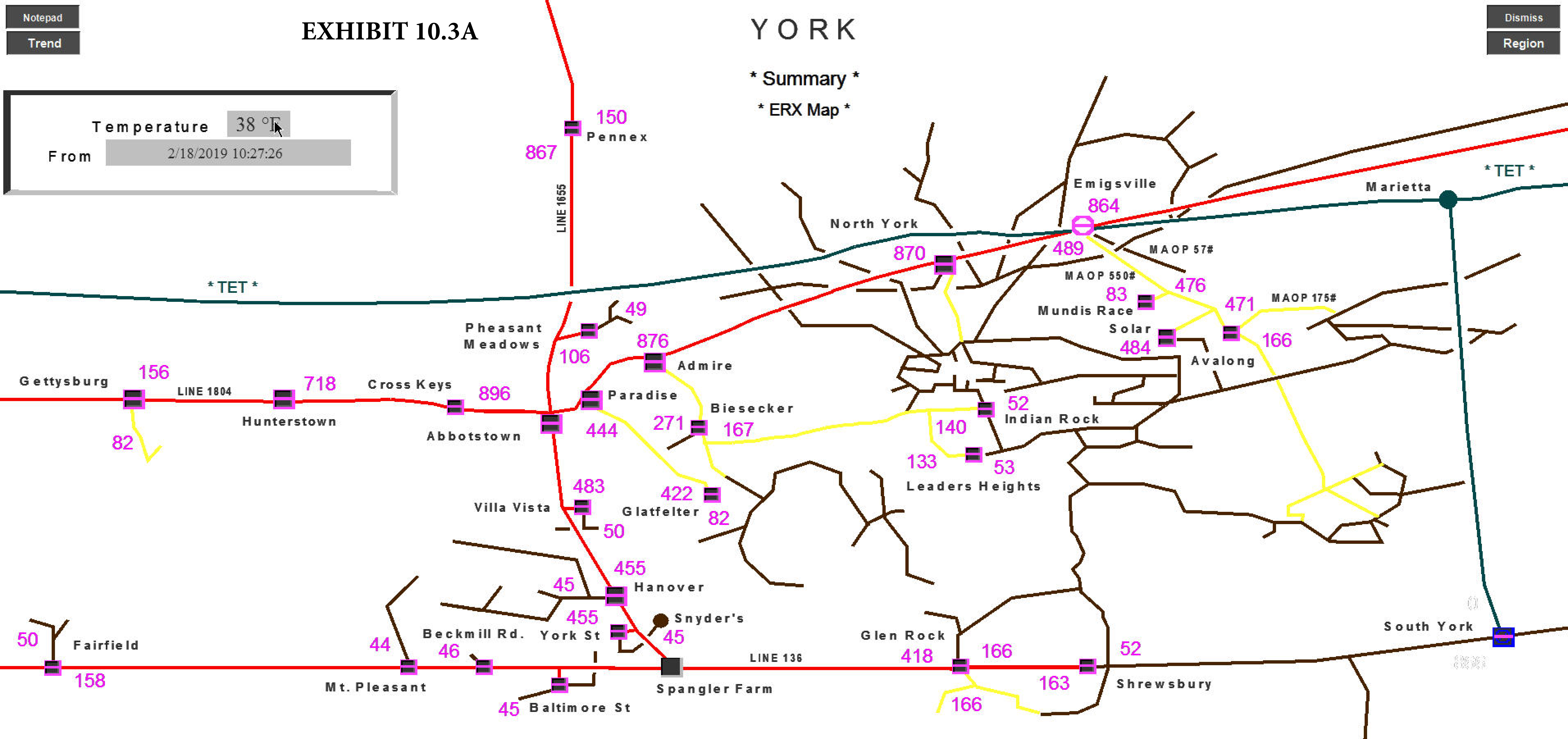
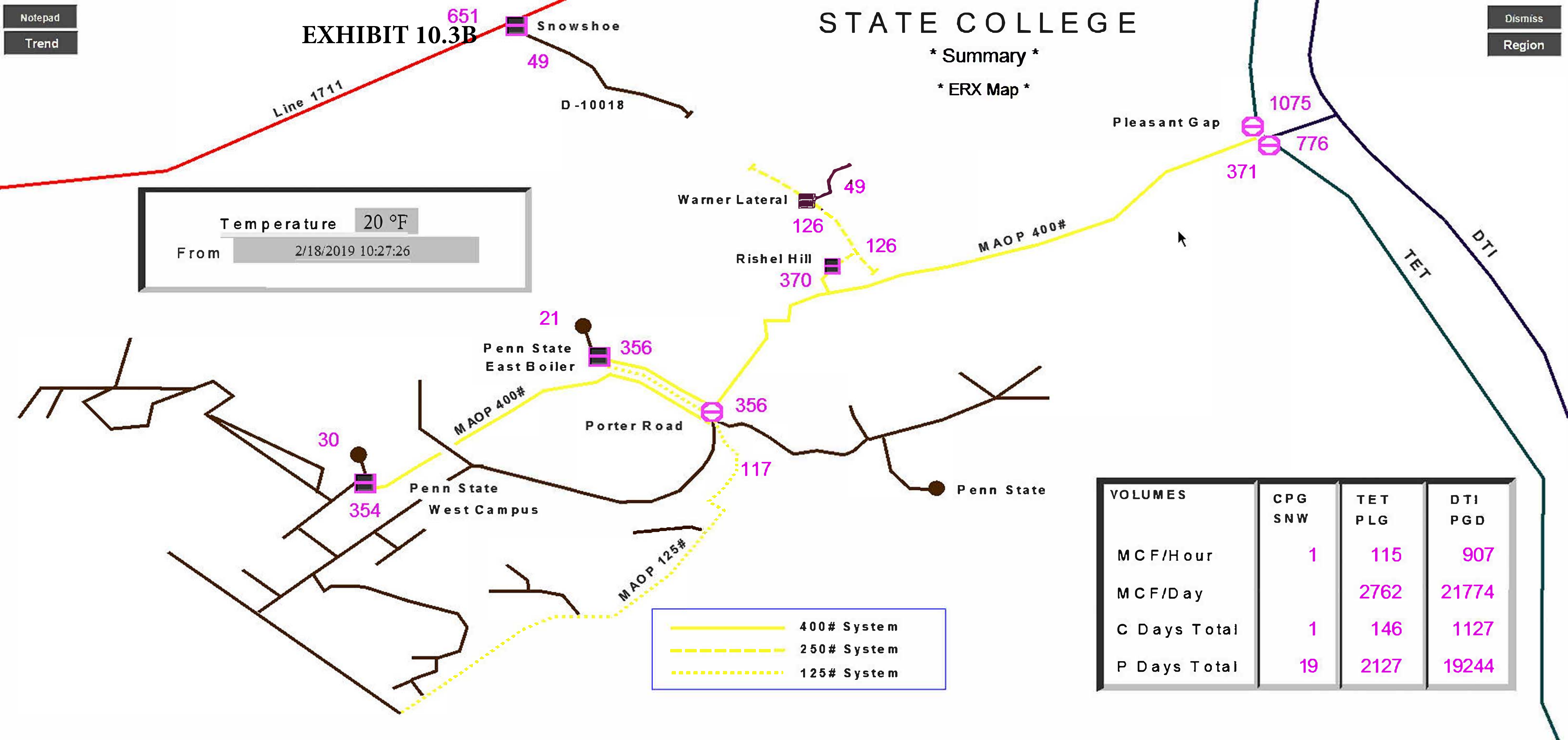


EXHIBIT 10.3B



VOLUMES	CPG SNW	TET PLG	DTI PGD
MCF/Hour	1	115	907
MCF/Day		2762	21774
C Days Total	1	146	1127
P Days Total	19	2127	19244

EXHIBIT 10.3C

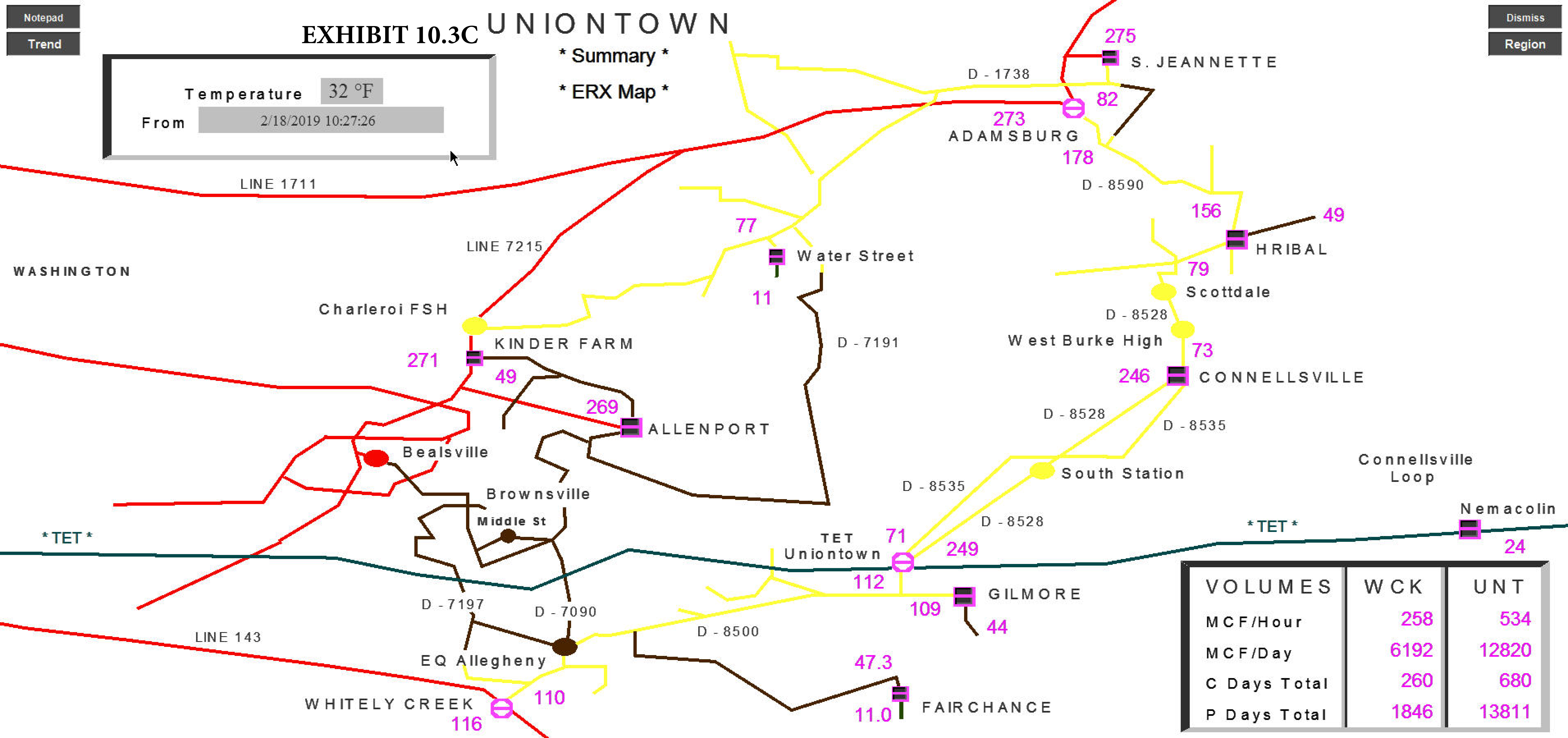


EXHIBIT 10.3D

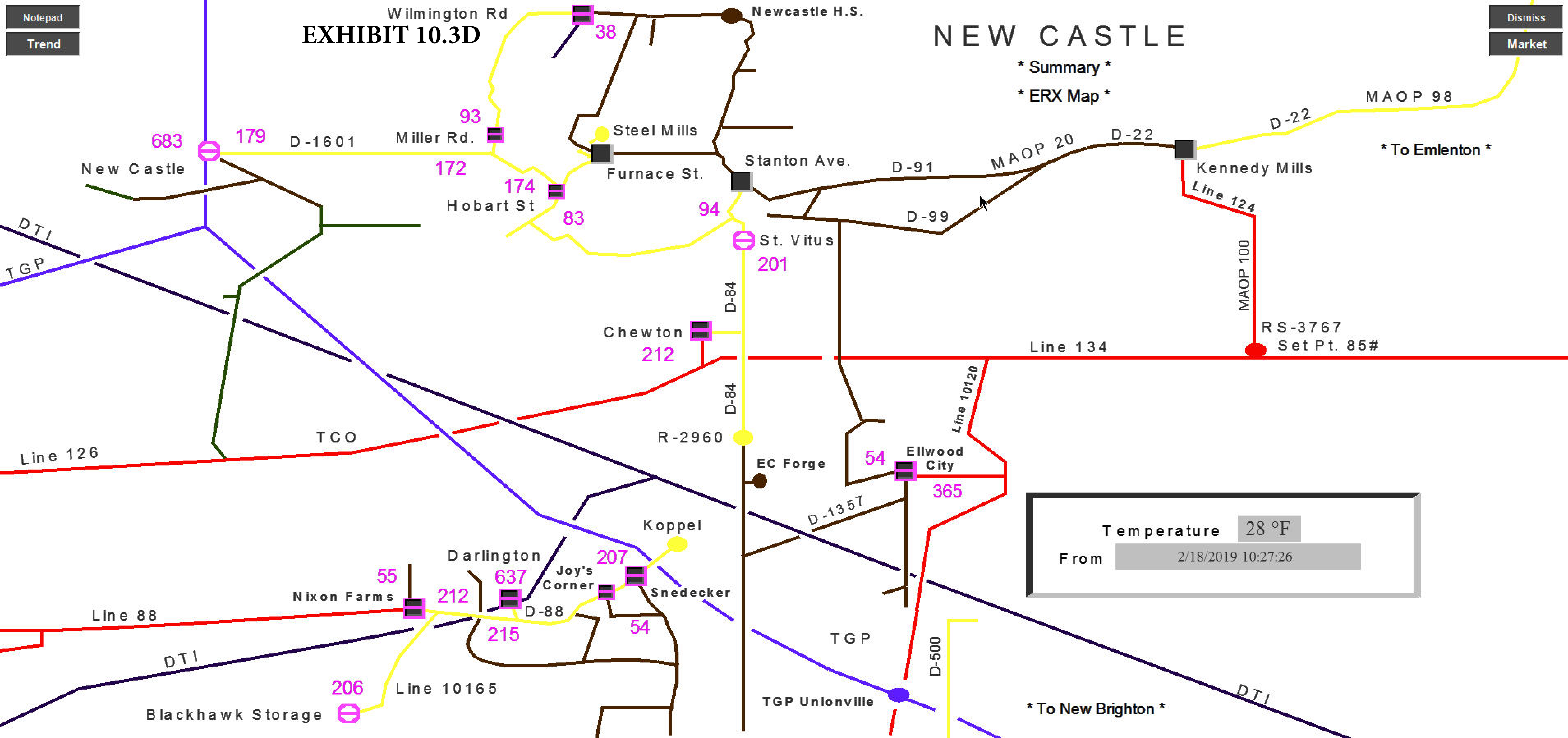
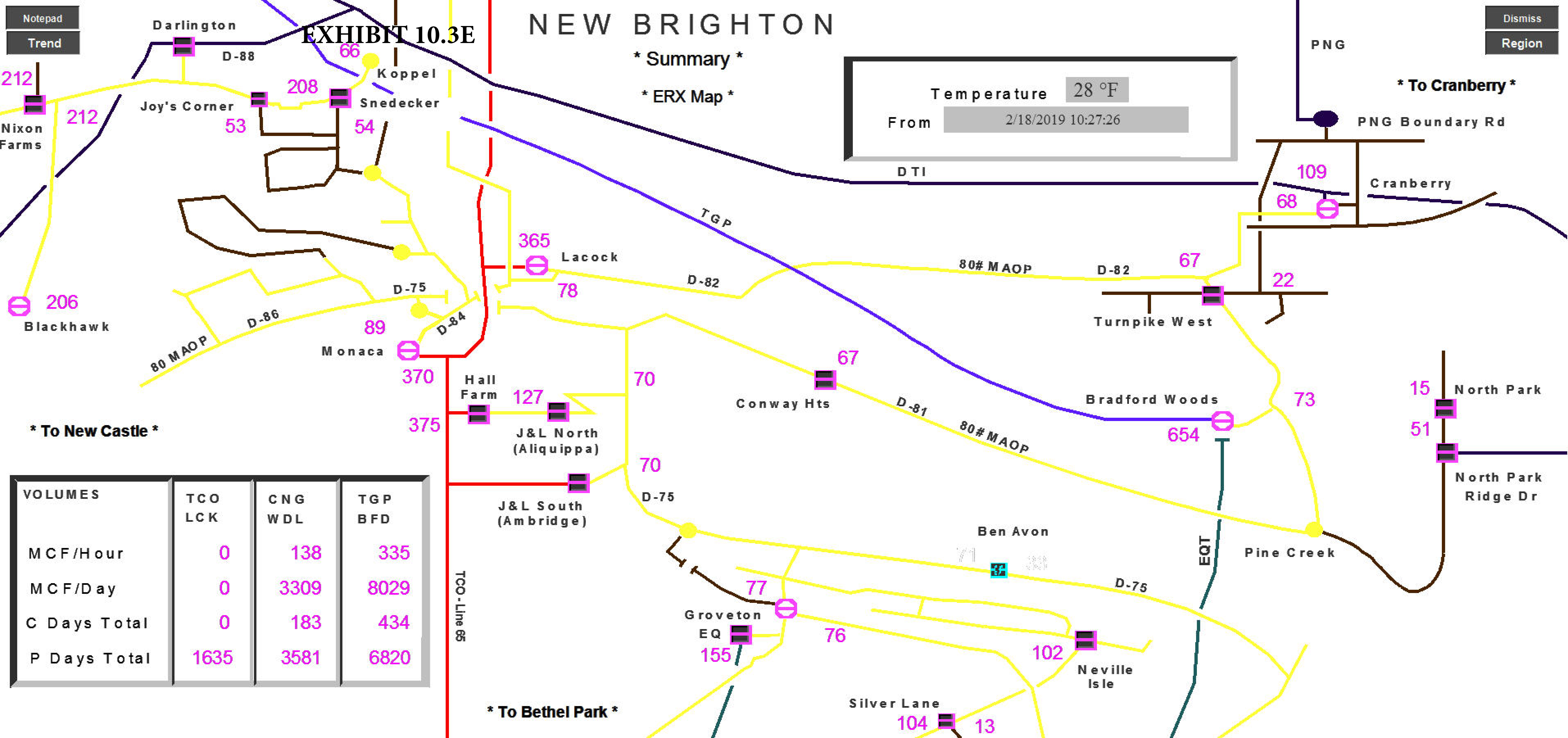
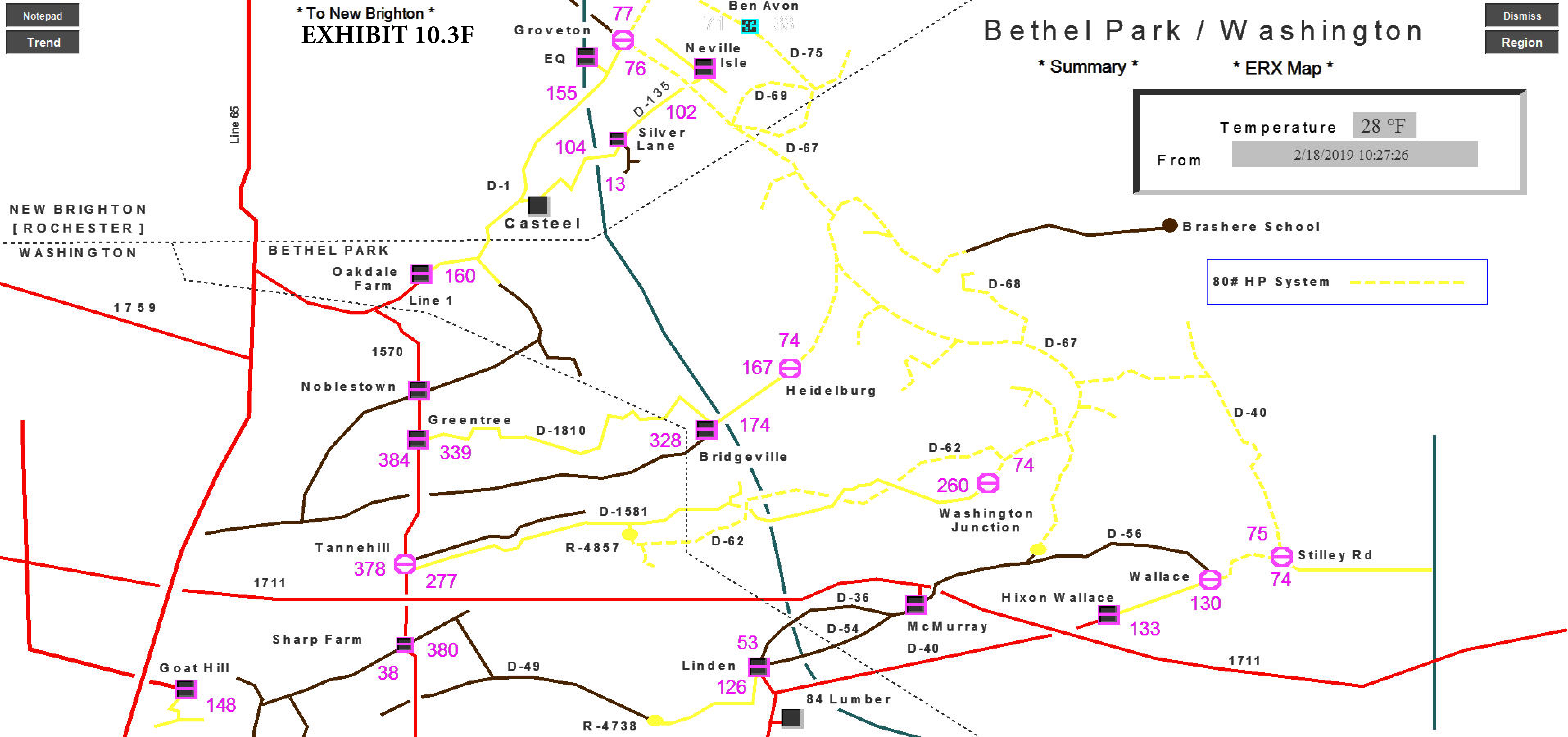


EXHIBIT 10.3E



VOLUMES	TCO LCK	CNG WDL	TGP BFD
MCF/Hour	0	138	335
MCF/Day	0	3309	8029
C Days Total	0	183	434
P Days Total	1635	3581	6820

EXHIBIT 10.3F



§53.64(c) (11) If any rate structure or rate allocation changes are to be proposed, a detailed explanation of each proposal, reasons therefore, number of customers affected, net effect on each customer class, and how the change relates to or is justified by changes in gas costs proposed in the Section 1307(f) tariff filing. Explain how gas supply, transportation and storage capacity costs are allocated to customers which are primarily non-heating, interruptible or transportation customers.

Response:

Columbia has not proposed any rate structure or rate allocation changes in this filing.

§53.64(c)(12) A schedule depicting the most recent 5-year consecutive 3-day peak data by customer class (or other historic peak day data used for system planning), daily volumetric throughput by customer class (including end-user transportation throughput), gas interruptions and high, low and average temperature during each day.

Response:

Sheet 2 of this exhibit shows the actual total daily throughput for a three day consecutive period in each of the most recent five winter seasons with estimated use by customer class also included. As explained in a footnote, all five Winter Seasons had reductions in the Company's non-firm banking and balancing service on the given dates. For Winter Season 2019/2020, peak day occurred in December, while the coincidental three-day peak occurred in January 2020. For Winter Season 2021/2022, peak day occurred on January 26, 2022, while the coincidental three-day peak occurred earlier, from January 20, 2022 to January 22, 2022.

Columbia Gas of Pennsylvania

Maximum Coincident Three Day Peak Period
Quantities in Dth/Day

	Winter Season 2022 - 2023 1/			**Winter Season 2021 - 2022** 1/				**Winter Season 2020 - 2021** 1/			**Winter Season 2019 - 2020** 1/				**Winter Season 2018 - 2019** 1/		
	12/23/2022	**12/24/2022**	**12/25/2022**	**1/26/2022**	**1/20/2022**	**1/21/2022**	**1/22/2022**	**1/28/2021**	**1/29/2021**	**1/30/2021**	**12/18/2019**	**1/20/2020**	**1/21/2020**	**1/22/2020**	**1/30/2019**	**1/31/2019**	**2/1/2019**
	Friday	**Saturday**	**Sunday**	**Wednesday**	**Thursday**	**Friday**	**Saturday**	**Thursday**	**Friday**	**Saturday**	**Wednesday**	**Monday**	**Tuesday**	**Wednesday**	**Wednesday**	**Thursday**	**Friday**
Temperature	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F	°F
Average	1	10	14	11	18	11	22	22	20	28	20	22	20	27	1	8	12
High	13	14	17	21	26	21	26	26	27	32	28	26	26	37	9	11	18
Low	-2	3	10	2	10	1	11	19	13	21	13	17	12	19	-3	1	6
Residential	400,207	366,584	324,375	332,788	294,328	325,247	274,584	289,062	288,347	230,496	299,486	289,413	293,990	251,758	412,573	372,905	342,038
Commercial	245,288	224,681	198,810	203,967	180,394	199,345	168,294	169,767	169,347	135,371	168,461	162,795	165,369	141,614	242,305	219,008	200,879
Industrial	66,112	58,392	55,388	91,187	91,379	86,423	69,499	77,878	67,689	56,401	82,144	78,252	78,616	78,343	91,913	87,783	77,584
Total Retail and Transportation	711,607	649,657	578,573	627,942	566,101	611,015	512,377	536,707	525,383	422,268	550,091	530,460	537,975	471,715	746,791	679,696	620,501
Company Use	738	738	738	1,310	1,310	1,310	1,310	620	620	620	700	700	700	700	500	500	500
Unaccounted For	811	811	811	1,521	1,521	1,521	1,521	1,833	1,833	1,833	1,808	1,808	1,808	1,808	1,605	1,605	1,605
Total Requirements	713,156	651,206	580,122	630,773	568,932	613,846	515,208	539,160	527,836	424,721	552,599	532,968	540,483	474,223	748,896	681,801	622,606

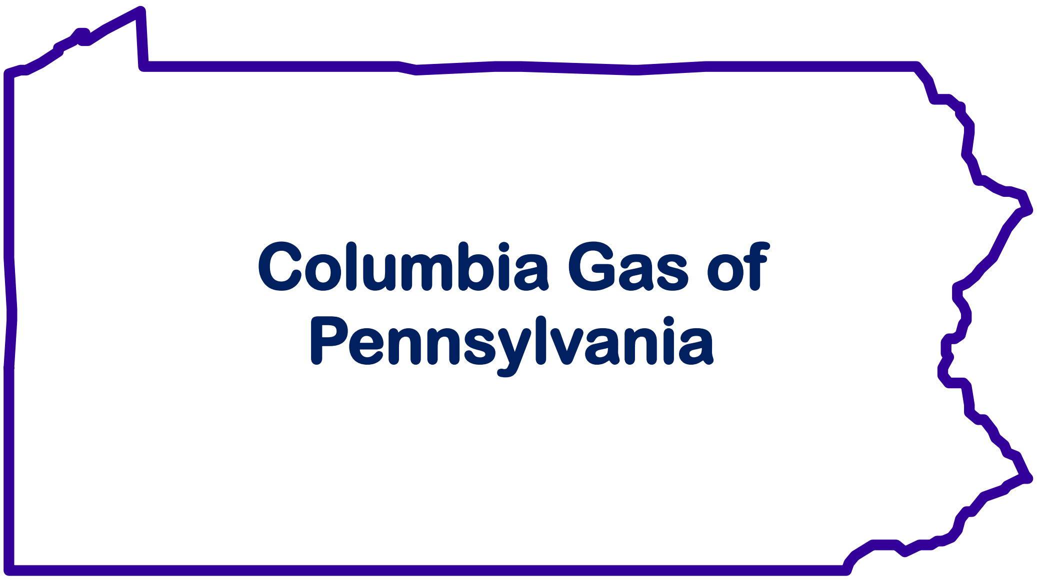
1/ Reduction in the Company's non-firm banking and balancing service occurred on all three dates.
For Winter 2019/20, peak day occurred in December, while the coincidental three-day peak occurred in January 2020. For Winter 2021/22, peak day occurred on January 26, 2022; the coincidental three-day peak occurred from January 20, 2022 to January 22, 2022.

§53.64(c)(13) Identification and support for any peak day methodology used to project future gas demands and studies supporting the validity of the methodology.

Response:

Exhibit 13 Attachment 1 is Columbia Gas of Pennsylvania's 2023 Design Day Forecast. This document describes CPA's Design Day Forecasting methodology in detail.

2023 Design Day Forecast, 2023/24 – 2027/28
By Pipeline Scheduling Point (PSP)



NiSource

Forecast Developed by
Energy Supply and Optimization

COLUMBIA GAS OF PENNSYLVANIA

2023 DESIGN DAY FORECAST, 2023/24 – 2027/28

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COLUMBIA GAS OF PENNSYLVANIA

2023 DESIGN DAY FORECAST, 2023/24 – 2027/28

LIST OF SCHEDULES & Exhibits

COLUMBIA GAS OF PENNSYLVANIA

2023 DESIGN DAY FORECAST, 2023/24 – 2027/2028

I. Introduction

The 2023 Design Day Forecast (DDF) for Columbia Gas of Pennsylvania (CPA or Company) as developed by the NiSource Energy Supply and Optimization Group, represents the official estimate of CPA's Design Day Demand for each of the winters 2023/24 through 2027/28. The DDF is a key-planning tool for CPA in the design of its design day supply/capacity portfolio. It is also critical to day-to-day operations since it serves as the foundation for CPA's daily demand forecasts. As a result, it is imperative that CPA quantify the firm and total demand expected at CPA's Design Day Conditions to ensure continuous, reliable, and economic service to its customers over the term of the forecast.

The projected Design Day Demand quantities contained within are based on CPA's Design Day Conditions, which consist of the Design Current Day Temperature, Design Prior Day Temperature, and Design Current Day Wind Speed, that are assumed to occur on a weekday. These conditions, as discussed in Section III and shown in the Appendix (see **Exhibit A** of the Appendix, at the back of the document), are incorporated in IBM SPSS statistics software to generate predictive equations for CPA's DDF. The resultant forecast provides Design Day Demand estimates by:

1) Revenue Class: Residential, Commercial, Industrial, and "Other",
2) Priority of Service: Firm and Non-Firm,
3) Type of Service: Sales, Choice, and Transportation, and
4) Pipeline Scheduling Point (PSP), as designated by CPA's supplying pipelines.

In addition to the forecasts of Design Day Demand, the DDF also provides each month's estimated daily maximum and minimum demands that may be factored into CPA's supply planning and daily operational processes.

For technical details pertaining to the development of the forecast, including statistical methods used and development of design conditions, please refer to the Appendix, at the end of this document.

II. Executive Summary

The DDF provides a projection of firm and non-firm demand expected to occur at CPA's Design Day Conditions for each of the next five years ending with the 2027-2028 winter. The process behind the development of CPA's 2023 DDF is consistent with that used for CPA's 2022 DDF with one exception:

due to new restrictions in the State College area, this market area has been divided into three major sections and analyzed accordingly, based on supply and capacity needs: (1) State College (supplied by Eastern Gas Transmission and Storage and Texas Eastern Gas Transmission meters), (2) National Fuel Gas (NFG) Warren markets and (3) TCO Only (i.e., supply to customers from Columbia Gas Transmission, or TCO, pipelines). The 2023 DDF Design Day Demand includes the following adjustment:

- ***Adjustments for Projected Large Customer Relations (LCR) Customers***
  The forecast of CPA's non-firm customer demand has given consideration to the current projection of expected new customer load developed by NiSource's Large Customer Relations group.

Table 1 provides a breakdown of forecast quantities by service priority (firm and non-firm). For supply planning purposes, the demand of transportation customers not served under the Company's Standby Service or Elective Balancing Service (EBS), is considered to be non-firm. All remaining demand is considered to be firm and would include CPA's firm obligation to transportation customers who have contracted for Standby Service or EBS.

Table 1
Columbia Gas of Pennsylvania
2023 Design Day Forecast
Quantities in MDth

	Firm					Total	Additional Firm Obligation		Total Firm
Winter	Sales	Choice	Other	Total	Non-Firm	Demand	Standby	EBS	Obligation
	(1)	(2)	(3)	(4)=(1 thru 3)	(5)	(6)=(4+5)	(7)	(8)	(9)=(4+7+8)
2022/23	488.8	131.2	1.5	621.5	194.5	816.0	5.6	12.5	639.6
2023/24	492.9	130.7	1.5	625.1	192.6	817.7	5.1	12.6	642.8
2024/25	500.9	125.2	1.5	627.6	193.8	821.4	5.1	12.6	645.3
2025/26	507.7	119.8	1.5	629.0	194.5	823.5	5.1	12.6	646.7
2026/27	515.7	114.4	1.5	631.6	195.1	826.7	5.1	12.6	649.3
2027/28	523.7	109.2	1.5	634.4	195.5	829.9	5.1	12.6	652.1
CAG 2023/24 - 2027/28				0.4%	0.4%	0.4%			0.4%

<u>**Schedule 1**</u> presents the 2023 DDF in more detail, identifying the forecast by customer class, segregated by Pipeline Scheduling Point (PSP) as well as by priority of service.

The growth rates shown in Table 1 are for CPA in total. <u>**Schedule 1**</u> provides the same information by Pipeline Scheduling Point (PSP) as well as by priority of service.

The Choice firm demand estimate is derived from data contained in the Company's AFP 2024 Gas Estimate, and the quantities above reflect the Design Day Demand for Choice customers. On <u>**Schedule 2**</u>, CPA's firm service obligations to commercial and industrial customers, inclusive of Standby and EBS Obligations, are identified by PSP.

Schedule 3 provides tabular and graphical trends related to firm demand, based on historic "Design Actual" Demands. The Design Actual Demand contained in Column 1 represents Energy Supply and Optimization's calculation of what the Design Day Demand would equate to for a given historical winter season (2003/04 through 2022/23) had Design Day Conditions been experienced. The Design Actual Demand serves as the basis for the forecasts of CPA's future Design Day Demand as presented in Column 2, as more fully explained in Section III E - Design Day Forecast. The forecast shows an increase in demand in response to projected lower gas prices and an increase in number of customers. In the forecast period, the number of customers is projected to increase by 1,330 per year. Column 3 reflects the adjustment to firm demand based on an increase attributable to contracted Standby/EBS Service. The Total Firm Obligation (sum of Column 2 and Column 3) is shown in Column 4.

Schedule 4 parallels **Schedule 3**, with Columbia's **Total** Design Day Demand.

III. 2023 DDF Development

Columbia's Design Day Forecast uses two linear regression-based models to develop a forecast of Columbia's expected Design Day Demand for each of its eight PSPs. The first linear regression-based model is used to determine Design Actual Demand for each historical winter season. The second regression model is based on an analysis of the Design Actual Demand and determines the Design Day Forecast.

The process is described in sections A through H.

A. Obtaining Actual Total Daily Demand

The first step in the preparation of the DDF is to obtain actual total daily demand that was observed in the months of December through February for the prior heating seasons. Energy Supply and Optimization derives the actual total daily demand by accumulating daily supply data from all sources. Based on twelve months ending December 2022, CPA has 97% of its total deliveries measured on a daily basis. The deliveries that are monthly read are allocated to daily volumes using a base load / heat load allocation process. The total daily volume for every point of delivery (POD) is then summarized to produce the actual total daily demand for each PSP.

B. Obtaining Non-Firm Customer Daily Demand

The second step is the calculation of the daily demand for CPA's industrial and commercial customers receiving services from the company on a non-firm basis. As shown on **Schedule 5**, approximately 84% of total non-firm customer demand is subject to daily measurement. The percentages on **Schedule 5** are based on the actual January 2023 throughput for all such customers. For non-firm customers without daily read capability, CPA estimates their daily consumption using a base load / heat load allocation process. The non-firm quantities are summarized to produce total non-firm deliveries by PSP.

C. Calculation of Daily Firm Demand

Daily Firm Demand is calculated at the PSP level by subtracting the daily non-firm customer (industrial and commercial) demand, as described above, from the actual total daily demand. The resultant daily demand is considered to be firm customer demand, for supply planning purposes, and is utilized in the regression process described below.

As discussed in the Executive Summary section, CPA has additional firm obligations of 18.1 MDth under its Standby Service contracts and EBS contracts with transportation customers for 2022-23. The forecast period beginning with heating season 2023-24 shows the new contract level of 17.7 MDth. **Schedule 2** provides a breakdown of Standby Service and EBS quantities by revenue class and PSP.

D. Design Actual Demand

A linear regression-based model is used to determine, the "Design Actual Demand" for each historical winter season for Firm Demand, Industrial Non-Firm Demand and Commercial Non-Firm Demand. During the process the actual daily demand for the months of December through February for the past two heating seasons are regressed against four potential explanatory variables for all days and Cold Days (days having an average temperature of 30°F or colder). The potential explanatory variables are:

1. Current Day Temperature: the average daily temperature for the current day,
2. Prior Day Temperature: the average daily temperature for the prior day,
3. Wind Speed: the average daily wind speed for the current day, and
4. Day Type; weekday, weekends and holidays. The holidays are the period December 24th through January 1st, Martin Luther King Jr. Day, and President's Day. New day types included this year, which apply to industrial and commercial demand are coefficients for Friday, Saturday and Sunday. Using SPSS, it was determined that in some instances, certain customers' demand patterns are affected by the day of week. For example, some companies have reduced consumption or shut down starting Friday through Sunday. In these instances, special coefficients are needed to describe these customers' consumption patterns.

For each of these explanatory variables Columbia has determined the associated Design Day Conditions, for each PSP, as discussed in the Appendix. The Design Day Type is considered to be a weekday.

Selection of the Design Actual Demand model will consist of explanatory variables targeting 95% significance and the best statistical results of the regressions. Three statistical tests are developed, R-Square, Durbin-Watson, and Root Mean Square Error (RMSE). An accepted model will have a high R-Square, a Durbin-Watson near 2.000 and a low RMSE. There are some special cases in which a Non-Firm customer's data is so sporadic that a good linear regression is not possible. In these instances, with the new SPSS software, these customers were identified and, rather than using the traditional linear regression, a special analysis was performed that yielded the best estimate of demand based on a 95% confidence interval.

Schedule 6 summarizes the regression results and provides the coefficient of determination, R^2 for each PSP. The statistic R^2 is "the estimated proportion of the variance of Y (the demand) that can be attributed to its linear regression on X (the collection of explanatory variables)". (Snedecor and Cochran, Statistical Methods, Seventh Edition, page 181.) For those special Non-Firm customers in which an average estimate based on the 95% confidence interval was calculated, there are no statistical results; "95%" has been included in the column heading. Please see Section II in the Appendix, for details on how the regressions are made and what criteria are used in determining the regression coefficients.

Note that R^2 for the Firm Demand component typically exceeds R^2 for the Industrial demand components. The higher R^2 for Firm Demand indicates that the explanatory variables included in the model account for a high proportion of the day-to-day variation in demand. The lower R^2 for the industrial models indicates that additional variables not included in the models affect demand. For example, day-to-day production / operations, pricing of alternative fuels may affect industrial demand.

In some PSPs the models have missing coefficients. A missing coefficient indicates that the associated variable does not affect demand with 95 percent confidence. In order to affect demand with 95 percent confidence, an explanatory variable must have an estimated regression coefficient, which is large compared to its standard error. In statistical terms, the probability of obtaining such a large estimated coefficient is less than 5 percent if the true coefficient is zero.

The day type variable includes both holiday and weekend demand impacts relative to weekdays. If weekend is found to be a valid explanatory variable, then holiday will have at least the same value as a weekend or may be greater. For Non-Firm (Industrial or Commercial), when applicable, the Friday, Saturday and/or Sunday variables would impact demand. On days when applicable, these day type variables reduce the intercept by the amount shown. Since the forecast is based on weekday, these variables do not impact the Design Day Demand.

Using PSP 25E-25 (Lancaster) (Schedule 6, Page 1) as an example, the Daily Firm Demand model includes all four explanatory variables. As shown in **Table 2** the 2022/23 Design Actual Demand for firm customers is 176,359 Dth and the equation is:

Daily Firm Demand in Dth = Intercept + Temperature Coefficient * Current Day Temperature
+ Prior Day Temperature Coefficient * Prior Day Temperature,
+ Wind Speed Coefficient * Wind Speed,
+ Day Type coefficient.

Table 2
Columbia Gas of Pennsylvania

Use of the Regression Coefficients to Determine 2022/23 Design Actual Demand
Example: System Firm Demand for PSP 25E-25 (Lancaster)

Explanatory Variable (1)	Regression Coefficient Value (2)	Regression Coefficient Units (3)	Design Value of the Explanatory Variable Value (4)	Design Value of the Explanatory Variable Units (5)	Product Dth (6) = (2) * (4)
Intercept	168,227.09	DTh	1	--	168,227
Temperature	(2,355.11)	DTh/Deg	2	Deg	(4,710)
Prior Day Temp.	(430.53)	DTh/Deg	10	Deg	(4,305)
Wind Speed	843.94	DTh/ MPH	12	MPH	10,127
Day Type:					
Holiday	(3,970.32)	DTh	0	--	0
Weekend	(1,977.11)	DTh	0	--	0
2022/23 Design Actual					**169,339**
Additional Firm Obligations 2022/23					
Standby Service	1,671.00	DTh	1	--	1,671
EBS	5,349.15	DTh	1	--	5,349
Subtotal					**7,020**
2022/23 PSP 17-15 Design Actual Firm Obligation:					**176,359**

Since this PSP has Standby Service and EBS agreements, these obligations need to be added to arrive at the Total Firm Obligation. During the 2022/23 heating season, PSP 25E-25 (Lancaster) had Standby and Elective Balancing obligations of 7,020 Dth. Table 2 shows the use of the coefficients to determine the PSP 25E-25 (Lancaster) 2022/23 Design Actual Firm Demand (the weekday firm daily demand that would be expected under Design Day Conditions) plus the Standby Service and EBS obligations. With this addition, PSP 25E-25 (Lancaster) had a Total Firm Obligation of 176,359 Dth at a Design Current Day Temperature of 2 degrees, Design Prior Day Temperature of 10 degrees and Design Current Day Wind Speed of 12 MPH.

<u>Schedule 6</u> shows for each PSP the 2022/23 Design Actual Demands, regression components, forecasted 2023/24 Design Day Demand, and the 2023/24 Standby Service and EBS obligations. Pages 9 through 12 of Schedule 6 show the Design Actuals, forecast and Standby Service/EBS obligations for the components that comprise PSP36 (National Fuel Warren, State College market, TCO only market and a design for the exchange volumes in PSP36).

E. Design Day Forecast

Historical Design Actual Demands for each PSP beginning with the 2003/04 winter are utilized as the basis for the regressions to determine the Design Day Forecast. The analysis at the PSP level is needed for planning purposes and allows for identifying variances in customer demand over the historical period studied. In the process, the impact on the annual Design Actual Demands of four variables is determined. Those variables are:

1. Customer count in the month of January,
2. Actual degree days in the months of December and January,
3. Actual winter period gas cost, and
4. Average Non-Farm Employment in the months of December through February.

These variables were considered in the analysis; a separate analysis was also made using the log of the variables. Both analyses consider an annual trend term to capture appliance efficiency effect on demand and customer demand usage behavior over time.

For log variables, the result generates a forecasted Log of UPC when the regression equation is applied to the forecast of these explanatory variables. The Log of UPC is converted to a UPC and applied to the forecasted January number of customers to arrive at a Design Day Demand. The forecast of January number of customers is derived from the Company's AFP 2024 Gas Estimate.

For the purpose of forecasting both firm and non-firm Design Day Demand, the gas cost is the forecasted January NYMEX Gas Monthly Price at Henry Hub (NGI Bidweek Prices). The prior year's gas price may also be tested as an explanatory variable in combination with other explanatory variables.

This year's forecast continued the use of employment to capture the effect of local economic factors on demand for natural gas. For the purpose of modeling firm and non-firm Design Day Demand, the non-farm employment is the average of monthly December, January, and February employment aggregated to the PSP level. Historical and forecasted employment values come from the 2023 IHS Global Insight County Forecast.

Schedule 7 shows the Firm Design Actual Demand and corresponding forecast for the five year period along with the explanatory variables, resultant statistics, and the number of historical winter periods of the selected model. A model is considered for acceptance when meeting an acceptable threshold of statistical results which include an adjusted R^2 above 0.6, an F-test of model significance resulting in 85% confidence, and explanatory variable coefficients taking the “expected” sign. The expected sign for customer count, degree-day, and non-farm employment is positive and the expected sign for an additional dollar in price is negative. If an acceptable model is not found the forecast reflects the average of the three most recent Design Actual Demands. This year’s forecast accepted all four explanatory variables in various combinations, depending on the PSP, which achieved the best statistical results.

The adjustments to the forecast are described in Section F.

F. Adjustments to Forecast

As addressed in Section II (Executive Summary) and in Section E above, additional analyses and adjustments were required to account for:

- ***Adjustments for Projected Large Customer Relations (LCR) Customers***
  The forecast of CPA’s non-firm customer demand has given consideration to the current projection of expected new customer load developed by NiSource’s Large Customer Relations group.

- ***Smoothing Process For Design Forecast***
  The forecast of CPA’s firm customer demand for the first winter (2023/24) incorporates a smoothing process in PSPs 25E-25 and 25-35, which reflects the average of the 2022/23 historical firm Design Actual Demand and the 2024/25 projected firm Design Day Demand.

In addition to **Schedule 7** showing each PSP’s firm Design Actual Demand and forecasted Firm Design Day Demand, the adjustments to the forecast described in Section F, are shown.

Schedule 8 relates to the non-firm analysis and parallels the process discussed above for Firm Demand, with two exceptions. First, as previously mentioned, the gas cost considered in forecasting non-firm demand is the January NYMEX price. Second, specified criteria are not considered. The schedule shows the non-firm demand and adjustments as described in Section F.

G. Design Day Demand by Revenue Class

The Firm and Non-Firm Design Actual Demands are used in the allocation process to determine Design Day Demand by revenue class. This is a multiple step process as explained below.

Four steps are performed to allocate firm customer demand. In **Step 1**, the annual and monthly forecasts reflected in CPA's Gas Estimate are used to calculate Company Use, and Unaccounted-For Gas. For the Design Day Forecast, Company Use quantities are calculated to be one-twentieth of the January requirement from the AFP 2024 Gas Estimate. The Design Day Demand of Unaccounted for Gas is calculated to be 1/365th of the annual Unaccounted for Gas load from the AFP 2024 Gas Estimate. Like residential demand, Company Use, and Unaccounted for Gas are entirely firm; i.e., they contain no non-firm component. Since Company Use, and Unaccounted for Gas do not have a historical pattern, CPA projects this demand to remain constant.

In **Step 2**, Industrial Firm Sales is developed by regression analysis of the estimated daily industrial firm sales demand of the most recent winter (derived from monthly billing data for December 2022 through February 2023) against the gas-day average temperature.

In **Step 3**, the remainder of Firm Demand (Firm Demand less Industrial Firm Demand less Company Use, and Unaccounted-For Gas) is allocated to Residential and Firm Commercial based on the forecasted demands from the Gas Estimate, inclusive of Choice.

In **Step 4**, the Firm Demand is then further categorized between Sales and Choice. This split is derived from the inputs used in the development of CPA's AFP 2024 Gas Estimate and adjusted for the Choice eligibility of smaller transportation customers.

H. Results

The 2022/23 Design Actual Demands and five-year Design Day Forecast by revenue class and priority of service are summarized on **Schedule 1**. The forecast includes non-firm demand since it is vital for planning and operations to know potential total (firm and non-firm) demand under Design Day Conditions.

Schedule 9 provides a breakdown of customer demand for the first forecast year of the 2023 DDF by rate schedule. The allocation of the forecasted commercial and industrial Design Day Demand to the various firm rate schedules is based on the actual total demand for the month of January 2023, as accounted for by rate schedule. Non-Firm rate schedules allocation is based on the most recent peak day experienced. Both the Standby Service obligation and the EBS are reflected on this schedule.

IV. Historical Demands and Supplies

Schedule 10 shows the historic actual peak day demand and associated supply sources for the three consecutive winter days of greatest demand for each of the past four winter seasons. The demands shown represent total throughput, meaning the demand of all customers served by Columbia. The breakdown by revenue class is an estimate since actual daily-metered volumes are not available for all customers and is based on an analysis of billing data. The total demand represents the actual demand of all customers predicated upon the total, measured supply quantities from all sources delivered to CPA for both sales and transportation customers. Also shown are the actual average temperatures, date, and day of week.

V. Monthly Maximum and Monthly Minimum Design Conditions and Demands

A. Monthly Maximum Conditions and Corresponding Demand

To serve CPA's planning needs, Monthly Maximum Conditions and associated Forecast Demand are included in the DDF. Monthly Maximum Conditions and Forecast Demand are shown on **Schedule 11.** For a description of how the monthly maximum design conditions and demand are determined, please refer to Section III of the Appendix at the end of this document.

B. Monthly Minimum Demand

The Monthly Minimum Demands, shown on **Schedule 12** are based on the analysis of daily demand that has occurred over the most recent five years for each month. The selection of five years of history is driven by the need to obtain as many observations of actual demand as possible for analysis, in determining Monthly Minimum Demand, recognizing use of more history may provide a result that is not reflective of current customer demand. The Monthly Minimum Demand is calculated to be the demand having a 10% probability of occurrence.

VI. Discussion: PSP 25-36 and Its Market Segments

A. Description of the Market Segments

Around June 2018, TCO's Snowshoe POD Station no longer supplied the State College market. Due to new pipeline/storage restrictions, it became necessary to identify the independent segments that supply PSP25-36 customers. The three supply sources upon with this market area's design forecast is based provide service to:

(1) Customers in the State College market (supply from Texas Eastern Company Pleasant Gap, Eastern Gas Transmission and Storage Pleasant Gap and Eastern Gas Transmission and Storage Centre Hall measuring stations)
(2) Customers in the National Fuel Gas Warren Market
(3) Customers served by Columbia Gas Transmission (aka, TCO, a subsidiary of TC Energy) pipeline facilities.

The sum of these three market segments makes up the Firm and NonFirm requirements for PSP 25-36, starting with the 2018-19 Winter.

SCHEDULES

Schedule 1

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Firm and Total Requirements by Class, Service Type, Priority of Service and Pipeline Scheduling Point
Demand Units are MDth/Day

	Residential			Commercial							Industrial								All Classes			Additional Firm Obligation		Total Firm
			Grand	Firm			Non-Firm			Grand	Firm			Non-Firm			Grand							
Winter	Sales	Choice	Total	Sales	Choice	Total	Transpt.	Sales	Total	Total	Sales	Choice	Total	Transpt.	Sales	Total	Total	Other	Firm	Non-Firm	Total	Standby	EBS	Obligation
Total																								
2022/23	350.0	92.6	442.6	136.9	38.6	175.5	95.8	0.0	95.8	271.3	1.9	0.0	1.9	98.7	0.0	98.7	100.6	1.5	621.5	194.5	816.0	5.6	12.5	639.6
2023/24	357.2	92.2	449.4	133.7	38.5	172.2	95.6	0.0	95.6	267.8	2.0	0.0	2.0	97.0	0.0	97.0	99.0	1.5	625.1	192.6	817.7	5.1	12.6	642.8
2024/25	365.9	86.7	452.6	133.0	38.5	171.5	96.6	0.0	96.6	268.1	2.0	0.0	2.0	97.2	0.0	97.2	99.2	1.5	627.6	193.8	821.4	5.1	12.6	645.3
2025/26	372.4	81.3	453.7	133.3	38.5	171.8	96.7	0.0	96.7	268.5	2.0	0.0	2.0	97.8	0.0	97.8	99.8	1.5	629.0	194.5	823.5	5.1	12.6	646.7
2026/27	380.1	75.9	456.0	133.6	38.5	172.1	97.1	0.0	97.1	269.2	2.0	0.0	2.0	98.0	0.0	98.0	100.0	1.5	631.6	195.1	826.7	5.1	12.6	649.3
2027/28	387.8	70.6	458.4	133.9	38.6	172.5	97.4	0.0	97.4	269.9	2.0	0.0	2.0	98.1	0.0	98.1	100.1	1.5	634.4	195.5	829.9	5.1	12.6	652.1
CAG:			0.5%							0.2%							0.3%	0.0%	0.4%	0.4%	0.4%			0.4%
PSP 25E-25																								
2022/23	94.9	25.2	120.1	36.3	11.3	47.6	28.2	0.0	28.2	75.8	1.2	0.0	1.2	47.3	0.0	47.3	48.5	0.4	169.3	75.5	244.8	1.7	5.3	176.3
2023/24	98.3	25.1	123.4	34.9	11.3	46.2	27.1	0.0	27.1	73.3	1.3	0.0	1.3	47.2	0.0	47.2	48.5	0.4	171.3	74.3	245.6	1.6	5.2	178.1
2024/25	100.9	23.6	124.5	34.7	11.3	46.0	27.3	0.0	27.3	73.3	1.3	0.0	1.3	47.1	0.0	47.1	48.4	0.4	172.2	74.4	246.6	1.6	5.2	179.0
2025/26	103.2	22.2	125.4	34.8	11.3	46.1	27.5	0.0	27.5	73.6	1.3	0.0	1.3	47.5	0.0	47.5	48.8	0.4	173.2	75.0	248.2	1.6	5.2	180.0
2026/27	105.6	20.7	126.3	34.9	11.3	46.2	27.9	0.0	27.9	74.1	1.3	0.0	1.3	47.6	0.0	47.6	48.9	0.4	174.2	75.5	249.7	1.6	5.2	181.0
2027/28	108.1	19.2	127.3	34.9	11.4	46.3	28.2	0.0	28.2	74.5	1.3	0.0	1.3	47.9	0.0	47.9	49.2	0.4	175.3	76.1	251.4	1.6	5.2	182.1
CAG:			0.8%							0.4%							0.4%	0.0%	0.6%	0.6%	0.6%			0.6%
PSP 25-26																								
2022/23	28.9	7.6	36.5	12.6	1.8	14.4	4.4	0.0	4.4	18.8	0.0	0.0	0.0	1.1	0.0	1.1	1.1	0.1	51.0	5.5	56.5	0.5	0.3	51.8
2023/24	30.5	7.6	38.1	12.5	1.8	14.3	4.5	0.0	4.5	18.8	0.0	0.0	0.0	1.0	0.0	1.0	1.0	0.1	52.5	5.5	58.0	0.5	0.3	53.3
2024/25	32.7	7.1	39.8	12.4	1.8	14.2	4.5	0.0	4.5	18.7	0.0	0.0	0.0	1.1	0.0	1.1	1.1	0.1	54.1	5.6	59.7	0.5	0.3	54.9
2025/26	33.5	6.7	40.2	12.4	1.8	14.2	4.5	0.0	4.5	18.7	0.0	0.0	0.0	1.2	0.0	1.2	1.2	0.1	54.5	5.7	60.2	0.5	0.3	55.3
2026/27	34.3	6.2	40.5	12.5	1.8	14.3	4.5	0.0	4.5	18.8	0.0	0.0	0.0	1.4	0.0	1.4	1.4	0.1	54.9	5.9	60.8	0.5	0.3	55.7
2027/28	34.9	5.8	40.7	12.5	1.8	14.3	4.5	0.0	4.5	18.8	0.0	0.0	0.0	1.5	0.0	1.5	1.5	0.1	55.1	6.0	61.1	0.5	0.3	55.9
CAG:			1.7%							0.0%							10.7%	0.0%	1.2%	2.2%	1.3%			1.2%
PSP 25E-29																								
2022/23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.3	0.0	9.3	9.3	0.0	0.0	9.3	9.3	0.0	0.5	0.5
2023/24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.1	0.0	9.1	9.1	0.0	0.0	9.1	9.1	0.0	0.5	0.5
2024/25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	9.0	9.0	0.0	0.0	9.0	9.0	0.0	0.5	0.5
2025/26	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	9.0	9.0	0.0	0.0	9.0	9.0	0.0	0.5	0.5
2026/27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	9.0	9.0	0.0	0.0	9.0	9.0	0.0	0.5	0.5
2027/28	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	9.0	9.0	0.0	0.0	9.0	9.0	0.0	0.5	0.5
CAG:			0.0%							0.0%							-0.3%	0.0%	0.0%	-0.3%	-0.3%			0.0%
PSP 25-35																								
2022/23	170.9	45.1	216.0	70.9	14.7	85.6	36.6	0.0	36.6	122.2	0.6	0.0	0.6	26.4	0.0	26.4	27.0	0.8	303.0	63.0	366.0	2.6	3.8	309.4
2023/24	171.3	44.9	216.2	70.2	14.7	84.9	36.5	0.0	36.5	121.4	0.6	0.0	0.6	25.6	0.0	25.6	26.2	0.8	302.5	62.1	364.6	2.3	3.7	308.5
2024/25	173.5	42.3	215.8	70.0	14.7	84.7	37.0	0.0	37.0	121.7	0.6	0.0	0.6	25.7	0.0	25.7	26.3	0.8	301.9	62.7	364.6	2.3	3.7	307.9
2025/26	175.8	39.6	215.4	70.1	14.7	84.8	36.6	0.0	36.6	121.4	0.6	0.0	0.6	25.6	0.0	25.6	26.2	0.8	301.6	62.2	363.8	2.3	3.7	307.6
2026/27	179.3	37.0	216.3	70.2	14.7	84.9	36.4	0.0	36.4	121.3	0.6	0.0	0.6	25.3	0.0	25.3	25.9	0.8	302.6	61.7	364.3	2.3	3.7	308.6
2027/28	183.0	34.4	217.4	70.2	14.7	84.9	36.4	0.0	36.4	121.3	0.6	0.0	0.6	24.6	0.0	24.6	25.2	0.8	303.7	61.0	364.7	2.3	3.7	309.7
CAG:			0.1%							0.0%							-1.0%	0.0%	0.1%	-0.5%	0.0%			0.1%
PSP 25-36																								
2022/23	19.7	5.2	24.9	0.9	9.0	9.9	22.3	0.0	22.3	32.2	0.0	0.0	0.0	0.6	0.0	0.6	0.6	0.1	34.9	22.9	57.8	0.4	1.2	36.5
2023/24	20.3	5.2	25.5	0.7	8.9	9.6	23.2	0.0	23.2	32.8	0.0	0.0	0.0	0.9	0.0	0.9	0.9	0.1	35.2	24.1	59.3	0.4	1.6	37.2
2024/25	20.9	4.9	25.8	0.7	8.9	9.6	23.4	0.0	23.4	33.0	0.0	0.0	0.0	1.1	0.0	1.1	1.1	0.1	35.5	24.5	60.0	0.4	1.6	37.5
2025/26	21.3	4.6	25.9	0.8	8.9	9.7	23.7	0.0	23.7	33.4	0.0	0.0	0.0	1.3	0.0	1.3	1.3	0.1	35.7	25.0	60.7	0.4	1.6	37.7
2026/27	21.8	4.3	26.1	0.8	8.9	9.7	23.9	0.0	23.9	33.6	0.0	0.0	0.0	1.5	0.0	1.5	1.5	0.1	35.9	25.4	61.3	0.4	1.6	37.9
2027/28	22.3	4.0	26.3	0.8	8.9	9.7	23.9	0.0	23.9	33.6	0.0	0.0	0.0	1.9	0.0	1.9	1.9	0.1	36.1	25.8	61.9	0.4	1.6	38.1
CAG:			0.8%							0.6%							20.5%	0.0%	0.6%	1.7%	1.1%			0.6%
PSP 25-38																								
2022/23	5.9	1.6	7.5	2.6	0.4	3.0	0.9	0.0	0.9	3.9	0.0	0.0	0.0	0.2	0.0	0.2	0.2	0.0	10.5	1.1	11.6	0.3	0.1	10.9
2023/24	6.2	1.6	7.8	2.5	0.4	2.9	0.9	0.0	0.9	3.8	0.0	0.0	0.0	0.3	0.0	0.3	0.3	0.0	10.7	1.2	11.9	0.2	0.1	11.0
2024/25	6.5	1.5	8.0	2.5	0.4	2.9	0.9	0.0	0.9	3.8	0.0	0.0	0.0	0.3	0.0	0.3	0.3	0.0	10.9	1.2	12.1	0.2	0.1	11.2
2025/26	6.7	1.4	8.1	2.5	0.4	2.9	0.9	0.0	0.9	3.8	0.0	0.0	0.0	0.3	0.0	0.3	0.3	0.0	11.0	1.2	12.2	0.2	0.1	11.3
2026/27	6.8	1.3	8.1	2.5	0.4	2.9	0.9	0.0	0.9	3.8	0.0	0.0	0.0	0.3	0.0	0.3	0.3	0.0	11.0	1.2	12.2	0.2	0.1	11.3
2027/28	6.9	1.2	8.1	2.6	0.4	3.0	0.9	0.0	0.9	3.9	0.0	0.0	0.0	0.3	0.0	0.3	0.3	0.0	11.1	1.2	12.3	0.2	0.1	11.4
CAG:			1.0%							0.7%							0.0%	0.0%	0.9%	0.0%	0.8%			0.9%
PSP 25-39																								
2022/23	28.6	7.6	36.2	13.1	1.3	14.4	3.1	0.0	3.1	17.5	0.1	0.0	0.1	13.8	0.0	13.8	13.9	0.1	50.8	16.9	67.7	0.1	1.3	52.2
2023/24	29.4	7.5	36.9	12.5	1.3	13.8	3.1	0.0	3.1	16.9	0.1	0.0	0.1	12.9	0.0	12.9	13.0	0.1	50.9	16.0	66.9	0.1	1.2	52.2
2024/25	30.0	7.1	37.1	12.4	1.3	13.7	3.2	0.0	3.2	16.9	0.1	0.0	0.1	12.9	0.0	12.9	13.0	0.1	51.0	16.1	67.1	0.1	1.2	52.3
2025/26	30.4	6.6	37.0	12.4	1.3	13.7	3.2	0.0	3.2	16.9	0.1	0.0	0.1	12.9	0.0	12.9	13.0	0.1	50.9	16.1	67.0	0.1	1.2	52.2
2026/27	30.7	6.2	36.9	12.4	1.3	13.7	3.2	0.0	3.2	16.9	0.1	0.0	0.1	12.9	0.0	12.9	13.0	0.1	50.8	16.1	66.9	0.1	1.2	52.1
2027/28	31.0	5.8	36.8	12.5	1.3	13.8	3.2	0.0	3.2	17.0	0.1	0.0	0.1	12.9	0.0	12.9	13.0	0.1	50.8	16.1	66.9	0.1	1.2	52.1
CAG:			-0.1%							0.2%							0.0%	0.0%	-0.1%	0.2%	0.0%			-0.1%
PSP 25-40																								
2022/23	1.1	0.3	1.4	0.5	0.1	0.6	0.3	0.0	0.3	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.3	2.3	0.0	0.0	2.0
2023/24	1.2	0.3	1.5	0.4	0.1	0.5	0.3	0.0	0.3	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.3	2.3	0.0	0.0	2.0
2024/25	1.4	0.2	1.6	0.3	0.1	0.4	0.3	0.0	0.3	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.3	2.3	0.0	0.0	2.0
2025/26	1.5	0.2	1.7	0.3	0.1	0.4	0.3	0.0	0.3	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	0.3	2.4	0.0	0.0	2.1
2026/27	1.6	0.2	1.8	0.3	0.1	0.4	0.3	0.0	0.3	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.3	2.5	0.0	0.0	2.2
2027/28	1.6	0.2	1.8	0.4	0.1	0.5	0.3	0.0	0.3	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.3	0.3	2.6	0.0	0.0	2.3
CAG:			4.7%							0.0%							0.0%	0.0%	3.6%	0.0%	3.1%			

CAG = Compound Annual Growth 2023/24 - 2027/28

Schedule 2

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Commercial and Industrial Design Day Firm Oblication
Demand Units are Dth/Day

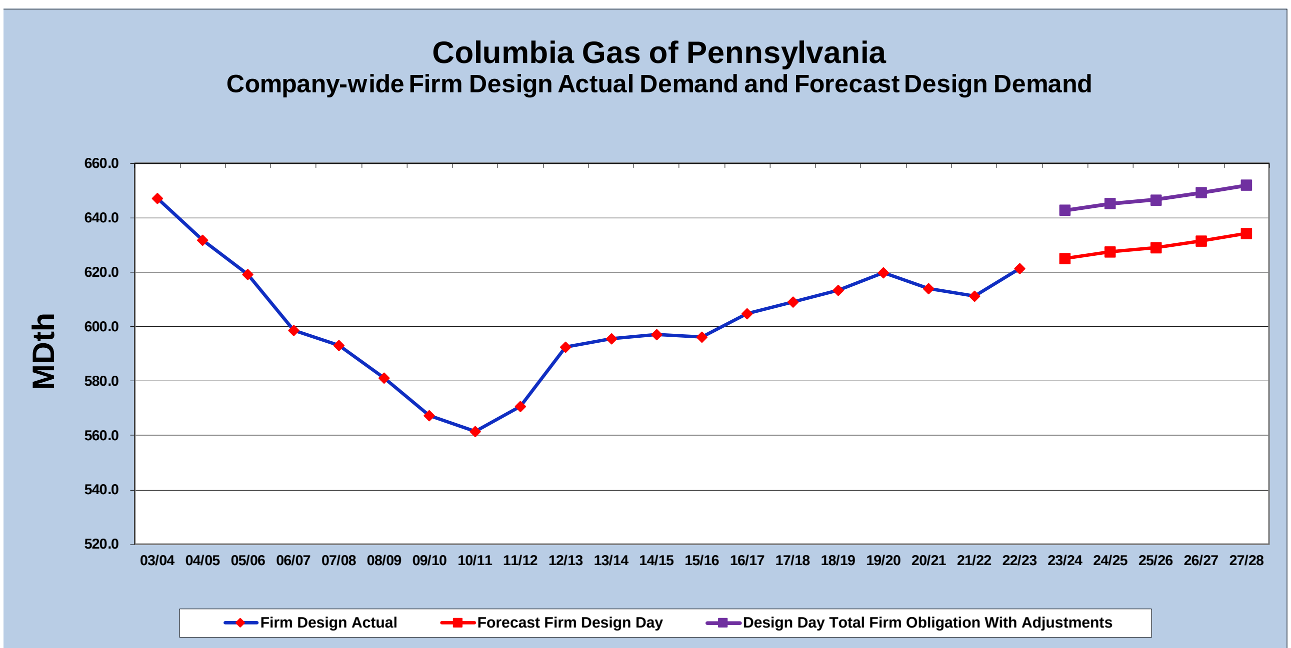
	Commercial					Industrial				
	Sales	Choice	Standby	EBS	Firm Obligation	Sales	Choice	Standby	EBS	Firm Obligation
Total										
2022/23	136.9	38.6	5.6	4.7	185.8	1.9	0.0	0.0	7.8	9.7
2023/24	133.7	38.5	5.1	4.8	182.1	2.0	0.0	0.0	7.8	9.8
2024/25	133.0	38.5	5.1	4.8	181.4	2.0	0.0	0.0	7.8	9.8
2025/26	133.3	38.5	5.1	4.8	181.7	2.0	0.0	0.0	7.8	9.8
2026/27	133.6	38.5	5.1	4.8	182.0	2.0	0.0	0.0	7.8	9.8
2027/28	133.9	38.6	5.1	4.8	182.4	2.0	0.0	0.0	7.8	9.8
PSP 25E-25										
2022/23	36.3	11.3	1.7	2.0	51.3	1.2	0.0	0.0	3.3	4.5
2023/24	34.9	11.3	1.6	2.0	49.8	1.3	0.0	0.0	3.3	4.6
2024/25	34.7	11.3	1.6	2.0	49.6	1.3	0.0	0.0	3.3	4.6
2025/26	34.8	11.3	1.6	2.0	49.7	1.3	0.0	0.0	3.3	4.6
2026/27	34.9	11.3	1.6	2.0	49.8	1.3	0.0	0.0	3.3	4.6
2027/28	34.9	11.4	1.6	2.0	49.9	1.3	0.0	0.0	3.3	4.6
PSP 25-26										
2022/23	12.6	1.8	0.5	0.1	15.0	0.0	0.0	0.0	0.2	0.2
2023/24	12.5	1.8	0.5	0.1	14.9	0.0	0.0	0.0	0.2	0.2
2024/25	12.4	1.8	0.5	0.1	14.8	0.0	0.0	0.0	0.2	0.2
2025/26	12.4	1.8	0.5	0.1	14.8	0.0	0.0	0.0	0.2	0.2
2026/27	12.5	1.8	0.5	0.1	14.9	0.0	0.0	0.0	0.2	0.2
2027/28	12.5	1.8	0.5	0.1	14.9	0.0	0.0	0.0	0.2	0.2
PSP 25E-29										
2022/23	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.3	0.3
2023/24	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.3	0.3
2024/25	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.3	0.3
2025/26	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.3	0.3
2026/27	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.3	0.3
2027/28	0.0	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.3	0.3
PSP 25-35										
2022/23	70.9	14.7	2.6	1.4	89.6	0.6	0.0	0.0	2.4	3.0
2023/24	70.2	14.7	2.3	1.4	88.6	0.6	0.0	0.0	2.3	2.9
2024/25	70.0	14.7	2.3	1.4	88.4	0.6	0.0	0.0	2.3	2.9
2025/26	70.1	14.7	2.3	1.4	88.5	0.6	0.0	0.0	2.3	2.9
2026/27	70.2	14.7	2.3	1.4	88.6	0.6	0.0	0.0	2.3	2.9
2027/28	70.2	14.7	2.3	1.4	88.6	0.6	0.0	0.0	2.3	2.9
PSP 25-36										
2022/23	0.9	9.0	0.4	0.5	10.8	0.0	0.0	0.0	0.7	0.7
2023/24	0.7	8.9	0.4	0.6	10.6	0.0	0.0	0.0	1.0	1.0
2024/25	0.7	8.9	0.4	0.6	10.6	0.0	0.0	0.0	1.0	1.0
2025/26	0.8	8.9	0.4	0.6	10.7	0.0	0.0	0.0	1.0	1.0
2026/27	0.8	8.9	0.4	0.6	10.7	0.0	0.0	0.0	1.0	1.0
2027/28	0.8	8.9	0.4	0.6	10.7	0.0	0.0	0.0	1.0	1.0
PSP 25-38										
2022/23	2.6	0.4	0.3	0.0	3.3	0.0	0.0	0.0	0.1	0.1
2023/24	2.5	0.4	0.2	0.0	3.1	0.0	0.0	0.0	0.0	0.0
2024/25	2.5	0.4	0.2	0.0	3.1	0.0	0.0	0.0	0.0	0.0
2025/26	2.5	0.4	0.2	0.0	3.1	0.0	0.0	0.0	0.0	0.0
2026/27	2.5	0.4	0.2	0.0	3.1	0.0	0.0	0.0	0.0	0.0
2027/28	2.6	0.4	0.2	0.0	3.2	0.0	0.0	0.0	0.0	0.0
PSP 25-39										
2022/23	13.1	1.3	0.1	0.5	15.0	0.1	0.0	0.0	0.8	0.9
2023/24	12.5	1.3	0.1	0.5	14.4	0.1	0.0	0.0	0.7	0.8
2024/25	12.4	1.3	0.1	0.5	14.3	0.1	0.0	0.0	0.7	0.8
2025/26	12.4	1.3	0.1	0.5	14.3	0.1	0.0	0.0	0.7	0.8
2026/27	12.4	1.3	0.1	0.5	14.3	0.1	0.0	0.0	0.7	0.8
2027/28	12.5	1.3	0.1	0.5	14.4	0.1	0.0	0.0	0.7	0.8
PSP 25-40										
2022/23	0.5	0.1	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0
2023/24	0.4	0.1	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0
2024/25	0.3	0.1	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0
2025/26	0.3	0.1	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0
2026/27	0.3	0.1	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0
2027/28	0.4	0.1	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0

Schedule 3

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Design Actual, Forecasted Firm Design Day Demand, and Forecasted Total Firm Obligation Quantities In MDTH

Year	1/ Firm Design Actual (1)	2/ Forecast Firm Design Day (2)	3/ Adjustments To Design Day (3)	Design Day Total Firm Obligation With Adjustments (4) = (2) + (3)
03/04	647.1			
04/05	632.0			
05/06	619.2			
06/07	598.6			
07/08	593.1			
08/09	581.1			
09/10	567.3			
10/11	561.6			
11/12	570.7			
12/13	592.7			
13/14	595.6			
14/15	597.1			
15/16	596.3			
16/17	604.7			
17/18	609.2			
18/19	613.5			
19/20	619.8			
20/21	614.0			
21/22	611.2			
22/23	621.5			
23/24		625.1	17.7	642.8
24/25		627.6	17.7	645.3
25/26		629.0	17.7	646.7
26/27		631.6	17.7	649.3
27/28		634.4	17.7	652.1



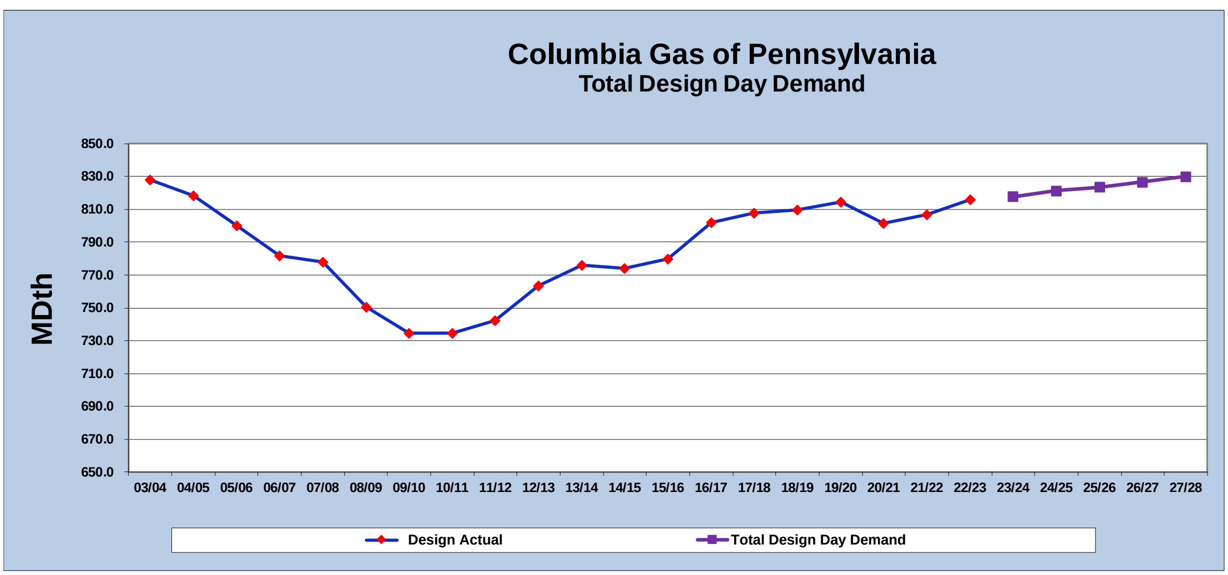
1/ Applicable heating season's regression equation applied to "Design Conditions" produces the annual "Design Actual" Demand.
2/ The result from Customer Sensitivity Growth Regression Analysis.
3/ The adjustments reflect contracted Standby and FBBS Service.

Schedule 4

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Total Design Actual and Projected Total Design Day Demand
Quantities In MDTH

Year	1/ Design Actual (1)	2/ Total Design Day Demand (2)
03/04	827.8	
04/05	818.4	
05/06	800.2	
06/07	781.6	
07/08	777.7	
08/09	750.7	
09/10	734.4	
10/11	734.6	
11/12	742.2	
12/13	763.5	
13/14	775.9	
14/15	774.1	
15/16	779.8	
16/17	801.8	
17/18	807.9	
18/19	809.9	
19/20	814.7	
20/21	801.3	
21/22	807.0	
22/23	816.0	
23/24		817.7
24/25		821.4
25/26		823.5
26/27		826.7
27/28		829.9



1/ Applicable heating season's regression equation applied to "Design Conditions" produces the annual "Design Actual" Demand.

2/ The result from Customer Sensitivity Growth Regression Analysis.

Schedule 5

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Measuring Report For Non-Firm Customers
Based on January 2023 Demand
Quantities in DTh

	#PCID (1)	#PSID (2)	January Demand	%
COMMERCIAL:				
Daily (3)	92	98	414,506	54%
Monthly	2,298	2,417	359,849	46%
COM Sum	2,390	2,515	774,355	100%
INDUSTRIAL:				
Daily (3)	114	123	1,803,453	97%
Monthly	87	101	64,669	3%
IND Sum	201	224	1,868,122	100%
TOTALS:				
Daily (3)	206	221	2,217,959	84%
Monthly	2,385	2,518	424,518	16%
Grand Total	2,591	2,739	2,642,477	100%

(1) PCID is an identification for a customer.

(2) PSID is an identification of a meter associated with a customer.

(3) Daily measurement includes chart read and electronically measured meters.

Schedule 6

Columbia Gas of Pennsylvania

2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25E-25 Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		169,339	47,318	28,178
			Regression Coefficients		
	Intercept		168,227.09	47,950.34	29,163.60
Variable 1 :	Current Temperature	**2**	(2,355.11)	(316.06)	(363.20)
Variable 2 :	Prior Day Temperature	**10**	(430.53)	0.00	(25.91)
Variable 3 :	Wind Speed	**12**	843.94	0.00	0.00
Variable 4 :	Day Type				
	Holiday		(3,970.32)	(7,914.39)	(1,076.28)
	Weekend		(1,977.11)	(5,745.19)	(918.54)
	Friday		0.00	(3,549.80)	0.00
	Saturday		0.00	(2,594.19)	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0113	0.9973	0.9630
	2023/24 Design Demand(1)		171,247	47,192	27,135
	Standby Service		1,600.00		
	Elective Balancing Service		5,241.95		
	Total R-Square		0.9750	0.6760	0.9410
	Durbin-Watson		1.3860	0.7660	0.3660
	Root MSE		3,945	2,871	841
	Regression Type		2 Winters	2 Winter	2 Winter
	Number of Observations		180	180	180

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) 2023/24 Design Day Demand reflected is after adjustments.

Columbia Gas of Pennsylvania

2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25-26 Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm[1]	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		50,965	1,054	4,416
			Regression Coefficients		
	Intercept		45,867.31	1,031.65	4,071.12
Variable 1 :	Current Temperature	**-6**	(640.69)	(5.67)	(48.10)
Variable 2 :	Prior Day Temperature	**5**	(126.19)	(2.42)	(2.85)
Variable 3 :	Wind Speed	**7**	269.22	0.00	10.06
Variable 4 :	Day Type				
	Holiday		(2,309.03)	(457.07)	(111.84)
	Weekend		0.00	(224.02)	(111.84)
	Friday		0.00	(153.18)	0.00
	Saturday		0.00	(99.76)	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0309	0.9578	1.0098
	2023/24 Design Demand[2]		52,542	1,010	4,459
	Standby Service		481.00		
	Elective Balancing Service		285.70		
	R-Square		0.9310	0.8570	0.9810
	Durbin-Watson		1.5040	1.1350	0.9690
	Root MSE		1,485	75	87
	Regression Type		1 Winter	2 Winter	2 Winter
	Number of Observations		71	172	179

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) Due to the interaction of TCO Whitely Creek between PSPs 25-26 and 25-35, adjustments were made to proportion the System Firm Demand between both PSPs based on history.
(2) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25E-29 Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		0	9,310	0
			Regression Coefficients		
	Intercept		---	9,309.89	---
Variable 1 :	Current Temperature	**2**	---	0.00	---
Variable 2 :	Prior Day Temperature	**10**	---	0.00	---
Variable 3 :	Wind Speed	**12**	---	0.00	---
Variable 4 :	Day Type				
	Holiday		---	(1,482.56)	---
	Weekend		---	(1,482.56)	---
	Friday		---	0.00	---
	Saturday		---	0.00	---
	Sunday		---	0.00	---
	2023/24 Growth Factor		---	0.9737	---
	2023/24 Design Demand[(1)]		---	9,066	---
	Standby Service		0.00	---	---
	Elective Balancing Service		492.55	---	---
	R-Square		---	N/A	---
	Durbin-Watson		---	N/A	---
	Root MSE		---	N/A	---
	Regression Type		---	2 Winters	---
	Number of Observations		---	180	---

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) 2023/24 Design Day Demand reflected is after adjustments.

Columbia Gas of Pennsylvania

2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25-35 Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm[1]	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		302,982	26,395	36,604
			Regression Coefficients		
	Intercept		266,553.29	25,951.37	33,620.79
Variable 1 :	Current Temperature	**-7**	(3,736.20)	(90.37)	(434.52)
Variable 2 :	Prior Day Temperature	**5**	(656.78)	(37.72)	(11.68)
Variable 3 :	Wind Speed	**10**	1,355.96	0.00	0.00
Variable 4 :	Day Type				
	Holiday		(3,630.74)	(6,267.89)	(425.64)
	Weekend		(3,630.74)	(4,026.08)	(425.64)
	Friday		0.00	(2,329.96)	0.00
	Saturday		0.00	(2,217.97)	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		0.9981	0.9686	0.9985
	2023/24 Design Demand[2]		302,399	25,566	36,548
	Standby Service		2,342.00	---	---
	Elective Balancing Service		3,676.15	---	---
	R-Square		0.9810	0.7980	0.9950
	Durbin-Watson		1.5210	0.9520	0.6550
	Root MSE		5,149	1,445	367
	Regression Type		2 Winters	2 Winter	2 Winter
	Number of Observations		122	177	180

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) Due to the interaction of TCO Whitely Creek between PSPs 25-26 and 25-35, adjustments were made to proportion the System Firm Demand between both PSPs based on history.
(2) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania

2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25-36 Design Actual and Forecast Design Demand

Total Market Area Design Demand (see pages 9 through 12 for Individual Market Components)

Coefficients of the Design Actual Regressions

Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		34,899	582	22,263
			Regression Coefficients		
	Intercept		28,806.72	570.72	19,449.08
Variable 1 :	Current Temperature	**-15**	(320.67)	(0.74)	(181.62)
Variable 2 :	Prior Day Temperature	**-2**	(121.70)	0.00	(44.72)
Variable 3 :	Wind Speed	**11**	94.56	0.00	0.00
Variable 4 :	Day Type				
	Holiday		(466.35)	(107.80)	(931.75)
	Weekend		(454.96)	0.00	(816.39)
	Friday		0.00	0.00	0.00
	Saturday		0.00	0.00	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0107	1.5677	1.0389
	2023/24 Design Demand[1]		35,272	912	23,129
	Standby Service		433.00	---	---
	Elective Balancing Service		1,554.55	---	---
	R-Square				
	Durbin-Watson				
	Root MSE				
	Regression Type				
	Number of Observations				

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) 2023/24 Design Day Demand reflected is after adjustments.
Statistical results are shown for the individual demand components, pages 9 through 12.

Schedule 6

Columbia Gas of Pennsylvania

2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25-38 Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		10,472	227	949
			Regression Coefficients		
	Intercept		8,613.66	208.11	809.96
Variable 1 :	Current Temperature	**-11**	(133.85)	(1.70)	(12.65)
Variable 2 :	Prior Day Temperature	**2**	(14.78)	0.00	0.00
Variable 3 :	Wind Speed	**9**	46.13	0.00	0.00
Variable 4 :	Day Type				
	Holiday		0.00	0.00	0.00
	Weekend		0.00	0.00	0.00
	Friday		0.00	0.00	0.00
	Saturday		0.00	0.00	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0223	1.3228	0.9985
	2023/24 Design Demand[1]		10,706	300	948
	Standby Service		198.00	---	---
	Elective Balancing Service		56.85	---	---
	R-Square		0.9720	0.4110	0.9750
	Durbin-Watson		1.6850	0.4840	0.9950
	Root MSE		212	28	22
	Regression Type		2 Winters	2 Winter	1 Winter
	Number of Observations		51	159	90

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania

2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25-39 Design Actual and Forecast Design Demand (1)
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		50,791	13,756	3,153
			Regression Coefficients		
	Intercept		44,900.22	13,409.89	2,842.56
Variable 1 :	Current Temperature	**-7**	(606.24)	(49.41)	(41.03)
Variable 2 :	Prior Day Temperature	**5**	(68.47)	0.00	0.00
Variable 3 :	Wind Speed	**11**	180.86	0.00	2.11
Variable 4 :	Day Type				
	Holiday		(876.77)	(1,084.33)	0.00
	Weekend		(876.77)	0.00	0.00
	Friday		0.00	(1,182.00)	0.00
	Saturday		0.00	(782.75)	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0016	0.9345	0.9985
	2023/24 Design Demand(1)		50,872	12,855	3,148
	Standby Service		104.00	---	---
	Elective Balancing Service		1,249.35	---	---
	R-Square		0.9620	0.5960	0.9940
	Durbin-Watson		1.7160	1.0880	0.5960
	Root MSE		1,062	501	37
	Regression Type		2 Winters	1 Winter	2 Winter
	Number of Observations		93	82	180

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

PSP 25-40 Design Actual and Forecast Design Demand [(1)]
Coefficients of the Design Actual Regressions
Quantities In Dth

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual		2,039	0	322
			Regression Coefficients		
	Intercept		1,863.64	---	299.73
Variable 1 :	Current Temperature	**-6**	(29.28)	---	(3.97)
Variable 2 :	Prior Day Temperature	**5**	0.00	---	(0.31)
Variable 3 :	Wind Speed	**7**	0.00	---	0.00
Variable 4 :	Day Type				
	Holiday		0.00	---	0.00
	Weekend		0.00	---	0.00
	Friday		0.00	---	(5.54)
	Saturday		0.00	---	(10.96)
	Sunday		0.00	---	0.00
	2023/24 Growth Factor		1.0060	---	1.0213
	2023/24 Design Demand[(1)]		2,051	---	329
	Standby Service		0.00	---	---
	Elective Balancing Service		16.85	---	---
	R-Square		0.8570	---	0.9750
	Durbin-Watson		0.4050	---	0.7300
	Root MSE		148	---	8.0000
	Regression Type		2 Winters	---	2 Winter
	Number of Observations		180	---	180

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28
NATIONAL FUEL WARREN (PSP 25-36)
Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual[1]		4,514	4	82
			Regression Coefficients		
	Intercept		3,609.38	3.62	65.84
Variable 1 :	Current Temperature	**-15**	(48.99)	(0.01)	(1.10)
Variable 2 :	Prior Day Temperature	**-2**	(10.40)	0.00	0.00
Variable 3 :	Wind Speed	**11**	13.52	0.00	0.00
Variable 4 :	Day Type				
	Holiday		0.00	(0.42)	0.00
	Weekend		0.00	0.00	0.00
	Friday		0.00	0.00	0.00
	Saturday		0.00	0.00	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0122	0.9862	0.9862
	2023/24 Design Demand[2]		4,569	4	81
	Standby Service		0.00	---	---
	Elective Balancing Service		47.60	---	---
	R-Square		0.9730	0.2330	0.9690
	Durbin-Watson		1.8670	0.2840	0.2880
	Root MSE		79	0.3000	2
	Regression Type		1 Winter	1 Winter	1 Winter
	Number of Observations		39	90	90

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) Minor adjustments to the 2022/23 design were made so that the sum would match Total PSP36 design.
(2) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28
STATE COLLEGE MARKET (PSP 25-36)
Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual[1]		21,489	515	21,895
			Regression Coefficients		
	Intercept		17,872.02	515.11	19,154.02
Variable 1 :	Current Temperature	**-15**	(178.51)	0.00	(176.80)
Variable 2 :	Prior Day Temperature	**-2**	(97.13)	0.00	(44.72)
Variable 3 :	Wind Speed	**11**	67.77	0.00	0.00
Variable 4 :	Day Type				
	Holiday		(377.57)	(107.38)	(931.75)
	Weekend		(377.57)	0.00	(816.39)
	Friday		0.00	0.00	0.00
	Saturday		0.00	0.00	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0097	1.0529	1.0529
	2023/24 Design Demand[2]		21,697	542	23,053
	Standby Service		433.00	---	---
	Elective Balancing Service		1,488.45	---	---
	R-Square		0.8922	N/A	0.9410
	Durbin-Watson			N/A	0.7640
	Root MSE		986	N/A	586
	Regression Type		2 Winters	2 Winters	2 Winter
	Number of Observations		180	173	176

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) Minor adjustments to the 2022/23 design were made so that the sum would match Total PSP36 design.
(2) 2023/24 Design Day Demand reflected is after adjustments.

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28
TCO ONLY MARKET (PSP 25-36)
Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In DTh

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual[1]		6,800	63	285
			Regression Coefficients		
	Intercept		5,619.72	51.99	229.22
Variable 1 :	Current Temperature	**-15**	(67.08)	(0.73)	(3.73)
Variable 2 :	Prior Day Temperature	**-2**	(14.17)	0.00	0.00
Variable 3 :	Wind Speed	**11**	13.27	0.00	0.00
Variable 4 :	Day Type				
	Holiday		(77.39)	0.00	0.00
	Weekend		(77.39)	0.00	0.00
	Friday		0.00	0.00	0.00
	Saturday		0.00	0.00	0.00
	Sunday		0.00	0.00	0.00
	2023/24 Growth Factor		1.0122	1.0352	1.0387
	2023/24 Design Demand[2]		6,883	65	296
	Standby Service		0.00	---	---
	Elective Balancing Service		18.50	---	---
	R-Square		0.9592	0.9660	0.9820
	Durbin-Watson			0.4710	1.0910
	Root MSE		180	1	5
	Regression Type		2 Winters	1 Winter	1 Winter
	Number of Observations		180	90	90

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) Minor adjustments to the 2022/23 design were made so that the sum would match Total PSP36 design.
(2) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 6

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28
EXCHANGE VOLUMES (PSP 25-36)
Design Actual and Forecast Design Demand
Coefficients of the Design Actual Regressions
Quantities In Dth

		Design Conditions	System Firm	Industrial Non-Firm	Commercial Non-Firm
	2022/23 Design Actual(1)		2,097	0	0
			Regression Coefficients		
	Intercept		1,705.61	---	---
Variable 1 :	Current Temperature	**-15**	(26.08)	---	---
Variable 2 :	Prior Day Temperature	**-2**	0.00	---	---
Variable 3 :	Wind Speed	**11**	0.00	---	---
Variable 4 :	Day Type				
	Holiday		(11.39)	---	---
	Weekend		0.00	---	---
	Friday		0.00	---	---
	Saturday		0.00	---	---
	Sunday		0.00	---	---
	2023/24 Growth Factor		1.0122	---	---
	2023/24 Design Demand(2)		2,123	---	---
	Standby Service		0.00	---	---
	Elective Balancing Service		0.00	---	---
	R-Square		0.9990	---	---
	Durbin-Watson		0.1930	---	---
	Root MSE		8	---	---
	Regression Type		1 Winter	---	---
	Number of Observations		90	---	---

Note: If a variable did not meet a 95% significance level, it is not included in the design model.
(1) Minor adjustments to the 2022/23 design were made so that the sum would match Total PSP36 design.
(2) 2023/24 Design Day Demand reflected is after adjustments.

Schedule 7

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Firm Design Actual [1/] Demand and Forecasted Firm Design Day Demand by PSP
Quantities in Dth

	PSP 25E-25 (1)	PSP 25-26 (2)	PSP 25E-29 (3)	PSP 25-35 (4)	PSP 25-36 Markets: State College	PSP 25-36 Markets: NFG Warren	PSP 25-36 Markets: TCO Only	PSP 25-36 Markets: Exchange Vols	Total PSP 25-36 (5)	PSP 25-38 (6)	PSP 25-39 (7)	PSP 25-40 (8)	Sum (9)
03/04	152,044	50,394	0	351,526					30,710	11,149	50,579	720	647,122
04/05	153,682	49,987	0	340,949					29,783	10,288	46,579	738	632,007
05/06	154,319	46,640	0	330,935					29,173	10,039	47,241	844	619,190
06/07	152,953	46,469	0	317,073					30,841	9,852	40,515	921	598,623
07/08	152,779	46,819	0	315,205					29,045	9,400	38,730	1,086	593,064
08/09	153,325	47,285	0	302,945					29,692	9,815	37,020	1,059	581,141
09/10	151,478	46,112	0	286,285					27,175	8,527	46,350	1,390	567,316
10/11	150,798	46,296	0	280,265					27,126	8,501	47,359	1,299	561,644
11/12	150,654	46,236	0	287,216					29,165	8,502	47,560	1,373	570,706
12/13	155,948	50,917	0	292,788					31,840	9,703	50,170	1,287	592,653
13/14	153,154	49,201	0	299,674					30,152	9,762	52,502	1,143	595,589
14/15	149,774	50,905	0	299,912					30,752	10,385	54,296	1,118	597,142
15/16	152,527	45,117	0	304,280					32,831	9,155	51,222	1,136	596,268
16/17	156,666	44,953	0	307,272					33,022	9,715	51,843	1,271	604,742
17/18	162,639	49,693	0	298,344					34,587	10,455	52,307	1,142	609,167
18/19	166,233	53,702	0	295,732	20,858	4,381	6,600	2,035	33,875	10,329	52,230	1,411	613,512
19/20	163,620	47,295	0	309,579	20,701	4,348	6,550	2,020	33,619	10,329	53,513	1,833	619,788
20/21	164,788	46,917	0	305,690	21,357	4,486	6,758	2,084	34,685	10,212	49,968	1,760	614,020
21/22	169,238	49,540	0	295,110	21,406	4,496	6,773	2,089	34,764	10,286	50,391	1,865	611,194
22/23	169,339	50,965	0	302,982	21,489	4,514	6,800	2,097	34,899	10,472	50,791	2,039	621,487

PSP 25-26 and 25-35 have been re-stated to reflect movement of TET Uniontown from PSP25-35 to PSP25-26
PSP25-36 is now divided into the markets comprising this market area (NFG Warren, State College Market, TCO Only Market and Exhchange Volume Market). The history of this new market breakdown begins in 2018/19, when the measurement at the Snowshoe POD Station was diminished as a result of customer movement and the sale of TCO pipeline facilities in the area.

Design Forecast Statistical Result

	PSP 25E-25 (1)	PSP 25-26 (2)	PSP 25E-29 (3)	PSP 25-35 (4)	State College	NFG Warren	TCO Only	Exchange Vols	Total PSP 25-36 (5)	PSP 25-38 (6)	PSP 25-39 (7)	PSP 25-40 (8)	Sum (9)
Years =	9	7		6	5	5	5	5		8	9	9	
Multiple R^2 =	0.80	0.79		0.69	0.79	0.76	0.76	0.76		0.86	0.71	0.89	
Adjusted R^2 =	0.78	0.68		0.62	0.71	0.68	0.68	0.68		0.80	0.67	0.87	
Significance =	0.0011	0.0449		0.0395	0.0453	0.0544	0.0544	0.0544		0.0077	0.0042	0.0002	
Scenarios :	Log Trend	Log Trend Log Nonfarm		Log Rate	Customers	Trend	Trend	Trend		Degree Days Customers	Log Trend	Customers	

	PSP 25E-25 (1)	PSP 25-26 (2)	PSP 25E-29 (3)	PSP 25-35 (4)	State College	NFG Warren	TCO Only	Exchange Vols	Total PSP 25-36 (5)	PSP 25-38 (6)	PSP 25-39 (7)	PSP 25-40 (8)	Sum (9)
Forecast :													
23/24	171,277	53,835	0	303,893	21,697	4,569	6,883	2,123	35,272	10,893	51,073	2,019	628,261
24/25	172,236	54,118	0	301,816	21,777	4,610	6,945	2,142	35,474	10,940	50,952	2,064	627,600
25/26	173,204	54,564	0	301,552	21,868	4,651	7,007	2,161	35,688	10,989	50,868	2,109	628,974
26/27	174,241	54,888	0	302,538	21,980	4,693	7,070	2,180	35,922	11,054	50,833	2,169	631,645
27/28	175,305	55,115	0	303,626	22,103	4,734	7,132	2,199	36,168	11,123	50,829	2,244	634,409
Smoothed Forecast [(2)] :													
23/24	171,277	52,542	0	302,399	21,697	4,569	6,883	2,123	35,272	10,706	50,872	2,051	625,119
24/25	172,236	54,118	0	301,816	21,777	4,610	6,945	2,142	35,474	10,940	50,952	2,064	627,600
25/26	173,204	54,564	0	301,552	21,868	4,651	7,007	2,161	35,688	10,989	50,868	2,109	628,974
26/27	174,241	54,888	0	302,538	21,980	4,693	7,070	2,180	35,922	11,054	50,833	2,169	631,645
27/28	175,305	55,115	0	303,626	22,103	4,734	7,132	2,199	36,168	11,123	50,829	2,244	634,409
Adjustment to Forecast : Customers Flipping from Tariff to GTS													
23/24	0	0	0	0	0	0	0	0	0	0	0	0	0
24/25	0	0	0	0	0	0	0	0	0	0	0	0	0
25/26	0	0	0	0	0	0	0	0	0	0	0	0	0
26/27	0	0	0	0	0	0	0	0	0	0	0	0	0
27/28	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Forecast : Customers Flipping from GTS to Tariff													
23/24	(30)	0	0	0	0	0	0	0	0	0	0	0	(30)
24/25	(30)	0	0	0	0	0	0	0	0	0	0	0	(30)
25/26	(30)	0	0	0	0	0	0	0	0	0	0	0	(30)
26/27	(30)	0	0	0	0	0	0	0	0	0	0	0	(30)
27/28	(30)	0	0	0	0	0	0	0	0	0	0	0	(30)
Adjusted Forecast Prior to Standby and EBS													
23/24	171,247	52,542	0	302,399	21,697	4,569	6,883	2,123	35,272	10,706	50,872	2,051	625,089
24/25	172,206	54,118	0	301,816	21,777	4,610	6,945	2,142	35,474	10,940	50,952	2,064	627,570
25/26	173,174	54,564	0	301,552	21,868	4,651	7,007	2,161	35,688	10,989	50,868	2,109	628,944
26/27	174,211	54,888	0	302,538	21,980	4,693	7,070	2,180	35,922	11,054	50,833	2,169	631,615
27/28	175,275	55,115	0	303,626	22,103	4,734	7,132	2,199	36,168	11,123	50,829	2,244	634,379
Standby Contract Level [3/]													
23/24	1,600	481	0	2,342	433	0	0	0	433	198	104	0	5,158
24/25	1,600	481	0	2,342	433	0	0	0	433	198	104	0	5,158
25/26	1,600	481	0	2,342	433	0	0	0	433	198	104	0	5,158
26/27	1,600	481	0	2,342	433	0	0	0	433	198	104	0	5,158
27/28	1,600	481	0	2,342	433	0	0	0	433	198	104	0	5,158
EBS Contract Level [3/]													
23/24	5,242	286	493	3,676	1,488	48	19	0	1,555	57	1,249	17	12,574
24/25	5,242	286	493	3,676	1,488	48	19	0	1,555	57	1,249	17	12,574
25/26	5,242	286	493	3,676	1,488	48	19	0	1,555	57	1,249	17	12,574
26/27	5,242	286	493	3,676	1,488	48	19	0	1,555	57	1,249	17	12,574
27/28	5,242	286	493	3,676	1,488	48	19	0	1,555	57	1,249	17	12,574
Total Firm Obligation													
23/24	178,089	53,308	493	308,417	23,619	4,616	6,901	2,123	37,259	10,961	52,225	2,068	642,821
24/25	179,048	54,885	493	307,834	23,699	4,658	6,964	2,142	37,462	11,195	52,306	2,080	645,302
25/26	180,016	55,331	493	307,570	23,790	4,699	7,026	2,161	37,676	11,244	52,222	2,125	646,676
26/27	181,053	55,655	493	308,556	23,901	4,740	7,088	2,180	37,910	11,309	52,187	2,185	649,347
27/28	182,117	55,881	493	309,644	24,024	4,782	7,150	2,199	38,155	11,378	52,183	2,260	652,111

[1/] The Design Actual is an estimate of what the peak day demand would equate to if design conditions had occurred during the applicable winter.
[2/] To compensate for economic conditions winter 2023/24 design demands may have been adjusted to reflect an average between the 2022/23 Design Actual and 2024/25 forecast design.
[3/] Standby and EBS held at contract level as of July 2023.

Schedule 8

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Non-Firm Design Actual [1/] and Forecasted Non-Firm Design Day Demand by PSP
Quantities in Dth

	PSP 25E-25	PSP 25-26	PSP 25E-29	PSP 25-35	PSP 25-36 Markets				Total PSP 25-36	PSP 25-38	PSP 25-39	PSP 25-40	Sum
	(1)	(2)	(3)	(4)	State College	NFG Warren	TCO Only	Exchange Vols	(5)	(6)	(7)	(8)	(9)
03/04	64,451	8,493	10,310	72,539					8,574	540	15,437	288	180,631
04/05	64,351	4,969	12,079	78,833					9,422	832	15,383	486	186,354
05/06	63,279	4,999	10,739	75,711					10,100	405	15,321	474	181,028
06/07	63,713	4,893	11,395	77,613					9,185	740	14,917	495	182,951
07/08	65,849	4,842	11,473	76,903					9,043	1,001	15,055	476	184,643
08/09	63,113	4,609	9,808	69,204					6,451	961	15,031	428	169,606
09/10	60,409	3,947	9,655	70,519					6,752	916	14,535	369	167,102
10/11	61,530	4,092	9,966	73,110					7,605	960	15,314	418	172,995
11/12	56,848	4,166	11,148	74,432					8,530	1,022	15,039	355	171,539
12/13	57,896	3,912	10,702	69,906					12,134	1,101	14,782	460	170,893
13/14	58,372	4,159	10,275	74,316					14,547	3,022	15,142	453	180,286
14/15	56,013	5,059	8,456	74,090					14,301	3,076	15,478	435	176,909
15/16	60,085	5,310	10,083	72,871					15,569	2,874	16,330	375	183,497
16/17	71,638	5,421	9,803	70,050					21,215	3,323	15,175	403	197,028
17/18	72,534	5,364	9,786	68,839					21,885	3,661	16,236	386	198,691
18/19	72,940	5,618	9,697	69,006	21,133	81	329	0	21,543	1,153	16,068	376	196,401
19/20	72,891	5,755	9,449	67,922	21,262	82	331	0	21,675	1,120	15,762	319	194,893
20/21	72,135	5,347	9,163	62,501	22,032	85	343	0	22,460	1,191	14,228	300	187,325
21/22	74,307	5,519	9,490	65,109	22,888	88	356	0	23,332	1,187	16,583	320	195,847
22/23	75,496	5,470	9,310	62,999	22,410	86	348	0	22,845	1,176	16,909	322	194,527

PSP 25-26 and 25-35 have been re-stated to reflect movement of TET Uniontown from PSP25-35 to PSP25-26

PSP25-36 is now divided into the markets comprising this market area (NFG Warren, State College Market, TCO Only Market and Exhchange Volume Market). The history of this new market breakdown begins in 2018/19, when the measurement at the Snowshoe POD Station was diminished as a result of customer movement and the sale of TCO pipeline facilities in the area.

Design Forecast Statistical Result

	(1)	(2)	(3)	(4)	State College	NFG Warren	TCO Only	Exchange Vols	(5)	(6)	(7)	(8)	(9)
Years =	7	7	8	12	5	5	5			20		13	
Multiple R^2 =	0.93	0.93	0.88	0.90	0.78	0.92	0.78			0.82		0.80	
Adjusted R^2 =	0.89	0.92	0.84	0.88	0.71	0.89	0.71			0.81		0.77	
Significance =	0.0052	0.0004	0.0045	0.0000	0.0469	0.0101	0.0469			0.0000		0.0003	
Scenarios :	Nonfarm Trend	Log Trend	Log Trend Log Nonfarm	Log Degree Days Log Trend	Trend	Log Trend	Trend			Customers	3-Yr Avge	Nonfarm Degree Days	

	(1)	(2)	(3)	(4)	State College	NFG Warren	TCO Only	Exchange Vols	(5)	(6)	(7)	(8)	(9)
Forecast :													
23/24	61,784	5,469	9,372	61,984	23,199	85	361	0	23,645	3,495	15,907	329	181,984
24/25	62,114	5,607	9,339	61,163	23,617	88	367	0	24,072	3,495	15,907	329	182,026
25/26	62,608	5,734	9,324	60,409	24,035	90	374	0	24,499	3,495	15,907	329	182,305
26/27	63,139	5,852	9,313	59,712	24,453	92	380	0	24,925	3,495	15,907	328	182,670
27/28	63,682	5,961	9,305	59,064	24,871	94	387	0	25,352	3,495	15,907	326	183,090
Adjustment to Forecast : GTS Economic Adjustment [2/]													
23/24	12,513	0	(307)	129	396	0	0	0	396	(2,247)	97	0	10,581
24/25	12,289	0	(307)	1,483	429	0	0	0	429	(2,247)	151	0	11,799
25/26	12,361	0	(307)	1,831	429	0	0	0	429	(2,247)	151	0	12,219
26/27	12,361	0	(307)	1,973	429	0	0	0	429	(2,247)	151	0	12,361
27/28	12,361	0	(307)	1,973	429	0	0	0	429	(2,247)	151	0	12,361
Adjustment to Forecast : Customers Flipping from Tariff to GTS													
23/24	0	0	0	0	0	0	0	0	0	0	0	0	0
24/25	0	0	0	0	0	0	0	0	0	0	0	0	0
25/26	0	0	0	0	0	0	0	0	0	0	0	0	0
26/27	0	0	0	0	0	0	0	0	0	0	0	0	0
27/28	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Forecast : Customers Flipping from GTS to Tariff													
23/24	30	0	0	0	0	0	0	0	0	0	0	0	30
24/25	30	0	0	0	0	0	0	0	0	0	0	0	30
25/26	30	0	0	0	0	0	0	0	0	0	0	0	30
26/27	30	0	0	0	0	0	0	0	0	0	0	0	30
27/28	30	0	0	0	0	0	0	0	0	0	0	0	30
Adjusted Non-Firm Forecast													
23/24	74,326	5,469	9,066	62,113	23,595	85	361	0	24,041	1,248	16,004	329	192,596
24/25	74,433	5,607	9,032	62,646	24,047	88	367	0	24,502	1,248	16,058	329	193,855
25/26	75,000	5,734	9,017	62,240	24,465	90	374	0	24,928	1,248	16,058	329	194,554
26/27	75,530	5,852	9,006	61,684	24,883	92	380	0	25,355	1,248	16,058	328	195,061
27/28	76,073	5,961	8,998	61,037	25,301	94	387	0	25,781	1,248	16,058	326	195,482

[1/] The Design Actual is an estimate of what the peak day demand would equate to if design conditions had occurred during the applicable winter.

[2/] In PSP 25E-25, Glatfelter is shown as an Economic Adjustment, since it is added back into the regression analysis and forecasts as of Winter 2016/17.
Likewise, adjustments due to the loss of Calumet in 2018/19 were included in the original regression analysis for PSP25-38 but are backed out in the forecast.

Schedule 9

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

2023/24 Design Day Requirements by Rate Schedule
Volume in MDth/Day

	Total Demand			Firm Demand			Non-Firm Demand			Additional	Total
		GTS /	Total			Total			Total	Firm	Firm
	Tariff	Choice	Throughput	Tariff	Choice	Throughput	Tariff	GTS	Throughput	Obligation	Obligation
Residential											
RS	326.1	0.0	326.1	326.1	0.0	326.1	0.0	0.0	0.0	0.0	326.1
RCC	31.1	0.0	31.1	31.1	0.0	31.1	0.0	0.0	0.0	0.0	31.1
RTC	0.0	92.2	92.2	0.0	92.2	92.2	0.0	0.0	0.0	0.0	92.2
Residential Total	**357.2**	**92.2**	**449.4**	**357.2**	**92.2**	**449.4**	**0.0**	**0.0**	**0.0**	**0.0**	**449.4**
Commercial											
LDS/LGSS	0.0	29.8	29.8	0.0	0.0	0.0	0.0	29.8	29.8	0.0	0.0
MDS	0.6	0.9	1.5	0.6	0.0	0.6	0.0	0.9	0.9	0.0	0.6
SDS/LGSS	13.8	31.9	45.6	13.8	0.0	13.8	0.0	31.9	31.9	0.0	13.8
SGDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SGS2	58.2	0.0	58.2	58.2	0.0	58.2	0.0	0.0	0.0	0.0	58.2
SGS1	61.1	0.0	61.1	61.1	0.0	61.1	0.0	0.0	0.0	0.0	61.1
SCD1	0.0	18.5	18.5	0.0	18.5	18.5	0.0	0.0	0.0	0.0	18.5
SCD2	0.0	20.0	20.0	0.0	20.0	20.0	0.0	0.0	0.0	0.0	20.0
SGDS1	0.0	3.2	3.2	0.0	0.0	0.0	0.0	3.2	3.2	0.0	0.0
SGDS2	0.0	29.8	29.8	0.0	0.0	0.0	0.0	29.8	29.8	0.0	0.0
SS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	5.1
EBS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.8	4.8
Total Commercial	**133.7**	**134.1**	**267.8**	**133.7**	**38.5**	**172.2**	**0.0**	**95.6**	**95.6**	**9.9**	**182.1**
Industrial											
LDS/LGSS	0.0	65.6	65.6	0.0	0.0	0.0	0.0	65.6	65.6	0.0	0.0
MDS	0.0	18.3	18.3	0.0	0.0	0.0	0.0	18.3	18.3	0.0	0.0
TMA	0.0	3.3	3.3	0.0	0.0	0.0	0.0	3.3	3.3	0.0	0.0
SDS/LGSS	1.3	9.2	10.4	1.3	0.0	1.3	0.0	9.2	9.2	0.0	1.3
SGDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SGS	0.7	0.0	0.7	0.7	0.0	0.7	0.0	0.0	0.0	0.0	0.7
SGS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCD1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SCD2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SGDS1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SGDS2	0.0	0.7	0.7	0.0	0.0	0.0	0.0	0.7	0.7	0.0	0.0
SS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EBS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.8	7.8
Total Industrial	**2.0**	**97.0**	**99.0**	**2.0**	**0.0**	**2.0**	**0.0**	**97.0**	**97.0**	**7.8**	**9.8**
Other	**1.5**	**0.0**	**1.5**	**1.5**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**1.5**
2023/24 Design Day	**494.4**	**323.3**	**817.7**	**494.4**	**130.7**	**625.1**	**0.0**	**192.6**	**192.6**	**17.7**	**642.8**

(1) Standby and Elective Balancing Service Quantities

Schedule 10

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Historical Maximum Coincident Three Day Peak Day
Quantities In DTh

	Winter Season						
	2021/22 [1]				2022/23 [1]		
	Peak Day	Coincident Three Days			Peak Day		
Day of Week	Wed	Thur	Fri	Sat	Fri	Sat	Sun
Date	Jan. 26	Jan. 20	Jan. 21	Jan. 22	Dec. 23	Dec. 24	Dec. 25
Avg Temp	11° F	18° F	11° F	22° F	1° F	10° F	14° F
Requirements [2]							
Residential	332,788	294,328	325,247	274,584	400,207	366,584	324,375
Commercial	203,967	180,394	199,345	168,294	245,288	224,681	198,810
Industrial	91,187	91,379	86,423	69,499	66,112	58,392	55,388
Other	0	0	0	0	0	0	0
Total Retail and Transportation:	**627,942**	**566,101**	**611,015**	**512,377**	**711,607**	**649,657**	**578,573**
Wholesale:	0	0	0	0	0	0	0
Company Use:	1,310	1,310	1,310	1,310	738	738	738
Unaccounted For:	1,521	1,521	1,521	1,521	811	811	811
Total Requirements:	**630,773**	**568,932**	**613,846**	**515,208**	**713,156**	**651,206**	**580,122**
Supply [3]							
Columbia Gas Transmission Corp.	494,929	441,620	479,363	398,292	557,890	507,541	443,425
Eastern Gas Transmission & Storage, Inc.	43,585	39,389	41,865	36,123	43,130	41,781	37,525
Equitrans	14,888	14,920	14,913	14,925	29,167	29,781	29,605
National Fuel Gas Supply Corp.	5,032	4,695	5,366	4,159	5,608	5,206	4,643
Tennessee Gas Pipeline	21,444	20,841	21,975	18,907	24,673	22,679	24,942
Texas Eastern Transmission	46,696	42,091	46,530	39,322	48,717	40,880	36,769
Direct Local	4,012	4,547	3,834	3,480	3,971	3,338	3,213
Blackhawk Storage	187	829	0	0	0	0	0
Total Supply:	**630,773**	**568,932**	**613,846**	**515,208**	**713,156**	**651,206**	**580,122**

	Winter Season						
	2019/20 [1]				2020/21 [1]		
	Peak Day	Coincident Three Days			Peak Day		
Day of Week	Wed	Mon	Tues	Wed	Thur	Fri	Sat
Date	Dec. 18	Jan. 20	Jan. 21	Jan. 22	Jan. 28	Jan. 29	Jan. 30
Avg Temp	20° F	22° F	20° F	27° F	22° F	20° F	28° F
Requirements [2]							
Residential	299,486	289,413	293,990	251,758	289,062	288,347	230,496
Commercial	168,461	162,795	165,369	141,614	169,767	169,347	135,371
Industrial	82,144	78,252	78,616	78,343	77,878	67,689	56,401
Other	0	0	0	0	0	0	0
Total Retail and Transportation :	**550,091**	**530,460**	**537,975**	**471,715**	**536,707**	**525,383**	**422,268**
Wholesale:	0	0	0	0	0	0	0
Company Use:	700	700	700	700	620	620	620
Unaccounted For:	1,808	1,808	1,808	1,808	1,833	1,833	1,833
Total Requirements:	**552,599**	**532,968**	**540,483**	**474,223**	**539,160**	**527,836**	**424,721**
Supply [3]							
Columbia Gas Transmission Corp.	446,127	421,723	427,930	375,492	431,688	422,011	333,698
Eastern Gas Transmission & Storage, Inc.	39,746	35,568	36,007	34,610	33,309	32,325	27,533
Equitrans	10,463	14,003	14,015	14,100	6,028	6,050	6,054
National Fuel Gas Supply Corp.	4,351	4,150	4,145	3,708	4,246	4,060	3,833
Tennessee Gas Pipeline	18,892	19,414	20,195	15,235	19,579	18,433	16,062
Texas Eastern Transmission	29,894	34,456	34,468	27,988	40,346	41,027	33,833
Direct Local	3,126	3,563	3,173	2,540	3,807	3,765	3,708
Blackhawk Storage	0	91	550	550	157	165	0
Total Supply:	**552,599**	**532,968**	**540,483**	**474,223**	**539,160**	**527,836**	**424,721**

[1] Daily throughput based on the time of analysis and does not reflect any subsequent prior period adjustments.

[2] Total actual throughput; breakdown by category/class is an estimate.

[3] Actual supplies via identified sources. Note: Dominion is now Eastern Gas Transmission & Storage, Inc.

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Design and Monthly Maximum Conditions With Corresponding Demand
Contract Year 2023-2024
Demand Units are MDth

	Design	Months											
	Peak	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
	Design Assumes Occurrence On Weekday												
Maximum													
Design Conditions													
Temperatures ºF													
Current Day [1]	-5	20	8	0	5	15	30	42	53	60	58	47	35
Prior Day [2]	6	25	13	9	12	21	34	46	57			51	39
Wind Speed (Mph) [2]	11	9	10	11	11	11	11						
Design Demand													
Firm [3]	625.1	374.0	511.7	582.8	539.4	440.7	284.0	141.5	53.5	27.2	30.1	68.9	245.1
Non-Firm	192.6	153.8	174.8	187.7	179.6	162.5	140.2	97.6	78.8	72.3	78.5	101.5	69.4
Total	817.7	527.8	686.5	770.5	719.0	603.2	424.2	239.1	132.3	99.5	108.6	170.4	314.5
Day Type Adjustments													
Holiday													
Firm [3]	(11.3)	(10.0)	(11.3)	(11.3)	(11.3)	(9.3)	0.0	(26.5)	0.0	(2.8)	(2.4)	(4.7)	0.0
Non-Firm	(19.8)	(23.0)	(19.8)	(19.8)	(19.8)	(17.2)	(28.7)	(24.7)	(22.3)	(14.2)	(17.7)	(12.8)	(25.3)
Total	(31.1)	(33.0)	(31.1)	(31.1)	(31.1)	(26.5)	(28.7)	(51.2)	(22.3)	(17.0)	(20.1)	(17.5)	(25.3)
Weekend													
Firm [3]	(6.9)	(10.0)	(6.9)	(6.9)	(6.9)	(9.3)	0.0	0.0	0.0	(2.8)	(2.4)	(4.7)	0.0
Non-Firm	(13.8)	(18.6)	(13.8)	(13.8)	(13.8)	(17.2)	(18.3)	(14.4)	(22.3)	(14.2)	(17.7)	(12.8)	(25.3)
Total	(20.7)	(28.6)	(20.7)	(20.7)	(20.7)	(26.5)	(18.3)	(14.4)	(22.3)	(17.0)	(20.1)	(17.5)	(25.3)
Standby	5.1												
EBS	12.6												

[1] Design Current Day Temperature is based on a 1-in-15 Gumbel Distribution risk level. The Design Monthly Maximum Temperatures is based on a 1-in-10 Normal Distribution risk level.
[2] Design Prior Day Temperature not applicable during July and August; Design Wind Speed not applicable May through October
[3] Excludes Standby and EBS quantities.

Schedule 12

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Monthly Minimum Demand
Contract Year 2023-2024
Demand Units are MDth

	Months											
	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun [(2)]	Jul	Aug	Sep [(3)]	Oct
All Days												
Demand												
Firm [(1)]	94.4	151.2	189.0	169.7	89.3	36.6	6.8	6.8	22.0	23.8	23.8	25.7
Non-Firm	88.2	98.0	105.3	108.5	86.7	75.2	66.3	66.3	55.8	60.0	61.3	76.4
Total [(1)]	182.6	249.2	294.3	278.2	176.0	111.8	73.1	73.1	77.8	83.8	85.1	102.1
Weekdays												
Demand												
Firm [(1)]	90.2	156.0	189.2	157.8	83.7	33.5	7.6	7.6	23.0	24.9	24.9	23.1
Non-Firm	91.2	101.1	110.6	110.1	88.9	79.5	72.7	72.7	64.0	69.8	69.8	81.1
Total [(1)]	181.4	257.1	299.8	267.9	172.6	113.0	80.3	80.3	87.0	94.7	94.7	104.2
Weekends												
Demand												
Firm [(1)]	105.3	138.5	187.3	202.6	105.0	44.7	4.2	4.2	20.9	22.4	22.4	31.7
Non-Firm	81.3	91.3	93.4	102.3	78.9	66.9	54.6	54.6	49.3	52.8	52.8	66.2
Total [(1)]	186.6	229.8	280.7	304.9	183.9	111.6	58.8	58.8	70.2	75.2	75.2	97.9

Notes

(1) The Minimum Demand is calculated to be the demand having a 10% probability based on the actual daily demand experienced over the past five years.

(2) June's minimum demand calculated to be higher than shown for May. When this occurs May's values are used for June's minimum demand.

(3) September's minimum demand calculated to be lower than shown for August. When this occurs August's values are used for September's minimum demand.

APPENDIX

APPENDIX

DEVELOPMENT OF DESIGN CONDITIONS AND STATISTICAL ANALYSIS METHODS USED

I. Design Day Conditions

CPA's Design Day Conditions include Design Current Day Temperature, Design Prior Day Temperature, Design Current Day Wind Speed, and with assumed occurrence on a weekday.

The Design Day Conditions for CPA are premised upon all available historical weather data ending with the winter 2014/15. Traditionally, CPA updates this historical weather data for analytical purposes approximately every ten years. The weights associated with the weather stations to generate the PSP Design Day Conditions are premised on December 2014 through February 2015 firm throughput. **Exhibit A** shows the Design Current Day Temperatures, Design Prior Day Temperatures, Design Current Day Wind Speed, the associated historical period, and the weights of the National Weather Service locations used to arrive at the Design Day Conditions for each PSP. The weather stations used for this determination are those located at Hagerstown, Maryland; Morgantown, West Virginia; Harrisburg, Pittsburgh; and Bradford, Pennsylvania. These weather stations are used because of their proximity to CPA's customers.

CPA's Design Current Day Temperature is that temperature having a 1 in 15 percent risk level. That is, the probability is 1 in 15, or 6.7 percent that any given winter will have one or more days with an average daily temperature equal to or colder than the Design Current Day Temperature. CPA uses the Gumbel, or double exponential, distribution to calculate the probabilities. This skewed distribution fits the coldest day temperature data better than a normal bell-shaped distribution.

CPA has developed temperature probability distributions for eight PSPs in Pennsylvania. The PSPs correspond to geographically defined locations in Columbia Gas Transmission LLC's (TCO) FERC approved Tariff. The development of a Design Current Day Temperature for a PSP is a two-step process. First, for each weather station within the PSP, all available history is used to develop an associated design temperature. Next, the design temperatures for each weather station are weighted based on the firm demand associated with each weather station. CPA's system wide Design Current Day Temperature is minus 5 degrees Fahrenheit. The same method is used to develop Design Prior Day Temperature and Design Current Day Wind Speed by PSP and for CPA in total.

CPA's Design Prior Day Temperature is the sum of the Design Current Day Temperature plus the mean difference of Prior Day Temperature minus Current Day Temperature for all "Cold Days". A Cold Day is defined as a day as cold as or colder than the Design Current Day Temperature, plus 5 degrees Fahrenheit. For example, the Pittsburgh weather station has a Design Current Day Temperature of minus 7 degrees

Fahrenheit, so Cold Days for Pittsburgh, by definition, have temperatures minus 2 degrees Fahrenheit or colder. The resultant average difference (Cold Days and their respective Prior Days) from this analysis is then added to the Design Current Day Temperature. The Pittsburgh, Design Prior Day Temperature is 5 degrees Fahrenheit. **Exhibit B** shows the historical temperature differences and calculation of Design Prior Day Temperature for the Pittsburgh weather station. Each station's Design Prior Day Temperature and their station weighting are shown on **Exhibit A**.

Consistent with the Prior Day Design Temperature methodology, the approach of using an average of Cold Days is used to establish CPA's Design Current Day Wind Speed. However, because Wind Speed data has only been available since 1991/92, a Cold Day is defined as Design Current Day Temperature plus 15 degrees Fahrenheit for Wind Speed design. Using Cold Days defined as 15 degrees plus Design Current Day Temperature provides more observations per station. Again, the design is developed at the weather station level, and then weighted for the PSP and total company design. **Exhibit C** shows the data considered for determining the Design Current Day Wind Speed (the calculated average wind speed on cold days) for the Pittsburgh weather station. The Design Current Day Wind Speed for each weather station is shown on **Exhibit A**.

Exhibit D shows the latest date within a winter season beyond which there is only a 10% probability of occurrence of a temperature equal to or colder than Design Current Day Temperature. To determine this "Latest Date of Design Current Day Temperature", only the latest actual day of Design Current Day Temperature or colder occurring per winter heating season is considered in the distribution (red bars). Since there are few days in this analysis, a t-distribution was used to calculate the January 25th date.

II. Regression Analysis and Criteria Considered

The statistic R^2 is "the estimated proportion of the variance of Y (the demand) that can be attributed to its linear regression on X (the collection of explanatory variables)". (Snedecor and Cochran, Statistical Methods, Seventh Edition, page 181.)

Note that R^2 for the Firm Demand component typically exceeds R^2 for the Industrial Demand component. The higher R^2 for Firm Demand indicates that the explanatory variables included in the model account for a high proportion of the day to day variation in demand. The lower R^2 for the industrial models indicates that variables not included in the models affect demand. For example, day-to-day production / operations, pricing of alternative fuels or customers' ability to use previously banked gas supplies may affect industrial demand.

In some PSPs the models have missing coefficients. A missing coefficient indicates that the associated variable does not affect demand with 95 percent confidence. In order to affect demand with 95 percent confidence, an explanatory variable must have an estimated regression coefficient, which is large compared to its standard error. In statistical terms, the probability of obtaining such a large estimated coefficient is less than 5 percent if the true coefficient is zero.

The day type variable includes both holiday and weekend demand impacts relative to weekdays. If weekend is found to be a valid explanatory variable, then holiday will have at least the same value as a weekend, or may be greater (absolute value). In 2018, refinement of the new SPSS regression modeling tool facilitated a way to review and refine customers whose demand patterns are sporadic or are different from a typical demand load pattern. It was found through detailed analysis that certain industrial and commercial customers had demand patterns that were peculiar to the day of the week. For example, some companies have reduced consumption or shut down starting Friday through Sunday. In these instances, special coefficients are needed to describe these customers' consumption patterns. Therefore new variables for Friday, Saturday and Sunday were introduced to the regression analysis for these customers. These variables are treated in a forecast calculation the same as a weekend or holiday coefficient. That is, the intercept is reduced by the amount of the coefficient for that particular day type. Since the Design Day Forecast assumes a weekday as the default design variable, these additional coefficients are for informational purposes only and do not affect the Design Day Demand Forecast. With this knowledge, however, the impact of these special variables can be approximated when looking at operational design. Additionally, with these special customers separated from the PSP forecast model, a more optimal design can be developed, since their design is held out from traditional designs but added in for the final design. There are other customers whose data is sporadic; when no demand pattern can be ascertained, the new SPSS software has the capability to calculate an average day for these customers based on a 95% confidence interval of the data.

III. Development of Winter Monthly Maximum Conditions and Corresponding Demand

The Monthly Maximum Conditions are obtained using all available weather station temperature history which is then weighted to determine the company level design (see Section I of the Appendix, "Design Day Conditions"). Selection of the Monthly Maximum Current Day Temperature is predicated on the actual average daily temperatures for a given month fitted to a normal distribution (vs. Gumbel distribution for Design Day Demand). The Monthly Maximum Current Day Temperature is that temperature having a 10% risk level. That is, there is a 10 percent probability of a daily average temperature equal to or colder than the Monthly Maximum Current Day Temperature. As with Design Day Demand, Monthly Design Conditions are based on weather station weighting (see Section III). The Monthly Maximum Prior Day Temperature was developed using the same methodology for developing the Design Prior Day Temperature. Design Prior Day Temperature is reflected in the months of September through June. Regression analysis has found that prior day temperature is not significant during the months of July and August.

For the months of November through April, Monthly Design Current Day Wind Speed reflects the average Wind Speed. Note, for each month, that Monthly Design Current Day Wind Speed is not reflected for any of the summer months (May through October). This is because the regression analysis has found wind to have significance only during the colder months of the year, in which wind speed has a direct effect on the heating load.

Regression analyses of daily firm and total demand were performed for each month using the past three years of history. Selection of the days to be analyzed for each month depended on the actual average temperature. Only days that had an average temperature within the range specified for each month were selected. The resulting regression coefficients were then applied to the Monthly Maximum Conditions to obtain the Monthly Maximum Demand.

The contracted Standby volume and EBS are shown on the schedule. This is a firm obligation for CPA when called upon by its customers.

IV. Winter Historical Information

Exhibit E reflects the winter historical information for the winters used in the regression analysis. For instance, this past winter, peak day occurred on Friday, December 23, 2022. The temperature was 1°F, total winter degree days at 59°F was 2,980 and there were 15 days in which the gas day average temperature was colder than 31°F in December and January. Over a 74-year history, this past winter was 17% warmer than normal.

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28
Design Day Conditions

PSP	Pipeline Area	Station Location	2015 Station Weighting	Weather Station Design Conditions [1] Historical Period	Current Day Temp [2]	Prior Day Temp	Wind Speed
25E-25	Lancaster	Harrisburg, PA	95.1311	1925-2015	2	10	12
		Hagerstown, MD	4.8689	1925-2015	0	10	12
		Total	**100.0000**		**2**	**10**	**12**
25-26	Bedford	Morgantown, WV	**100.0000**	1949-2015	**-6**	**5**	**7**
25E-29	Downingtown	Harrisburg, PA	**100.0000**	1925-2015	**2**	**10**	**12**
25-35	Pittsburgh	Pittsburgh, PA	74.9116	1925-2015	-7	5	11
		Morgantown, WV	25.0884	1949-2015	-6	5	7
		Total	**100.0000**		**-7**	**5**	**10**
25-36	Olean	Pittsburgh, PA	2.8939	1925-2015	-7	5	11
		Bradford, PA	97.1061	1941-2015	-15	-2	11
		Total	**100.0000**		**-15**	**-2**	**11**
25-38	Rimersburg	Pittsburgh, PA	56.1941	1925-2015	-7	5	11
		Bradford, PA	43.8059	1941-2015	-15	-2	7
		Total	**100.0000**		**-11**	**2**	**9**
25-39	New Castle	Pittsburgh, PA	**100.0000**	1925-2015	**-7**	**5**	**11**
25-40	PA/WV Misc.	Pittsburgh, PA	3.1982	1925-2015	-7	5	11
		Morgantown, WV	96.8018	1949-2015	-6	5	7
		Total	**100.0000**		**-6**	**5**	**7**
CPA Total		Harrisburg	24.9422	1925-2015	2	10	12
		Pittsburgh	51.3767	1925-2015	-7	5	11
		Hagerstown	1.2765	1925-2015	0	10	12
		Bradford	6.5920	1941-2015	-15	-2	11
		Morgantown	15.8126	1949-2015	-6	5	7
			100.0000	**Total Co**	**-5**	**6**	**11**

(1) Using all available temperature data through March 2015 and weather station weights based on actual firm customer demand from December 2014 through February 2015.
(2) Temperature having a 1 in 15 probability of occurrence.

Exhibit B

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Airport: PIT Weather Station: PITTSBURGH, PA.
Determination of Weather Station Design Prior Day Temperature
Based on the 90 Heating Seasons 1925/1926 Through 2014/2015
For Variable: MID_MID_AVG_TMP with a Risk of 1 in 15

	Average Cold Day Temp. In °F	Average Prior Day Temp. In °F	Difference Between Prior Day and Cold Day Temp.
01/23/1936	-9	11	20
01/24/1936	-2	-9	-7
01/27/1936	-2	7	9
01/19/1940	-3	7	10
01/24/1963	-9	16	25
01/08/1970	-2	8	10
01/17/1977	-9	1	10
01/10/1982	-4	12	16
01/17/1982	-10	9	19
12/25/1983	-5	1	6
01/21/1984	-4	3	7
01/20/1985	-8	14	22
01/21/1985	-5	-8	-3
01/18/1994	-4	23	27
01/19/1994	-12	-4	8
01/07/2014	-2	15	17
Average:	**-6**	**7**	**12**

Design Day Temperature °F:	**-7**
Range Temperature °F:	**5**
Minium Cold Day Temperature °F:	**-2**
Design Prior Day Temperature °F:	**5**

(1) For the purpose of determining the design Prior Day Temperature the Cold Day Temperature equals Design Day Temperature plus five degrees (-7° + 5° = -2°).

(2) Days on which the observed average temperature was equal to or colder than -2°.

(3) The Design Prior Day Temperature is derived from the calculated average difference in temperatures on "Cold Days" and the preceding, or prior, day that is then added to the Design Current Day Temperature.

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28

Airport: PIT Weather Station: PITTSBURGH, PA.
Determination of Weather Station Design Wind Speed
Based on the 24 Heating Seasons 1991/1992 Through 2014/2015
For Variable: MID_MID_WIND_SPEED with a Risk of 1 in 15

	Average Cold Day Temp. In °F	Average Wind Speed in MPH
01/19/1992	8	9
02/18/1993	8	13
01/15/1994	-1	16
01/16/1994	1	10
01/18/1994	-4	16
01/19/1994	-12	10
01/20/1994	1	4
01/21/1994	5	9
02/05/1995	6	22
02/06/1995	6	18
02/12/1995	4	13
02/03/1996	5	10
02/04/1996	1	9
02/05/1996	8	12
01/17/1997	3	17
01/18/1997	4	12
01/05/1999	4	6
01/23/2003	8	14
01/27/2003	7	6
01/10/2004	8	6
01/31/2004	7	8
01/18/2005	8	7
01/23/2005	7	16
02/04/2007	7	16
02/05/2007	2	12
02/06/2007	4	7
12/22/2008	8	13
01/16/2009	0	10
01/17/2009	8	7
01/22/2013	8	13
01/07/2014	-2	13
01/22/2014	5	6
01/28/2014	1	5
01/29/2014	7	9
01/08/2015	6	12
01/10/2015	8	8
02/15/2015	0	18
02/16/2015	3	5
02/19/2015	2	16
02/20/2015	2	7

Average Cold Day Wind Speed (3)	**11**
Design Day Temperature °F:	**-7**
Range Temperature °F:	**15**
Maximum Wind Speed Cold Day Temperature	**8**

(1) For the purpose of determining the Design Current Day Wind Speed the Cold Day Temperature equals Design Day Temperature plus fifteen degrees (5° +15° = 20°).
(2) Days on which the observed average temperature was equal to or colder than 20°.
(3) Design Day Average Wind Speed equals average wind speed on "Cold Days" or 12 mph.
(4) History on Wind Speed Begins October 1991.

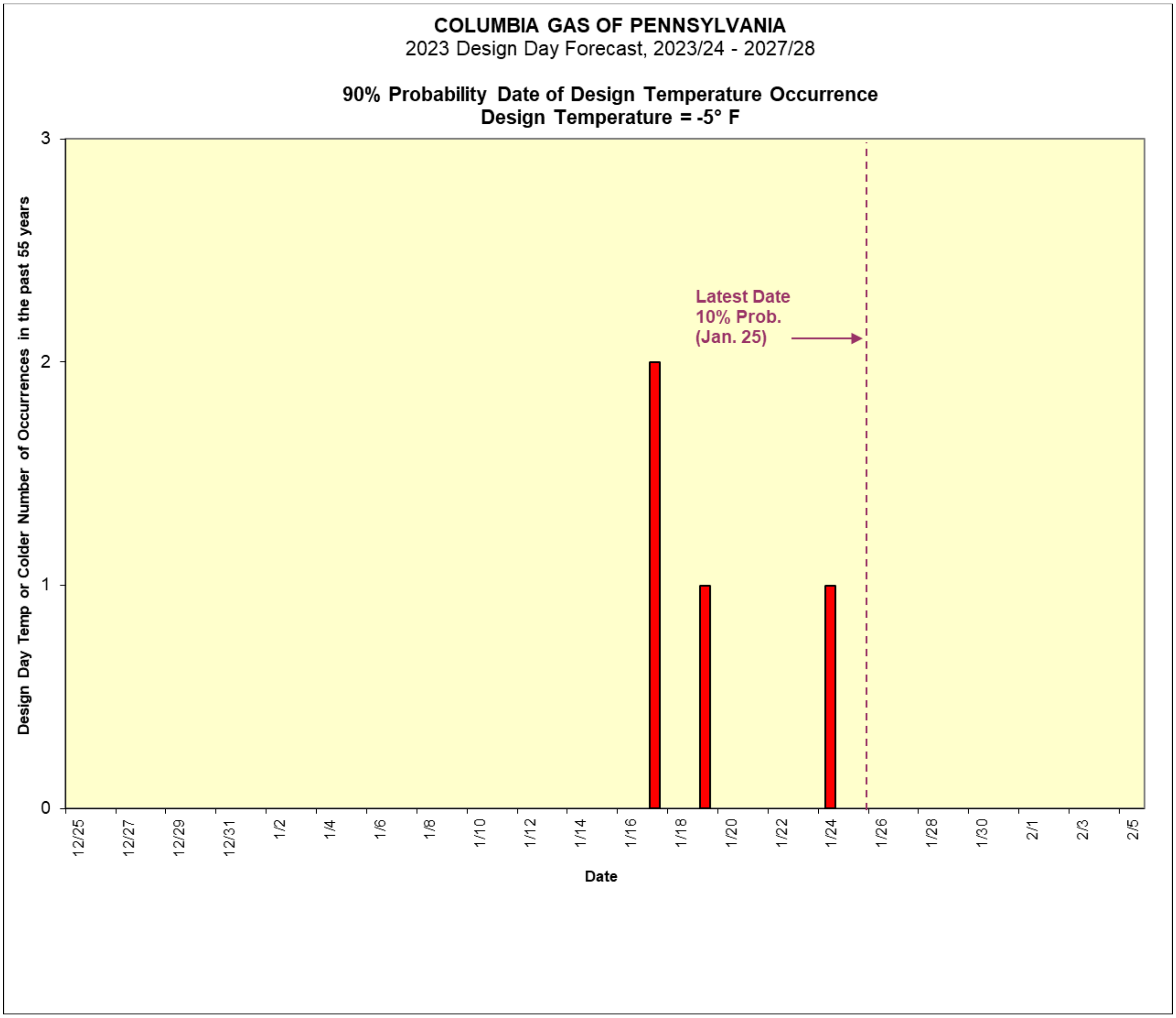

COLUMBIA GAS OF PENNSYLVANIA
2023 Design Day Forecast, 2023/24 - 2027/28
90% Probability Date of Design Temperature Occurrence
Design Temperature = -5° F
Design Day Temp or Colder Number of Occurrences in the past 55 years
0
1
2
3
Latest Date
10% Prob.
(Jan. 25)
12/25
12/27
12/29
12/31
1/2
1/4
1/6
1/8
1/10
1/12
1/14
1/16
1/18
1/20
1/22
1/24
1/26
1/28
1/30
2/1
2/3
2/5
Date

Exhibit E

Columbia Gas of Pennsylvania
2023 Design Day Forecast, 2023/24 - 2027/28
Winter Historical Information

Year	Winter DDs @ 59º F	% From 74 Yr Avg	Peak	Peak Day of Week	Dec - Jan Days <31°F
01/02	2,865	-21	2/4, 20°F	Monday	18
02/03	4,018	11	1/23, 12°F	Thursday	40
03/04	3,642	0	1/30, 9°F	Friday	40
04/05	3,519	-3	1/23, 9°F	Sunday	27
05/06	3,428	-6	12/13, 16°F	Tuesday	25
06/07	3,369	-7	2/5, 5°F	Monday	20
07/08	3,602	-1	1/20, 11°F	Sunday	23
08/09	3,712	2	1/16, 2°F	Friday	35
09/10	3,487	-4	1/2, 14°F	Saturday	32
10/11	3,871	7	1/23, 10°F	Sunday	52
11/12	2,751	-24	1/3, 15°F	Tuesday	15
12/13	3,555	-2	1/22, 9°F	Tuesday	24
13/14	4,107	13	1/7, 5°F	Tuesday	75
14/15	4,141	14	2/19, 1°F	Thursday	24
15/16	2,811	-23	2/13, 17°F	Saturday	18
16/17	3,011	-17	12/15, 11°F	Thursday	19
17/18	3,649	1	1/5, 5°F	Friday	29
18/19	3,632	0	1/30, 1°F	Wednesday	24
19/20	3,110	-14	12/18, 20°F	Wednesday	13
20/21	3,196	-12	1/28, 22°F	Thursday	18
21/22	3,305	-9	1/26, 11°F	Wednesday	26
22/23	2,980	-17	12/23, 1°F	Friday	15

Design Temp: -5°F (1 in 15 Risk)
DD Avg. 1949/50 - 2022/23: 3,604
2022/23 Winter 17% warmer than 74 year average
2022/23 Winter ranks as the 71st coldest of 74 years

Columbia Gas of Pennsylvania, Inc.
Exhibit No. 14

§53.64(c)(14) Analysis and data demonstrating, on an historic and projected future basis, the minimum gas entitlements needed to provide reliable and uninterrupted service to priority one customers during peak periods.

Response:

The following table shows the estimated requirements of Human Need type customers under actual (historical) or design (projected) peak day conditions.

Columbia Gas of Pennsylvania
Estimated Human Needs Requirements
(Quantities in MDth)

	Historical				Projected				
	2019/20	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	**2026/27**	**2027/28**
Temperature in °F	**20**	**22**	**11**	**1**	**-5**	**-5**	**-5**	**-5**	**-5**
Residential									
Sales	223.5	217.4	260.6	318.1	357.2	365.9	372.4	380.1	387.8
Choice	65.6	71.7	72.2	82.1	92.2	86.7	81.3	75.9	70.6
Subtotal	289.1	289.1	332.8	400.2	449.4	452.6	453.7	456.0	458.4
Commercial									
Sales	30.2	30.4	36.5	43.9	42.9	42.6	42.7	42.8	42.9
Choice	3.8	3.8	4.6	5.5	5.5	5.5	5.5	5.5	5.5
GTS Human Needs	22.8	24.6	28.3	23.2	23.2	23.2	23.2	23.2	23.2
Subtotal	56.8	58.8	69.4	72.6	71.6	71.3	71.4	71.5	71.6
Industrial									
Sales	1.3	1.3	1.3	1.9	2.0	2.0	2.0	2.0	2.0
Choice	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GTS Human Needs	0.0	0.1	0.6	0.2	0.2	0.2	0.2	0.2	0.2
Subtotal	1.3	1.4	1.9	2.1	2.2	2.2	2.2	2.2	2.2
Other	2.5	2.5	2.8	1.5	1.5	1.5	1.5	1.5	1.5
Total Human Needs	349.7	351.8	406.9	476.5	524.8	527.7	528.9	531.3	533.8

It should be noted that Columbia is obligated to provide reliable and uninterrupted service to other customer requirements in addition to those considered to be "Human Needs". Columbia's current estimate of total firm obligation on a design peak day for each of the next five years is contained on Schedule 1 of CPA's 2023 Design Day Forecast as provided with Exhibit No. 13.

Columbia Gas of Pennsylvania
Report Supporting Capacity
Contract Years 2024-25 Through 2027-28

February 3, 2024

CONTENTS

PURPOSE OF THE REPORT SUPPORTING CAPACITY [1]

In Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or the "Company") 2013 Rate Investigation Pursuant to 66 Pa.C.S. §1307(f), Columbia filed a Joint Petition for Settlement ("Settlement") which was executed by Columbia, the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), and the Office of Small Business Advocate ("OSBA"). On July 12, 2013, the ALJ issued a Recommended Decision recommending approval of the Settlement. On August 15, 2013, the Commission adopted the Recommended Decision approving the Settlement ("Order"). As part of the Settlement, Columbia agreed in future 1307(f) filings to file and provide to all parties a report related to the level of peak day capacity retained.

The relevant Settlement Terms as delineated in the Recommended Decision and approved in the Order are as follows:

D. Peak Day Capacity
c. Columbia will continue its policy to 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 Peak Demand Forecast. If the results of Columbia's Peak Day Forecast indicate that Columbia has peak day capacity in excess of this policy, Columbia agrees to reduce its peak day capacity portfolio as appropriate to the extent that any components of its portfolio are not operationally required and can contractually be reduced.

d. In future 1307(f) pre-filings, Columbia will file and provide to all parties a report identifying: (1) the level of peak day capacity retained consistent with its policy and this Stipulation and the results of the Peak Day Forecast; and (2) any adjustment to capacity taken pursuant to Columbia's policy and available contractual opportunities. If Columbia retains or renews any capacity in excess of its policy because it deems that capacity "operationally required" as the term is used in paragraph "c" above, the report will include an explanation of the reason(s) Columbia considers such retained capacity to be operationally required.

[1] The terms Peak Day and Design Day are used interchangeably herein.

Recommended Decision at p. 17.

The following report fulfills Columbia's commitment related to capacity as set forth in the Commission-approved Settlement resolving its 2013 1307(f) proceeding.

ANALYSIS AND CONCLUSION

Columbia's policy is to 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 Peak Day Forecast. Based on Columbia's 2023 Design Day Forecast, spanning the winter seasons of 2023-24 through 2027-28, Columbia's existing peak day capacity is within this policy. Growth in Columbia's firm demand is expected over the term of this forecast such that Columbia's existing available capacity equals 101.8 percent of projected firm demand for contract year 2027-28, the highest projected design day firm requirements in Columbia's 2023 Design Day Forecast. Therefore, no additional reductions in Columbia's existing capacity portfolio are required at this time outside those discussed in Exhibit 5 pursuant to the aforementioned agreement. Because no capacity was renewed in excess of policy, no discussion of operationally required capacity is included. For further discussion of Columbia's peak day capacity and demand projections, please see Exhibit No. 5, Table 4 and the associated discussion.