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File #: 182460

March 1, 2021

VIA ELECTRONIC FILING

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

Re: Pennsylvania Public Utility Commission, et al. v. Peoples Natural Gas Company LLC 1307(f) – 2021 Proceeding Docket No. R-2021-3023965

Dear Secretary Chiavetta:

Enclosed, for filing with the Pennsylvania Public Utility Commission ("Commission"), on behalf of Peoples Natural Gas Company LLC ("Peoples Natural Gas") are the following materials:

1. The materials that the Commission's regulations at 52 Pa. Code Sections 53.64(c) and 53.65 require to be filed thirty (30) days before the filing of a tariff under 77 Pa. C.S. Section 1307(f); and

2. The reconciliation statement that the Commission's regulation at 52 Pa. Code Section 53.64(i) requires to be filed at the same time.

3. A report detailing Peoples Natural Gas' analysis of the potential for an additional retainage charge on the gas supplies acquired by customers that purchase local production supplies that would not be imposed on customers that acquire interstate delivered supplies. The report also addresses issues related to implementing a gathering retainage charge phase-in period. This report is consistent with the Partial Settlement reached at Docket No. R-2020-3017850 and approved by the Commission on September 17, 2020.

A CD is also provided containing a copy of this filing.

Peoples Natural Gas will be represented in this proceeding by the following counsel:

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All service on and communications in this proceeding should be addressed to the above-referenced counsel. Further, Peoples Natural Gas requests that copies of all documents served upon the Company in this proceeding also be served Andrew Wachter via email at Andrew.Wachter@peoples-gas.com and/or via first class mail using the following address: Peoples Natural Gas Company LLC, 375 North Shore Drive, Pittsburgh, PA 15212-5866.

Copies of this filing will be provided as indicated on the enclosed Certificate of Service. Please direct any questions regarding this matter to the undersigned.

Respectfully submitted,

Anthony D. Kanagy

Anthony D. Kanagy

ADK/kls
Enclosures

cc: Office of Administrative Law Judge
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 FIRST CLASS MAIL

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Anthony D. Kanagy

Date: March 1, 2021

Anthony D. Kanagy

Peoples Natural Gas
Docket No. R-2021-3023965
1307(f)-2021 Annual Gas Cost Pre-Filing
Table of Contents

Regulation Designation

Peoples Natural Gas
1307(f) - 2021

Section 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 the 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.

* * * * * * * * * * * * * * *

NOTE: Effective November 2, 2020, interstate pipeline Dominion Energy Transmission, Inc. (“DETI”) has changed its name to Eastern Gas Transmission and Storage, Inc. (“EGTS”). Accordingly, throughout this PRE-FILING of Materials, DETI and EGTS will be used interchangeably and refer to the same company.

Peoples Natural Gas Company
Annual 1307(f)-2021
Historic Period Actual Gas Costs

53.64(c)(1)

	2020 February ACTUAL	2020 March ACTUAL	2020 April ACTUAL	2020 May ACTUAL	2020 June ACTUAL	2020 July ACTUAL	2020 August ACTUAL	2020 September ACTUAL	2020 October ACTUAL	2020 November ACTUAL	2020 December ACTUAL	2021 January estimate	12-Mth Total
Local / Gathered Purchases													
Quantity - Mcf	600,564	609,484	607,424	612,874	661,907	412,301	856,211	618,211	595,368	571,184	393,342	780,321	7,319,191
Rate per Mcf	$1.6902	$1.3712	$1.2132	$1.4618	$1.2876	$1.1722	$1.2699	$1.0905	$0.9927	$1.6336	$1.5442	$1.9747	$1.4008
Cost	$1,015,082	$835,726	$736,926	$895,877	$852,263	$483,312	$1,087,325	$674,129	$591,000	$933,085	$607,385	$1,540,913	$ 10,253,024
Interstate Pipeline Purchases													
Quantity - Mcf	2,495,896	1,340,467	6,219,385	5,643,170	3,382,900	2,933,997	3,780,324	4,496,246	3,570,319	3,202,849	5,430,024	4,900,312	47,395,889
Rate per Mcf	$1.6888	$1.4209	$1.3322	$1.5086	$1.3708	$1.3154	$1.3323	$1.1970	$1.1487	$1.3284	$2.1705	$2.3724	$1.5529
Cost	$4,214,991	$1,904,726	$8,285,705	$8,513,235	$4,637,170	$3,859,460	$5,036,428	$5,381,946	$4,101,122	$ 4,254,730	$ 11,785,879	$11,625,469	$ 73,600,860
Total Commodity Purchases													
Quantity - Mcf	3,096,460	1,949,951	6,826,809	6,256,044	4,044,807	3,346,298	4,636,535	5,114,457	4,165,687	3,774,033	5,823,366	5,680,633	54,715,080
Rate per Mcf	$1.6890	$1.4054	$1.3216	$1.5040	$1.3572	$1.2978	$1.3208	$1.1841	$1.1264	$1.3746	$2.1282	$2.3178	$1.5326
Cost	$5,230,073	$2,740,452	$9,022,632	$9,409,111	$5,489,433	$4,342,773	$6,123,753	$6,056,074	$4,692,122	$5,187,815	$12,393,264	$13,166,382	$ 83,853,884
Storage (Injection)/Withdrawals - WACCOG													
Quantity - Mcf	5,193,737	4,167,606	(1,938,366)	(3,094,403)	(2,836,909)	(2,587,070)	(3,148,935)	(3,121,634)	(1,641,633)	932,363	3,141,267	4,662,164	(271,813)
WACCOG Rate per Mcf	$2.2604	$2.2604	$1.4300	$1.5900	$1.4800	$1.3900	$1.4100	$1.3371	$1.2647	$1.5268	$1.5268	$1.5268	
Cost	$11,739,847	$9,420,397	($2,771,863)	($4,920,101)	($4,198,626)	($3,596,026)	($4,439,998)	($4,174,042)	($2,076,135)	$1,423,532	$4,796,087	$7,118,155	$ 8,321,227
Injection/Withdrawal Costs	$40,323	$41,999	$26,517	$32,439	$35,674	$33,595	$33,224	$30,332	$29,928	$15,479	$29,533	$44,112	$ 393,155
Pipeline Transportation Charges	$420,523	$316,558	$691,384	$580,063	$466,751	$307,403	$407,048	$1,115,584	$531,524	$458,863	$664,654	$747,764	$ 6,708,118
Other Purchased Gas Costs													
Other Gas Costs - Mcf	647,370	140,150	1,147,254	376,476	179,906	188,936	276,228	181,150	75,058	137,190	358,931	-	3,708,649
Gas Admin Costs	$14,588	$14,160	$14,588	$14,160	$14,588	$14,157	$14,591	$14,918	$10,243	$10,715	$10,429	$0	$ 147,136
Imbalance Buyback Costs	$1,466,589	$324,135	$1,450,066	$453,708	$445,900	$376,725	$465,905	$164,835	$96,101	$206,953	$492,826	$0	$ 5,943,743
Exchange Costs	($167,429)	($47,419)	$232,752	$54,245	($148,028)	($102,694)	($96,086)	$88,041	($35,985)	($46,159)	($277,340)	$0	$ (546,102)
Compressed Natural Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ -
Subtotal	$1,313,747	$290,876	$1,697,405	$522,114	$312,459	$288,188	$384,410	$267,793	$70,360	$171,509	$225,915	$0	$ 5,544,777
Capacity Costs - Firm Transportation	$7,337,779	$7,478,313	$2,558,545	$2,992,632	$2,980,367	$2,992,746	$2,993,342	$2,994,905	$2,993,792	$7,408,317	$7,480,811	$7,479,734	$ 57,691,282
Capacity Costs - Firm Storage	$1,249,082	$1,242,131	$1,231,592	$1,231,592	$1,231,592	$1,231,592	$1,231,592	$1,231,592	$1,231,592	$1,233,763	$1,233,763	$1,233,763	$ 14,813,647
AVC Capacity Costs	$6,031,000	$6,148,762	$2,803,413	$2,803,413	$2,803,413	$2,803,413	$2,802,940	$2,803,413	$2,803,413	$6,184,359	$6,184,359	$6,184,359	$ 50,356,257
	$14,617,860	$14,869,206	$6,593,550	$7,027,637	$7,015,372	$7,027,751	$7,027,874	$7,029,910	$7,028,797	$14,826,439	$14,898,933	$14,897,856	$ 122,861,185
Total 1307(f) Gas Costs	$ 33,362,373	$ 27,679,487	$ 15,259,624	$ 12,651,263	$ 9,121,064	$ 8,403,683	$ 9,536,312	$ 10,325,652	$ 10,276,596	$ 22,083,637	$ 33,008,386	$ 35,974,270	$ 227,682,347
Total - w/o AVC	$ 27,331,373	$ 21,530,725	$ 12,456,211	$ 9,847,851	$ 6,317,651	$ 5,600,270	$ 6,733,372	$ 7,522,239	$ 7,473,183	$ 15,899,278	$ 26,824,026	$ 29,789,910	$ 177,326,090
Capacity	$ 8,586,860	$ 8,720,444	$ 3,790,137	$ 4,224,224	$ 4,211,959	$ 4,224,338	$ 4,224,934	$ 4,226,497	$ 4,225,384	$ 8,642,080	$ 8,714,573	$ 8,713,496	$ 72,504,928
Commodity	$ 18,744,513	$ 12,810,281	$ 8,666,074	$ 5,623,626	$ 2,105,692	$ 1,375,932	$ 2,508,438	$ 3,295,742	$ 3,247,799	$ 7,257,198	$ 18,109,453	$ 21,076,414	$ 104,821,162
1307(f) Mcf	8,937,567	6,257,707	6,035,697	3,538,117	1,387,804	948,164	1,763,828	2,173,973	2,599,112	4,843,586	9,323,564	10,342,797	58,151,916

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
SUMMARY

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	
Local / Gathered Purchases									
Quantity - Mcf	602,148	626,113	618,077	626,042	618,007	625,972	625,937	617,902	
Rate per Mcf	$2.7044	$2.8864	$2.8042	$2.7563	$2.7258	$2.7168	$2.6704	$2.4370	
Cost	$1,628,458	$1,807,192	$1,733,193	$1,725,530	$1,684,588	$1,700,650	$1,671,518	$1,505,798	
Interstate Pipeline Purchases									
Quantity - Mcf	4,200,396	2,771,736	4,885,142	3,857,316	3,488,789	3,445,121	3,585,812	3,416,669	
Rate per Mcf	$2.5851	$2.7303	$2.6573	$2.5898	$2.5433	$2.5338	$2.5124	$2.2790	
Cost	$10,858,619	$7,567,546	$12,981,253	$9,989,686	$8,873,198	$8,729,321	$9,008,970	$7,786,435	
Total Commodity Purchases									
Quantity - Mcf	4,802,544	3,397,848	5,503,219	4,483,359	4,106,797	4,071,093	4,211,749	4,034,570	
Rate per Mcf	$2.6001	$2.7590	$2.6738	$2.6130	$2.5708	$2.5620	$2.5359	$2.3032	
Cost	$12,487,076	$9,374,737	$14,714,445	$11,715,216	$10,557,786	$10,429,971	$10,680,488	$9,292,234	
Storage (Injection)/Withdrawals									
Quantity - Mcf	4,240,517	3,502,038	(1,636,818)	(2,530,000)	(3,060,000)	(3,065,000)	(3,195,000)	(2,780,000)	
WACCOG Rate per Mcf	$1.5268	$1.5268	$2.6963	$2.6516	$2.6197	$2.6111	$2.5827	$2.3459	
Cost	$6,474,421	$5,346,912	($4,413,386)	($6,708,484)	($8,016,318)	($8,003,162)	($8,251,828)	($6,521,505)	
Injection/Withdrawal Costs	$30,241	$21,858	$114,535	$163,283	$191,479	$190,888	$187,972	$162,966	
Other Purchased Gas Costs									
Other Gas Costs - Mcf	0	0	0	0	0	0	0	0	
Risk Mgmt / Gas Admin Costs	$9,462	$9,462	$9,462	$9,462	$9,359	$9,359	$9,359	$9,359	
Imbalance Buyback Costs	$0	$0	$0	$0	$0	$0	$0	$0	
Exchange Costs	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$9,462	$9,462	$9,462	$9,462	$9,359	$9,359	$9,359	$9,359	
Capacity Costs - Firm Transportation	$6,060,530	$6,278,763	$2,411,292	$2,411,292	$2,411,292	$2,411,292	$2,411,292	$2,411,292	
Capacity Costs - Firm Storage	$2,379,630	$2,379,630	$1,793,716	$1,793,716	$1,793,716	$1,793,716	$1,793,716	$1,793,716	
AVC Capacity Costs	$6,184,359	$6,385,822	$2,858,820	$2,858,820	$2,858,820	$2,858,820	$2,858,820	$2,858,820	
	$14,624,519	$15,044,215	$7,063,827	$7,063,827	$7,063,827	$7,063,827	$7,063,827	$7,063,827	
Total 1307(f) Gas Costs	**$ 33,625,720**	**$ 29,797,183**	**$ 17,488,884**	**$ 12,243,304**	**$ 9,806,133**	**$ 9,690,883**	**$ 9,689,817**	**$ 10,006,881**	$ 132,348,804
Total - no AVC	$27,441,360	$23,411,361	$14,630,065	$9,384,484	$6,947,313	$6,832,063	$6,830,997	$7,148,061	$102,625,705
Commodity	$19,001,200	$14,752,968	$10,425,057	$5,179,476	$2,742,305	$2,627,055	$2,625,990	$2,943,053	$60,297,105
Capacity (excludes AVC)	$8,440,160	$8,658,393	$4,205,008	$4,205,008	$4,205,008	$4,205,008	$4,205,008	$4,205,008	$42,328,600
1307(f) Mcf	9,043,061	6,899,886	3,866,401	1,953,359	1,046,797	1,006,093	1,016,749	1,254,570	

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Local Purchases

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
Local / Gathered Purchases									
Quantity - Mcf	602,148	626,113	618,077	626,042	618,007	625,972	625,937	617,902	4,960,197
Rate per Mcf	$ 2.704	$ 2.886	$ 2.804	$ 2.756	$ 2.726	$ 2.717	$ 2.670	$ 2.437	$ 2.713
Cost	$ 1,628,458	$ 1,807,192	$ 1,733,193	$ 1,725,530	$ 1,684,588	$ 1,700,650	$ 1,671,518	$ 1,505,798	$ 13,456,926

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Interstate Pipeline Purchases

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	TOTAL
City-Gate Mcf									
EQT - NAESB	3,814,896	2,581,736	4,518,142	3,371,316	2,890,789	2,841,521	2,987,212	2,843,669	25,849,282
EGT&S SP	0	0	100,000	305,000	320,000	320,000	315,000	280,000	1,640,000
Tennessee Gas Pipeline	150,000	0	0	0	0	0	0	15,000	165,000
Texas Eastern Transmission - M3	165,000	130,000	120,000	6,000	90,000	90,000	90,000	90,000	781,000
National Fuel Gas Supply	14,500	0	102,000	155,000	168,000	173,600	173,600	168,000	954,700
Tennessee into Columbia	56,000	60,000	45,000	20,000	20,000	20,000	20,000	20,000	261,000
TOTAL MCF	4,200,396	2,771,736	4,885,142	3,857,316	3,488,789	3,445,121	3,585,812	3,416,669	29,650,982
Interstate Pricing									
EQT - NAESB	$2.5561	$2.7168	$2.6614	$2.6004	$2.5530	$2.5404	$2.5251	$2.2900	
EGT&S SP	$2.4814	$2.6427	$2.5674	$2.5132	$2.4893	$2.4739	$2.4278	$2.2016	
Tennessee Gas Pipeline	$2.7170	$2.9950	$2.8378	$2.7873	$2.7587	$2.7462	$2.6957	$2.4661	
Texas Eastern Transmission - M3	$3.1022	$2.8752	$2.6087	$2.4984	$2.5244	$2.6551	$2.5551	$2.2840	
National Fuel Gas Supply	$2.4570	$2.6169	$2.5422	$2.4886	$2.4649	$2.4497	$2.4039	$2.1799	
Tennessee into Columbia	$2.7170	$2.9950	$2.8378	$2.7873	$2.7587	$2.7462	$2.6957	$2.4661	
Interstate Purchase Cost									
EQT - NAESB	$9,751,428	$7,014,067	$12,024,461	$8,766,690	$7,380,136	$7,218,522	$7,543,036	$6,511,898	$66,210,238
EGT&S SP	0	0	256,737	766,532	796,586	791,660	764,742	616,451	3,992,708
Tennessee Gas Pipeline	407,552	0	0	0	0	0	0	36,992	444,543
Texas Eastern Transmission - M3	511,860	373,781	313,050	14,990	227,198	238,956	229,962	205,556	2,115,354
National Fuel Gas Supply	35,627	0	259,306	385,728	414,104	425,260	417,317	366,216	2,303,557
Tennessee into Columbia	152,153	179,697	127,699	55,746	55,173	54,923	53,913	49,323	728,627
TOTAL COST	$10,858,619	$7,567,546	$12,981,253	$9,989,686	$8,873,198	$8,729,321	$9,008,970	$7,786,435	$75,795,027

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
WACCOG Storage Inventory Pricing

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
WACCOG Storage Inventory Pricing									
(Injection)/Withdrawal Mcf									
60SS/115SS - 863/865	1,500,000	1,400,000	(1,200,000)	(1,200,000)	(1,400,000)	(1,400,000)	(1,400,000)	(1,400,000)	(5,100,000)
EGT&S GSS - 300196	504,000	175,000	(280,000)	(300,000)	(310,000)	(315,000)	(315,000)	(310,000)	(1,151,000)
EQT AVC GSS	1,500,000	1,403,495	(151,818)	(475,000)	(675,000)	(675,000)	(675,000)	(545,000)	(293,323)
EGT&S GSS - PNG	356,517	263,543	(90,000)	(305,000)	(305,000)	(305,000)	(305,000)	(300,000)	(989,940)
NFGS ESS	130,000	110,000	(40,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(300,000)
On-System (Dice)	250,000	150,000	125,000	(150,000)	(270,000)	(270,000)	(400,000)	(125,000)	(690,000)
TOTAL	4,240,517	3,502,038	(1,636,818)	(2,530,000)	(3,060,000)	(3,065,000)	(3,195,000)	(2,780,000)	(8,524,263)
WACCOG Storage Inventory Rate	$ 1.5268	$ 1.5268	$ 2.6963	$ 2.6516	$ 2.6197	$ 2.6111	$ 2.5827	$ 2.3459	
WACCOG Storage Inventory Cost	$ 6,474,421	$ 5,346,912	$ (4,413,386)	$ (6,708,484)	$ (8,016,318)	$ (8,003,162)	$ (8,251,828)	$ (6,521,505)	$ (30,093,350)

	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October
Local Purchases - Mcf	618,077	626,042	618,007	625,972	625,937	617,902	625,867
Interstate Purchases - Mcf	4,885,142	3,857,316	3,488,789	3,445,121	3,585,812	3,416,669	3,975,565
	5,503,219	4,483,359	4,106,797	4,071,093	4,211,749	4,034,570	4,601,432
Local Purchases - Cost	$1,733,193	$1,725,530	$1,684,588	$1,700,650	$1,671,518	$1,505,798	$1,530,467
Interstate Purchases - Cost	$12,981,253	$9,989,686	$8,873,198	$8,729,321	$9,008,970	$7,786,435	$9,111,405
Injection/Withdrawal Costs	$114,535	$163,283	$191,479	$190,888	$187,972	$162,966	$101,656
Other Purchased Gas Costs	$9,462	$9,462	$9,359	$9,359	$9,359	$9,359	$9,359
	$14,838,442	$11,887,960	$10,758,623	$10,630,217	$10,877,818	$9,464,559	$10,752,887
WACCOG Inventory Pricing	$ 2.6963	$ 2.6516	$ 2.6197	$ 2.6111	$ 2.5827	$ 2.3459	$ 2.3369

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Storage Injection / Withhdrawal Costs

Storage Injection/Withdrawal Costs		2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
EQT AVC GSS										
(Injection)/Withdrawal Mcf		1,500,000	1,403,495	(151,818)	(475,000)	(675,000)	(675,000)	(675,000)	(545,000)	
Fuel on Injection	3.50%	$ -	$ -	$ 0.0898	$ 0.0880	$ 0.0871	$ 0.0866	$ 0.0850	$ 0.0771	
Injection Charge		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Withdrawal Charge		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
		$ -	$ -	$ 0.0898	$ 0.0880	$ 0.0871	$ 0.0866	$ 0.0850	$ 0.0771	
EQT AVC GSS Cost		$ -	$ -	$ 13,641	$ 41,780	$ 58,809	$ 58,446	$ 57,358	$ 42,010	
EQT 60SS/115SS										
(Injection)/Withdrawal Mcf		1,500,000	1,400,000	(1,200,000)	(1,200,000)	(1,400,000)	(1,400,000)	(1,400,000)	(1,400,000)	
Fuel on Injection	1.88%	$ -	$ -	$ 0.0508	$ 0.0498	$ 0.0494	$ 0.0491	$ 0.0482	$ 0.0440	
Injection Charge		$ -	$ -	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	
Withdrawal Charge		$ 0.0069	$ 0.0069	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0069	$ 0.0069	$ 0.0577	$ 0.0567	$ 0.0563	$ 0.0560	$ 0.0551	$ 0.0509	
EQT 60SS/115SS Cost		$ 10,350	$ 9,660	$ 69,285	$ 68,063	$ 78,778	$ 78,373	$ 77,157	$ 71,204	
EGT&S GSS - PNG										
(Injection)/Withdrawal Mcf		356,517	263,543	(90,000)	(305,000)	(305,000)	(305,000)	(305,000)	(300,000)	
Fuel on Injection	1.99%	$ -	$ -	$ 0.0511	$ 0.0500	$ 0.0495	$ 0.0492	$ 0.0483	$ 0.0438	
Injection Charge		$ -	$ -	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	
Withdrawal Charge		$ 0.0160	$ 0.0160	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0160	$ 0.0160	$ 0.0778	$ 0.0767	$ 0.0762	$ 0.0759	$ 0.0750	$ 0.0705	
DTI GSS COSTS - PNG		$ 5,704	$ 4,217	$ 6,998	$ 23,388	$ 23,243	$ 23,150	$ 22,870	$ 21,146	
EGT&S GSS - EGC										
(Injection)/Withdrawal Mcf		504,000	175,000	(280,000)	(300,000)	(310,000)	(315,000)	(315,000)	(310,000)	
Fuel on Injection	1.99%	$ -	$ -	$ 0.0511	$ 0.0500	$ 0.0495	$ 0.0492	$ 0.0483	$ 0.0438	
Injection Charge		$ -	$ -	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	
Withdrawal Charge		$ 0.0160	$ 0.0160	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0160	$ 0.0160	$ 0.0778	$ 0.0767	$ 0.0762	$ 0.0759	$ 0.0750	$ 0.0705	
DTI GSS COSTS - EGC		$ 8,064	$ 2,800	$ 21,773	$ 23,005	$ 23,624	$ 23,909	$ 23,620	$ 21,850	
NFGS ESS										
(Injection)/Withdrawal Mcf		130,000	110,000	(40,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	
Fuel on Injection	0.94%	$ -	$ -	$ 0.0239	$ 0.0234	$ 0.0231	$ 0.0230	$ 0.0226	$ 0.0205	
Injection Charge		$ -	$ -	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	
Withdrawal Charge		$ 0.0471	$ 0.0471	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0471	$ 0.0471	$ 0.0710	$ 0.0705	$ 0.0702	$ 0.0701	$ 0.0697	$ 0.0676	
NFGS ESS Cost		$ 6,123	$ 5,181	$ 2,839	$ 7,046	$ 7,024	$ 7,010	$ 6,967	$ 6,756	
TOTAL STORAGE INJ/WD COST		$ 30,241	$ 21,858	$ 114,535	$ 163,283	$ 191,479	$ 190,888	$ 187,972	$ 162,966	$ 1,063,221

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Other Gas Costs

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
Gas Admin Costs	$ 9,462	$ 9,462	$ 9,462	$ 9,462	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 75,280
Imbalance Buyback									
Mcf	0	0	0	0	0	0	0	0	0
Amount	0	0	0	0	0	0	0	0	0
Exchange Gas									
Mcf	0	0	0	0	0	0	0	0	0
Amount	0	0	0	0	0	0	0	0	0
TOTAL OTHER GAS COSTS	$ 9,462	$ 9,462	$ 9,462	$ 9,462	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 75,280

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Interstate Pipeline Demand and Capacity Costs

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
Interstate Transportation									
Equitrans									
FTS - 770									
Demand Determinant - Dth	251,700	251,700	62,000	62,000	62,000	62,000	62,000	62,000	
Demand Rate - $/Dth	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	
Demand Cost - $	$ 1,934,315	$ 1,934,315	$ 476,470	$ 476,470	$ 476,470	$ 476,470	$ 476,470	$ 476,470	$ 6,727,449
Equitrans									
NOFT - 860									
Demand Determinant - Dth	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	
Demand Rate - $/Dth	$ 8.291	$ 8.291	$ 7.519	$ 7.519	$ 7.519	$ 7.519	$ 7.519	$ 7.519	
Demand Cost - $	$ 659,500	$ 659,500	$ 598,091	$ 598,091	$ 598,091	$ 598,091	$ 598,091	$ 598,091	$ 4,907,545
Equitrans									
FTS - 861									
Demand Determinant - Dth	164,935	164,935	164,935	164,935	164,935	164,935	164,935	164,935	
Demand Rate - $/Dth	$ 6.121	$ 6.121	$ 5.556	$ 5.556	$ 5.556	$ 5.556	$ 5.556	$ 5.556	
Demand Cost - $	$ 1,009,501	$ 1,009,501	$ 916,362	$ 916,362	$ 916,362	$ 916,362	$ 916,362	$ 916,362	$ 7,517,177
Eastern GT&S									
FTNN - 100119									
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	
Demand Cost - $ 1/	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 1,421,347
Eastern GT&S									
FT - 200654									
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	
Demand Cost - $	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 1,335,712
Texas Eastern Transmission									
FT-1									
Demand Determinant - Dth	15,650	15,650	15,650	15,650	15,650	15,650	15,650	15,650	
Demand Rate - $/Dth	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	
Demand Cost - $	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 1,560,743
National Fuel Gas Supply									
EFT									
Demand Determinant - Dth	15,476	15,476	15,476	15,476	15,476	15,476	15,476	15,476	
Demand Rate - $/Dth	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	
Demand Cost - $	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 575,150
Equitable Energy - NAESB									
Demand Determinant - Dth	11,665,780	12,915,685	-	-	-	-	-	-	
Demand Rate - $/Dth	$ 0.1746	$ 0.1746	$ -	$ -	$ -	$ -	$ -	$ -	
Demand Cost - $	$ 2,036,845	$ 2,255,079	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,291,924
TGP Winter Reservation - Z4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO Winter Reservation - M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO - AMA 2/	$ (191,250)	$ (191,250)	$ (191,250)	$ (191,250)	$ (191,250)	$ (191,250)	$ (191,250)	$ (191,250)	$ (1,530,000)
Total Demand and Capacity Costs									
Demand Determinant - Dth	607,306	607,306	417,606	417,606	417,606	417,606	417,606	417,606	
Demand Cost - $	$ 6,060,530	$ 6,278,763	$ 2,411,292	$ 2,411,292	$ 2,411,292	$ 2,411,292	$ 2,411,292	$ 2,411,292	$ 26,807,046

1/ EGT&S Contract 100119 Capacity Charges include additional costs for HUB III project
2/ Reflects 75% of the AMA capacity release revenues.

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Interstate Pipeline Demand and Capacity Costs

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
Interstate Storage									
Eastern GT&S									
GSS -300181									
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	
Demand Cost - $	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	
Capacity Determinant - Dth	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	
Capacity Rate - $/Dth	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	
Capacity Cost - $	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	
Eastern GT&S									
GSS -300196									
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	
Demand Cost - $	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	
Capacity Determinant - Dth	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	
Capacity Rate - $/Dth	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	
Capacity Cost - $	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	
Equitrans									
60SS - 863									
Demand Determinant - Dth	137,010	137,010	137,010	137,010	137,010	137,010	137,010	137,010	
Demand Rate - $/Dth	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	
Demand Cost - $	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	
Capacity Determinant - Dth	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	
Capacity Rate - $/Dth	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	
Capacity Cost - $	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	
Equitrans									
115SS - 865									
Demand Determinant - Dth	50,536	50,536	50,536	50,536	50,536	50,536	50,536	50,536	
Demand Rate - $/Dth	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	
Demand Cost - $	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	
Capacity Determinant - Dth	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	
Capacity Rate - $/Dth	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	
Capacity Cost - $	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	
National Fuel Gas Supply									
ESS									
Demand Determinant - Dth	9,793	9,793	9,793	9,793	9,793	9,793	9,793	9,793	
Demand Rate - $/Dth	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	
Demand Cost - $	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	
Capacity Determinant - Dth	748,611	748,611	748,611	748,611	748,611	748,611	748,611	748,611	
Capacity Rate - $/Dth	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	
Capacity Cost - $	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	
Equitrans									
60SS - Acquired Capacity from PG									
Demand Determinant - Dth	-	-	-	-	-	-	-	-	
Demand Rate - $/Dth	$ 1.8438	$ 1.8438							
Demand Cost - $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Capacity Determinant - Dth	-	-	-	-	-	-	-	-	
Capacity Rate - $/Dth	$ 0.0145	$ 0.0145							
Capacity Cost - $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Storage Demand/Capacity Costs									
Demand Determinant - Dth	277,339	277,339	277,339	277,339	277,339	277,339	277,339	277,339	
Capacity Determinant - Dth	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	
Total Cost - $	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 9,853,890

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
Interstate Pipeline Demand and Capacity Costs

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
Interstate Storage Transportation									
Equitrans									
FTS - 862									
Demand Determinant - Dth	137,010	137,010	74,733	74,733	74,733	74,733	74,733	74,733	
Demand Rate - $/Dth	$ 6.1206	$ 6.1206	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	
Demand Cost - $	$ 838,583	$ 838,583	$ 415,209	$ 415,209	$ 415,209	$ 415,209	$ 415,209	$ 415,209	$ 4,168,421
Equitrans									
FTS - 864									
Demand Determinant - Dth	50,536	50,536	26,417	26,417	26,417	26,417	26,417	26,417	
Demand Rate - $/Dth	$ 6.1206	$ 6.1206	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	
Demand Cost - $	$ 309,311	$ 309,311	$ 146,770	$ 146,770	$ 146,770	$ 146,770	$ 146,770	$ 146,770	$ 1,499,243
Total Demand and Capacity Costs									
Demand Determinant - Dth	187,546	187,546	101,150	101,150	101,150	101,150	101,150	101,150	
Demand Cost - $	$ 1,147,894	$ 1,147,894	$ 561,979	$ 561,979	$ 561,979	$ 561,979	$ 561,979	$ 561,979	$ 5,667,664

Peoples Natural Gas Company
Annual 1307(f)-2021
Interim Period Projected Gas Costs
EQT AVC Demand and Capacity Charges

	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	Total
Interstate Transportation									
Equitrans									
AVC - 773									
Demand Determinant - Dth	251,700	251,700	62,000	62,000	62,000	62,000	62,000	62,000	
Demand Rate - $/Dth	$ 10.3172	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	
Demand Cost - $	$ 2,596,839	$ 2,709,022	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 9,309,660
Interstate Storage Transportation									
Equitrans									
AVC - 774									
Demand Determinant - Dth	200,000	200,000	62,000	62,000	62,000	62,000	62,000	62,000	
Demand Rate - $/Dth	$ 10.3172	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	
Demand Cost - $	$ 2,063,440	$ 2,152,580	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 8,219,819
Interstate Storage									
Equitrans									
AVC - 775									
Demand Determinant - Dth	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	
Demand Rate - $/Dth	$ 3.8106	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	
Demand Cost - $	$ 762,120	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 6,097,940
Capacity Determinant - Dth	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	
Capacity Rate - $/Dth	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	
Capacity Cost - $	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 6,095,680
AVC GSS Capacity Release									
Demand Determinant - Mcf	-	-	-	-	-	-	-	-	
Demand Rate - $/Mcf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Demand Cost - $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
TOTAL AVC Capacity Costs	$ 6,184,359	$ 6,385,822	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 29,723,099

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
SUMMARY

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Total
Local / Gathered Purchases													
Quantity - Mcf	625,867	617,831	625,796	625,761	601,726	625,691	617,656	625,620	617,585	625,550	625,515	617,480	7,452,078
Rate per Mcf	$2.4454	$2.6902	$2.9569	$3.1175	$3.0470	$2.8380	$2.4675	$2.3063	$2.2729	$2.2626	$2.2631	$1.9760	$2.5529
Cost	$1,530,467	$1,662,098	$1,850,447	$1,950,827	$1,833,447	$1,775,741	$1,524,044	$1,442,842	$1,403,720	$1,415,339	$1,415,604	$1,220,157	$19,024,734
Interstate Pipeline Purchases													
Quantity - Mcf	3,975,565	3,087,119	5,402,125	5,005,301	4,173,013	2,789,947	4,874,101	3,852,313	3,441,442	3,472,856	3,583,469	3,393,963	47,051,216
Rate per Mcf	$2.2919	$2.5170	$2.8306	$3.0760	$2.9975	$2.6998	$2.3201	$2.1432	$2.0952	$2.0840	$2.1018	$1.8219	$2.4513
Cost	$9,111,405	$7,770,289	$15,291,361	$15,396,113	$12,508,791	$7,532,411	$11,308,173	$8,256,469	$7,210,400	$7,237,489	$7,531,627	$6,183,344	$115,337,872
Total Commodity Purchases													
Quantity - Mcf	4,601,432	3,704,950	6,027,922	5,631,062	4,774,739	3,415,638	5,491,757	4,477,934	4,059,028	4,098,406	4,208,984	4,011,443	54,503,294
Rate per Mcf	$2.3127	$2.5459	$2.8437	$3.0806	$3.0038	$2.7252	$2.3366	$2.1660	$2.1222	$2.1113	$2.1257	$1.8456	$2.4652
Cost	$10,641,872	$9,432,387	$17,141,808	$17,346,941	$14,342,239	$9,308,152	$12,832,216	$9,699,311	$8,614,120	$8,652,828	$8,947,231	$7,403,501	$134,362,606
Storage (Injection)/Withdrawals - WACCOG													
Quantity - Mcf	(1,794,494)	1,964,000	3,331,000	5,035,000	4,240,517	3,463,459	(1,636,818)	(2,530,000)	(3,015,000)	(3,095,000)	(3,195,000)	(2,760,000)	7,664
WACCOG Rate per Mcf	$2.3369	$2.5542	$2.5542	$2.5542	$2.5542	$2.5542	$2.3584	$2.2016	$2.1676	$2.1561	$2.1691	$1.8845	
Cost	($4,193,475)	$5,016,392	$8,507,943	$12,860,250	$10,831,005	$8,846,266	($3,860,266)	($5,570,103)	($6,535,344)	($6,673,015)	($6,930,215)	($5,201,218)	$7,098,221
Injection/Withdrawal Costs	$101,656	$19,074	$35,237	$45,931	$30,241	$21,241	$110,164	$150,048	$174,910	$174,235	$173,039	$146,701	$1,182,478
Pipeline Transportation Charges													$0
Other Purchased Gas Costs													
Other Gas Costs - Mcf	-	-	-	-	-	-	-	-	-	-	-	-	0
Risk Mgmt / Gas Admin Costs	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$112,302
Imbalance Buyback Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Exchange Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Compressed Natural Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359	$112,302
Capacity Costs - Firm Transportation	$2,411,292	$6,397,268	$6,470,013	$6,470,013	$6,251,780	$6,470,013	$2,602,542	$2,602,542	$2,602,542	$2,602,542	$2,602,542	$2,602,542	$50,085,633
Capacity Costs - Firm Storage	$1,793,716	$2,379,630	$2,379,630	$2,379,630	$2,379,630	$2,379,630	$1,793,716	$1,793,716	$1,793,716	$1,793,716	$1,793,716	$1,793,716	$24,454,161
AVC Capacity Costs	$2,858,820	$6,385,822	$6,385,822	$6,385,822	$6,385,822	$6,385,822	$2,858,820	$2,858,820	$2,858,820	$2,858,820	$2,858,820	$2,858,820	$51,940,847
	$7,063,827	$15,162,721	$15,235,465	$15,235,465	$15,017,232	$15,235,465	$7,255,077	$7,255,077	$7,255,077	$7,255,077	$7,255,077	$7,255,077	$126,480,641
Total 1307(f) Gas Costs	$ 13,623,239	$ 29,639,932	$ 40,929,812	$ 45,497,946	$ 40,230,075	$ 33,420,483	$ 16,346,551	$ 11,543,691	$ 9,518,122	$ 9,418,484	$ 9,454,491	$ 9,613,420	$ 269,236,247
Total - w/o AVC	$ 10,764,420	$ 23,254,110	$ 34,543,990	$ 39,112,124	$ 33,844,253	$ 27,034,661	$ 13,487,731	$ 8,684,871	$ 6,659,303	$ 6,559,665	$ 6,595,672	$ 6,754,600	$ 217,295,401
Capacity (excludes AVC)	$ 4,205,008	$ 8,776,899	$ 8,849,643	$ 8,849,643	$ 8,631,410	$ 8,849,643	$ 4,396,258	$ 4,396,258	$ 4,396,258	$ 4,396,258	$ 4,396,258	$ 4,396,258	$ 74,539,794
Commodity	**$ 6,559,412**	**$ 14,477,212**	**$ 25,694,346**	**$ 30,262,481**	**$ 25,212,844**	**$ 18,185,018**	**$ 9,091,473**	**$ 4,288,614**	**$ 2,263,045**	**$ 2,163,407**	**$ 2,199,414**	**$ 2,358,343**	**$ 142,755,607**
1307(f) Mcf	2,806,938	5,668,950	9,358,922	10,666,062	9,015,256	6,879,097	3,854,939	1,947,934	1,044,028	1,003,406	1,013,984	1,251,443	54,510,958

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
Local Purchases

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
Local / Gathered Purchases													
Quantity - Mcf	625,867	617,831	625,796	625,761	601,726	625,691	617,656	625,620	617,585	625,550	625,515	617,480	7,452,078
Rate per Mcf	$ 2.445	$ 2.690	$ 2.957	$ 3.118	$ 3.047	$ 2.838	$ 2.467	$ 2.306	$ 2.273	$ 2.263	$ 2.263	$ 1.976	$ 2.553
Cost	$ 1,530,467	$ 1,662,098	$ 1,850,447	$ 1,950,827	$ 1,833,447	$ 1,775,741	$ 1,524,044	$ 1,442,842	$ 1,403,720	$ 1,415,339	$ 1,415,604	$ 1,220,157	$ 19,024,734

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
Interstate Pipeline Purchases

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
City-Gate Mcf													
EQT - NAESB	3,519,565	2,825,119	4,758,625	4,352,801	3,787,513	2,599,947	4,507,101	3,366,313	2,843,442	2,869,256	2,984,869	2,820,963	41,235,516
EGT&S SP	125,000	0	0	0	0	0	100,000	305,000	320,000	320,000	315,000	280,000	1,765,000
Tennessee Gas Pipeline	20,000	22,000	150,000	210,000	150,000	0	0	0	0	0	0	15,000	567,000
Texas Eastern Transmission - M3	90,000	140,000	310,000	285,000	165,000	130,000	120,000	6,000	90,000	90,000	90,000	90,000	1,606,000
National Fuel Gas Supply	186,000	60,000	108,500	77,500	14,500	0	102,000	155,000	168,000	173,600	173,600	168,000	1,386,700
Tennessee into Columbia	35,000	40,000	75,000	80,000	56,000	60,000	45,000	20,000	20,000	20,000	20,000	20,000	491,000
TOTAL MCF	3,975,565	3,087,119	5,402,125	5,005,301	4,173,013	2,789,947	4,874,101	3,852,313	3,441,442	3,472,856	3,583,469	3,393,963	47,051,216
Interstate Pricing													
EQT - NAESB	$2.2965	$2.5017	$2.7642	$2.9259	$2.8966	$2.6662	$2.3236	$2.1535	$2.1040	$2.0907	$2.1121	$1.8302	
EGT&S SP	$2.2037	$2.4538	$2.7128	$2.8726	$2.8227	$2.5944	$2.2319	$2.0652	$2.0381	$2.0217	$2.0222	$1.7424	
Tennessee Gas Pipeline	$2.4890	$2.7186	$2.9830	$3.1761	$3.0959	$2.9033	$2.5426	$2.3974	$2.3579	$2.3521	$2.3527	$2.0705	
Texas Eastern Transmission - M3	$2.3407	$2.7732	$3.7898	$5.3284	$5.2092	$3.2781	$2.2720	$2.0773	$2.1054	$2.1934	$2.1757	$1.8910	
National Fuel Gas Supply	$2.1820	$2.4297	$2.6863	$2.8446	$2.7952	$2.5690	$2.2098	$2.0447	$2.0179	$2.0016	$2.0021	$1.7249	
Tennessee into Columbia	$2.4890	$2.7186	$2.9830	$3.1761	$3.0959	$2.9033	$2.5426	$2.3974	$2.3579	$2.3521	$2.3527	$2.0705	
Interstate Purchase Cost													
EQT - NAESB	$8,082,535	$7,067,707	$13,153,899	$12,736,007	$10,970,987	$6,932,056	$10,472,526	$7,249,248	$5,982,557	$5,998,640	$6,304,210	$5,163,018	$100,113,390
EGT&S SP	275,467	0	0	0	0	0	223,187	629,880	652,195	646,928	636,987	487,879	3,552,523
Tennessee Gas Pipeline	49,781	59,809	447,448	666,979	464,390	0	0	0	0	0	0	31,058	1,719,464
Texas Eastern Transmission - M3	210,662	388,251	1,174,826	1,518,582	859,512	426,154	272,638	12,464	189,488	197,405	195,812	170,188	5,615,982
National Fuel Gas Supply	405,845	145,780	291,465	220,458	40,530	0	225,403	316,928	339,003	347,473	347,564	289,790	2,970,238
Tennessee into Columbia	87,116	108,743	223,724	254,087	173,372	174,201	114,419	47,948	47,157	47,043	47,053	41,411	1,366,275
TOTAL COST	$9,111,405	$7,770,289	$15,291,361	$15,396,113	$12,508,791	$7,532,411	$11,308,173	$8,256,469	$7,210,400	$7,237,489	$7,531,627	$6,183,344	$115,337,872

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
WACCOG Storage Inventory Pricing

WACCOG Storage Inventory Pricing	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
(Injection)/Withdrawal Mcf													
60SS/115SS - 863/865	(950,000)	1,400,000	2,000,000	2,655,000	1,500,000	1,400,000	(1,200,000)	(1,200,000)	(1,400,000)	(1,400,000)	(1,400,000)	(1,400,000)	5,000
EGT&S GSS - 300196	(275,000)	250,000	460,000	715,000	504,000	175,000	(280,000)	(300,000)	(310,000)	(315,000)	(315,000)	(310,000)	(1,000)
EQT AVC GSS	(259,494)	-	-	550,000	1,500,000	1,403,459	(151,818)	(475,000)	(675,000)	(675,000)	(675,000)	(545,000)	(2,853)
EGT&S GSS - PNG	(125,000)	150,000	450,000	525,000	356,517	225,000	(90,000)	(305,000)	(305,000)	(305,000)	(305,000)	(275,000)	(3,483)
NFGS ESS	(75,000)	64,000	146,000	165,000	130,000	110,000	(40,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	-
On-System (Dice)	(110,000)	100,000	275,000	425,000	250,000	150,000	125,000	(150,000)	(225,000)	(300,000)	(400,000)	(130,000)	10,000
TOTAL	(1,794,494)	1,964,000	3,331,000	5,035,000	4,240,517	3,463,459	(1,636,818)	(2,530,000)	(3,015,000)	(3,095,000)	(3,195,000)	(2,760,000)	7,664
WACCOG Storage Inventory Rate	$ 2.3369	$ 2.5542	$ 2.5542	$ 2.5542	$ 2.5542	$ 2.5542	$ 2.3584	$ 2.2016	$ 2.1676	$ 2.1561	$ 2.1691	$ 1.8845	
WACCOG Storage Inventory Cost	$ (4,193,475)	$ 5,016,392	$ 8,507,943	$ 12,860,250	$ 10,831,005	$ 8,846,266	$ (3,860,266)	$ (5,570,103)	$ (6,535,344)	$ (6,673,015)	$ (6,930,215)	$ (5,201,218)	$ 7,098,221

	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September
Local Purchases - Mcf	617,656	625,620	617,585	625,550	625,515	617,480
Interstate Purchases - Mcf	4,874,101	3,852,313	3,441,442	3,472,856	3,583,469	3,393,963
	5,491,757	4,477,934	4,059,028	4,098,406	4,208,984	4,011,443
Local Purchases - Cost	$1,524,044	$1,442,842	$1,403,720	$1,415,339	$1,415,604	$1,220,157
Interstate Purchases - Cost	$11,308,173	$8,256,469	$7,210,400	$7,237,489	$7,531,627	$6,183,344
Injection/Withdrawal Costs	$110,164	$150,048	$174,910	$174,235	$173,039	$146,701
Other Purchased Gas Costs	$9,359	$9,359	$9,359	$9,359	$9,359	$9,359
	$12,951,739	$9,858,717	$8,798,389	$8,836,422	$9,129,629	$7,559,560
WACCOG Inventory Pricing	$ 2.3584	$ 2.2016	$ 2.1676	$ 2.1561	$ 2.1691	$ 1.8845

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
Storage Injection / Withhdrawal Costs

Storage Injection/Withdrawal Costs		2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
EQT AVC GSS														
(Injection)/Withdrawal Mcf		(259,494)	-	-	550,000	1,500,000	1,403,459	(151,818)	(475,000)	(675,000)	(675,000)	(675,000)	(545,000)	(2,853)
Fuel on Injection	3.50%	$ 0.0772	$ -	$ -	$ -	$ -	$ -	$ 0.0781	$ 0.0723	$ 0.0714	$ 0.0708	$ 0.0708	$ 0.0611	
Injection Charge		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Withdrawal Charge		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0772	$ -	$ -	$ -	$ -	$ -	$ 0.0781	$ 0.0723	$ 0.0714	$ 0.0708	$ 0.0708	$ 0.0611	
EQT AVC GSS Cost		$ 20,022	$ -	$ -	$ -	$ -	$ -	$ 11,863	$ 34,353	$ 48,179	$ 47,791	$ 47,804	$ 33,276	$ 243,288
EQT 60SS/115SS														
(Injection)/Withdrawal Mcf		(950,000)	1,400,000	2,000,000	2,655,000	1,500,000	1,400,000	(1,200,000)	(1,200,000)	(1,400,000)	(1,400,000)	(1,400,000)	(1,400,000)	5,000
Fuel on Injection	1.88%	$ 0.0440	$ -	$ -	$ -	$ -	$ -	$ 0.0508	$ 0.0498	$ 0.0494	$ 0.0491	$ 0.0482	$ 0.0440	
Injection Charge		$ 0.0069	$ -	$ -	$ -	$ -	$ -	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	
Withdrawal Charge		$ -	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0509	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0069	$ 0.0577	$ 0.0567	$ 0.0563	$ 0.0560	$ 0.0551	$ 0.0509	
EQT 60SS/115SS Cost		$ 48,355	$ 9,660	$ 13,800	$ 18,320	$ 10,350	$ 9,660	$ 69,285	$ 68,063	$ 78,778	$ 78,373	$ 77,157	$ 71,204	$ 553,006
EGT&S GSS - PNG														
(Injection)/Withdrawal Mcf		(125,000)	150,000	450,000	525,000	356,517	225,000	(90,000)	(305,000)	(305,000)	(305,000)	(305,000)	(275,000)	(3,483)
Fuel on Injection	1.99%	$ 0.0438	$ -	$ -	$ -	$ -	$ -	$ 0.0444	$ 0.0411	$ 0.0405	$ 0.0402	$ 0.0402	$ 0.0347	
Injection Charge		$ 0.0267	$ -	$ -	$ -	$ -	$ -	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	
Withdrawal Charge		$ -	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0705	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0711	$ 0.0678	$ 0.0672	$ 0.0669	$ 0.0669	$ 0.0614	
DTI GSS COSTS - PNG		$ 8,816	$ 2,400	$ 7,200	$ 8,400	$ 5,704	$ 3,600	$ 6,398	$ 20,670	$ 20,506	$ 20,406	$ 20,410	$ 16,872	$ 141,383
EGT&S GSS - EGC														
(Injection)/Withdrawal Mcf		(275,000)	250,000	460,000	715,000	504,000	175,000	(280,000)	(300,000)	(310,000)	(315,000)	(315,000)	(310,000)	(1,000)
Fuel on Injection	1.99%	$ 0.0438	$ -	$ -	$ -	$ -	$ -	$ 0.0444	$ 0.0411	$ 0.0405	$ 0.0402	$ 0.0402	$ 0.0347	
Injection Charge		$ 0.0267	$ -	$ -	$ -	$ -	$ -	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	$ 0.0267	
Withdrawal Charge		$ -	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0705	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0160	$ 0.0711	$ 0.0678	$ 0.0672	$ 0.0669	$ 0.0669	$ 0.0614	
DTI GSS COSTS - EGC		$ 19,395	$ 4,000	$ 7,360	$ 11,440	$ 8,064	$ 2,800	$ 19,904	$ 20,332	$ 20,842	$ 21,075	$ 21,079	$ 19,019	$ 175,311
NFGS ESS														
(Injection)/Withdrawal Mcf		(75,000)	64,000	146,000	165,000	130,000	110,000	(40,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	-
Fuel on Injection	0.94%	$ 0.0205	$ -	$ -	$ -	$ -	$ -	$ 0.0207	$ 0.0192	$ 0.0189	$ 0.0188	$ 0.0188	$ 0.0162	
Injection Charge		$ 0.0471	$ -	$ -	$ -	$ -	$ -	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	
Withdrawal Charge		$ -	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ -	$ -	$ -	$ -	$ -	$ -	
		$ 0.0676	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0471	$ 0.0678	$ 0.0663	$ 0.0660	$ 0.0659	$ 0.0659	$ 0.0633	
NFGS ESS Cost		$ 5,069	$ 3,014	$ 6,877	$ 7,772	$ 6,123	$ 5,181	$ 2,714	$ 6,629	$ 6,604	$ 6,589	$ 6,589	$ 6,329	$ 69,490
TOTAL STORAGE INJ/WD COST		$ 101,656	$ 19,074	$ 35,237	$ 45,931	$ 30,241	$ 21,241	$ 110,164	$ 150,048	$ 174,910	$ 174,235	$ 173,039	$ 146,701	$ 1,182,478

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
Other Gas Costs

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
Gas Admin Costs	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 112,302
Imbalance Buyback													
Mcf	0	0	0	0	0	0	0	0	0	0	0	0	0
Amount	0	0	0	0	0	0	0	0	0	0	0	0	0
Exchange Gas													
Mcf	0	0	0	0	0	0	0	0	0	0	0	0	0
Amount	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OTHER GAS COSTS	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 9,359	$ 112,302

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
Interstate Pipeline Demand and Capacity Costs

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
Interstate Transportation													
Equitrans													
FTS - 770													
Demand Determinant - Dth	62,000	251,700	251,700	251,700	251,700	251,700	62,000	62,000	62,000	62,000	62,000	62,000	
Demand Rate - $/Dth	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	$ 7.685	
Demand Cost - $	$ 476,470	$ 1,934,315	$ 1,934,315	$ 1,934,315	$ 1,934,315	$ 1,934,315	$ 476,470	$ 476,470	$ 476,470	$ 476,470	$ 476,470	$ 476,470	$ 13,006,863
Equitrans													
NOFT - 860													
Demand Determinant - Dth	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	79,545	
Demand Rate - $/Dth	$ 7.519	$ 8.291	$ 8.291	$ 8.291	$ 8.291	$ 8.291	$ 7.519	$ 7.519	$ 7.519	$ 7.519	$ 7.519	$ 7.519	
Demand Cost - $	$ 598,091	$ 659,500	$ 659,500	$ 659,500	$ 659,500	$ 659,500	$ 598,091	$ 598,091	$ 598,091	$ 598,091	$ 598,091	$ 598,091	$ 7,484,135
Equitrans													
FTS - 861													
Demand Determinant - Dth	164,935	164,935	164,935	164,935	164,935	164,935	164,935	164,935	164,935	164,935	164,935	164,935	
Demand Rate - $/Dth	$ 5.556	$ 6.121	$ 6.121	$ 6.121	$ 6.121	$ 6.121	$ 5.556	$ 5.556	$ 5.556	$ 5.556	$ 5.556	$ 5.556	
Demand Cost - $	$ 916,362	$ 1,009,501	$ 1,009,501	$ 1,009,501	$ 1,009,501	$ 1,009,501	$ 916,362	$ 916,362	$ 916,362	$ 916,362	$ 916,362	$ 916,362	$ 11,462,042
Eastern GT&S													
FTNN - 100119													
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	
Demand Cost - $	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 177,668	$ 2,132,021
Eastern GT&S													
FT - 200654													
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	$ 4.174	
Demand Cost - $	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 166,964	$ 2,003,568
Texas Eastern Transmission													
FT-1													
Demand Determinant - Dth	15,650	15,650	15,650	15,650	15,650	15,650	15,650	15,650	15,650	15,650	15,650	15,650	
Demand Rate - $/Dth	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	$ 12.466	
Demand Cost - $	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 195,093	$ 2,341,115
National Fuel Gas Supply													
EFT													
Demand Determinant - Dth	15,476	15,476	15,476	15,476	15,476	15,476	15,476	15,476	15,476	15,476	15,476	15,476	
Demand Rate - $/Dth	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	$ 4.646	
Demand Cost - $	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 71,894	$ 862,725
Equitable Energy - NAESB													
Demand Determinant - Dth	-	12,499,050	12,915,685	12,915,685	11,665,780	12,915,685	-	-	-	-	-	-	
Demand Rate - $/Dth	$ -	$ 0.1746	$ 0.1746	$ 0.1746	$ 0.1746	$ 0.1746	$ -	$ -	$ -	$ -	$ -	$ -	
Demand Cost - $	$ -	$ 2,182,334	$ 2,255,079	$ 2,255,079	$ 2,036,845	$ 2,255,079	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,984,415
TGP Winter Reservation - Z4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO Winter Reservation - M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO - AMA 2/	$ (191,250)												$ (191,250)
Total Demand and Capacity Costs													
Demand Determinant - Dth	417,606	607,306	607,306	607,306	607,306	607,306	417,606	417,606	417,606	417,606	417,606	417,606	
Demand Cost - $	$ 2,411,292	$ 6,397,268	$ 6,470,013	$ 6,470,013	$ 6,251,780	$ 6,470,013	$ 2,602,542	$ 2,602,542	$ 2,602,542	$ 2,602,542	$ 2,602,542	$ 2,602,542	$ 50,085,633

1/ EGT&S Contract 100119 Capacity Charges include additional costs for HUB III project
2/ Reflects 75% of the AMA capacity release revenues.

Peoples Natural Gas Company
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Projected Period Gas Costs
Interstate Pipeline Demand and Capacity Costs

Interstate Storage	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
Eastern GT&S													
GSS -300181													
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	$ 1.8716	
Demand Cost - $	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 74,864	$ 898,368
Capacity Determinant - Dth	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	4,600,000	
Capacity Rate - $/Dth	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	$ 0.0145	
Capacity Cost - $	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 66,700	$ 800,400
Eastern GT&S													
GSS -300196													
Demand Determinant - Dth	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	
Demand Rate - $/Dth	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	$ 5.1206	
Demand Cost - $	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 204,824	$ 2,457,888
Capacity Determinant - Dth	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	2,480,000	
Capacity Rate - $/Dth	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	$ 0.0841	
Capacity Cost - $	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 208,568	$ 2,502,816
Equitrans													
60SS - 863													
Demand Determinant - Dth	137,010	137,010	137,010	137,010	137,010	137,010	137,010	137,010	137,010	137,010	137,010	137,010	
Demand Rate - $/Dth	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	
Demand Cost - $	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 204,816	$ 2,457,795
Capacity Determinant - Dth	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	7,473,296	
Capacity Rate - $/Dth	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	
Capacity Cost - $	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 195,800	$ 2,349,604
Equitrans													
115SS - 865													
Demand Determinant - Dth	50,536	50,536	50,536	50,536	50,536	50,536	50,536	50,536	50,536	50,536	50,536	50,536	
Demand Rate - $/Dth	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	$ 1.4949	
Demand Cost - $	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 75,546	$ 906,555
Capacity Determinant - Dth	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	5,283,357	
Capacity Rate - $/Dth	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	$ 0.0262	
Capacity Cost - $	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 138,424	$ 1,661,087
National Fuel Gas Supply													
ESS													
Demand Determinant - Dth	9,793	9,793	9,793	9,793	9,793	9,793	9,793	9,793	9,793	9,793	9,793	9,793	
Demand Rate - $/Dth	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	$ 2.6433	
Demand Cost - $	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 25,886	$ 310,630
Capacity Determinant - Dth	748,611	748,611	748,611	748,611	748,611	748,611	748,611	748,611	748,611	748,611	748,611	748,611	
Capacity Rate - $/Dth	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	$ 0.0485	
Capacity Cost - $	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 36,308	$ 435,692
Equitrans													
60SS - Acquired Capacity from PG													
Demand Determinant - Dth	-	-	-	-	-	-	-	-	-	-	-	-	
Demand Rate - $/Dth													
Demand Cost - $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capacity Determinant - Dth	-	-	-	-	-	-	-	-	-	-	-	-	
Capacity Rate - $/Dth													
Capacity Cost - $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage Demand/Capacity Costs													
Demand Determinant - Dth	277,339	277,339	277,339	277,339	277,339	277,339	277,339	277,339	277,339	277,339	277,339	277,339	
Capacity Determinant - Dth	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	20,585,264	
Total Cost - $	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 1,231,736	$ 14,780,836

Peoples Natural Gas Company
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Projected Period Gas Costs
Interstate Pipeline Demand and Capacity Costs

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	12-Mth Collection
Interstate Storage Transportation													
Equitrans													
FTS - 862													
Demand Determinant - Dth	74,733	137,010	137,010	137,010	137,010	137,010	74,733	74,733	74,733	74,733	74,733	74,733	
Demand Rate - $/Dth	$ 5.5559	$ 6.1206	$ 6.1206	$ 6.1206	$ 6.1206	$ 6.1206	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	
Demand Cost - $	$ 415,209	$ 838,583	$ 838,583	$ 838,583	$ 838,583	$ 838,583	$ 415,209	$ 415,209	$ 415,209	$ 415,209	$ 415,209	$ 415,209	$ 7,099,381
Equitrans													
FTS - 864													
Demand Determinant - Dth	26,417	50,536	50,536	50,536	50,536	50,536	26,417	26,417	26,417	26,417	26,417	26,417	
Demand Rate - $/Dth	$ 5.5559	$ 6.1206	$ 6.1206	$ 6.1206	$ 6.1206	$ 6.1206	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	$ 5.5559	
Demand Cost - $	$ 146,770	$ 309,311	$ 309,311	$ 309,311	$ 309,311	$ 309,311	$ 146,770	$ 146,770	$ 146,770	$ 146,770	$ 146,770	$ 146,770	$ 2,573,945
Total Demand and Capacity Costs													
Demand Determinant - Dth	101,150	187,546	187,546	187,546	187,546	187,546	101,150	101,150	101,150	101,150	101,150	101,150	
Demand Cost - $	$ 561,979	$ 1,147,894	$ 1,147,894	$ 1,147,894	$ 1,147,894	$ 1,147,894	$ 561,979	$ 561,979	$ 561,979	$ 561,979	$ 561,979	$ 561,979	$ 9,673,325

Peoples Natural Gas Company
Annual 1307(f)-2021
Projected Period Gas Costs
EQT AVC Demand and Capacity Charges

	2021 October	2021 November	2021 December	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	#REF! #REF!
Interstate Transportation													
Equitrans													
AVC - 773													
Demand Determinant - Dth	62,000	251,700	251,700	251,700	251,700	251,700	62,000	62,000	62,000	62,000	62,000	62,000	
Demand Rate - $/Dth	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	
Demand Cost - $	$ 667,300	$ 2,709,022	$ 2,709,022	$ 2,709,022	$ 2,709,022	$ 2,709,022	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 18,216,208
Interstate Storage Transportation													
Equitrans													
AVC - 774													
Demand Determinant - Dth	62,000	200,000	200,000	200,000	200,000	200,000	62,000	62,000	62,000	62,000	62,000	62,000	
Demand Rate - $/Dth	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	$ 10.7629	
Demand Cost - $	$ 667,300	$ 2,152,580	$ 2,152,580	$ 2,152,580	$ 2,152,580	$ 2,152,580	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 667,300	$ 15,433,999
Interstate Storage													
Equitrans													
AVC - 775													
Demand Determinant - Dth	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	
Demand Rate - $/Dth	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	$ 3.8113	
Demand Cost - $	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 762,260	$ 9,147,120
Capacity Determinant - Dth	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	8,600,000	
Capacity Rate - $/Dth	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	$ 0.0886	
Capacity Cost - $	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 761,960	$ 9,143,520
AVC GSS Capacity Release													
Demand Determinant - Mcf	-	-	-	-	-	-	-	-	-	-	-	-	
Demand Rate - $/Mcf	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Demand Cost - $	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL AVC Capacity Costs	$ 2,858,820	$ 6,385,822	$ 6,385,822	$ 6,385,822	$ 6,385,822	$ 6,385,822	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 2,858,820	$ 51,940,847

Section 53.64 (c)(1):

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. .

* * * * * * * * * *

Examples of such provisions for Peoples Natural Gas' current gas supply contracts are as follows:

<u>I. GISB Standard Form Base Contract For The Short-Term Sale And Purchase Of Natural Gas 1</u>

Penalty Provisions:

<u>Cover Standard</u>: In addition to any liability for Imbalance Charges, which shall not be recovered twice by the following remedy, the exclusive and sole remedy of the parties in the event of a breach of a Performance Obligation, other than the delivery and receipt of Gas on an Interruptible basis, shall be the recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard for replacement Gas or alternative fuels and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s); or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s); or (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, then the exclusive and sole remedy of the non-breaching party shall be any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the

1 The GISB form contract was the first standard gas sales and purchase contract form for use in the spot market, and it became the prevalent form for purchases of interstate gas in the mid-1990s. In December of 2001, the North American Energy Standards Board (NAESB) was formed and took the place of GISB in the market. The NAESB form contract was introduced in 2002 and has largely replaced the GISB form agreement. Still, Peoples Natural Gas makes some purchases under GISB form contracts.

difference between the Contract Quantity and the quantity actually delivered by Seller and received by Buyer for such Day(s).

(or)

Spot Price Standard: In addition to any liability for Imbalance Charges, which shall not be recovered twice by the following remedy, the exclusive and sole remedy of the parties in the event of a breach of a Performance Obligation, other than the delivery and receipt of Gas on an Interruptible basis, shall be the recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price.

Warranty Provisions:

Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims.

Balancing Provisions:

The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's actions or inactions (which shall include, but shall not be limited to, Buyer's failure to accept quantities of Gas equal to the Scheduled Gas), then Buyer shall pay for such Imbalance Charges, or reimburse Seller for such Imbalance Charges paid by Seller to the Transporter. If the Imbalance Charges were incurred as a result of Seller's actions or inactions (which shall include, but shall not be limited to, Seller's failure to deliver quantities of Gas equal to the Scheduled Gas), then Seller shall pay for such Imbalance Charges, or reimburse Buyer for such Imbalance Charges paid by Buyer to the Transporter.

II. NAESB Standard Form Base Contract For the Sale And Purchase Of Natural Gas

Penalty Provisions:

(a) Cover Standard: The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the positive difference, if any, between the purchase price paid by Buyer utilizing the Cover Standard and the Contract Price, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller for such Day(s); or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in the amount equal to the positive difference, if any, between the Contract Price and the price received by Seller utilizing the Cover Standard for the resale of such Gas, adjusted for commercially reasonable differences in transportation costs to or from the Delivery Point(s), multiplied by the difference between the Contract Quantity and the quantity actually taken by Buyer for such Day(s); or (iii) in the event that Buyer has used commercially reasonable efforts to replace the Gas or Seller has used commercially reasonable efforts to sell the Gas to a third party, and no such replacement or sale is available, then the sole and exclusive remedy of the performing party shall be any unfavorable difference between the Contract Price and the Spot Price, adjusted for such transportation to the applicable Delivery Point, multiplied by the difference between the Contract Quantity and the quantity actually delivered by Seller and received by Buyer for such Day(s). Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

(or)

<u>(b) Spot Price Standard</u>: The sole and exclusive remedy of the parties in the event of a breach of a Firm obligation to deliver or receive Gas shall be recovery of the following: (i) in the event of a breach by Seller on any Day(s), payment by Seller to Buyer in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the Contract Price from the Spot Price; or (ii) in the event of a breach by Buyer on any Day(s), payment by Buyer to Seller in an amount equal to the difference between the Contract Quantity and the actual quantity delivered by Seller and received by Buyer for such Day(s), multiplied by the positive difference, if any, obtained by subtracting the applicable Spot Price from the Contract Price. Imbalance Charges shall not be recovered under this Section 3.2, but Seller and/or Buyer shall be responsible for Imbalance Charges, if any, as provided in Section 4.3. The amount of such unfavorable difference shall be payable five Business Days after presentation of the performing party's invoice, which shall set forth the basis upon which such amount was calculated.

<u>Warranty Provisions:</u>

Seller warrants that it will have the right to convey and will transfer good and merchantable title to all Gas sold hereunder and delivered by it to Buyer, free and clear of all liens, encumbrances, and claims. EXCEPT AS PROVIDED IN THIS SECTION 8.2 AND IN SECTION 14.8, ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR ANY PARTICULAR PURPOSE, ARE DISCLAIMED.

Balancing Provisions:

The parties shall coordinate their nomination activities, giving sufficient time to meet the deadlines of the affected Transporter(s). Each party shall give the other party timely prior Notice, sufficient to meet the requirements of all Transporter(s) involved in the transaction, of the quantities of Gas to be delivered and purchased each Day. Should either party become aware that actual deliveries at the Delivery Point(s) are greater or lesser than the Scheduled Gas, such party shall promptly notify the other party.

The parties shall use commercially reasonable efforts to avoid imposition of any Imbalance Charges. If Buyer or Seller receives an invoice from a Transporter that includes Imbalance Charges, the parties shall determine the validity as well as the cause of such Imbalance Charges. If the Imbalance Charges were incurred as a result of Buyer's receipt of quantities of Gas greater than or less than the Scheduled Gas, then Buyer shall pay for such Imbalance Charges or reimburse Seller for such Imbalance Charges paid by Seller. If the Imbalance Charges were incurred as a result of Seller's delivery of quantities of Gas greater than or less than the Scheduled Gas, then Seller shall pay for such Imbalance Charges or reimburse Buyer for such Imbalance Charges paid by Buyer.

III. Local Gas Standard Form Base Contract For The Sale And Purchase of Natural Gas

Penalty Provisions:

Suspension: If Producer fails to comply with any of the covenants contained in this Master Agreement, or any other gas supply and/or delivery agreement between Producer and Peoples' direct natural gas affiliates, Peoples may refuse to allow Gas to flow through the Interconnect until, in Peoples' sole opinion, Producer is fully complying with all of the terms and conditions of this Master Agreement. Peoples, in its sole judgment, shall have the right to shut-in the Interconnect immediately if equipment is not operating properly, an overpressure condition exists, design limitations are exceeded, or safe operating conditions are compromised. Furthermore, Peoples has the right to keep the Interconnect shut-in until the Producer makes the necessary provisions to rectify the situation. If the abnormal conditions repeatedly arise, Peoples has the right to shut-in the Interconnect indefinitely and/or to terminate this Master Agreement.

Producer shall reimburse Peoples for any damages caused by Producer failing to comply with any of the covenants contained in this Master Agreement, including payments made by Peoples to other affected customers in settlement of claims arising out of such service if Producer was notified that Peoples was invoking indemnification under Section 13.03 and Producer was given the opportunity to defend against the claim prior to such settlement agreement. To the extent any damages required to be paid hereunder are liquidated, the parties acknowledge that the damages are difficult or impossible to determine, otherwise obtaining an adequate remedy is inconvenient and the liquidated damages constitute a reasonable approximation of the harm or loss.

If litigation results from any dispute between Producer and Peoples, Peoples may pay any money withheld under this Master Agreement to a court of competent jurisdiction without any further liability, or may interplead all claimants, including Producer. The prevailing party in a litigated dispute between Peoples and Producer shall have the right to collect from the other party its reasonable costs and necessary disbursements and attorneys' fees incurred in enforcing this Agreement.

From EXHIBIT A-02 to Master Interconnect and Measurement Agreement - Additional Terms and Conditions Governing the Purchase of Gas

1. **Sale and Purchase Obligations**. Producer shall produce and sell to Peoples, and Peoples shall take and pay for, quantities of Gas delivered to the Receipt Point(s) set forth below. Peoples shall have no obligation to pay for any Gas until such time as it has been produced and delivered to the designated Receipt Point(s). Except in instances where Peoples and Producer agree otherwise, Producer's sale shall be a full requirements sale where all Gas produced shall be delivered to Peoples. Notwithstanding the foregoing, Peoples may reduce or suspend its purchases under this Master Agreement in the event that Peoples has insufficient pipeline capacity or insufficient market demand to facilitate the sale and/or use of Producer's Gas. Upon notice to Producer, Producer shall promptly comply with Peoples' reduction or suspension request. In the event Peoples should ever cease, in whole or in part, to sell Gas directly to end-use customers (otherwise known as providing merchant or sales service), then Peoples may, in its sole discretion, terminate this Master Agreement upon at least sixty (60) days written notice to Producer.

APPLICABLE TO SETTLING PARTIES PURSUANT TO
THE DECEMBER 6, 2013 STIPULATION IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.6)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [3] Surcharge	EPCA [4] Surcharge	Other Adj.	Current Rate [6]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FT, FTNN [2], [5]									
	RESERVATION CHARGE:								
	(Maximum Rate)	$3.8820	$0.2756	$0.0038	$0.0057	$0.0006	-	$4.1677	-
	(Minimum Rate)	$0.0000	-	-	-	-	-	$0.0000	-
	USAGE CHARGE:								
	(Maximum Rate)	$0.0083	$0.0051	$0.0023	$0.0001	$0.0004	-	$0.0162	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
	CAPACITY RELEASE (Vol. Charge):								
	(Maximum Rate)	$0.1276	$0.0091	$0.0001	$0.0002	$0.0000	-	$0.1370	-
FT(SC), FTNN(SC) [2]									
	(Maximum Rate)	$0.2636	$0.0232	$0.0025	$0.0005	$0.0004	-	$0.2902	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
IT [2]									
	(Maximum Rate)	$0.1359	$0.0032	$0.0024	$0.0003	$0.0004	-	$0.1422	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]

[1] The Base Tariff Rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] The Maximum Transportation Service Fuel Retention Percentage is 1.38% plus Adders of 0.57% (RP00-632 S&A, approved 9/13/01), totaling 1.95%.
[3] 858 over/under from previous TCRA period.
[4] Electric over/under from previous EPCA period.
[5] The maximum base tariff rate for Hope Gas, Inc. (d/b/a Dominion Energy West Virginia) for (a) up to 38,765 DT/d of its FTNN service and (b) up to 91,241 DT/d of its FTNN-GSS service shall be $3.5618 per DT.
[6] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[7] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO
THE DECEMBER 6, 2013 STIPULATION IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.6)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [3] Surcharge	EPCA [4] Surcharge	Other Adj.	Current Rate [6]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FT, FTNN [2], [5]									
	RESERVATION CHARGE:								
	(Maximum Rate)	$3.8820	$0.2756	$0.0040	$0.0057	$0.0003	-	$4.1676	-
	(Minimum Rate)	$0.0000	-	-	-	-	-	$0.0000	-
	USAGE CHARGE:								
	(Maximum Rate)	$0.0083	$0.0051	$0.0019	$0.0001	($0.0003)	-	$0.0151	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
	CAPACITY RELEASE (Vol. Charge):								
	(Maximum Rate)	$0.1276	$0.0091	$0.0001	$0.0002	$0.0000	-	$0.1370	-
FT(SC), FTNN(SC) [2]									
	(Maximum Rate)	$0.2636	$0.0232	$0.0022	$0.0005	($0.0003)	-	$0.2892	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
IT [2]									
	(Maximum Rate)	$0.1359	$0.0032	$0.0020	$0.0003	($0.0003)	-	$0.1411	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]

[1] The Base Tariff Rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] The Maximum Transportation Service Fuel Retention Percentage is 1.38% plus Adders of 0.57% (RP00-632 S&A, approved 9/13/01), totaling 1.95%.
[3] 858 over/under from previous TCRA period.
[4] Electric over/under from previous EPCA period.
[5] The maximum base tariff rate for Hope Gas, Inc. (d/b/a Dominion Energy West Virginia) for (a) up to 38,765 DT/d of its FTNN service and (b) up to 91,241 DT/d of its FTNN-GSS service shall be $3.5618 per DT.
[6] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[7] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO
THE DECEMBER 6, 2013 STIPULATION IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.6)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [3] Surcharge	EPCA [4] Surcharge	Other Adj.	Current Rate [6]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FT, FTNN [2], [5]									
	RESERVATION CHARGE:								
	(Maximum Rate)	$3.8820	$0.2847	$0.0040	$0.0031	$0.0003	-	$4.1741	-
	(Minimum Rate)	$0.0000	-	-	-	-	-	$0.0000	-
	USAGE CHARGE:								
	(Maximum Rate)	$0.0083	$0.0048	$0.0019	($0.0005)	($0.0003)	-	$0.0142	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
	CAPACITY RELEASE (Vol. Charge):								
	(Maximum Rate)	$0.1276	$0.0094	$0.0001	$0.0001	$0.0000	-	$0.1372	-
FT(SC), FTNN(SC) [2]									
	(Maximum Rate)	$0.2636	$0.0235	$0.0022	($0.0003)	($0.0003)	-	$0.2887	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
IT [2]									
	(Maximum Rate)	$0.1359	$0.0034	$0.0020	($0.0004)	($0.0003)	-	$0.1406	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]

[1] The Base Tariff Rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] The Maximum Transportation Service Fuel Retention Percentage is 1.38% plus Adders of 0.57% (RP00-632 S&A, approved 9/13/01), totaling 1.95%.
[3] 858 over/under from previous TCRA period.
[4] Electric over/under from previous EPCA period.
[5] The maximum base tariff rate for Hope Gas, Inc. (d/b/a Dominion Energy West Virginia) for (a) up to 38,765 DT/d of its FTNN service and (b) up to 91,241 DT/d of its FTNN-GSS service shall be $3.5618 per DT.
[6] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[7] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO
THE DECEMBER 6, 2013 STIPULATION IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.6)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [3] Surcharge	EPCA [4] Surcharge	Other Adj.	Current Rate [6]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FT, FTNN [2], [5]									
	RESERVATION CHARGE:								
	(Maximum Rate)	$3.8820	$0.2847	$0.0040	$0.0031	$0.0003	-	$4.1741	-
	(Minimum Rate)	$0.0000	-	-	-	-	-	$0.0000	-
	USAGE CHARGE:								
	(Maximum Rate)	$0.0083	$0.0048	$0.0019	($0.0005)	($0.0003)	-	$0.0142	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
	CAPACITY RELEASE (Vol. Charge):								
	(Maximum Rate)	$0.1276	$0.0094	$0.0001	$0.0001	$0.0000	-	$0.1372	-
FT(SC), FTNN(SC) [2]									
	(Maximum Rate)	$0.2636	$0.0235	$0.0022	($0.0003)	($0.0003)	-	$0.2887	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]
IT [2]									
	(Maximum Rate)	$0.1359	$0.0034	$0.0020	($0.0004)	($0.0003)	-	$0.1406	[7]
	(Minimum Rate)	$0.0083	-	-	-	-	-	$0.0083	[7]

[1] The Base Tariff Rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] The Maximum Transportation Service Fuel Retention Percentage is 1.38% plus Adders of 0.57% (RP00-632 S&A, approved 9/13/01), totaling 1.95%.
[3] 858 over/under from previous TCRA period.
[4] Electric over/under from previous EPCA period.
[5] The maximum base tariff rate for Hope Gas, Inc. (d/b/a Dominion Energy West Virginia) for (a) up to 38,765 DT/d of its FTNN service and (b) up to 91,241 DT/d of its FTNN-GSS service shall be $3.5618 per DT.
[6] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[7] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0666	$0.0072	($0.0046)	$0.0022	$1.8698	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0128	$0.0000	($0.0014)	$0.0268	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0014)	$0.0140	[8]
	GSS-TE Surcharge [3]	-	$0.0047	-	$0.0001	-	$0.0048	-
	From Customers Balance	$0.6163	$0.0144	$0.0015	($0.0010)	($0.0009)	$0.6303	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0666	$0.0072	($0.0046)	$0.0022	$2.2827	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0128	$0.0000	($0.0014)	$0.0268	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0014)	$0.0140	[8]
	Authorized Overruns	$1.0657	$0.0144	$0.0015	($0.0010)	($0.0009)	$1.0797	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0002)	$0.0001	$0.0759	-
	Injection Charge	$0.0154	-	$0.0128	$0.0000	($0.0014)	$0.0268	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0014)	$0.0140	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0144	$0.0015	($0.0010)	($0.0009)	$0.6303	[8]
	Excess Injection Charge	$0.2245	-	$0.0128	$0.0000	($0.0014)	$0.2359	-

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6163. Daily Capacity Release Rate for GSS-E per Dt is $1.0657.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0666	$0.0073	($0.0046)	$0.0008	$1.8685	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	GSS-TE Surcharge [3]	-	$0.0047	-	$0.0001	-	$0.0048	-
	From Customers Balance	$0.6163	$0.0144	$0.0016	($0.0010)	($0.0005)	$0.6308	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0666	$0.0073	($0.0046)	$0.0008	$2.2814	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overruns	$1.0657	$0.0144	$0.0016	($0.0010)	($0.0005)	$1.0802	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0002)	$0.0000	$0.0758	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0144	$0.0016	($0.0010)	($0.0005)	$0.6308	[8]
	Excess Injection Charge	$0.2245	-	$0.0120	$0.0000	($0.0007)	$0.2358	-

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6161. Daily Capacity Release Rate for GSS-E per Dt is $1.0655.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0673	$0.0073	($0.0022)	$0.0008	$1.8716	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	GSS-TE Surcharge [3]	-	$0.0047	-	$0.0006	-	$0.0053	-
	From Customers Balance	$0.6163	$0.0144	$0.0016	($0.0005)	($0.0005)	$0.6313	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0673	$0.0073	($0.0022)	$0.0008	$2.2845	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overruns	$1.0657	$0.0144	$0.0016	($0.0005)	($0.0005)	$1.0807	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0001)	$0.0000	$0.0759	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0144	$0.0016	($0.0005)	($0.0005)	$0.6313	[8]
	Excess Injection Charge	$0.2245	-	$0.0120	$0.0000	($0.0007)	$0.2358	-

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6166. Daily Capacity Release Rate for GSS-E per Dt is $1.0660.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)

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

Rate Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0673	$0.0073	($0.0022)	$0.0008	$1.8716	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	GSS-TE Surcharge [3]	-	$0.0047	-	$0.0006	-	$0.0053	-
	From Customers Balance	$0.6163	$0.0144	$0.0016	($0.0005)	($0.0005)	$0.6313	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0673	$0.0073	($0.0022)	$0.0008	$2.2845	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overruns	$1.0657	$0.0144	$0.0016	($0.0005)	($0.0005)	$1.0807	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0001)	$0.0000	$0.0759	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0144	$0.0016	($0.0005)	($0.0005)	$0.6313	[8]
	Excess Injection Charge	$0.2245	-	$0.0120	$0.0000	($0.0007)	$0.2358	-

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6166. Daily Capacity Release Rate for GSS-E per Dt is $1.0660.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (http://www.ferc.gov/industries/gas/annual-charges.asp).

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.71)

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

Incremental Facility Surcharges

Rate Schedule (1)	Incremental Facilities Docket (2)	Surcharge (3)
FT, FTNN		
	Lebanon to Leidy (Docket No. CP89-638)	
	RESERVATION	$2.0280
	CAPACITY RELEASE (Max. Vol. Charge)	$0.0667
	Leidy to Market (Docket No. CP89-638)	
	RESERVATION	$0.8127
	CAPACITY RELEASE (Max. Vol. Charge)	$0.0267
	Dominion Hub III (Docket No. CP09-18-000)	
	RESERVATION	$2.0625
	Sabinsville to Morrisville (Docket No. CP12-20-000)	
	RESERVATION	$2.6869
	Leidy South (Docket No. CP15-492-000)	
	RESERVATION (Electric)	$0.1646
	USAGE (Electric)	$0.0559
	FUEL	0.35%

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.71)

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

Incremental Facility Surcharges

Rate Schedule	Incremental Facilities Docket	Surcharge
(1)	(2)	(3)
FT, FTNN		
	Lebanon to Leidy (Docket No. CP89-638)	
	RESERVATION	$2.0280
	CAPACITY RELEASE (Max. Vol. Charge)	$0.0667
	Leidy to Market (Docket No. CP89-638)	
	RESERVATION	$0.8127
	CAPACITY RELEASE (Max. Vol. Charge)	$0.0267
	Dominion Hub III (Docket No. CP09-18-000)	
	RESERVATION	$2.0625
	Sabinsville to Morrisville (Docket No. CP12-20-000)	
	RESERVATION	$2.6869
	Leidy South (Docket No. CP15-492-000)	
	RESERVATION (Electric)	$0.1938
	USAGE (Electric)	$0.0435
	FUEL	0.35%

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262
(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.71)

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

Incremental Facility Surcharges

Rate Schedule	Incremental Facilities Docket	Surcharge
(1)	(2)	(3)
FT, FTNN		
	Lebanon to Leidy (Docket No. CP89-638)	
	RESERVATION	$2.0280
	CAPACITY RELEASE (Max. Vol. Charge)	$0.0667
	Leidy to Market (Docket No. CP89-638)	
	RESERVATION	$0.8127
	CAPACITY RELEASE (Max. Vol. Charge)	$0.0267
	Dominion Hub III (Docket No. CP09-18-000)	
	RESERVATION	$2.0625
	Sabinsville to Morrisville (Docket No. CP12-20-000)	
	RESERVATION	$2.6869
	Leidy South (Docket No. CP15-492-000)	
	RESERVATION (Electric)	$0.1938
	USAGE (Electric)	$0.0435
	FUEL	0.35%

STATEMENT OF RATES
TRANSPORTATION RATES (Rates per Dth)

RATE SCHEDULE NOFT

RATE ZONE	NOFT RESERVATION CHARGE MAXIMUM	MINIMUM
Mainline System		
Winter (November 1 – March 31)	$ 8.2909	$ 0.0000
Base (April 1 – October 31)	$ 7.5189	$ 0.0000

RATE SCHEDULE FTS

RATE ZONE	FTS RESERVATION CHARGE MAXIMUM	MINIMUM
Mainline System		
Winter (November 1 – March 31) 1/	$ 6.1206	$ 0.0000
Base (April 1 – October 31) 1/	$ 5.5559	$ 0.0000
Incremental Rates		
Sunrise Transmission System	$ 12.7329	$ 0.0000
Ohio Valley Connector	$ 8.9871	$ 0.0000
Allegheny Valley Connector	$ 9.6511	$ 0.0000

RATE SCHEDULE EFT

RATE ZONE	EFT RESERVATION CHARGE MAXIMUM	MINIMUM
Mainline System		
Winter (November 1 – March 31) 1/	$ 9.1809	$ 0.0000
Base (April 1 – October 31) 1/	$ 8.3339	$ 0.0000
Incremental Rates		
Sunrise Transmission System	$ 19.0994	$ 0.0000
Ohio Valley Connector	$ 13.4807	$ 0.0000
Allegheny Valley Connector	$ 14.4767	$ 0.0000

RATE SCHEDULE STS-1

RATE ZONE	STS-1 RESERVATION CHARGE MAXIMUM	MINIMUM
Mainline System		
Winter (November 1 – March 31) 1/	$ 6.1206	$ 0.0000
Base (April 1 – October 31) 1/	$ 5.5559	$ 0.0000

RATE SCHEDULE FTSS

RATE ZONE	FTSS RESERVATION CHARGE MAXIMUM	MINIMUM
Allegheny Valley Connector	$ 9.6511	$ 0.0000

1/ Includes PSC Reservation Charge of $0.8108.

RATE SCHEDULE NOFT

RATE ZONE	NOFT USAGE CHARGE 1/ MAXIMUM 2/		NOFT USAGE CHARGE 1/ MINIMUM	
Mainline System				
Winter (November 1 – March 31)	$	0.1481	$	0.0000
Base (April 1 – October 31)	$	0.1466	$	0.0000

RATE SCHEDULES FTS and EFT

WINTER (NOVEMBER 1 – MARCH 31) MAXIMUM USAGE 1/

Service Provided on	Mainline System 3/ 4/		Delivered To Sunrise Transmission System		Allegheny Valley Connector	
Mainline System 3/ 4/						
From Mainline System	$	0.1481	$	0.1481	$	0.4654
From Sunrise Transmission System	$	0.1481	$	0.1481	$	0.4654
From Allegheny Valley Connector	$	0.4654	$	0.4654	$	0.3173
Sunrise Transmission System						
From Mainline System 3/ 4/	$	0.1372	$	0.0000	$	0.3173
From Sunrise Transmission System	$	0.1372	$	0.0000	$	0.3173
From Allegheny Valley Connector	$	0.4545	$	0.3173	$	0.3173
Allegheny Valley Connector						
From Mainline System 3/ 4/	$	0.3239	$	0.3239	$	0.3239
From Sunrise Transmission System 3/	$	0.3239	$	0.3239	$	0.3239
From Allegheny Valley Connector	$	0.3239	$	0.3239	$	0.0000

WINTER (NOVEMBER 1 – MARCH 31) MINIMUM USAGE 1/

Service Provided on	Mainline System		Delivered To Sunrise Transmission System		Allegheny Valley Connector	
Mainline System	$	0.0109	$	0.0109	$	0.0109
Sunrise Transmission System	$	0.0000	$	0.0000	$	0.0000
Allegheny Valley Connector	$	0.0109	$	0.0109	$	0.0000

BASE (APRIL 1 – OCTOBER 31) MAXIMUM USAGE 1/

Service Provided on	Mainline System 3/ 4/	Delivered To Sunrise Transmission System	Allegheny Valley Connector
Mainline System 3/ 4/			
From Mainline System	$ 0.1466	$ 0.1466	$ 0.4639
From Sunrise Transmission System	$ 0.1466	$ 0.1466	$ 0.4639
From Allegheny Valley Connector	$ 0.4639	$ 0.4639	$ 0.3173
Sunrise Transmission System			
From Mainline System 3/ 4/	$ 0.1372	$ 0.0000	$ 0.3173
From Sunrise Transmission System	$ 0.1372	$ 0.0000	$ 0.3173
From Allegheny Valley Connector	$ 0.4545	$ 0.3173	$ 0.3173
Allegheny Valley Connector			
From Mainline System 3/ 4/	$ 0.3018	$ 0.3018	$ 0.3018
From Sunrise Transmission System 3/	$ 0.3018	$ 0.3018	$ 0.3018
From Allegheny Valley Connector	$ 0.3018	$ 0.3018	$ 0.0000

BASE (APRIL 1 – OCTOBER 31) MINIMUM USAGE 1/

Service Provided on	Mainline System	Delivered To Sunrise Transmission System	Allegheny Valley Connector
Mainline System	$ 0.0094	$ 0.0094	$ 0.0094
Sunrise Transmission System	$ 0.0000	$ 0.0000	$ 0.0000
Allegheny Valley Connector	$ 0.0094	$ 0.0094	$ 0.0000

RATE SCHEDULE STS-1

RATE ZONE	STS-1 USAGE CHARGE 1/ MAXIMUM 3/	MINIMUM
Mainline System	$ 0.1466	$ 0.0094

RATE SCHEDULE FTSS

RATE ZONE	FTSS USAGE CHARGE 1/ MAXIMUM	MINIMUM
Allegheny Valley Connector	$ 0.0000	$ 0.0000

1/ In accordance with Section 6.29 of the General Terms and Conditions, the ACA Surcharge will be applied to Usage, Max. Capacity Rel., and Authorized Overrun delivered volumes.

2/ PSC usage rate of $0.1372 only applies to NOFT service nominated on a point to point basis.

3/ Gas transported on the Mainline System under Rate Schedules FTS, EFT, or STS-1 or under an Allegheny Valley Connector Service Agreement to the Mainline or Sunrise Transmission Systems includes the PSC usage rate of $0.1372.

4/ For the usage and authorized overrun rates, Mainline System rates include the Ohio Valley Connector but do not include the Sunrise Transmission System, which are separately stated.

RATE SCHEDULE NOFT

RATE ZONE	NOFT AUTHORIZED OVERRUN 1/ MAXIMUM 2/	MINIMUM
Mainline System		
Winter (November 1 – March 31)	$ 0.4226	$ 0.0109
Base (April 1 – October 31)	$ 0.3925	$ 0.0094

RATE SCHEDULES FTS and EFT

WINTER (NOVEMBER 1 – MARCH 31) MAXIMUM AUTHORIZED OVERRUN 1/

Service Provided on	Mainline System 3/ 4/	Delivered To Sunrise Transmission System	Allegheny Valley Connector
Mainline System 3/ 4/			
From Mainline System	$ 0.3239	$ 0.3239	$ 0.6412
From Sunrise Transmission System	$ 0.3239	$ 0.3239	$ 0.6412
From Allegheny Valley Connector	$ 0.6412	$ 0.6412	$ 0.3173
Sunrise Transmission System			
From Mainline System	$ 0.5558	$ 0.4186	$ 0.7359
From Sunrise Transmission System	$ 0.5558	$ 0.4186	$ 0.7359
From Allegheny Valley Connector	$ 0.8731	$ 0.7359	$ 0.3173
Allegheny Valley Connector			
From Mainline System	$ 0.3239	$ 0.3239	$ 0.6412
From Sunrise Transmission System	$ 0.3239	$ 0.3239	$ 0.6412
From Allegheny Valley Connector	$ 0.6412	$ 0.6412	$ 0.3173

WINTER (NOVEMBER 1 – MARCH 31) MINIMUM AUTHORIZED OVERRUN 1/

Service Provided on	Mainline System	Delivered To Sunrise Transmission System	Allegheny Valley Connector
Mainline System	$ 0.0109	$ 0.0109	$ 0.0109
Sunrise Transmission System	$ 0.0000	$ 0.0000	$ 0.0000
Allegheny Valley Connector	$ 0.0109	$ 0.0000	$ 0.0000

BASE (APRIL 1 – OCTOBER 31) MAXIMUM AUTHORIZED OVERRUN 1/

Service Provided on	Mainline System 3/ 4/	Delivered To Sunrise Transmission System	Allegheny Valley Connector
Mainline System 3/ 4/			
From Mainline System	$ 0.3018	$ 0.3018	$ 0.6191
From Sunrise Transmission System	$ 0.3018	$ 0.3018	$ 0.6191
From Allegheny Valley Connector	$ 0.6191	$ 0.6191	$ 0.3173
Sunrise Transmission System			
From Mainline System	$ 0.5558	$ 0.4186	$ 0.7359
From Sunrise Transmission System	$ 0.5558	$ 0.4186	$ 0.7359
From Allegheny Valley Connector	$ 0.8731	$ 0.7359	$ 0.3173
Allegheny Valley Connector			
From Mainline System	$ 0.3018	$ 0.3018	$ 0.6191
From Sunrise Transmission System	$ 0.3018	$ 0.3018	$ 0.6191
From Allegheny Valley Connector	$ 0.6191	$ 0.6191	$ 0.3173

BASE (APRIL 1 – OCTOBER31) MINIMUM AUTHORIZED OVERRUN 1/

Service Provided on	Mainline System	Delivered To Sunrise Transmission System	Allegheny Valley Connector
Mainline System	$ 0.0094	$ 0.0094	$ 0.0094
Sunrise Transmission System	$ 0.0000	$ 0.0000	$ 0.0000
Allegheny Valley Connector	$ 0.0094	$ 0.0000	$ 0.0000

RATE SCHEDULE STS-1

RATE ZONE	STS-1 AUTHORIZED OVERRUN 1/ MAXIMUM 3/	MINIMUM
Mainline System	$ 0.3018	$ 0.0000

RATE SCHEDULE FTSS

RATE ZONE	FTSS AUTHORIZED OVERRUN 1/ MAXIMUM	MINIMUM
Allegheny Valley Connector	$ 0.3173	$ 0.0000

1/ In accordance with Section 6.29 of the General Terms and Conditions, the ACA Surcharge will be applied to Usage, Max. Capacity Rel., and Authorized Overrun delivered volumes.

2/ PSC usage rate of $0.1372 only applies to NOFT service nominated on a point to point basis.

3/ Gas transported on the Mainline System under Rate Schedules FTS, EFT, or STS-1 includes the PSC usage rate of $0.1372.

4/ For the usage and authorized overrun rates, Mainline System rates include the Ohio Valley Connector but do not include the Sunrise Transmission System, which are separately stated.

RATE SCHEDULE NOFT

RATE ZONE	MAX. CAPACITY REL. VOL. CHARGE 1/, 2/	
Mainline System		
Winter (November 1 – March 31)	$	0.4226
Base (April 1 – October 31)	$	0.3925

RATE SCHEDULES FTS and EFT

RATE ZONE	MAX. CAPACITY REL. VOL. CHARGE 1/	
Mainline System 3/ 4/		
Winter (November 1 – March 31)	$	0.3239
Base (April 1 – October 31) 1/	$	0.3018
Incremental Rate		
Sunrise Transmission System	$	0.4186
Allegheny Valley Connector	$	0.3173

RATE SCHEDULE FTSS

RATE ZONE	MAX. CAPACITY REL. VOL. CHARGE 1/	
Allegheny Valley Connector	$	0.3173

1/ In accordance with Section 6.29 of the General Terms and Conditions, the ACA Surcharge will be applied to Usage, Max. Capacity Rel., and Authorized Overrun delivered volumes.

2/ PSC usage rate of $0.1372 only applies to NOFT service nominated on a point to point basis.

3/ Gas transported on the Mainline System under Rate Schedules FTS, EFT, or STS-1 includes the PSC usage rate of $0.1372.

4/ For the Max. Capacity Rel. Vol. Charge, Mainline System rates include the Ohio Valley Connector but do not include the Sunrise Transmission System, which is separately stated.

STATEMENT OF RATES
STORAGE SERVICE RATES (Rates per Dth)

	Base Tariff Rates	Total Rates
RATE SCHEDULE 115SS and 60SS:		
MAINLINE SYSTEM		
Demand Charge		
Maximum	$1.4949	$1.4949
Minimum	$0.0000	$0.0000
Storage Space Charge		
Maximum	$0.0262	$0.0262
Minimum	$0.0000	$0.0000
Injection Charge	$0.0069	$0.0069
Withdrawal Charge	$0.0069	$0.0069
Storage Overrun Charge		
Maximum	$0.2934	$0.2934
Minimum	$0.0069	$0.0069
Max. Capacity Rel Volumetric Charge	$0.4998	$0.4998
RATE SCHEDULE GSS:		
ALLEGHENY VALLEY CONNECTOR		
Demand Charge		
Maximum	$2.5941	$2.5941
Minimum	$0.0000	$0.0000
Storage Space Charge		
Maximum	$0.0447	$0.0447
Minimum	$0.0000	$0.0000
Injection Charge	$0.0000	$0.0000
Withdrawal Charge	$0.0000	$0.0000
Storage Overrun Charge		
Maximum	$0.5360	$0.5360
Minimum	$0.0000	$0.0000
Max. Capacity Rel Volumetric Charge	$1.0721	$1.0721

	Base Tariff Rates	Total Rates
RATE SCHEDULE INSS:		
MAINLINE SYSTEM		
Storage Space Charge		
Maximum	$0.0537	$0.0537
Minimum	$0.0000	$0.0000
Injection Charge		
Maximum	$0.0069	$0.0069
Minimum	$0.0069	$0.0069
Withdrawal Charge		
Maximum	$0.0069	$0.0069
Minimum	$0.0069	$0.0069
ALLEGHENY VALLEY CONNECTOR		
Storage Space Charge		
Maximum	$0.0893	$0.0893
Minimum	$0.0000	$0.0000
Injection Charge		
Maximum	$0.0000	$0.0000
Minimum	$0.0000	$0.0000
Withdrawal Charge		
Maximum	$0.0000	$0.0000
Minimum	$0.0000	$0.0000
RATE SCHEDULE SS-3:		
MAINLINE SYSTEM		
Demand Charge	$1.4949	$1.4949
Storage Space Charge	$0.0262	$0.0262
Injection Charge	$0.0069	$0.0069
Withdrawal Charge	$0.0069	$0.0069
Storage Overrun Charge		
Maximum	$0.2934	$0.2934
Minimum	$0.0069	$0.0069

STATEMENT OF RETAINAGE FACTORS

	Retainage Factors
Mainline System (including the Sunrise Transmission System and the Ohio Valley Connector) Retainage Factor 1/	2.72%
Allegheny Valley Connector Transmission Retainage Factor 2/	0.00%
Gathering Retainage Factor 3/	
Equitrans Gathering System	9.50%
Mainline Storage Loss Retainage Factor 4/	1.85%
Allegheny Valley Connector Storage Loss Retainage Factor 5/	1.64%

1/ Percentage is applied to receipt quantities on Rate Schedules NOFT, FTS, STS-1 and ITS.

2/ Applicable to Allegheny Valley Connector FTS, FTSS and ITS Customers.

3/ Percentage is applied to receipt quantities under Rate Schedule AGS.

4/ Percentage is applied to storage injections into Mainline storage facilities.

5/ Percentage is applied to storage injections into Allegheny Valley Connector storage facilities and is subject to True-up as set forth in Section 6.31.

STATEMENT OF RETAINAGE FACTORS

	Retainage Factors
Mainline System (including the Sunrise Transmission System and the Ohio Valley Connector) Retainage Factor 1/	1.72%
Allegheny Valley Connector Transmission Retainage Factor 2/	0.00%
Gathering Retainage Factor 3/	
Equitrans Gathering System	9.50%
Mainline Storage Loss Retainage Factor 4/	1.85%
Allegheny Valley Connector Storage Loss Retainage Factor 5/	3.38%

1/ Percentage is applied to receipt quantities on Rate Schedules NOFT, FTS, STS-1, EFT and ITS.

2/ Applicable to Allegheny Valley Connector FTS, FTSS, EFT and ITS Customers.

3/ Percentage is applied to receipt quantities under Rate Schedule AGS.

4/ Percentage is applied to storage injections into Mainline storage facilities.

5/ Percentage is applied to storage injections into Allegheny Valley Connector storage facilities and is subject to True-up as set forth in Section 6.31.

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	CW2274014-1576	EFT	03/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		
Peoples Natural Gas Company, LLC	EQTR17415-774	FTSS	03/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		
EQT Energy, LLC	EQTR19837-1296	FTS	10/1/2019		
	$8.0437 per MDQ	$0.0000 per Dth delivered	$0.2645 per Dth delivered	from Mobley Receipt Point (Meter# 24505) to REX Clarington Delivery Point (60062) or Rover Traveler Delivery Point (Meter# 70007D)	
	$11.2614 per MDQ	$0.0000 per Dth delivered	$0.3702 per Dth delivered	from Applegate Receipt Point (Meter# 5100080) to REX Clarington Delivery Point (60062) or Rover Traveler Delivery Point (70007D)	
	$14.4785 per MDQ	$0.0000 per Dth delivered	$0.4760 per Dth delivered	from East Side Receipt Point (Meter# TBD) and Pluto Receipt Point (Meter# 24490) to REX Clarington Delivery Point (60062) or Rover Traveler Delivery Point (Meter# 70007D)	

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	EQTR17416-775	GSS	03/01/2019		
	$3.6190 per MDWQ	$0.0842 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0100 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	EQTR10404-515	0.42%	4/1/2019
Mountain V Oil & Gas	EQTR10400-517	0.42%	4/1/2019
Arsenal Resources Energy LLC	CW2239335-510	0.42%	4/1/2019
Arsenal Resources Energy LLC	CW2239579-700	0.42%	4/1/2019
K Petroleum	EQTR25533-1317	0.42%	4/1/2019
EQT Energy LLC	EQTR20242-852	0.20%	9/1/2019
EQT Energy LLC	CW2238636-1441	0.20%	9/1/2019
Dominion Energy Field Services, Inc	EQTR10412-522	0.20%	9/1/2019
Northeast Natural Energy, LLC	EQTR12105-604	0.20%	9/1/2019
Range Resources Appalachia LLC	EQTR25020-1240	0.20%	9/1/2019
EQT Energy LLC	EQTR18237-785	0.20%	9/1/2019
EQT Energy LLC	EQTR19837-1296	0.20%	9/1/2019
Term Energy	EQTR10340-512	0.20%	9/1/2019
XTO Energy Inc.	EQTR17981-695	0.20%	9/1/2019
KIMCO A Partnership	EQTR10342-514	0.20%	9/1/2019
EQT Energy LLC	CW2271044-1537	0.20%	9/1/2019

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	CW2274014-1576	EFT	03/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		
Peoples Natural Gas Company, LLC	EQTR17415-774	FTSS	03/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		
EQT Energy, LLC	EQTR19837-1296	FTS	10/1/2019		
	$8.0437 per MDQ	$0.0000 per Dth delivered	$0.2645 per Dth delivered	from Mobley Receipt Point (Meter# 24505) to REX Clarington Delivery Point (60062) or Rover Traveler Delivery Point (Meter# 70007D)	
	$11.2614 per MDQ	$0.0000 per Dth delivered	$0.3702 per Dth delivered	from Applegate Receipt Point (Meter# 5100080) to REX Clarington Delivery Point (60062) or Rover Traveler Delivery Point (70007D)	
	$14.4785 per MDQ	$0.0000 per Dth delivered	$0.4760 per Dth delivered	from East Side Receipt Point (Meter# TBD) and Pluto Receipt Point (Meter# 24490) to REX Clarington Delivery Point (60062) or Rover Traveler Delivery Point (Meter# 70007D)	

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	EQTR17416-775	GSS	03/01/2019		
	$3.6190 per MDWQ	$0.0842 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0100 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	EQTR10404-515	0.42%	4/1/2019
Mountain V Oil & Gas	EQTR10400-517	0.42%	4/1/2019
K Petroleum	EQTR25533-1317	0.42%	4/1/2019
EQT Energy LLC	EQTR20242-852	0.20%	9/1/2019
EQT Energy LLC	CW2238636-1441	0.20%	9/1/2019
Dominion Energy Field Services, Inc	EQTR10412-522	0.20%	9/1/2019
Northeast Natural Energy, LLC	EQTR12105-604	0.20%	9/1/2019
Range Resources Appalachia LLC	EQTR25020-1240	0.20%	9/1/2019
EQT Energy LLC	EQTR18237-785	0.20%	9/1/2019
EQT Energy LLC	EQTR19837-1296	0.20%	9/1/2019
Term Energy	EQTR10340-512	0.20%	9/1/2019
XTO Energy Inc.	EQTR17981-695	0.20%	9/1/2019
KIMCO A Partnership	EQTR10342-514	0.20%	9/1/2019
EQT Energy LLC	CW2271044-1537	0.20%	9/1/2019

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	CW2274014-1576	EFT	06/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		
Peoples Natural Gas Company, LLC	EQTR17415-774	FTSS	03/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	EQTR17416-775	GSS	03/01/2019		
	$3.6190 per MDWQ	$0.0842 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0100 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	EQTR10404-515	0.42%	4/1/2019
Mountain V Oil & Gas	EQTR10400-517	0.42%	4/1/2019
K Petroleum	EQTR25533-1317	0.42%	4/1/2019
EQT Energy LLC	EQTR20242-852	0.20%	9/1/2019
EQT Energy LLC	CW2238636-1441	0.20%	9/1/2019
Dominion Energy Field Services, Inc	EQTR10412-522	0.20%	9/1/2019
Northeast Natural Energy, LLC	EQTR12105-604	0.20%	9/1/2019
Range Resources Appalachia LLC	EQTR25020-1240	0.20%	9/1/2019
EQT Energy LLC	EQTR18237-785	0.20%	9/1/2019
Term Energy	EQTR10340-512	0.20%	9/1/2019
XTO Energy Inc.	EQTR17981-695	0.20%	9/1/2019
KIMCO A Partnership	EQTR10342-514	0.20%	9/1/2019
EQT Energy LLC	CW2271044-1537	0.20%	9/1/2019

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	1576	EFT	06/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		
Peoples Natural Gas Company, LLC	774	FTSS	03/01/2019		
	$10.2251 per MDQ	$0.0000 per Dth delivered	$0.3362 per Dth delivered		

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	775	GSS	03/01/2019		
	$3.6190 per MDWQ	$0.0842 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0100 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	515	0.42%	4/1/2019
Mountain V Oil & Gas	517	0.42%	4/1/2019
K Petroleum	1317	0.42%	4/1/2019
EQT Energy LLC	852	0.55%	2/1/2020
EQT Energy LLC	1441	0.55%	2/1/2020
Dominion Energy Field Services, Inc	522	0.55%	2/1/2020
Northeast Natural Energy, LLC	604	0.55%	2/1/2020
Range Resources Appalachia LLC	1240	0.55%	2/1/2020
EQT Energy LLC	785	0.55%	2/1/2020
Term Energy	512	0.55%	2/1/2020
XTO Energy Inc.	695	0.55%	2/1/2020
KIMCO A Partnership	514	0.55%	2/1/2020
EQT Energy LLC	1537	0.55%	2/1/2020
EQT Energy LLC	1296	0.55%	2/1/2020
Arsenal Resources Development LLC	510	0.55%	2/1/2020

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	1576	EFT	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
Peoples Natural Gas Company, LLC	774	FTSS	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	775	GSS	03/01/2020		
	$3.8106 per MDWQ	$0.0886 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0634 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	515	0.42%	4/1/2019
Mountain V Oil & Gas	517	0.42%	4/1/2019
K Petroleum	1317	0.42%	4/1/2019
EQT Energy LLC	852	0.55%	2/1/2020
EQT Energy LLC	1441	0.55%	2/1/2020
Dominion Energy Field Services, Inc	522	0.55%	2/1/2020
Northeast Natural Energy, LLC	604	0.55%	2/1/2020
Range Resources Appalachia LLC	1240	0.55%	2/1/2020
EQT Energy LLC	785	0.55%	2/1/2020
Term Energy	512	0.55%	2/1/2020
XTO Energy Inc.	695	0.55%	2/1/2020
KIMCO A Partnership	514	0.55%	2/1/2020
EQT Energy LLC	1537	0.55%	2/1/2020
EQT Energy LLC	1296	0.55%	2/1/2020
Arsenal Resources Development LLC	510	0.55%	2/1/2020

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	1576	EFT	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
Peoples Natural Gas Company, LLC	774	FTSS	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		

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	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	775	GSS	03/01/2020		
	$3.8106 per MDWQ	$0.0886 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0634 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	515	0.42%	4/1/2019
Mountain V Oil & Gas	517	0.42%	4/1/2019
EQT Energy LLC	852	0.55%	2/1/2020
EQT Energy LLC	1441	0.55%	2/1/2020
Dominion Energy Field Services, Inc	522	0.55%	2/1/2020
Northeast Natural Energy, LLC	604	0.55%	2/1/2020
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EQT Energy LLC	785	0.55%	2/1/2020
Term Energy	512	0.55%	2/1/2020
XTO Energy Inc.	695	0.55%	2/1/2020
KIMCO A Partnership	514	0.55%	2/1/2020
EQT Energy LLC	1537	0.55%	2/1/2020
EQT Energy LLC	1296	0.55%	2/1/2020
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Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	1576	EFT	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
Peoples Natural Gas Company, LLC	774	FTSS	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
EQT Energy, LLC	1296	FTS	10/1/2020		
	$8.0483 per MDQ	$0.0000 per Dth delivered	$0.2646 per Dth delivered	from Mobley Receipt Point (Meter# 24505) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	
	$11.2660 per MDQ	$0.0000 per Dth delivered	$0.3704 per Dth delivered	from Mcintosh Receipt Point (Meter# 5259543) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	
	$14.4877 per MDQ	$0.0000 per Dth delivered	$0.4763 per Dth delivered	from Taurus Receipt Point (Meter# M5237075), Hopewell Ridge Receipt Point (Meter# 17172), and Pluto Receipt Point (Meter# 24490) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	775	GSS	03/01/2020		
	$3.8106 per MDWQ	$0.0886 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0634 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Jerry Poling	515	0.42%	4/1/2019
Mountain V Oil & Gas	517	0.42%	4/1/2019
EQT Energy LLC	852	0.55%	2/1/2020
EQT Energy LLC	1441	0.55%	2/1/2020
Dominion Energy Field Services, Inc	522	0.55%	2/1/2020
Northeast Natural Energy, LLC	604	0.55%	2/1/2020
Range Resources Appalachia LLC	1240	0.55%	2/1/2020
EQT Energy LLC	785	0.55%	2/1/2020
Term Energy	512	0.55%	2/1/2020
XTO Energy Inc.	695	0.55%	2/1/2020
KIMCO A Partnership	514	0.55%	2/1/2020
EQT Energy LLC	1537	0.55%	2/1/2020
EQT Energy LLC	1296	0.55%	2/1/2020
Arsenal Resources Development LLC	510	0.55%	2/1/2020

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	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	1576	EFT	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
Peoples Natural Gas Company, LLC	774	FTSS	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
EQT Energy, LLC	1296	FTS	10/1/2020		
	$8.0483 per MDQ	$0.0000 per Dth delivered	$0.2646 per Dth delivered	from Mobley Receipt Point (Meter# 24505) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	
	$11.2660 per MDQ	$0.0000 per Dth delivered	$0.3704 per Dth delivered	from Mcintosh Receipt Point (Meter# 5259543) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	
	$14.4877 per MDQ	$0.0000 per Dth delivered	$0.4763 per Dth delivered	from Taurus Receipt Point (Meter# M5237075), Hopewell Ridge Receipt Point (Meter# 17172), and Pluto Receipt Point (Meter# 24490) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	

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	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	775	GSS	03/01/2020		
	$3.8106 per MDWQ	$0.0886 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0634 per Dth

Customer	Contract Number	Estimated Retainage Rate	Effective Date
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EQT Energy LLC	852	0.55%	2/1/2020
EQT Energy LLC	1441	0.55%	2/1/2020
Dominion Energy Field Services, Inc	522	0.55%	2/1/2020
Northeast Natural Energy, LLC	604	0.55%	2/1/2020
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EQT Energy LLC	785	0.55%	2/1/2020
Term Energy	512	0.55%	2/1/2020
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EQT Energy LLC	1537	0.55%	2/1/2020
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Arsenal Resources Development LLC	510	0.55%	2/1/2020

FORMULA-BASED NEGOTIATED RATES

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Reservation Rate	**Usage Rate**	**Authorized Overrun Rate**		
Peoples Natural Gas Company, LLC	1576	EFT	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
Peoples Natural Gas Company, LLC	774	FTSS	03/01/2020		
	$10.3172 per MDQ	$0.0000 per Dth delivered	$0.3392 per Dth delivered		
EQT Energy, LLC	1296	FTS	10/1/2020		
	$8.0483 per MDQ	$0.0000 per Dth delivered	$0.2646 per Dth delivered	from Mobley Receipt Point (Meter# 24505) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	
	$11.2660 per MDQ	$0.0000 per Dth delivered	$0.3704 per Dth delivered	from Mcintosh Receipt Point (Meter# 5259543) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	
	$14.4877 per MDQ	$0.0000 per Dth delivered	$0.4763 per Dth delivered	from Taurus Receipt Point (Meter# M5237075), Hopewell Ridge Receipt Point (Meter# 17172), and Pluto Receipt Point (Meter# 24490) to REX Isaly Delivery Point (Meter# 60062D) or Rover Traveler Delivery Point (Meter# 70007D)	

Customer	**Contract Number**	**Rate Schedule**	**Effective Date**		
	Monthly Demand Reservation Rate	**Monthly Storage Space Reservation Rate**	**Injection Charge**	**Withdrawal Charge**	**Storage Authorized Overrun Charge**
Peoples Natural Gas Company, LLC	775	GSS	03/01/2020		
	$3.8106 per MDWQ	$0.0886 per TASQ	$0.0000 per Dth	$0.0000 per Dth	$1.0634 per Dth

Customer	**Contract Number**	**Estimated Retainage Rate**	**Effective Date**
Mountain V Oil & Gas	517	0.42%	4/1/2019
EQT Energy LLC	852	0.55%	2/1/2020
EQT Energy LLC	1441	0.55%	2/1/2020
Northeast Natural Energy, LLC	604	0.55%	2/1/2020
Range Resources Appalachia LLC	1240	0.55%	2/1/2020
EQT Energy LLC	785	0.55%	2/1/2020
EQT Energy LLC	1537	0.55%	2/1/2020
EQT Energy LLC	1296	0.55%	2/1/2020
Arsenal Resources Development LLC	510	0.55%	2/1/2020

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)	$3.6293	-	-	$3.6293 [4]
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA [3]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA [3]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3]
EFT	Reservation	(Max)	3.8067	0.0000	0.0000	$3.8067 [4]
		(Min)	0.0000	0.0000	0.0000	$0.0000
	Commodity	(Max)	0.0148	0.0000	0.0000	$0.0148 plus ACA[3]
		(Min)	0.0148	0.0000	0.0000	$0.0148 plus ACA[3]
	Overrun	(Max)	0.1452	-	-	$0.1452 plus ACA[3]
		(Min)	0.0148	-	-	$0.0148 plus ACA[3]
FST	Reservation	(Max)	3.6293	-	-	$3.6293 [4]
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA [3]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA [3]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3]
IT	Commodity	(Max)	$0.1378	-	-	$0.1378 plus ACA [3]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3]
	Overrun	(Max)	0.1378	-		$0.1378 plus ACA [3]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3]

The NA15 Retention is 1.15% applicable to use of the Northern Access 2015 Lease. [2] [3]

1/ The unit of measure for each rate component is Dth unless otherwise indicated.

2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.99% and the Transportation LAUF Retention for all applicable rate schedules is 0.43%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.

3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.

4/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0943 shall be added as a Transmission PS/GHG Surcharge, in addition to the specified rate.

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)	$5.2781	-	-	$5.2781
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0163	-	-	$0.0163 plus ACA [3/]
		(Min)	0.0163	-	-	$0.0163 plus ACA [3/]
	Overrun	(Max)	0.1898	-	-	$0.1898 plus ACA [3/]
		(Min)	0.0163	-	-	$0.0163 plus ACA [3/]
EFT	Reservation	(Max)	$5.4548	0.0000	0.0000	$5.4548
		(Min)	0.0000	0.0000	0.0000	$0.0000
	Commodity	(Max)	0.0171	0.0000	0.0000	$0.0171 plus ACA[3/]
		(Min)	0.0171	0.0000	0.0000	$ 0.0171 plus ACA[3/]
	Overrun	(Max)	0.1964	-	-	$0.1964 plus ACA[3/]
		(Min)	0.0171	-	-	$0.0171 plus ACA[3/]
FST	Reservation	(Max)	$5.2781	-	-	$5.2781
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0163	-	-	$0.0163 plus ACA [3/]
		(Min)	0.0163	-	-	$0.0163 plus ACA [3/]
	Overrun	(Max)	0.1898	-	-	$0.1898 plus ACA [3/]
		(Min)	0.0163	-	-	$0.0163 plus ACA [3/]
IT	Commodity	(Max)	$0.1898	-		$0.1898 plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3/]
	Overrun	(Max)	0.1898	-		$0.1898 plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3/]

The NA15 Retention is 1.15% applicable to use of the Northern Access 2015 Lease. [2/ 3/]

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.99% and the Transportation LAUF Retention for all applicable rate schedules is 0.43%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.

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)	$4.5019	-	-	$4.5019	
		(Min)	0.0000	-	-	$0.0000	
	Commodity	(Max)	0.0140	-	-	$0.0140	plus ACA [3/]
		(Min)	0.0140	-	-	$0.0140	plus ACA [3/]
	Overrun	(Max)	0.1620	-	-	$0.1620	plus ACA [3/]
		(Min)	0.0140	-	-	$0.0140	plus ACA [3/]
EFT	Reservation	(Max)	$4.6455	0.0000	0.0000	$4.6455	
		(Min)	0.0000	0.0000	0.0000	$0.0000	
	Commodity	(Max)	0.0148	0.0000	0.0000	$0.0148	plus ACA[3/]
		(Min)	0.0148	0.0000	0.0000	$0.0148	plus ACA[3/]
	Overrun	(Max)	0.1675	-	-	$0.1675	plus ACA[3/]
		(Min)	0.0148	-	-	$0.0148	plus ACA[3/]
FST	Reservation	(Max)	$4.5019	-	-	$4.5019	
		(Min)	0.0000	-	-	$0.0000	
	Commodity	(Max)	0.0140	-	-	$0.0140	plus ACA [3/]
		(Min)	0.0140	-	-	$0.0140	plus ACA [3/]
	Overrun	(Max)	0.1620	-	-	$0.1620	plus ACA [3/]
		(Min)	0.0140	-	-	$0.0140	plus ACA [3/]
IT	Commodity	(Max)	$0.1620	-		$0.1620	plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000	plus ACA [3/]
	Overrun	(Max)	0.1620	-		$0.1620	plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000	plus ACA [3/]

The NA15 Retention is 1.05% applicable to use of the Northern Access 2015 Lease. [2/ 3/]

1/ The unit of measure for each rate component is Dth unless otherwise indicated.

2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.80% and the Transportation LAUF Retention for all applicable rate schedules is 0.23%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero (“Zero Fuel Point Pair Transactions”). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.

3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission’s website, will be charged in addition to the specified rate.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component 1/ (2)		Rate 2/ (3)
ESS	Demand	(Max)	$2.4921 5/
		(Min)	$0.0000
	Capacity	(Max)	$0.0388 6/
		(Min)	$0.0000
	Injection/ Withdrawal	(Max)	$0.0411plus ACA 3/
		(Min)	$0.0000
	Storage Balance Transfer	(Max) 6/	$3.8600
		(Min) 6/	$0.0000
ISS	Injection	(Max)	$0.9923plus ACA 3/
		(Min)	$0.0000
	Storage Balance Transfer	(Max) 4/	$3.8600
		(Min) 4/	$0.0000
FSS	Demand	(Max)	$2.3833 5/
		(Min)	$0.0000
	Capacity	(Max)	$0.0366 6/
		(Min)	$0.0000
	Injection/ Withdrawal	(Max)	$0.0391plus ACA 3/
		(Min)	$0.0000
	Storage Balance Transfer	(Max) 4/	$3.8600
		(Min) 4/	$0.0000

1/ The unit of measure for each rate component is Dth unless otherwise indicated.

2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 0.61%.

3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.

4/ Rate per nomination.

5/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0757 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.

6/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0011 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Rate [2/] (3)
ESS	Demand	(Max)	$3.3020
		(Min)	$0.0000
	Capacity	(Max)	$0.0604
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0457 plus ACA[3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)	$3.8600
		(Min)	$0.0000
ISS	Injection	(Max)	$1.3855 plus ACA[3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$0.0000
FSS	Demand	(Max)	$3.1679
		(Min)	$0.0000
	Capacity	(Max)	$0.0576
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0439 plus ACA[3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$0.0000

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 0.61%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Rate per nomination.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Rate [2/] (3)
ESS	Demand	(Max)	$2.6433
		(Min)	$0.0000
	Capacity	(Max)	$0.0485
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0458 plus ACA[3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)	$3.8600
		(Min)	$0.0000
ISS	Injection	(Max)	$1.1271 plus ACA[3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$0.0000
FSS	Demand	(Max)	$2.5326
		(Min)	$0.0000
	Capacity	(Max)	$0.0462
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0439 plus ACA[3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4/]	$3.8600
		(Min)[4/]	$0.0000

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 0.93%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Rate per nomination.

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	8.3260	0.0000	0.2737	0.0000
WLA-AAB	4.3840	0.0000	0.1441	0.0000
ELA-AAB	2.9600	0.0000	0.0973	0.0000
ETX-AAB	3.0590	0.0000	0.1006	0.0000
STX-STX	5.7750	0.0000	0.1899	0.0000
STX-WLA	7.2000	0.0000	0.2367	0.0000
STX-ELA	8.3470	0.0000	0.2744	0.0000
STX-ETX	8.3480	0.0000	0.2745	0.0000
WLA-WLA	3.2580	0.0000	0.1072	0.0000
WLA-ELA	4.4060	0.0000	0.1449	0.0000
WLA-ETX	4.4060	0.0000	0.1449	0.0000
ELA-ELA	2.9820	0.0000	0.0980	0.0000
ETX-ETX	3.0810	0.0000	0.1013	0.0000
ETX-ELA	2.9820	0.0000	0.0980	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.8030	0.0000	0.1250	0.0000
M1-M2	8.5230	0.0000	0.2802	0.0000
M1-M3	15.3230	0.0000	0.5038	0.0000
M2-M2	6.5660	0.0000	0.2159	0.0000
M2-M3	13.3530	0.0000	0.4390	0.0000
M3-M3	8.6330	0.0000	0.2838	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0093	0.0104	0.0143	0.0143	0.0300	0.0589	0.0990
from WLA	0.0104	0.0055	0.0102	0.0102	0.0259	0.0548	0.0949
from ELA	0.0143	0.0102	0.0090	0.0090	0.0247	0.0536	0.0937
from ETX	0.0143	0.0102	0.0090	0.0090	0.0247	0.0536	0.0937
from M1	0.0300	0.0259	0.0247	0.0247	0.0157	0.0446	0.0847
from M2	0.0589	0.0548	0.0536	0.0536	0.0446	0.0324	0.0714
from M3	0.0990	0.0949	0.0937	0.0937	0.0847	0.0714	0.0423
USAGE-1 - MINIMUM							
from STX	0.0080	0.0091	0.0130	0.0130	0.0274	0.0564	0.0964
from WLA	0.0091	0.0043	0.0090	0.0090	0.0234	0.0524	0.0924
from ELA	0.0130	0.0090	0.0078	0.0078	0.0222	0.0512	0.0912
from ETX	0.0130	0.0090	0.0078	0.0078	0.0222	0.0512	0.0912
from M1	0.0274	0.0234	0.0222	0.0222	0.0144	0.0434	0.0834
from M2	0.0564	0.0524	0.0512	0.0512	0.0434	0.0311	0.0701
from M3	0.0964	0.0924	0.0912	0.0912	0.0834	0.0701	0.0411
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0052						
from WLA		0.0027					
from ELA			0.0050				
from ETX				0.0050			
from M1				0.0214	0.0124		
from M2				0.0475	0.0384	0.0274	
from M3						0.0620	0.0358
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0039						
from WLA		0.0015					
from ELA			0.0038				
from ETX				0.0038			
from M1				0.0189	0.0111		
from M2				0.0450	0.0372	0.0261	
from M3						0.0607	0.0346
USAGE-2	0.1910	0.1910	0.1910	0.1910	0.3317	0.5158	0.7795

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	8.3320	0.0000	0.2739	0.0000
WLA-AAB	4.3870	0.0000	0.1442	0.0000
ELA-AAB	2.9610	0.0000	0.0974	0.0000
ETX-AAB	3.0600	0.0000	0.1006	0.0000
STX-STX	5.7790	0.0000	0.1900	0.0000
STX-WLA	7.2050	0.0000	0.2368	0.0000
STX-ELA	8.3540	0.0000	0.2747	0.0000
STX-ETX	8.3540	0.0000	0.2747	0.0000
WLA-WLA	3.2590	0.0000	0.1072	0.0000
WLA-ELA	4.4090	0.0000	0.1450	0.0000
WLA-ETX	4.4060	0.0000	0.1449	0.0000
ELA-ELA	2.9830	0.0000	0.0981	0.0000
ETX-ETX	3.0820	0.0000	0.1013	0.0000
ETX-ELA	2.9830	0.0000	0.0981	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.7740	0.0000	0.1241	0.0000
M1-M2	8.4330	0.0000	0.2773	0.0000
M1-M3	15.1860	0.0000	0.4993	0.0000
M2-M2	6.5050	0.0000	0.2139	0.0000
M2-M3	13.2440	0.0000	0.4354	0.0000
M3-M3	8.5850	0.0000	0.2822	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0093	0.0104	0.0143	0.0143	0.0278	0.0520	0.0874
from WLA	0.0104	0.0055	0.0102	0.0102	0.0237	0.0479	0.0833
from ELA	0.0143	0.0102	0.0090	0.0090	0.0225	0.0467	0.0821
from ETX	0.0143	0.0102	0.0090	0.0090	0.0225	0.0467	0.0821
from M1	0.0278	0.0237	0.0225	0.0225	0.0135	0.0377	0.0731
from M2	0.0520	0.0479	0.0467	0.0467	0.0377	0.0276	0.0620
from M3	0.0874	0.0833	0.0821	0.0821	0.0731	0.0620	0.0377
USAGE-1 - MINIMUM							
from STX	0.0080	0.0091	0.0130	0.0130	0.0252	0.0495	0.0848
from WLA	0.0091	0.0043	0.0090	0.0090	0.0212	0.0455	0.0808
from ELA	0.0130	0.0090	0.0078	0.0078	0.0200	0.0443	0.0796
from ETX	0.0130	0.0090	0.0078	0.0078	0.0200	0.0443	0.0796
from M1	0.0252	0.0212	0.0200	0.0200	0.0122	0.0365	0.0718
from M2	0.0495	0.0455	0.0443	0.0443	0.0365	0.0263	0.0607
from M3	0.0848	0.0808	0.0796	0.0796	0.0718	0.0607	0.0365
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0052						
from WLA		0.0027					
from ELA			0.0050				
from ETX				0.0050			
from M1				0.0192	0.0102		
from M2				0.0406	0.0315	0.0226	
from M3						0.0526	0.0312
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0039						
from WLA		0.0015					
from ELA			0.0038				
from ETX				0.0038			
from M1				0.0167	0.0089		
from M2				0.0381	0.0303	0.0213	
from M3						0.0513	0.0300
USAGE-2	0.1911	0.1911	0.1911	0.1911	0.3287	0.5061	0.7635

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1530	0.0000	0.2352	0.0000
WLA-AAB	3.8370	0.0000	0.1262	0.0000
ELA-AAB	2.6410	0.0000	0.0868	0.0000
ETX-AAB	2.7230	0.0000	0.0895	0.0000
STX-STX	5.0000	0.0000	0.1644	0.0000
STX-WLA	6.1960	0.0000	0.2037	0.0000
STX-ELA	7.1620	0.0000	0.2354	0.0000
STX-ETX	7.1620	0.0000	0.2354	0.0000
WLA-WLA	2.8820	0.0000	0.0948	0.0000
WLA-ELA	3.8460	0.0000	0.1265	0.0000
WLA-ETX	3.8460	0.0000	0.1265	0.0000
ELA-ELA	2.6500	0.0000	0.0871	0.0000
ETX-ETX	2.7320	0.0000	0.0898	0.0000
ETX-ELA	2.6500	0.0000	0.0871	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2570	0.0000	0.1071	0.0000
M1-M2	7.0020	0.0000	0.2302	0.0000
M1-M3	12.2680	0.0000	0.4033	0.0000
M2-M2	5.4290	0.0000	0.1785	0.0000
M2-M3	10.6950	0.0000	0.3516	0.0000
M3-M3	6.9520	0.0000	0.2286	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0103	0.0116	0.0179	0.0179	0.0372	0.0719	0.1033
from WLA	0.0116	0.0057	0.0123	0.0123	0.0316	0.0663	0.0977
from ELA	0.0179	0.0123	0.0101	0.0101	0.0294	0.0641	0.0955
from ETX	0.0179	0.0123	0.0101	0.0101	0.0294	0.0641	0.0955
from M1	0.0372	0.0316	0.0294	0.0294	0.0193	0.0540	0.0854
from M2	0.0719	0.0663	0.0641	0.0641	0.0540	0.0379	0.0688
from M3	0.1033	0.0977	0.0955	0.0955	0.0854	0.0688	0.0340
USAGE-1 - MINIMUM							
from STX	0.0085	0.0098	0.0161	0.0161	0.0336	0.0682	0.0996
from WLA	0.0098	0.0039	0.0105	0.0105	0.0280	0.0626	0.0940
from ELA	0.0161	0.0105	0.0083	0.0083	0.0258	0.0604	0.0918
from ETX	0.0161	0.0105	0.0083	0.0083	0.0258	0.0604	0.0918
from M1	0.0336	0.0280	0.0258	0.0258	0.0175	0.0521	0.0835
from M2	0.0682	0.0626	0.0604	0.0604	0.0521	0.0360	0.0670
from M3	0.0996	0.0940	0.0918	0.0918	0.0835	0.0670	0.0322
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0275	0.0174		
from M2				0.0610	0.0509	0.0354	
from M3						0.0654	0.0319
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0239	0.0156		
from M2				0.0573	0.0490	0.0335	
from M3						0.0636	0.0301
USAGE-2	0.1709	0.1709	0.1709	0.1709	0.2973	0.4551	0.6596

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1540	0.0000	0.2352	0.0000
WLA-AAB	3.8370	0.0000	0.1262	0.0000
ELA-AAB	2.6410	0.0000	0.0868	0.0000
ETX-AAB	2.7230	0.0000	0.0895	0.0000
STX-STX	5.0010	0.0000	0.1644	0.0000
STX-WLA	6.1980	0.0000	0.2037	0.0000
STX-ELA	7.1620	0.0000	0.2354	0.0000
STX-ETX	7.1630	0.0000	0.2354	0.0000
WLA-WLA	2.8820	0.0000	0.0948	0.0000
WLA-ELA	3.8460	0.0000	0.1265	0.0000
WLA-ETX	3.8460	0.0000	0.1265	0.0000
ELA-ELA	2.6500	0.0000	0.0871	0.0000
ETX-ETX	2.7320	0.0000	0.0898	0.0000
ETX-ELA	2.6500	0.0000	0.0871	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2670	0.0000	0.1074	0.0000
M1-M2	7.0560	0.0000	0.2320	0.0000
M1-M3	12.4870	0.0000	0.4105	0.0000
M2-M2	5.4740	0.0000	0.1800	0.0000
M2-M3	10.9040	0.0000	0.3585	0.0000
M3-M3	7.1160	0.0000	0.2340	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0103	0.0116	0.0179	0.0179	0.0343	0.0654	0.1068
from WLA	0.0116	0.0057	0.0123	0.0123	0.0287	0.0598	0.1012
from ELA	0.0179	0.0123	0.0101	0.0101	0.0265	0.0576	0.0990
from ETX	0.0179	0.0123	0.0101	0.0101	0.0265	0.0576	0.0990
from M1	0.0343	0.0287	0.0265	0.0265	0.0164	0.0475	0.0889
from M2	0.0654	0.0598	0.0576	0.0576	0.0475	0.0343	0.0752
from M3	0.1068	0.1012	0.0990	0.0990	0.0889	0.0752	0.0440
USAGE-1 - MINIMUM							
from STX	0.0085	0.0098	0.0161	0.0161	0.0307	0.0617	0.1031
from WLA	0.0098	0.0039	0.0105	0.0105	0.0251	0.0561	0.0975
from ELA	0.0161	0.0105	0.0083	0.0083	0.0229	0.0539	0.0953
from ETX	0.0161	0.0105	0.0083	0.0083	0.0229	0.0539	0.0953
from M1	0.0307	0.0251	0.0229	0.0229	0.0146	0.0456	0.0870
from M2	0.0617	0.0561	0.0539	0.0539	0.0456	0.0324	0.0734
from M3	0.1031	0.0975	0.0953	0.0953	0.0870	0.0734	0.0422
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0246	0.0145		
from M2				0.0545	0.0444	0.0318	
from M3						0.0718	0.0419
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0210	0.0127		
from M2				0.0508	0.0425	0.0299	
from M3						0.0700	0.0401
USAGE-2	0.1709	0.1709	0.1709	0.1709	0.2947	0.4504	0.6703

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1540	0.0000	0.2352	0.0000
WLA-AAB	3.8370	0.0000	0.1262	0.0000
ELA-AAB	2.6410	0.0000	0.0868	0.0000
ETX-AAB	2.7230	0.0000	0.0895	0.0000
STX-STX	5.0010	0.0000	0.1644	0.0000
STX-WLA	6.1980	0.0000	0.2037	0.0000
STX-ELA	7.1620	0.0000	0.2354	0.0000
STX-ETX	7.1630	0.0000	0.2354	0.0000
WLA-WLA	2.8820	0.0000	0.0948	0.0000
WLA-ELA	3.8460	0.0000	0.1265	0.0000
WLA-ETX	3.8460	0.0000	0.1265	0.0000
ELA-ELA	2.6500	0.0000	0.0871	0.0000
ETX-ETX	2.7320	0.0000	0.0898	0.0000
ETX-ELA	2.6500	0.0000	0.0871	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2670	0.0000	0.1074	0.0000
M1-M2	7.0560	0.0000	0.2320	0.0000
M1-M3	12.4870	0.0000	0.4105	0.0000
M2-M2	5.4740	0.0000	0.1800	0.0000
M2-M3	10.9040	0.0000	0.3585	0.0000
M3-M3	7.1160	0.0000	0.2340	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0103	0.0116	0.0179	0.0179	0.0343	0.0654	0.1068
from WLA	0.0116	0.0057	0.0123	0.0123	0.0287	0.0598	0.1012
from ELA	0.0179	0.0123	0.0101	0.0101	0.0265	0.0576	0.0990
from ETX	0.0179	0.0123	0.0101	0.0101	0.0265	0.0576	0.0990
from M1	0.0343	0.0287	0.0265	0.0265	0.0164	0.0475	0.0889
from M2	0.0654	0.0598	0.0576	0.0576	0.0475	0.0343	0.0752
from M3	0.1068	0.1012	0.0990	0.0990	0.0889	0.0752	0.0440
USAGE-1 - MINIMUM							
from STX	0.0085	0.0098	0.0161	0.0161	0.0307	0.0617	0.1031
from WLA	0.0098	0.0039	0.0105	0.0105	0.0251	0.0561	0.0975
from ELA	0.0161	0.0105	0.0083	0.0083	0.0229	0.0539	0.0953
from ETX	0.0161	0.0105	0.0083	0.0083	0.0229	0.0539	0.0953
from M1	0.0307	0.0251	0.0229	0.0229	0.0146	0.0456	0.0870
from M2	0.0617	0.0561	0.0539	0.0539	0.0456	0.0324	0.0734
from M3	0.1031	0.0975	0.0953	0.0953	0.0870	0.0734	0.0422
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0246	0.0145		
from M2				0.0545	0.0444	0.0318	
from M3						0.0718	0.0419
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0210	0.0127		
from M2				0.0508	0.0425	0.0299	
from M3						0.0700	0.0401
USAGE-2	0.1709	0.1709	0.1709	0.1709	0.2947	0.4504	0.6703

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1540	0.0000	0.2352	0.0000
WLA-AAB	3.8370	0.0000	0.1262	0.0000
ELA-AAB	2.6410	0.0000	0.0868	0.0000
ETX-AAB	2.7230	0.0000	0.0895	0.0000
STX-STX	5.0140	0.0000	0.1648	0.0000
STX-WLA	6.2110	0.0000	0.2041	0.0000
STX-ELA	7.1750	0.0000	0.2358	0.0000
STX-ETX	7.1760	0.0000	0.2358	0.0000
WLA-WLA	2.8950	0.0000	0.0952	0.0000
WLA-ELA	3.8590	0.0000	0.1270	0.0000
WLA-ETX	3.8590	0.0000	0.1270	0.0000
ELA-ELA	2.6630	0.0000	0.0876	0.0000
ETX-ETX	2.7450	0.0000	0.0903	0.0000
ETX-ELA	2.6630	0.0000	0.0876	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2800	0.0000	0.1078	0.0000
M1-M2	7.0760	0.0000	0.2326	0.0000
M1-M3	12.5220	0.0000	0.4117	0.0000
M2-M2	5.4940	0.0000	0.1806	0.0000
M2-M3	10.9390	0.0000	0.3596	0.0000
M3-M3	7.1440	0.0000	0.2349	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0124	0.0140	0.0204	0.0204	0.0382	0.0710	0.1166
from WLA	0.0140	0.0070	0.0142	0.0142	0.0320	0.0648	0.1104
from ELA	0.0204	0.0142	0.0121	0.0121	0.0299	0.0627	0.1083
from ETX	0.0204	0.0142	0.0121	0.0121	0.0299	0.0627	0.1083
from M1	0.0382	0.0320	0.0299	0.0299	0.0178	0.0506	0.0962
from M2	0.0710	0.0648	0.0627	0.0627	0.0506	0.0368	0.0812
from M3	0.1166	0.1104	0.1083	0.1083	0.0962	0.0812	0.0484
USAGE-1 - MINIMUM							
from STX	0.0106	0.0122	0.0186	0.0186	0.0346	0.0673	0.1129
from WLA	0.0122	0.0052	0.0124	0.0124	0.0284	0.0611	0.1067
from ELA	0.0186	0.0124	0.0103	0.0103	0.0263	0.0590	0.1046
from ETX	0.0186	0.0124	0.0103	0.0103	0.0263	0.0590	0.1046
from M1	0.0346	0.0284	0.0263	0.0263	0.0160	0.0487	0.0943
from M2	0.0673	0.0611	0.0590	0.0590	0.0487	0.0349	0.0794
from M3	0.1129	0.1067	0.1046	0.1046	0.0943	0.0794	0.0466
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0266	0.0145		
from M2				0.0565	0.0444	0.0318	
from M3						0.0718	0.0419
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0230	0.0127		
from M2				0.0528	0.0425	0.0299	
from M3						0.0700	0.0401
USAGE-2	0.1735	0.1735	0.1735	0.1735	0.2991	0.4567	0.6814

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1600	0.0000	0.2354	0.0000
WLA-AAB	3.8400	0.0000	0.1263	0.0000
ELA-AAB	2.6420	0.0000	0.0869	0.0000
ETX-AAB	2.7240	0.0000	0.0896	0.0000
STX-STX	5.0180	0.0000	0.1650	0.0000
STX-WLA	6.2160	0.0000	0.2043	0.0000
STX-ELA	7.1820	0.0000	0.2360	0.0000
STX-ETX	7.1820	0.0000	0.2360	0.0000
WLA-WLA	2.8960	0.0000	0.0953	0.0000
WLA-ELA	3.8620	0.0000	0.1271	0.0000
WLA-ETX	3.8590	0.0000	0.1270	0.0000
ELA-ELA	2.6640	0.0000	0.0876	0.0000
ETX-ETX	2.7460	0.0000	0.0903	0.0000
ETX-ELA	2.6640	0.0000	0.0876	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2510	0.0000	0.1069	0.0000
M1-M2	6.9860	0.0000	0.2297	0.0000
M1-M3	12.3850	0.0000	0.4072	0.0000
M2-M2	5.4330	0.0000	0.1786	0.0000
M2-M3	10.8300	0.0000	0.3561	0.0000
M3-M3	7.0960	0.0000	0.2333	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0124	0.0140	0.0204	0.0204	0.0360	0.0641	0.1050
from WLA	0.0140	0.0070	0.0142	0.0142	0.0298	0.0579	0.0988
from ELA	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from ETX	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from M1	0.0360	0.0298	0.0277	0.0277	0.0156	0.0437	0.0846
from M2	0.0641	0.0579	0.0558	0.0558	0.0437	0.0320	0.0718
from M3	0.1050	0.0988	0.0967	0.0967	0.0846	0.0718	0.0438
USAGE-1 - MINIMUM							
from STX	0.0106	0.0122	0.0186	0.0186	0.0324	0.0604	0.1013
from WLA	0.0122	0.0052	0.0124	0.0124	0.0262	0.0542	0.0951
from ELA	0.0186	0.0124	0.0103	0.0103	0.0241	0.0521	0.0930
from ETX	0.0186	0.0124	0.0103	0.0103	0.0241	0.0521	0.0930
from M1	0.0324	0.0262	0.0241	0.0241	0.0138	0.0418	0.0827
from M2	0.0604	0.0542	0.0521	0.0521	0.0418	0.0301	0.0700
from M3	0.1013	0.0951	0.0930	0.0930	0.0827	0.0700	0.0420
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0244	0.0123		
from M2				0.0496	0.0375	0.0270	
from M3						0.0624	0.0373
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0208	0.0105		
from M2				0.0459	0.0356	0.0251	
from M3						0.0606	0.0355
USAGE-2	0.1736	0.1736	0.1736	0.1736	0.2961	0.4470	0.6654

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1600	0.0000	0.2354	0.0000
WLA-AAB	3.8400	0.0000	0.1263	0.0000
ELA-AAB	2.6420	0.0000	0.0869	0.0000
ETX-AAB	2.7240	0.0000	0.0896	0.0000
STX-STX	5.0180	0.0000	0.1650	0.0000
STX-WLA	6.2160	0.0000	0.2043	0.0000
STX-ELA	7.1820	0.0000	0.2360	0.0000
STX-ETX	7.1820	0.0000	0.2360	0.0000
WLA-WLA	2.8960	0.0000	0.0953	0.0000
WLA-ELA	3.8620	0.0000	0.1271	0.0000
WLA-ETX	3.8590	0.0000	0.1270	0.0000
ELA-ELA	2.6640	0.0000	0.0876	0.0000
ETX-ETX	2.7460	0.0000	0.0903	0.0000
ETX-ELA	2.6640	0.0000	0.0876	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2510	0.0000	0.1069	0.0000
M1-M2	6.9860	0.0000	0.2297	0.0000
M1-M3	12.3850	0.0000	0.4072	0.0000
M2-M2	5.4330	0.0000	0.1786	0.0000
M2-M3	10.8300	0.0000	0.3561	0.0000
M3-M3	7.0960	0.0000	0.2333	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0124	0.0140	0.0204	0.0204	0.0360	0.0641	0.1050
from WLA	0.0140	0.0070	0.0142	0.0142	0.0298	0.0579	0.0988
from ELA	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from ETX	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from M1	0.0360	0.0298	0.0277	0.0277	0.0156	0.0437	0.0846
from M2	0.0641	0.0579	0.0558	0.0558	0.0437	0.0320	0.0718
from M3	0.1050	0.0988	0.0967	0.0967	0.0846	0.0718	0.0438
USAGE-1 - MINIMUM							
from STX	0.0106	0.0122	0.0186	0.0186	0.0324	0.0604	0.1013
from WLA	0.0122	0.0052	0.0124	0.0124	0.0262	0.0542	0.0951
from ELA	0.0186	0.0124	0.0103	0.0103	0.0241	0.0521	0.0930
from ETX	0.0186	0.0124	0.0103	0.0103	0.0241	0.0521	0.0930
from M1	0.0324	0.0262	0.0241	0.0241	0.0138	0.0418	0.0827
from M2	0.0604	0.0542	0.0521	0.0521	0.0418	0.0301	0.0700
from M3	0.1013	0.0951	0.0930	0.0930	0.0827	0.0700	0.0420
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0244	0.0123		
from M2				0.0496	0.0375	0.0270	
from M3						0.0624	0.0373
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0208	0.0105		
from M2				0.0459	0.0356	0.0251	
from M3						0.0606	0.0355
USAGE-2	0.1736	0.1736	0.1736	0.1736	0.2961	0.4470	0.6654

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1600	0.0000	0.2354	0.0000
WLA-AAB	3.8400	0.0000	0.1263	0.0000
ELA-AAB	2.6420	0.0000	0.0869	0.0000
ETX-AAB	2.7240	0.0000	0.0896	0.0000
STX-STX	5.0180	0.0000	0.1650	0.0000
STX-WLA	6.2160	0.0000	0.2043	0.0000
STX-ELA	7.1820	0.0000	0.2360	0.0000
STX-ETX	7.1820	0.0000	0.2360	0.0000
WLA-WLA	2.8960	0.0000	0.0953	0.0000
WLA-ELA	3.8620	0.0000	0.1271	0.0000
WLA-ETX	3.8590	0.0000	0.1270	0.0000
ELA-ELA	2.6640	0.0000	0.0876	0.0000
ETX-ETX	2.7460	0.0000	0.0903	0.0000
ETX-ELA	2.6640	0.0000	0.0876	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2510	0.0000	0.1069	0.0000
M1-M2	6.9860	0.0000	0.2297	0.0000
M1-M3	12.3850	0.0000	0.4072	0.0000
M2-M2	5.4330	0.0000	0.1786	0.0000
M2-M3	10.8300	0.0000	0.3561	0.0000
M3-M3	7.0960	0.0000	0.2333	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0124	0.0140	0.0204	0.0204	0.0360	0.0641	0.1050
from WLA	0.0140	0.0070	0.0142	0.0142	0.0298	0.0579	0.0988
from ELA	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from ETX	0.0204	0.0142	0.0121	0.0121	0.0277	0.0558	0.0967
from M1	0.0360	0.0298	0.0277	0.0277	0.0156	0.0437	0.0846
from M2	0.0641	0.0579	0.0558	0.0558	0.0437	0.0320	0.0718
from M3	0.1050	0.0988	0.0967	0.0967	0.0846	0.0718	0.0438
USAGE-1 - MINIMUM							
from STX	0.0106	0.0122	0.0186	0.0186	0.0324	0.0604	0.1013
from WLA	0.0122	0.0052	0.0124	0.0124	0.0262	0.0542	0.0951
from ELA	0.0186	0.0124	0.0103	0.0103	0.0241	0.0521	0.0930
from ETX	0.0186	0.0124	0.0103	0.0103	0.0241	0.0521	0.0930
from M1	0.0324	0.0262	0.0241	0.0241	0.0138	0.0418	0.0827
from M2	0.0604	0.0542	0.0521	0.0521	0.0418	0.0301	0.0700
from M3	0.1013	0.0951	0.0930	0.0930	0.0827	0.0700	0.0420
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0083						
from WLA		0.0042					
from ELA			0.0081				
from ETX				0.0081			
from M1				0.0244	0.0123		
from M2				0.0496	0.0375	0.0270	
from M3						0.0624	0.0373
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0065						
from WLA		0.0024					
from ELA			0.0063				
from ETX				0.0063			
from M1				0.0208	0.0105		
from M2				0.0459	0.0356	0.0251	
from M3						0.0606	0.0355
USAGE-2	0.1736	0.1736	0.1736	0.1736	0.2961	0.4470	0.6654

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1690	0.0000	0.2357	0.0000
WLA-AAB	3.8430	0.0000	0.1263	0.0000
ELA-AAB	2.6430	0.0000	0.0869	0.0000
ETX-AAB	2.7250	0.0000	0.0896	0.0000
STX-STX	5.0230	0.0000	0.1651	0.0000
STX-WLA	6.2230	0.0000	0.2046	0.0000
STX-ELA	7.1910	0.0000	0.2364	0.0000
STX-ETX	7.1910	0.0000	0.2364	0.0000
WLA-WLA	2.8980	0.0000	0.0953	0.0000
WLA-ELA	3.8650	0.0000	0.1271	0.0000
WLA-ETX	3.8590	0.0000	0.1269	0.0000
ELA-ELA	2.6650	0.0000	0.0876	0.0000
ETX-ETX	2.7470	0.0000	0.0903	0.0000
ETX-ELA	2.6650	0.0000	0.0876	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2660	0.0000	0.1074	0.0000
M1-M2	7.0340	0.0000	0.2313	0.0000
M1-M3	12.4660	0.0000	0.4098	0.0000
M2-M2	5.4660	0.0000	0.1797	0.0000
M2-M3	10.8970	0.0000	0.3583	0.0000
M3-M3	7.1300	0.0000	0.2344	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0131	0.0148	0.0219	0.0219	0.0385	0.0691	0.1126
from WLA	0.0148	0.0072	0.0151	0.0151	0.0317	0.0623	0.1058
from ELA	0.0219	0.0151	0.0127	0.0127	0.0293	0.0599	0.1034
from ETX	0.0219	0.0151	0.0127	0.0127	0.0293	0.0599	0.1034
from M1	0.0385	0.0317	0.0293	0.0293	0.0166	0.0472	0.0907
from M2	0.0691	0.0623	0.0599	0.0599	0.0472	0.0345	0.0769
from M3	0.1126	0.1058	0.1034	0.1034	0.0907	0.0769	0.0465
USAGE-1 - MINIMUM							
from STX	0.0113	0.0130	0.0201	0.0201	0.0349	0.0654	0.1089
from WLA	0.0130	0.0054	0.0133	0.0133	0.0281	0.0586	0.1021
from ELA	0.0201	0.0133	0.0109	0.0109	0.0257	0.0562	0.0997
from ETX	0.0201	0.0133	0.0109	0.0109	0.0257	0.0562	0.0997
from M1	0.0349	0.0281	0.0257	0.0257	0.0148	0.0453	0.0888
from M2	0.0654	0.0586	0.0562	0.0562	0.0453	0.0326	0.0751
from M3	0.1089	0.1021	0.0997	0.0997	0.0888	0.0751	0.0447
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0090						
from WLA		0.0044					
from ELA			0.0087				
from ETX				0.0087			
from M1				0.0260	0.0133		
from M2				0.0537	0.0410	0.0295	
from M3						0.0675	0.0400
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0072						
from WLA		0.0026					
from ELA			0.0069				
from ETX				0.0069			
from M1				0.0224	0.0115		
from M2				0.0500	0.0391	0.0276	
from M3						0.0657	0.0382
USAGE-2	0.1748	0.1748	0.1748	0.1748	0.2988	0.4533	0.6753

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1690	0.0000	0.2357	0.0000
WLA-AAB	3.8430	0.0000	0.1263	0.0000
ELA-AAB	2.6430	0.0000	0.0869	0.0000
ETX-AAB	2.7250	0.0000	0.0896	0.0000
STX-STX	5.0340	0.0000	0.1655	0.0000
STX-WLA	6.2340	0.0000	0.2050	0.0000
STX-ELA	7.2020	0.0000	0.2368	0.0000
STX-ETX	7.2020	0.0000	0.2368	0.0000
WLA-WLA	2.9090	0.0000	0.0957	0.0000
WLA-ELA	3.8760	0.0000	0.1274	0.0000
WLA-ETX	3.8700	0.0000	0.1272	0.0000
ELA-ELA	2.6760	0.0000	0.0880	0.0000
ETX-ETX	2.7580	0.0000	0.0907	0.0000
ETX-ELA	2.6760	0.0000	0.0880	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2810	0.0000	0.1079	0.0000
M1-M2	7.0570	0.0000	0.2320	0.0000
M1-M3	12.5000	0.0000	0.4110	0.0000
M2-M2	5.4850	0.0000	0.1803	0.0000
M2-M3	10.9270	0.0000	0.3592	0.0000
M3-M3	7.1520	0.0000	0.2351	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0131	0.0148	0.0219	0.0219	0.0385	0.0691	0.1126
from WLA	0.0148	0.0072	0.0151	0.0151	0.0317	0.0623	0.1058
from ELA	0.0219	0.0151	0.0127	0.0127	0.0293	0.0599	0.1034
from ETX	0.0219	0.0151	0.0127	0.0127	0.0293	0.0599	0.1034
from M1	0.0385	0.0317	0.0293	0.0293	0.0166	0.0472	0.0907
from M2	0.0691	0.0623	0.0599	0.0599	0.0472	0.0345	0.0769
from M3	0.1126	0.1058	0.1034	0.1034	0.0907	0.0769	0.0465
USAGE-1 - MINIMUM							
from STX	0.0113	0.0130	0.0201	0.0201	0.0349	0.0654	0.1089
from WLA	0.0130	0.0054	0.0133	0.0133	0.0281	0.0586	0.1021
from ELA	0.0201	0.0133	0.0109	0.0109	0.0257	0.0562	0.0997
from ETX	0.0201	0.0133	0.0109	0.0109	0.0257	0.0562	0.0997
from M1	0.0349	0.0281	0.0257	0.0257	0.0148	0.0453	0.0888
from M2	0.0654	0.0586	0.0562	0.0562	0.0453	0.0326	0.0751
from M3	0.1089	0.1021	0.0997	0.0997	0.0888	0.0751	0.0447
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0090						
from WLA		0.0044					
from ELA			0.0087				
from ETX				0.0087			
from M1				0.0260	0.0133		
from M2				0.0537	0.0410	0.0295	
from M3						0.0675	0.0400
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0072						
from WLA		0.0026					
from ELA			0.0069				
from ETX				0.0069			
from M1				0.0224	0.0115		
from M2				0.0500	0.0391	0.0276	
from M3						0.0657	0.0382
USAGE-2	0.1748	0.1748	0.1748	0.1748	0.2993	0.4540	0.6765

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1690	0.0000	0.2357	0.0000
WLA-AAB	3.8430	0.0000	0.1263	0.0000
ELA-AAB	2.6430	0.0000	0.0869	0.0000
ETX-AAB	2.7250	0.0000	0.0896	0.0000
STX-STX	5.0340	0.0000	0.1655	0.0000
STX-WLA	6.2340	0.0000	0.2050	0.0000
STX-ELA	7.2020	0.0000	0.2368	0.0000
STX-ETX	7.2020	0.0000	0.2368	0.0000
WLA-WLA	2.9090	0.0000	0.0957	0.0000
WLA-ELA	3.8760	0.0000	0.1274	0.0000
WLA-ETX	3.8700	0.0000	0.1272	0.0000
ELA-ELA	2.6760	0.0000	0.0880	0.0000
ETX-ETX	2.7580	0.0000	0.0907	0.0000
ETX-ELA	2.6760	0.0000	0.0880	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2810	0.0000	0.1079	0.0000
M1-M2	7.0570	0.0000	0.2320	0.0000
M1-M3	12.5000	0.0000	0.4110	0.0000
M2-M2	5.4850	0.0000	0.1803	0.0000
M2-M3	10.9270	0.0000	0.3592	0.0000
M3-M3	7.1520	0.0000	0.2351	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0185	0.0205	0.0275	0.0275	0.0490	0.0811	0.1308
from WLA	0.0205	0.0117	0.0202	0.0202	0.0417	0.0738	0.1235
from ELA	0.0275	0.0202	0.0182	0.0182	0.0397	0.0718	0.1215
from ETX	0.0275	0.0202	0.0182	0.0182	0.0397	0.0718	0.1215
from M1	0.0490	0.0417	0.0397	0.0397	0.0215	0.0536	0.1033
from M2	0.0811	0.0738	0.0718	0.0718	0.0536	0.0403	0.0845
from M3	0.1308	0.1235	0.1215	0.1215	0.1033	0.0845	0.0546
USAGE-1 - MINIMUM							
from STX	0.0167	0.0187	0.0257	0.0257	0.0454	0.0774	0.1271
from WLA	0.0187	0.0099	0.0184	0.0184	0.0381	0.0701	0.1198
from ELA	0.0257	0.0184	0.0164	0.0164	0.0361	0.0681	0.1178
from ETX	0.0257	0.0184	0.0164	0.0164	0.0361	0.0681	0.1178
from M1	0.0454	0.0381	0.0361	0.0361	0.0197	0.0517	0.1014
from M2	0.0774	0.0701	0.0681	0.0681	0.0517	0.0384	0.0827
from M3	0.1271	0.1198	0.1178	0.1178	0.1014	0.0827	0.0528
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0090						
from WLA		0.0044					
from ELA			0.0087				
from ETX				0.0087			
from M1				0.0315	0.0133		
from M2				0.0592	0.0410	0.0295	
from M3						0.0675	0.0400
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0072						
from WLA		0.0026					
from ELA			0.0069				
from ETX				0.0069			
from M1				0.0279	0.0115		
from M2				0.0555	0.0391	0.0276	
from M3						0.0657	0.0382
USAGE-2	0.1817	0.1817	0.1817	0.1817	0.3111	0.4673	0.6960

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

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	7.1690	0.0000	0.2357	0.0000
WLA-AAB	3.8430	0.0000	0.1263	0.0000
ELA-AAB	2.6430	0.0000	0.0869	0.0000
ETX-AAB	2.7250	0.0000	0.0896	0.0000
STX-STX	5.0340	0.0000	0.1655	0.0000
STX-WLA	6.2340	0.0000	0.2050	0.0000
STX-ELA	7.2020	0.0000	0.2368	0.0000
STX-ETX	7.2020	0.0000	0.2368	0.0000
WLA-WLA	2.9090	0.0000	0.0957	0.0000
WLA-ELA	3.8760	0.0000	0.1274	0.0000
WLA-ETX	3.8700	0.0000	0.1272	0.0000
ELA-ELA	2.6760	0.0000	0.0880	0.0000
ETX-ETX	2.7580	0.0000	0.0907	0.0000
ETX-ELA	2.6760	0.0000	0.0880	0.0000
MARKET AREA	MAXIMUM	MINIMUM	MAXIMUM	MINIMUM
M1-M1	3.2810	0.0000	0.1079	0.0000
M1-M2	7.0570	0.0000	0.2320	0.0000
M1-M3	12.5000	0.0000	0.4110	0.0000
M2-M2	5.4850	0.0000	0.1803	0.0000
M2-M3	10.9270	0.0000	0.3592	0.0000
M3-M3	7.1520	0.0000	0.2351	0.0000

* Reservation Charge reflects a storage surcharge of: 0.0970

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	0.0235	0.0258	0.0328	0.0328	0.0586	0.0928	0.1486
from WLA	0.0258	0.0155	0.0247	0.0247	0.0505	0.0847	0.1405
from ELA	0.0328	0.0247	0.0230	0.0230	0.0488	0.0830	0.1388
from ETX	0.0328	0.0247	0.0230	0.0230	0.0488	0.0830	0.1388
from M1	0.0586	0.0505	0.0488	0.0488	0.0258	0.0600	0.1158
from M2	0.0928	0.0847	0.0830	0.0830	0.0600	0.0458	0.0933
from M3	0.1486	0.1405	0.1388	0.1388	0.1158	0.0933	0.0622
USAGE-1 - MINIMUM							
from STX	0.0217	0.0240	0.0310	0.0310	0.0550	0.0891	0.1449
from WLA	0.0240	0.0137	0.0229	0.0229	0.0469	0.0810	0.1368
from ELA	0.0310	0.0229	0.0212	0.0212	0.0452	0.0793	0.1351
from ETX	0.0310	0.0229	0.0212	0.0212	0.0452	0.0793	0.1351
from M1	0.0550	0.0469	0.0452	0.0452	0.0240	0.0581	0.1139
from M2	0.0891	0.0810	0.0793	0.0793	0.0581	0.0439	0.0915
from M3	0.1449	0.1368	0.1351	0.1351	0.1139	0.0915	0.0604
USAGE-1 - BACKHAUL MAXIMUM							
from STX	0.0090						
from WLA		0.0044					
from ELA			0.0087				
from ETX				0.0087			
from M1				0.0363	0.0133		
from M2				0.0640	0.0410	0.0295	
from M3						0.0675	0.0400
USAGE-1 - BACKHAUL MINIMUM							
from STX	0.0072						
from WLA		0.0026					
from ELA			0.0069				
from ETX				0.0069			
from M1				0.0327	0.0115		
from M2				0.0603	0.0391	0.0276	
from M3						0.0657	0.0382
USAGE-2	0.1879	0.1879	0.1879	0.1879	0.3216	0.4799	0.7147

ACA COMMODITY SURCHARGE TO APPLICABLE CUSTOMERS, PURSUANT TO SECTION 15.5 OF THE GENERAL TERMS AND CONDITIONS.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: December 1 through March 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	1.09	1.25	2.12	2.12	3.08	4.70	5.81
Base	from WLA	0.50	0.50	1.38	1.38	2.34	3.96	5.07
Applicable	from ELA	1.05	1.05	1.05	1.05	2.01	3.63	4.74
Shrinkage	from ETX	1.09	1.05	1.05	1.05	2.01	3.63	4.74
Percentage	from M1	3.08	2.34	2.01	2.01	0.96	2.58	3.69
|	from M2	4.70	3.96	3.63	3.63	2.58	1.80	2.90
|	from M3	5.81	5.07	4.74	4.74	3.69	2.90	1.28
|	from STX	-0.37	-0.46	-0.95	-0.95	-1.11	-1.91	-1.86
Applicable	from WLA	0.29	0.01	-0.46	-0.46	-0.62	-1.42	-1.37
Shrinkage	from ELA	0.12	-0.13	-0.06	-0.06	-0.22	-1.02	-0.97
Adjustment	from ETX	0.08	-0.13	-0.06	-0.06	-0.22	-1.02	-0.97
Percentage	from M1	-1.11	-0.62	-0.22	-0.22	-0.16	-0.96	-0.90
|	from M2	-1.91	-1.42	-1.02	-1.02	-0.96	-0.52	-0.45
|	from M3	-1.86	-1.37	-0.97	-0.97	-0.90	-0.45	0.37
|	from STX	0.72	0.79	1.17	1.17	1.97	2.79	3.95
Applicable	from WLA	0.79	0.51	0.92	0.92	1.72	2.54	3.70
Shrinkage	from ELA	1.17	0.92	0.99	0.99	1.79	2.61	3.77
Percentage	from ETX	1.17	0.92	0.99	0.99	1.79	2.61	3.77
|	from M1	1.97	1.72	1.79	1.79	0.80	1.62	2.79
|	from M2	2.79	2.54	2.61	2.61	1.62	1.28	2.45
|	from M3	3.95	3.70	3.77	3.77	2.79	2.45	1.65

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				0.99			
Percentage	from M1				0.99	0.00		
|	from M2				0.99	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				0.99			
|	from M1				0.99	0.00		
|	from M2				0.99	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.86 %	-1.26 %	1.60 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.22 %	0.54 %
Monthly Injections	1.76 %	-1.22 %	0.54 %
Monthly Inventory Level	0.08 %	-0.04 %	0.04 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Spring, Summer and Fall Periods: April 1 through November 30

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
Base	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
Applicable	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
Shrinkage	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
Percentage	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
|	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
|	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
|	from STX	-0.23	-0.29	-0.59	-0.59	-0.68	-1.19	-1.10
Applicable	from WLA	0.22	0.01	-0.27	-0.27	-0.36	-0.87	-0.78
Shrinkage	from ELA	0.14	-0.05	-0.01	-0.01	-0.10	-0.61	-0.52
Adjustment	from ETX	0.12	-0.05	-0.01	-0.01	-0.10	-0.61	-0.52
Percentage	from M1	-0.68	-0.36	-0.10	-0.10	-0.09	-0.60	-0.51
|	from M2	-1.19	-0.87	-0.61	-0.61	-0.60	-0.31	-0.22
|	from M3	-1.10	-0.78	-0.52	-0.52	-0.51	-0.22	0.30
|	from STX	0.70	0.75	1.05	1.05	1.81	2.40	3.24
Applicable	from WLA	0.75	0.54	0.86	0.86	1.62	2.21	3.05
Shrinkage	from ELA	1.05	0.86	0.90	0.90	1.66	2.25	3.09
Percentage	from ETX	1.05	0.86	0.90	0.90	1.66	2.25	3.09
|	from M1	1.81	1.62	1.66	1.66	0.76	1.35	2.19
|	from M2	2.40	2.21	2.25	2.25	1.35	1.11	1.95
|	from M3	3.24	3.05	3.09	3.09	2.19	1.95	1.37

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				0.90			
Percentage	from M1				0.90	0.00		
|	from M2				0.90	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				0.90			
|	from M1				0.90	0.00		
|	from M2				0.90	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-1.21 %	1.49 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.22 %	0.54 %
Monthly Injections	1.76 %	-1.22 %	0.54 %
Monthly Inventory Level	0.08 %	-0.04 %	0.04 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: December 1 through March 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
Base Applicable Shrinkage Percentage	from STX	1.09	1.25	2.12	2.12	3.08	4.70	5.81
	from WLA	0.50	0.50	1.38	1.38	2.34	3.96	5.07
	from ELA	1.05	1.05	1.05	1.05	2.01	3.63	4.74
	from ETX	1.09	1.05	1.05	1.05	2.01	3.63	4.74
	from M1	3.08	2.34	2.01	2.01	0.96	2.58	3.69
	from M2	4.70	3.96	3.63	3.63	2.58	1.80	2.90
	from M3	5.81	5.07	4.74	4.74	3.69	2.90	1.28
Applicable Shrinkage Adjustment Percentage	from STX	-0.18	-0.27	-0.74	-0.74	-0.69	-1.49	-1.43
	from WLA	0.48	0.18	-0.28	-0.28	-0.23	-1.03	-0.97
	from ELA	0.33	0.05	0.14	0.14	0.19	-0.61	-0.55
	from ETX	0.29	0.05	0.14	0.14	0.19	-0.61	-0.55
	from M1	-0.69	-0.23	0.19	0.19	0.05	-0.75	-0.68
	from M2	-1.49	-1.03	-0.61	-0.61	-0.75	-0.31	-0.23
	from M3	-1.43	-0.97	-0.55	-0.55	-0.68	-0.23	0.58
Applicable Shrinkage Percentage	from STX	0.91	0.98	1.38	1.38	2.39	3.21	4.38
	from WLA	0.98	0.68	1.10	1.10	2.11	2.93	4.10
	from ELA	1.38	1.10	1.19	1.19	2.20	3.02	4.19
	from ETX	1.38	1.10	1.19	1.19	2.20	3.02	4.19
	from M1	2.39	2.11	2.20	2.20	1.01	1.83	3.01
	from M2	3.21	2.93	3.02	3.02	1.83	1.49	2.67
	from M3	4.38	4.10	4.19	4.19	3.01	2.67	1.86

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
Base Applicable Shrinkage Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				0.00			
	from M1				0.00	0.00		
	from M2				0.00	0.00	0.00	
	from M3						0.00	0.00
Applicable Shrinkage Adjustment Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				1.19			
	from M1				1.19	0.00		
	from M2				1.19	0.00	0.00	
	from M3						0.00	0.00
Applicable Shrinkage Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				1.19			
	from M1				1.19	0.00		
	from M2				1.19	0.00	0.00	
	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.86 %	-1.05 %	1.81 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.22 %	0.54 %
Monthly Injections	1.76 %	-1.22 %	0.54 %
Monthly Inventory Level	0.08 %	-0.04 %	0.04 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES

Effective During the Spring, Summer and Fall Periods: April 1 through November 30

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
Base	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
Applicable	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
Shrinkage	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
Percentage	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
|	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
|	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
|	from STX	-0.04	-0.10	-0.42	-0.42	-0.31	-0.88	-0.87
Applicable	from WLA	0.41	0.20	-0.10	-0.10	0.01	-0.56	-0.55
Shrinkage	from ELA	0.31	0.12	0.16	0.16	0.27	-0.30	-0.29
Adjustment	from ETX	0.29	0.12	0.16	0.16	0.27	-0.30	-0.29
Percentage	from M1	-0.31	0.01	0.27	0.27	0.11	-0.46	-0.45
|	from M2	-0.88	-0.56	-0.30	-0.30	-0.46	-0.15	-0.13
|	from M3	-0.87	-0.55	-0.29	-0.29	-0.45	-0.13	0.44
|	from STX	0.89	0.94	1.22	1.22	2.18	2.71	3.47
Applicable	from WLA	0.94	0.73	1.03	1.03	1.99	2.52	3.28
Shrinkage	from ELA	1.22	1.03	1.07	1.07	2.03	2.56	3.32
Percentage	from ETX	1.22	1.03	1.07	1.07	2.03	2.56	3.32
|	from M1	2.18	1.99	2.03	2.03	0.96	1.49	2.25
|	from M2	2.71	2.52	2.56	2.56	1.49	1.27	2.04
|	from M3	3.47	3.28	3.32	3.32	2.25	2.04	1.51

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.07			
Percentage	from M1				1.07	0.00		
|	from M2				1.07	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.07			
|	from M1				1.07	0.00		
|	from M2				1.07	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-1.03 %	1.67 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.22 %	0.54 %
Monthly Injections	1.76 %	-1.22 %	0.54 %
Monthly Inventory Level	0.08 %	-0.04 %	0.04 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: December 1 through March 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	1.09	1.25	2.12	2.12	3.08	4.70	5.81
Base	from WLA	0.50	0.50	1.38	1.38	2.34	3.96	5.07
Applicable	from ELA	1.05	1.05	1.05	1.05	2.01	3.63	4.74
Shrinkage	from ETX	1.09	1.05	1.05	1.05	2.01	3.63	4.74
Percentage	from M1	3.08	2.34	2.01	2.01	0.96	2.58	3.69
|	from M2	4.70	3.96	3.63	3.63	2.58	1.80	2.90
|	from M3	5.81	5.07	4.74	4.74	3.69	2.90	1.28
|	from STX	-0.25	-0.34	-0.86	-0.86	-0.88	-1.76	-1.82
Applicable	from WLA	0.41	0.13	-0.37	-0.37	-0.39	-1.27	-1.33
Shrinkage	from ELA	0.21	-0.04	0.06	0.06	0.04	-0.84	-0.90
Adjustment	from ETX	0.17	-0.04	0.06	0.06	0.04	-0.84	-0.90
Percentage	from M1	-0.88	-0.39	0.04	0.04	-0.02	-0.90	-0.96
|	from M2	-1.76	-1.27	-0.84	-0.84	-0.90	-0.43	-0.47
|	from M3	-1.82	-1.33	-0.90	-0.90	-0.96	-0.47	0.42
|	from STX	0.84	0.91	1.26	1.26	2.20	2.94	3.99
Applicable	from WLA	0.91	0.63	1.01	1.01	1.95	2.69	3.74
Shrinkage	from ELA	1.26	1.01	1.11	1.11	2.05	2.79	3.84
Percentage	from ETX	1.26	1.01	1.11	1.11	2.05	2.79	3.84
|	from M1	2.20	1.95	2.05	2.05	0.94	1.68	2.73
|	from M2	2.94	2.69	2.79	2.79	1.68	1.37	2.43
|	from M3	3.99	3.74	3.84	3.84	2.73	2.43	1.70

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.11			
Percentage	from M1				1.11	0.00		
|	from M2				1.11	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.11			
|	from M1				1.11	0.00		
|	from M2				1.11	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.86 %	-1.01 %	1.85 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.09 %	0.67 %
Monthly Injections	1.76 %	-1.09 %	0.67 %
Monthly Inventory Level	0.08 %	-0.06 %	0.02 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Spring, Summer and Fall Periods: April 1 through November 30

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
Base Applicable Shrinkage Percentage	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
Applicable Shrinkage Adjustment Percentage	from STX	-0.09	-0.15	-0.50	-0.50	-0.41	-1.02	-1.08
	from WLA	0.36	0.21	-0.12	-0.12	-0.03	-0.64	-0.70
	from ELA	0.23	0.10	0.15	0.15	0.24	-0.37	-0.43
	from ETX	0.21	0.10	0.15	0.15	0.24	-0.37	-0.43
	from M1	-0.41	-0.03	0.24	0.24	0.09	-0.52	-0.58
	from M2	-1.02	-0.64	-0.37	-0.37	-0.52	-0.19	-0.25
	from M3	-1.08	-0.70	-0.43	-0.43	-0.58	-0.25	0.37
Applicable Shrinkage Percentage	from STX	0.84	0.89	1.14	1.14	2.08	2.57	3.26
	from WLA	0.89	0.74	1.01	1.01	1.95	2.44	3.13
	from ELA	1.14	1.01	1.06	1.06	2.00	2.49	3.18
	from ETX	1.14	1.01	1.06	1.06	2.00	2.49	3.18
	from M1	2.08	1.95	2.00	2.00	0.94	1.43	2.12
	from M2	2.57	2.44	2.49	2.49	1.43	1.23	1.92
	from M3	3.26	3.13	3.18	3.18	2.12	1.92	1.44

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
Base Applicable Shrinkage Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				0.00			
	from M1				0.00	0.00		
	from M2				0.00	0.00	0.00	
	from M3						0.00	0.00
Applicable Shrinkage Adjustment Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				1.06			
	from M1				1.06	0.00		
	from M2				1.06	0.00	0.00	
	from M3						0.00	0.00
Applicable Shrinkage Percentage	from STX	0.00						
	from WLA		0.00					
	from ELA			0.00				
	from ETX				1.06			
	from M1				1.06	0.00		
	from M2				1.06	0.00	0.00	
	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-0.93 %	1.77 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.09 %	0.67 %
Monthly Injections	1.76 %	-1.09 %	0.67 %
Monthly Inventory Level	0.08 %	-0.06 %	0.02 %

Footnote: Due to the bidirectional flow patterns of Pipeline’s Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES

Effective During the Winter Period: December 1 through December 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.93	1.04	1.64	1.64	2.49	3.59	4.34
Base	from WLA	0.53	0.53	1.13	1.13	1.98	3.08	3.83
Applicable	from ELA	0.91	0.91	0.91	0.91	1.76	2.86	3.61
Shrinkage	from ETX	0.93	0.91	0.91	0.91	1.76	2.86	3.61
Percentage	from M1	2.49	1.98	1.76	1.76	0.85	1.95	2.70
|	from M2	3.59	3.08	2.86	2.86	1.95	1.42	2.17
|	from M3	4.34	3.83	3.61	3.61	2.70	2.17	1.07
|	from STX	-0.04	-0.10	-0.42	-0.42	-0.31	-0.88	-0.87
Applicable	from WLA	0.41	0.20	-0.10	-0.10	0.01	-0.56	-0.55
Shrinkage	from ELA	0.31	0.12	0.16	0.16	0.27	-0.30	-0.29
Adjustment	from ETX	0.29	0.12	0.16	0.16	0.27	-0.30	-0.29
Percentage	from M1	-0.31	0.01	0.27	0.27	0.11	-0.46	-0.45
|	from M2	-0.88	-0.56	-0.30	-0.30	-0.46	-0.15	-0.13
|	from M3	-0.87	-0.55	-0.29	-0.29	-0.45	-0.13	0.44
|	from STX	0.89	0.94	1.22	1.22	2.18	2.71	3.47
Applicable	from WLA	0.94	0.73	1.03	1.03	1.99	2.52	3.28
Shrinkage	from ELA	1.22	1.03	1.07	1.07	2.03	2.56	3.32
Percentage	from ETX	1.22	1.03	1.07	1.07	2.03	2.56	3.32
|	from M1	2.18	1.99	2.03	2.03	0.96	1.49	2.25
|	from M2	2.71	2.52	2.56	2.56	1.49	1.27	2.04
|	from M3	3.47	3.28	3.32	3.32	2.25	2.04	1.51

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
|	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
|	from M2				0.00	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.07			
Percentage	from M1				1.07	0.00		
|	from M2				1.07	0.00	0.00	
|	from M3						0.00	0.00
|	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.07			
|	from M1				1.07	0.00		
|	from M2				1.07	0.00	0.00	
|	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.70 %	-1.03 %	1.67 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.22 %	0.54 %
Monthly Injections	1.76 %	-1.22 %	0.54 %
Monthly Inventory Level	0.08 %	-0.04 %	0.04 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

CURRENTLY EFFECTIVE PERCENTAGES FOR APPLICABLE SHRINKAGE FOR ASA RATE SCHEDULES
Effective During the Winter Period: January 1 through March 31

FOR TRANSPORTATION SERVICE		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
	from STX	1.09	1.25	2.12	2.12	3.08	4.70	5.81
Base	from WLA	0.50	0.50	1.38	1.38	2.34	3.96	5.07
Applicable	from ELA	1.05	1.05	1.05	1.05	2.01	3.63	4.74
Shrinkage	from ETX	1.09	1.05	1.05	1.05	2.01	3.63	4.74
Percentage	from M1	3.08	2.34	2.01	2.01	0.96	2.58	3.69
	from M2	4.70	3.96	3.63	3.63	2.58	1.80	2.90
	from M3	5.81	5.07	4.74	4.74	3.69	2.90	1.28
	from STX	-0.25	-0.34	-0.86	-0.86	-0.88	-1.76	-1.82
Applicable	from WLA	0.41	0.13	-0.37	-0.37	-0.39	-1.27	-1.33
Shrinkage	from ELA	0.21	-0.04	0.06	0.06	0.04	-0.84	-0.90
Adjustment	from ETX	0.17	-0.04	0.06	0.06	0.04	-0.84	-0.90
Percentage	from M1	-0.88	-0.39	0.04	0.04	-0.02	-0.90	-0.96
	from M2	-1.76	-1.27	-0.84	-0.84	-0.90	-0.43	-0.47
	from M3	-1.82	-1.33	-0.90	-0.90	-0.96	-0.47	0.42
	from STX	0.84	0.91	1.26	1.26	2.20	2.94	3.99
Applicable	from WLA	0.91	0.63	1.01	1.01	1.95	2.69	3.74
Shrinkage	from ELA	1.26	1.01	1.11	1.11	2.05	2.79	3.84
Percentage	from ETX	1.26	1.01	1.11	1.11	2.05	2.79	3.84
	from M1	2.20	1.95	2.05	2.05	0.94	1.68	2.73
	from M2	2.94	2.69	2.79	2.79	1.68	1.37	2.43
	from M3	3.99	3.74	3.84	3.84	2.73	2.43	1.70

FOR TRANSPORTATION SERVICE UNDER CONTRACTS WITH PARTIAL BACKHAUL PATHS		STX (%)	WLA (%)	ELA (%)	ETX (%)	M1 (%)	M2 (%)	M3 (%)
	from STX	0.00						
Base	from WLA		0.00					
Applicable	from ELA			0.00				
Shrinkage	from ETX				0.00			
Percentage	from M1				0.00	0.00		
	from M2				0.00	0.00	0.00	
	from M3						0.00	0.00
	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Adjustment	from ETX				1.11			
Percentage	from M1				1.11	0.00		
	from M2				1.11	0.00	0.00	
	from M3						0.00	0.00
	from STX	0.00						
Applicable	from WLA		0.00					
Shrinkage	from ELA			0.00				
Percentage	from ETX				1.11			
	from M1				1.11	0.00		
	from M2				1.11	0.00	0.00	
	from M3						0.00	0.00

FOR STORAGE SERVICE	Base Applicable Shrinkage Percentage	Applicable Shrinkage Adjustment Percentage	Applicable Shrinkage Percentage
Monthly W/d (SS,SS-1,X-28)	2.86 %	-1.01 %	1.85 %
Monthly W/d (FSS,ISS-1)	1.76 %	-1.09 %	0.67 %
Monthly Injections	1.76 %	-1.09 %	0.67 %
Monthly Inventory Level	0.08 %	-0.06 %	0.02 %

Footnote: Due to the bidirectional flow patterns of Pipeline's Access Area Zones, there is no distinction between forwardhauls and backhauls for applicable Shrinkage purposes in the Access Area Zones.

Peoples Natural Gas
1307(f)-2021

Section 53.64(c)(1) Details of contract negotiations for gas supply, production, transportation and storage.

1. Local Producers

Locally produced, Appalachian Gas has always been a significant source of gas on the Peoples Natural Gas Company LLC ("Peoples Natural Gas" or the "Company") system for both system supply and the transport market. Peoples Natural Gas purchased local supplies from approximately 163 producers as of January 2021.

With the implementation of Rate Appalachian Gathering Service as part of the settlement approved in resolution of Peoples Natural Gas' general rate case at Docket No. R-2018-3006818, the Company has replaced and/or amended nearly all existing contracts to implement approved terms and conditions. Among these replacements and/or amendments is a requirement that any party desiring to transport gas through the Company's gathering system, as well as to deliver gas directly into the Company's distribution and transmission system, must execute a Master Interconnect and Measurement Agreement ("MIMA"). The MIMA supersedes and terminates any previously executed agreement(s) between the parties for the transport and/or purchase of gas. The terms of the MIMA include Peoples Natural Gas' standard purchase price terms, as follows:

A price based on the Inside F.E.R.C.'s Gas Market Report, "Price of Spot Gas Delivered to Pipelines," for deliveries of Appalachian production into Dominion's dry transmission system for first of the month (a.k.a. Dominion South Point Index) was first used as a pricing option in 1999 and has become the standard, local gas, purchase price for the Company. These contracts are for 1-year terms with a price at either 100% or 103% of the index. Unless terminated upon at least thirty (30) days' advance notice by either party prior to the end of the term, the agreement shall renew automatically for successive additional one-month production period terms.

As Peoples Natural Gas implements MIMAs with legacy producers that have current contracts with non-standard pricing terms, those terms will change to standard pricing terms.

2. National Fuel Gas Supply Corporation (NFG)

The Company purchases interstate, natural gas transportation service and natural gas storage service from NFG. In 1993, Peoples Natural Gas entered into Rate Schedule EFT transportation contracts with NFG of 15,476 Dth/day and Rate Schedule ESS storage service at a demand level of 9,793 Dth/day and a capacity level of 748,611 Dth. The primary term of these service agreements expired March 31, 2003; however, the terms were extended each year for additional one-year periods under applicable provisions in the agreements so that the contracts now expire March 31, 2022 subject to notice of termination being provided no later than March 31, 2021. If notice of termination is not provided by March 31, 2021, the contracts will extend for another one-year period. Peoples Natural Gas requires this capacity to meet the needs of its customers in an operationally isolated portion of its service area and thus does not intend to provide such notice of termination.

3. Peoples Gas Company LLC

Exchange Agreement - Peoples Natural Gas and Peoples Gas Company LLC ("Peoples Gas") (collectively, "Companies") exchange natural gas supply pursuant to an agreement that was approved at Docket No. G-2011-2265150. After the original exchange agreement was filed for approval with the Pennsylvania Public Utility Commission ("Commission"), Peoples Natural Gas and Peoples Gas worked with Commission Staff as well as the state advocates to address any issues they had regarding the exchange agreement. As a result, Peoples Natural Gas and Peoples Gas filed, on January 5, 2012, an amended exchange agreement that includes various commitments made by Peoples Natural Gas and Peoples Gas in order to resolve those issues. The amended agreement was approved by the Commission on March 15, 2012.

On June 4, 2012, the Companies made a filing, requesting Commission approval of a First Amendment to the Gas Exchange Agreement to add a temporary point of interconnection and exchange. The filing was approved by Secretarial Letter issued on July 13, 2012.

On October 26, 2012, the Companies made a filing requesting Commission approval of a Second Amendment to the Gas Exchange Agreement to add an additional point of interconnection and exchange. The filing was approved by Secretarial Letter issued on January 29, 2013.

On November 21, 2013, the Companies made a filing requesting Commission approval of an Amended and Restated Gas Exchange Agreement (the "A&R GEA") which was designed to accommodate the Companies' ongoing system improvement plans. Over the next twenty (20) years, the Companies plan to replace all at-risk distribution mains and associated facilities. With geographically overlapping distribution systems, the Companies anticipate that the requests for new interconnection points are likely to increase. The A&R GEA would permit the Companies to install up to 15 new interconnection points without pre-approval, per calendar year, provided that, amongst other things, each new interconnection point does not exceed $250,000 in costs and each new interconnection point results in projected cost savings to the installing Company. The filing was approved by Secretarial Letter issued on May 27, 2014.

On June 26, 2014, Peoples Natural Gas and Peoples Gas filed a petition for Accounting and Regulatory Approvals at Docket No. P-2014-2429346. Among other things, this petition requested approval of another exchange agreement between the Companies that will encourage efficient pipeline replacement by, for example, allowing one company to abandon a pipeline that is due for replacement and continuing service to the customers formerly connected to that pipeline by connecting them to a duplicative pipeline owned by the other company. The resulting gas exchange will use the delivery points from the above-referenced A&R GEA to balance deliveries under the new agreement. Parties to that proceeding reached a settlement to resolve all issues. The settlement was approved on December 18, 2014.

4. <u>Dominion Energy Transmission, Inc. (DETI formerly DTI)</u>

Peoples Natural Gas purchases interstate, natural gas transportation service and natural gas storage service from DETI. On February 20, 2014, Peoples Natural Gas entered into FTNN and GSS service agreements with DTI effective April 1, 2014 through March 31, 2034. The service agreements provide for year-round FTNN service at 40,000 Dth/day and GSS service at 40,000 Dth/day and capacity of 4.6 MMDth. The FTNN and GSS service agreements bolster gas deliveries to critical city-gate points located on the western portion of Peoples Natural Gas' system.

Also in February 2014, Peoples Natural Gas executed FT and GSS contracts with DTI effective April 1, 2014 through March 31, 2034 to address cold weather supply restrictions on Equitrans in the northern part of the Peoples Natural Gas – Equitable Division system. These Rate Schedule GSS and Rate Schedule FT contracts ensure firm deliveries into Equitrans of 20,000 Dth/day and directly into Peoples Natural Gas of 20,000 Dth/day, with related seasonal storage capacity of 2,480,000 Dth. These agreements extend through March 31, 2034, and were approved in the 2014 1307(f) case.

5. <u>Texas Eastern Transmission, LP</u> (Texas Eastern or TETCO)

a. Firm Transportation Service - Peoples Natural Gas purchases interstate, natural gas transportation service from Texas Eastern. The Company entered into an agreement effective April 1, 2007 through March 31, 2019 for 15,650 Dth/day of Market Zone 3 (M3) firm transportation capacity under Rate Schedule FT-1. The primary term of this service agreement expired April 30, 2019; however, the agreement automatically extends for another one-year term if notice of termination is not provided at least one year prior to the termination date. Since no notice of termination has been given, the agreement has automatically extended for two additional one-year periods so that the contract now expires April 30, 2022 if notice of termination is provided no later than April 30, 2021. If notice of termination is not provided by April 30, 2021, the contract will extend for another one-year period. Peoples Natural Gas requires this capacity to meet the needs of its customers in an operationally isolated portion of its service area and thus does not intend to provide such notice of termination.

In August 2019, Peoples Natural Gas solicited third parties for an AMA of its TETCO capacity for the periods of November 2019 through March 31, 2020 and November 2019 through October 2020. The AMA stipulated that the awarded supplier would provide supply to Peoples Natural Gas with the same operational capacity as if Peoples Natural Gas retained control of the TETCO capacity. The AMA was awarded for the period of November 2019 through October 2020. Peoples Natural Gas' TETCO capacity was then released at zero cost per month for the same period. The AMA specifies that quantities may be called upon at specific points at monthly baseload or daily levels, or some combination. For monthly baseload requested quantities, pricing is INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Texas Eastern, M-2 Receipts plus TETCO variable costs to the requested meter in effect for the period. For daily requested quantities, pricing is Gas

Daily midpoint pricing for Texas Eastern, M-2 Receipts for the day of flow plus TETCO variable costs to the requested meter in effect for the period.

In September 2020, Peoples Natural Gas solicited third parties for an AMA of its TETCO capacity for the periods of November 2020 through March 2021 or November 2020 through October 2021. The AMA stipulated that the awarded supplier would provide supply to Peoples Natural Gas with the same operational capacity as if Peoples Natural Gas retained control of the TETCO capacity. The AMA was awarded for the entire period of November 2020 through October 2021. Peoples Natural Gas' TETCO capacity was then released at zero cost per month for the same period. The AMA specifies that quantities may be called on at specific points at monthly baseload or daily levels, or some combination thereof. For monthly baseload requested quantities, pricing is INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Texas Eastern, M-2 Receipts plus TETCO variable costs to the requested meter in effect for the period. For daily requested quantities, pricing is Gas Daily midpoint pricing for Texas Eastern, M-2 Receipts for the day of flow plus TETCO variable costs to the requested meter in effect for the period.

b. Delivered Supply - Peoples Natural Gas also needs firm deliveries of natural gas to other parts of its system adjacent to Texas Eastern's system in both Market Zone 3 (M3) and Market Zone 2 (M2). Previously, the Company supplied this need with Texas Eastern firm transportation service, but more recently, the Company has contracted for the purchase of natural gas delivered all the way to the Company's city-gate by the Supplier.

In May 2019, Peoples Natural Gas again issued an RFP for firm deliveries of up to 3,000 Dth/day at TETCO M2 Rockwood and 25,000 Dth/day at TETCO M3 Ebensburg, for the period of November 2019 through March 2020. Approximately twenty potential suppliers were solicited, and several proposals were received. Peoples Natural Gas accepted an offer for up to 25,000 Dth/day at Ebensburg and an offer for up to 3,000 Dth/day at Rockwood. Neither of the accepted proposals had associated reservation charges. Both accepted proposals offer the option to call on monthly baseload or daily spot quantities, or some combination. For monthly baseload requested quantities, all accepted proposals include premiums related to INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Texas Eastern, M-2 Receipts for that month. For daily requested quantities, all accepted proposals include premiums related to the Gas Daily midpoint pricing for Texas Eastern, M-2 Receipts reported for the day of flow.

In September 2020, Peoples Natural Gas issued an RFP for firm deliveries of up to 3,000 Dth/day at TETCO M2 Rockwood and 25,000 Dth/day at TETCO M3 Ebensburg, for the period of November 2020 through March 2021. Approximately twenty potential suppliers were solicited, however, no proposals were received for supply to Rockwood and only one response for supply to Ebensburg. This response was determined to be uneconomic and was not pursued. The lack of responses was apparently due to uncertainty of TETCO operating conditions because of landslide issues and Pipeline and Hazardous Materials Safety Administration ("PHMSA") inspections of their 30-inch line. Peoples Natural Gas contacted suppliers for further discussions and accepted an offer for up to 25,000 Dth/day at Ebensburg and up to 3,000 Dth/day at Rockwood from NJR Energy Services ("NJR").

NJR's offer for service to Ebensburg included a reservation fee of $37,750 per month, November 2020 through March 2021. NJR's deal allowed Peoples to call on daily supplies at Ebensburg priced at GDA TETCO M2 plus $0.25 per Dth. However, daily supplies would be priced at GDA TETCO M3 flat on any gas day that TETCO restricted any portion of secondary in path nominations between Uniontown and Ebensburg. The agreement called for baseload supply to Ebensburg to be priced at IFERC TETCO M3 index.

NJR's offer for service to Rockwood included a reservation feel of $9,060 per month, November 2020 through March 2021. NJR's deal allowed Peoples to call on daily supplies at Rockwood priced at GDA TETCO M2 plus $0.00 per Dth. Baseload supply to Rockwood would be priced at IFERC TETCO M2 index.

At the time of filing, Peoples Natural Gas had not entered into negotiations for replacement agreements for delivered gas that expire at the end of March 2021. Peoples Natural Gas intends to issue another RFP.

6. <u>Tennessee Gas Pipeline Company, LLC</u> (Tennessee or TGP)

Peoples Natural Gas needs firm deliveries of natural gas to parts of its system adjacent to TGP's system. Previously, the Company supplied this need with TGP firm transportation service, but more recently, the Company has contracted for the purchase of natural gas delivered all the way to the Company's city-gate by the Supplier.

In May 2019, Peoples Natural Gas again issued an RFP for deliveries to its TGP meters at Pitt Terminal, Pulaski and New Castle for the period of November 2019 through March 2020. Approximately twenty potential suppliers were solicited and several proposals were received. Peoples Natural Gas entered into an agreement with three suppliers to make deliveries ranging from 6,000 Dth/day to 26,000 Dth/day, depending on the supplier, with no associated reservation fee and a commodity based premium to the GDA Z4 index. All three agreements expired on March 31, 2020. One of the accepted proposal's pricing for baseload supplies is at the INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Tennessee, Zone 4-200 Leg for that month with no premium. The other proposals' pricing for baseload supplies is at the INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Tennessee, Zone 4-200 Leg for that month plus a premium. For daily requested quantities, all accepted proposals include premiums related to Gas Daily midpoint pricing for Tennessee, Zone 4-200 Leg reported for the day of flow.

In September 2020, Peoples Natural Gas issued an RFP for deliveries to its TGP meters at Pitt Terminal, Pulaski and New Castle, for the period of November 2020 through March 2021. Approximately twenty potential suppliers were solicited and several proposals were received. Peoples Natural Gas entered into an agreement with one supplier to make deliveries ranging from zero Dth/day to 26,000 Dth/day. The agreement included a reservation fee of $0.015 per daily Dth, or approximately $12,000 per month from November 2020 through March 2021. The agreement specified baseload supply pricing at the INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Tennessee, Zone 4-200 Leg for that month plus a premium. For daily requested quantities, the proposal specified a premium related to Gas Daily midpoint pricing for Tennessee, Zone 4-200 Leg reported for the day of flow. For the November 2020 through March 2021 period, Peoples Natural Gas rejected one less competitive offers related to its TGP meters supply RFP.

Peoples Natural Gas has evaluated its needs and plans to issue in the second quarter of 2021 another RFP for deliveries to its TGP meters for the winter of 2021 – 2022.

7. Equitrans, L.P. ("Equitrans") and EQT Energy, LLC ("EQT Energy")

On March 19, 2013, Peoples Natural Gas, Peoples Gas, and Equitable Gas Company, LLC ("Equitable") filed a Joint Application with the Commission requesting all necessary approvals pursuant to Sections 1102(a)(3), 1317(d), 2102(a), and 2204(e)(4) of the Public Utility Code ("Code"), 66 Pa.C.S. §§ 1102(a)(3), 1317(d), 2102(a), and 2204(e)(4), authorizing and approving: (1) the transfer of 100% of the issued and outstanding limited liability company membership interests in Equitable, an indirect subsidiary of EQT Corporation ("EQT"), to PNG Companies LLC ("PNG"), an indirect subsidiary of SteelRiver Infrastructure Fund North America LP ("SRIFNA"); (2) the merger of Equitable with Peoples Natural Gas, a wholly-owned subsidiary of PNG, and the operation of Equitable as an operating division of PNG; (3) the transfer of certain storage and transmission assets of Peoples Natural Gas to EQT; (4) the transfer of certain assets and/or the exchange of certain services between EQT and Equitable; (5) certain PNG ownership changes associated with the Transaction; (6) the associated gas capacity, storage, interconnects, leases, and supply service agreements among Peoples Natural Gas, Peoples Gas, Equitable, and/or EQT set forth in the Joint Application; and (7) certain changes in Peoples Natural Gas' tariff necessary to carry out the transactions. On November, 14, 2013, the Commission entered an Order at Docket Nos. A-2013-2353647, A-2013-2353649, and A-2013-2353651, approving a Joint Petition for Settlement of all issues in the above-captioned proceeding. By this Order, the Commission approved the transfer of certain storage and transmission assets of Peoples Natural Gas to affiliates of EQT Corporation and approved certain gas supply contracts between Peoples Natural Gas, Equitrans and EQT Energy. These approved gas supply contracts are described in the sections immediately below.

a. Equitrans - Allegheny Valley Connector ("AVC") Services - On December 10, 2013, Peoples Natural Gas and Equitrans entered into transportation service agreements under Rate Schedule FTS and FTSS, and a storage service agreement under Rate Schedule GSS. Under these service agreements, Equitrans provides year-round firm transportation and storage services to Peoples Natural Gas using the storage and transmission assets transferred by Peoples Natural Gas to EQT Corporation. These agreements provide Peoples Natural Gas with access to the capacity on the transferred assets needed to serve its customers. The transferred assets are referred to as the AVC system and are operated by Equitrans. The FTSS and GSS service agreements provide Peoples Natural Gas and its customers with access to AVC storage capacity of 200,000 Dth/day and 8.6 MMDth annually. The FTS service agreement provides Peoples Natural Gas and its customers with access to transportation capacity on the AVC system of 251,700 Dth/day. These service agreements provide for a total of 451,700 Dth/day of winter season, firm capacity on the AVC system.

b. Equitrans – Firm Transportation Service - On December 10, 2013, Peoples Natural Gas and Equitrans entered into an agreement under Equitrans Rate Schedule FTS for firm transportation services of 251,700 Dth/day. This agreement, which became effective April 1, 2014, replaced 251,700 Dth/day of firm transportation and storage capacity under the DTI storage and transportation agreements that expired March 31, 2014. Gas transported under this agreement is delivered to Ginger Hill, which is the point of interconnection between the Equitrans Mainline and AVC systems. This agreement provides for a maximum daily quantity of 251,700 Dth/day for the winter months of November through March and 62,000 Dth/day for the summer months of April through October.

Also on December 10, 2013, Peoples Natural Gas and Equitrans entered into an extension of existing agreements under Equitrans Rate Schedule FTS for services of 352,481 Dth/day of firm transportation and storage capacity previously available under the Equitrans storage and transportation agreements existing prior to the Peoples Natural Gas acquisition of Equitable. Gas transported under these agreements is delivered to various interconnections between the Equitrans Mainline and Peoples Natural Gas (into what was formerly the Equitable Division). These agreements provide for a maximum daily quantity of 352,481 Dth/day for the winter months of November through March and 267,992 Dth/day for the summer months of April through October. These contracts expire on March 31, 2034.

Peoples Natural Gas also holds a contract under Rate Schedule NOFT allowing No-Notice delivery of 79,545 Dth/day to its Equitrans interconnects. This contract replaced a contract previously held by Equitable, changing only the effective dates, effective April 1, 2014 and expiring on March 31, 2034.

c. Equitrans – Firm Storage Service - The Company has held two forms of storage service with Equitrans over the years. The first is a 60-day storage service under Rate Schedule 60SS, and the other is a 115 day storage service under Rate Schedule 115SS. The 60SS service provides for a Maximum Daily Withdrawal Quantity ("MDWQ") of 137,010 Dth with related storage capacity of 7,473,296 Dth, and the 115SS service provides for an MDWQ of 50,536 Dth and related storage capacity of 5,283,357 Dth. These storage contracts expire on March 31, 2034. The Company also holds sufficient Firm Transportation contracts to support these storage services.

d. EQT Energy – NAESB Gas Supply Agreement - On December 19, 2012, Equitable and EQT Energy entered into a base contract for the sale of natural gas by EQT Energy to Equitable. On December 17, 2013, Equitable and EQT Energy executed a transaction confirmation under the December 19, 2012 base contract with an effective date of December 17, 2013. Under this agreement, EQT Energy will deliver an annual volume of not less than 20 MMDth to Equitrans for redelivery to Peoples Natural Gas (into what was formerly the Equitable Division), with a maximum daily quantity ("MDQ") of 164,935 Dth/day. This agreement also provides for a first-of-the-month nomination of a fixed daily quantity with a winter intra-month call option that allows Peoples Natural Gas to change the daily quantity and call on supplies up to its MDQ on 24 hours' notice.

e. EQT Energy – NAESB Gas Supply Agreement - On December 19, 2012, Peoples Natural Gas and EQT Energy entered into a base contract for the sale of natural gas by EQT Energy to Peoples Natural Gas. On December 17, 2013, Peoples Natural Gas and EQT Energy executed a transaction confirmation under the December 19, 2012 base contract with an effective date of April 1, 2014. Under this agreement, EQT Energy will deliver to Equitrans for redelivery to Peoples Natural Gas an annual volume of not less than 15 MMDth, with an MDQ of 251,700 Dth/day. This agreement also provides for a first-of-the-month nomination of a fixed daily quantity with a winter intra-month call option that allows Peoples Natural Gas to change the daily quantity and call on supplies of up to its MDQ on 24 hours' notice.

On June 1, 2019, the Company and Equitrans entered into new agreements that effectively converted all of the firm transportation services listed in paragraphs a. through c., above, to enhanced firm transportation services provided under Equitrans Rate Schedule EFT, Enhanced Firm Transportation Service. This was done pursuant to a settlement approved in FERC Docket No. RP18-1167-000, et al.

8. Peoples Gas

Historically, for operational reasons, Equitable procured gas deliveries into its system from certain points of interconnection with Peoples Gas. Peoples Natural Gas entered into a transportation agreement with Peoples Gas to move supplies into these interconnections with People Gas under terms similar to those that existed previously. The agreement provides for transportation of these operationally necessary supplies at levels to satisfy the requirements in a certain area of the Peoples Natural system.

9. Term Gas Supply Contracts

"Term" gas supply contracts are gas purchase agreements with duration greater than one month for a firm amount.

As discussed in paragraphs 7.d. and 7.e., above, Peoples Natural Gas has long-term supply arrangements with EQT Energy with monthly and daily volume options. One supply contract provides up to 164,935 Dth/day and terminates December 16, 2033. The second supply contract provides up to 251,700 Dth/day and terminates March 31, 2034.

10. Spot-Gas Contracts

Peoples Natural Gas enters into numerous spot-market gas purchase contracts with various entities. By their very nature, spot-market contracts are negotiated on a monthly or daily basis.

Peoples Natural Gas Company
Summary of Pipeline Contracts
1307(f)-2021

Pipeline	Firm Storage & Transportation Service	Contract Number	Contract Volume (MDQ-Dth)	Contract Volume (Capacity-Dth)	Expiration Date
Dominion Transmission	Rate Schedule GSS	300181	40,000	4,600,000	3/31/2034
	Rate Schedule GSS	300196	40,000	2,480,000	3/31/2034
	Rate Schedule FTNN	100119	40,000	14,600,000	3/31/2034
	Rate Schedule FT	200654	40,000	14,600,000	3/31/2034
Texas Eastern	Rate Schedule FT-1	910089	15,650	5,712,250	4/30/2022
Equitrans	Rate Schedule GSS-AVC	775	200,000	8,600,000	12/31/2033
	Rate Schedule FTS-AVC	774			12/31/2033
	Winter		200,000	30,200,000	
	Summer		62,000	13,268,000	
	Rate Schedule EFT-AVC	1576			12/31/2033
	Winter		251,700	38,006,700	
	Summer		62,000	13,268,000	
	Rate Schedule 60SS				
	Winter	863	137,010	7,473,296	3/31/2034
	Summer		74,733		
	Rate Schedule 115SS				
	Winter	865	50,536	5,283,357	3/31/2034
	Summer		26,417		
	Rate Schedule EFT-Sunrise	1565			3/31/2034
	Winter		251,700	38,006,700	
	Summer		62,000	13,268,000	
	Rate Schedule NOFT	860	79,545	29,033,925	3/31/2034
	Rate Schedule EFT	1559			3/31/2034
	Winter		164,935	24,905,185	
	Summer		164,935	35,296,090	
	Rate Schedule EFT	1560			3/31/2034
	Winter		137,010	20,688,510	
	Summer		76,142	16,294,388	
	Rate Schedule EFT	1561			3/31/2034
	Winter		50,536	7,630,936	
	Summer		26,915	5,759,810	
National Fuel Gas Supply	Rate Schedule EFT	E00532	15,476	5,648,740	3/31/2022
	Rate Schedule ESS	G00543	9,793	748,611	3/31/2022

Peoples Natural Gas
1307(f) - 2021

Section 53.64(c)(2):

Notwithstanding paragraph (1), requests for confidential treatment of a submission required to be filed under § § 53.61—53.63, this section and § § 53.65—53.68 shall be made at the time the supporting information is submitted to the Commission. The information need not be served on another person until the request for nondisclosure is decided by the administrative law judge assigned to the proceeding and will be served under separate cover. The Commission will restrict access to this information pending its determination. The administrative law judge will make the determination within 15 days of the date the administrative law judge is assigned to the proceeding.

* * * * * * * * * *

Response:

Peoples Natural Gas does not request confidential treatment of any submission made as part of this original pre-filing information, with the exception of the detailed pipeline system map referred to in response to 53.64(c)(10). Peoples Natural Gas reserves the right to seek confidential treatment of any subsequent submissions made in the context of discovery or during the course of this proceeding and is willing to make confidential information available to certain parties pending receipt of the presiding ALJ's Order on nondisclosure, but only subject to confidentiality agreements acceptable to Peoples Natural Gas.

Peoples Natural Gas
1307(f)-2021

Section 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 two 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.

* * * * * * * * * * *

The natural gas spot market has evolved to the point where suppliers are no longer providing formal "bids" for gas supplies on a monthly basis to Peoples Natural Gas as was done in the past. Once it is determined how much spot gas supplies Peoples Natural Gas' retail customers will need on the interstate systems for the upcoming month or portion of a month, buyers begin the process of contacting suppliers and negotiating the price for those supplies. This process of negotiation is done primarily via Instant Messaging and telephone. The economics of the supply alternatives are continuously updated throughout the period during which supplies are sought to determine, at the particular point in time purchases are made, the least costly combination of gas supply and transportation alternatives then available for delivery of supplies to Peoples Natural Gas' city-gates. At the time of the negotiation, both buyer and seller have available to them the instant NYMEX screen price and general basis differentials from the NYMEX reference point to the receipt points where supplies are needed and other price discovery mechanisms. If buyer and seller can come to acceptable terms, a deal for supply is then completed.

In May 2019, Peoples Natural Gas issued an RFP for firm deliveries of up to 3,000 Dth/day at TETCO M2 Rockwood and 25,000 Dth/day at TETCO M3 Ebensburg, for the period of November 2019 through March 2020. Approximately twenty potential suppliers were solicited, and six proposals were received. Peoples Natural Gas accepted an offer for up to 25,000 Dth/day at Ebensburg and an offer for up to 3,000 Dth/day at Rockwood. Neither of the accepted proposals had associated reservation charges. Both accepted proposals offer the option to call on monthly baseload or daily spot quantities, or some combination. For monthly baseload requested quantities, all accepted proposals include premiums related to INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Texas Eastern, M-2 Receipts for that month. For daily requested quantities, all accepted proposals include premiums related to the Gas Daily midpoint pricing for Texas Eastern, M-2 Receipts reported for the day of flow. For the November 2019 through March 2020 period, Peoples Natural Gas rejected five less competitive offers related to its Rockwood supply RFP and four offers related to its Ebensburg supply RFP.

In May 2019, Peoples Natural Gas issued an RFP for deliveries to its TGP meters at Pitt Terminal, Pulaski and New Castle, for the period of November 2019 through March 2020. Approximately twenty potential suppliers were solicited and seven proposals were received.

Peoples Natural Gas entered into an agreement with three suppliers to make deliveries ranging from 6,000 Dth/day to 26,000 Dth/day, depending on the supplier, with no associated reservation fee and a commodity based premium to the GDA Z4 index. All three agreements expired on March 31, 2020. One of the accepted proposal's pricing for baseload supplies is at the INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Tennessee, Zone 4-200 Leg for that month with no premium. The other proposals' pricing for baseload supplies is at the INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Tennessee, Zone 4-200 Leg for that month plus a premium. For daily requested quantities, all accepted proposals include premiums related to Gas Daily midpoint pricing for Tennessee, Zone 4-200 Leg reported for the day of flow. For the November 2019 through March 2020 period, Peoples Natural Gas rejected four less competitive offers related to its TGP meters supply RFP.

In August 2019, Peoples Natural Gas solicited third parties for an AMA of its TETCO capacity for the periods of November 2019 through March 31, 2020 and November 2019 through October 2020. The AMA stipulated that the awarded supplier would provide supply to Peoples Natural Gas with the same operational capacity as if Peoples Natural Gas retained control of the TETCO capacity. The AMA was awarded for the entire period of November 2019 through October 2020. Peoples Natural Gas' TETCO capacity was then released at zero cost per month for the same period. The AMA specifies that quantities may be called on at specific points at monthly baseload or daily levels, or some combination. For monthly baseload requested quantities, pricing is INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Texas Eastern, M-2 Receipts plus TETCO variable costs to the requested meter in effect for the period. For daily requested quantities, pricing is Gas Daily midpoint pricing for Texas Eastern, M-2 Receipts for the day of flow plus TETCO variable costs to the requested meter in effect for the period. For the November 2019 through March 2020 period, Peoples Natural Gas rejected six less competitive offers related to its TETCO AMA RFP.

In September 2020, Peoples Natural Gas issued an RFP for deliveries to its TGP meters at Pitt Terminal, Pulaski and New Castle, for the period of November 2020 through March 2021. Approximately twenty potential suppliers were solicited and several proposals were received. Peoples Natural Gas entered into an agreement with one supplier to make deliveries ranging from zero Dth/day to 26,000 Dth/day. The agreement included a reservation fee of $0.015 per daily Dth, or approximately $12,000 per month from November 2020 through March 2021. The agreement specified baseload supply pricing at the INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Tennessee, Zone 4-200 Leg for that month plus a premium. For daily requested quantities, the proposal specified a premium related to Gas Daily midpoint pricing for Tennessee, Zone 4-200 Leg reported for the day of flow. For the November 2020 through March 2021 period, Peoples Natural Gas rejected one less competitive offer related to its TGP meters supply RFP.

In September 2020, Peoples Natural Gas issued an RFP for firm deliveries of up to 3,000 Dth/day at TETCO M2 Rockwood and 25,000 Dth/day at TETCO M3 Ebensburg, for the period of November 2020 through March 2021. Approximately twenty potential suppliers were solicited, however, no proposal was received for supply to Rockwood and only one response for supply to Ebensburg. This response was determined to be uneconomic and was not pursued. The lack of responses was apparently due to uncertainty of TETCO operating conditions because of landslide issues and PHMSA inspections of their 30-inch line. Peoples Natural Gas contacted suppliers for further discussions and accepted an offer for up to 25,000 Dth/day at Ebensburg and up to 3,000 Dth/day at Rockwood from NJR Energy Services.

NJR's offer for service to Ebensburg included a reservation fee of $37,750 per month, November 2020 through March 2021. NJR's deal allowed Peoples to call on daily supplies at Ebensburg priced at GDA TETCO M2 plus $0.25 per Dth. However, daily supplies would be priced at GDA TETCO M3 flat on any gas day that TETCO restricted any portion of secondary in path nominations between Uniontown and Ebensburg. The agreement called for baseload supply to Ebensburg to be priced at IFERC TETCO M3 index.

NJR's offer for service to Rockwood included a reservation fee of $9,060 per month, November 2020 through March 2021. NJR's deal allowed Peoples to call on daily supplies at Rockwood priced at GDA TETCO M2 per Dth. Baseload supply to Rockwood would be priced at IFERC TETCO M2 index.

In September 2020, Peoples Natural Gas solicited third parties for an AMA of its TETCO capacity for the periods of November 2020 through March 2021 or November 2020 through October 2021. The AMA stipulated that the awarded supplier would provide supply to Peoples Natural Gas with the same operational capacity as if Peoples Natural Gas retained control of the TETCO capacity. The AMA was awarded for the entire period of November 2020 through October 2021. Peoples Natural Gas' TETCO capacity was then released at zero cost per month for the same period. The AMA specifies that quantities may be called on at specific points at monthly baseload or daily levels, or some combination. For monthly baseload requested quantities, pricing is INSIDE FERC's Gas Market Report, Monthly Bidweek Spot Gas Price Index for Texas Eastern, M-2 Receipts plus TETCO variable costs to the requested meter in effect for the period. For daily requested quantities, pricing is Gas Daily midpoint pricing for Texas Eastern, M-2 Receipts for the day of flow plus TETCO variable costs to the requested meter in effect for the period. For the November 2020 through October 2021 period, Peoples Natural Gas rejected three less competitive offers related to its TETCO AMA RFP.

No other sources of gas supply, transportation, or storage were considered by or offered to the utility but not chosen for use during the 12-month period ending January 31, 2021.

Any other capacity or supply arrangements offered or considered but not chosen to meet supply for the next 20 months will be discussed in the testimony of Steven Kolich (Peoples Natural Gas Statement No. 2).

Peoples Natural Gas
Docket No. R-2021-3023965

For the Twelve Months Ending December 31, 2020

Section 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 interests 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 three years. Subsequent lists need only update prior lists and add new cases.

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Overview

Peoples Natural Gas Company LLC ("Peoples Natural Gas") and Peoples Gas LLC ("Peoples Gas") (collectively, "the Peoples LDCs" [1]), monitor proceedings before the Federal Energy Regulatory Commission ("FERC") and undertake legal action as necessary to protect the interests of the ratepayers of the Peoples LDCs. The Peoples LDCs continually assess strategic and cost effective means of tracking the rate, tariff and certificate filings of the interstate pipelines by which they are served, as well as significant generic FERC proceedings which may affect the cost of gas supplies purchased on the interstate system or otherwise affect the services that the Peoples LDCs provide to their customers.

The Peoples LDCs' combined efforts to monitor and participate in FERC proceedings also promote use of a combined annotated listing to satisfy the filing requirement of Section 53.64(c)(4). To this end, the FERC rulemakings and interstate pipeline cases affecting one or both of the Peoples LDCs will be combined to generate the annotated listing of FERC cases set forth in each company's 1307(f) pre-filing. This filing will contain an annotated listing of FERC rulemakings and interstate pipeline cases affecting one or both of the Peoples LDCs for the period January 1, 2020 through December 31, 2020, including what has transpired in each case, and the degree of the Peoples LDCs' participation, if any.

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[1] The Peoples LDCs also monitor FERC proceedings on behalf of affiliate Peoples Gas WV LLC ("Peoples WV" or "PWV") and the term "the Peoples LDCs" may include Peoples WV with regard to the proceedings of Equitrans, L.P.

Representatives for the Peoples LDCs will continue to participate in pertinent customer meetings, conference calls, webcasts and seminars sponsored by the interstate pipeline companies through which they are served. Participation in these meetings and seminars and other industry programs has helped the Peoples LDCs to remain informed about pending cases and current issues that could affect the cost and availability of their gas supplies on the interstate system.

PIPELINE PROCEEDINGS

Participation

From time to time, the Peoples LDCs have intervened in, monitored the progress of,and occasionally submitted written comments in FERC proceedings. Currently, Peoples Natural Gas monitors Dominion Energy Transmission, Inc. ("Dominion" or "DETI")[2], Equitrans ("Equitrans" or "ETRN"), National Fuel Gas Supply Corporation ("National Fuel" or "NFG") and Texas Eastern Transmission, LP ("Texas Eastern") because the outcome of the FERC proceedings of these interstate pipelines may directly affect the services that Peoples Natural Gas provides to its customers. Similarly, Peoples Gas Company presently monitors Dominion, Equitrans and Columbia Gas Transmission, LLC ("Columbia"), the three interstate pipelines from which Peoples Gas receives service. Typically, the Peoples LDCs do not intervene in the FERC proceedings of an interstate pipeline when they are not a customer of that pipeline or do not have a significant or direct interest in the outcome. Nonetheless, from time to time the Peoples LDCs also monitor the rates and, on a more limited basis, may review the FERC proceedings of other interstate pipelines where they have a continuing interest due to historical relationships or potential interest in receiving service in the future (e.g., Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP")). In addition, the Peoples LDCs may review FERC orders on non-supplier pipelines that may have precedential value.

Annotated Listings of Proceedings

Schedule A includes an annotated listing of pipeline proceedings, including docket numbers, a summary of what has transpired in the case and its status, and the degree of participation for Peoples Natural Gas and/or Peoples Gas Company. The listing covers pipeline filings submitted during the period January 1, 2020, through December 31, 2020.

Schedule B also includes a separate listing of pipeline proceedings monitored and reviewed by Peoples LDCs representatives during the same period but which no further action was required beyond, in some cases, an intervention. Some of these dockets involve routine annual or semi-annual cost tracking filings that are submitted pursuant to already-accepted settlements or tariff provisions. Other dockets involve either non-substantive tariff changes or routine reports filed pursuant to

[2] Dominion Energy Transmission changed its name to Eastern Gas Transmission and Storage Company ("EGTS") late in 2020. For the majority of the year it was still known as Dominion Energy and appears as Dominion Energy in this year's filing.

approved settlements or tariff provisions. Generally, there are no protests or adverse comments regarding these routine filings when the pipelines follow the cost tracking and reporting procedures set forth in effective pipeline tariffs or settlements. Typically, in these routine or non-substantive proceedings, the FERC accepts the rate change or report without conditions or further action and, with regard to routine pipeline reports, the FERC may not issue orders where no objections are filed.

FERC RULEMAKINGS AND OTHER INQUIRIES

Participation

From time to time, the FERC issues a notice of proposed rulemaking ("NOPR"), a notice of inquiry ("NOI"), or a policy statement on topics of interest to the natural gas industry. These notices are reviewed and an assessment is made of the Peoples LDCs' interest in the subject matter. The Peoples LDCs monitor the progress of all such proceedings of interest and will participate in a significant generic FERC proceeding if their interests are not covered by others.

In addition, Peoples LDCs' personnel participate in certain industry organizations, which were formed to advance the collective interest of their members. These organizations often offer members access to full-time consultants without payroll expenses. Given the short lead times allowed for preparation of comments, associations can channel resources, information, and ideas into the federal rulemaking process with efficiency and at little cost.

The American Gas Association ("AGA") is a group representing more than 200 local energy companies that deliver clean natural gas throughout the United States. The AGA reports that there are more than 74 million residential, commercial and industrial natural gas customers in the U.S., of which 95 percent – more than 71 million customers – receive their gas from AGA members. The AGA acts as an advocate for local natural gas utility companies who take service from virtually every interstate natural gas pipeline regulated by the FERC under the Natural Gas Act and participates in rulemakings and other generic policy dockets that affect its members' interests. The AGA also monitors and participates from time to time in issues at other agencies and commissions (e.g., the Commodities Futures Trading Commission and the Pipeline and Hazardous Materials Safety Administration ("PHMSA")) that impact gas utilities and energy consumers. Generally, with the active participation of the AGA FERC Regulatory Committee as an advocate for local natural gas utility companies, the need for individual local distribution companies to participate directly in rulemaking proceedings is minimized. Peoples LDCs' representatives participate on AGA committees.

From time to time the AGA also files comments with regard to the FERC's proposals to incorporate into its regulations business practice and electronic communications standards developed by the North American Energy Standards Board ("NAESB"). The NAESB holds itself out as an industry forum for the development and promotion of standards that will lead to a seamless marketplace for wholesale and retail natural gas and electricity. Formed in January 2002, the NAESB is an independent and voluntary organization that develops and promotes the use of business practices and electronic communications standards for the wholesale and retail natural gas and electricity industries.

Annotated Listings of Rulemakings and Other FERC Proceedings

Normally, Schedule C provides a listing of a number of "FERC Rulemakings" in which the AGA participated during the period January 1, 2020, through December 31, 2020, including a description of the status and what has transpired in each proceeding. In addition to those rulemakings listed, the AGA intervenes, participates, and files comments from time to time in proceedings that may not directly or significantly impact the Peoples LDCs or their interstate pipeline service providers. Schedule C is omitted this year because any such proceedings that had direct impacts on pipelines that service Peoples LDCs are described in Schedule A.

Historically, the Peoples LDCs have also included a Schedule D, a description of Peoples LDCs' filings made with the FERC related to the rates charged for or rules applied to FERC-jurisdictional services provided by the Peoples LDCs. In this reporting period, no such filings were made and schedule D is omitted this year.

SCHEDULE A

PIPELINE PROCEEDINGS

Columbia Gas Transmission, LLC (Peoples Gas only)

Right of First Refusal ("ROFR") Waiver
RP20-667

Summary: On March 20, 2020, Columbia filed a petition for Limited Tariff Waiver. Columbia inadvertently failed to post Peninsula Energy's capacity per its tariff section VII.4.a after a change in Peninsula Energy's ROFR election.

Upon discovering the error, Columbia posted the capacity and received no bids, indicating no harm to other shippers. FERC approved the waiver on October 16, 2020.

X-103 Abandonment
RP20-783

Summary: On April 14, 2020, Columbia filed a petition to abandon tariff service X-103. The X-103 service was an exchange agreement between Columbia and Texas Eastern that Columbia relied on to move customer gas from the western to eastern portions of its system. Texas Eastern canceled the arrangement due to changes in its own system.

FERC accepted the change on April 30, 2020.

Prepayment
RP20-812

Summary: On April 29, 2020, Columbia filed to amend its General Terms and Conditions ("GT&C") to allow prepayment of service. Prepayment of service satisfies credit requirements under the new language contained in the GT&C. The change was accepted by FERC on May 14, 2020.

Recontracting
RP20-813

Summary: On April 29, 2020, Columbia filed language in its GT&C allowing the shipper and Columbia to mutually agree on early termination. This provision would be used when both parties agree to allow the capacity to be repurposed, generally with the same shipper.

There were no objections and the FERC approved the language on May 14, 2020.

Reservation Charge Credits
RP20-857

Summary: On May 1, 2020, Columbia filed language in its GT&C to change how volumes are determined for reservation charge credits. The pipeline proposed to change the calculation from nominated volumes to average daily volumes for the prior seven days nominated between primary points when the pipeline gives prior notice of an outage.

Columbia also changed from the no-profit method of calculating reservation credits to the safe harbor method, consistent with the recent FERC policy allowing outages of up to ten days before requiring pipelines to refund reservation charges.

On May 13, 2020, protests were filed by Appalachian Basin Shippers, the Cities of Charlottesville and Richmond, and a shipper consortium led by EQT Energy. Protestors objected to the new method arguing that Columbia can reduce reservation credits simply by posting the outage. Furthermore, Protestors argued that the average daily flow calculation does not provide for the different usage patterns of producers and end users. Finally, Protestors argued that the average use on no-notice contracts was not a valid indicator of the harm done to a shipper who has restricted use of such a contract.

To address these concerns, Columbia proposed on May 22, 2020, to calculate volume by using the same period from the prior year, among other remedies. FERC accepted Columbia's tariff with these proposed changes on May 29, 2020.

<u>Base Rate Case</u>
RP20-1060

Summary: On July 31, 2020, Columbia filed for a Section 4 base rate increase. In addition to the increase, Columbia proposed rolling in its current Capital Cost Recovery Mechanism ("CCRM") costs to base rates, initiating a new CCRM tracker, and proposed a preferred case in which its system would have an East and West rate zone, though rates were also proposed using the existing structure. The change in rate zone stems from increasing difficulty in reaching east coast delivery points on peak days because most storage is located in Ohio, the far western portion of the system.

Protests varied depending on each shipper's position on the system and their view on certain Columbia rate constructs. While all shippers protested the very large rate increase, only some protested the Operational Transaction Rate Adjustment ("OTRA"), with others arguing it should remain as is. Continuation of the CCRM tracker was opposed by a number of shippers as well, citing FERC policy that rates should be reviewed *before* introducing such a tracker. Columbia's new tariff language outlining hourly takes as $1/24^{th}$ of daily allowances was also protested. Finally, some parties argue that Columbia filed earlier than permitted by its Modernization II settlement with shippers, which provided a longer stayout unless legislation not contemplated at the time of the settlement was enacted affecting Columbia's costs.

On August 12, 2020, Peoples Gas filed a protest focused on the reasonableness of the rates, leaving other topics for negotiation.

On August 21, 2020, Columbia responded to protests. It stated that it was within the confines of the Modernization II settlement, which provided the earlier filing date if new regulations requiring construction were enacted, which, according to Columbia, occurred with the PHMSA Mega Rule. It also provided defenses similar to those already in case testimony for the contemporaneous modernization tracker, limits on hourly takes and the standard cost drivers such as Return on Equity ("ROE").

On August 31, 2020, FERC accepted and suspended Columbia's rate increase for the maximum term of five months.

Confidential negotiations continued through the remainder of the year.

As of December 31, 2020, settlement had not been reached.

Dominion Energy Transmission, Inc. (Peoples Natural Gas & Peoples Gas)

RNG Gas Quality
RP21-144

Summary: On October 30, 2020, Dominion filed a Petition to add gas quality standards for Renewable Natural Gas ("RNG") in the General Terms and Conditions of its tariff. Although numerous shippers intervened, only two protested, Aria Energy, a Renewable Natural Gas ("RNG") producer, and the RNG Coalition both protested on November 12, 2020.

On November 30, 2020, The FERC suspended the new language until May 1, 2021 and called a technical conference. The FERC concluded that RNG industry standards may need to be reconsidered in light of the growing amount of interest in RNG. On December 16, 2020, the technical conference was set for January 28, 2021.

As of December 31, 2020, this issue was still pending settlement.

Name change
RP21-294
RP21-295

Summary: On December 3, 2020, Dominion filed to change its name to Eastern Gas Transmission and Storage after being purchased by Berkshire Hathaway. The tariff was replaced in its entirety and the Dominion tariff cancelled. The Company's name changed on November 5, 2020.

On December 21, 2020, FERC accepted both filings.

Equitrans, L.P. (Peoples Natural Gas & Peoples Gas)

Equitrans Expansion Project (Redhook Compressor)
CP16-13

Summary: On October 27, 2015, Equitrans filed to construct the Redhook Compressor which would dramatically change the flows on Equitrans moving gas from north to south to a new interconnect with the proposed affiliate, Mountain Valley Pipeline. The current system is designed to bring gas from West Virginia and counties south of Pittsburgh to the city and nearby interstate pipelines. Due to the proliferation of production from the Marcellus shale formation, Equitrans is proposing to reconfigure its system so that gas will flow in a north to south direction to new markets to be served by the proposed Mountain Valley Pipeline.

The project will be anchored by EQT Energy, an affiliate of Equitrans at the time of filing. Equitrans submitted information to show that the proposed rates are sufficient to pay for the project and to keep existing shippers from subsidizing the new construction.

The Peoples LDCs initially intervened in the case on November 12, 2015 and filed initial comments on November 26, 2015, voicing concerns about the reliability of service from Equitrans once this project goes into service. After several months of discussions with Equitrans, Peoples Natural Gas filed a protest on February 23, 2016. In the protest, Peoples outlined several areas of concern while stressing it is not opposed, in principle, to an Equitrans expansion. Peoples Natural Gas explained that it was concerned about flow changes on Equitrans' system, potential reliance on Equitrans use of displacement to provide for service, and delivery point pressures. Peoples Natural Gas proposed a technical conference.

Equitrans responded on March 10, 2016. Its answer stated that, because gas flows are controlled by nominations, there was little risk of the problems Peoples Natural Gas described. In fact, Equitrans asserted, because the project brings gas volumes into Equitrans closer to Pittsburgh, it will benefit the northern end of the system and improve reliability to Peoples Natural Gas. Equitrans further explained that Peoples Natural Gas proposed remedies, such as pressure guarantees, are not permissible under the pipeline's current tariff. Finally, the Equitrans claimed that the Peoples Natural Gas system contributed to some of the operational shortfalls in recent history and that those shortfalls were not the fault of Equitrans.

Peoples Natural Gas filed its response to Equitrans on May 6, 2016, challenging some of the Equitrans' modeling assumptions and assertions as to the inadequacy of Peoples Natural Gas facilities.

On June 28, 2016, the FERC issued its schedule for environmental review indicating that the Environmental Impact Statement would be available by March 10, 2017.

On August 4, 2016, Peoples Natural Gas requested a deferral of the Technical Conference while it attempted to reach agreement with Equitrans.

On September 16, 2016, a draft Environmental Statement was released, indicating that all substantial impacts could be sufficiently mitigated. This drew a number of new comments from various environmental groups, conservation groups, and individuals.

On April 18, 2017, Peoples Natural Gas withdrew its comments, satisfied with Equitrans' explanation of the project and how gas flows in the Pittsburgh region would be affected.

The Final Environmental Impact Statement was issued on June 23, 2017. After several construction delays, the project was placed into service in the summer of 2019 although the related Mountain Valley project (CP16-10) was not yet complete at that point. The project is currently the subject of numerous protests and FERC scrutiny, which is outside the scope of this review.

Gathering Abandonment
CP20-312

Summary: On April 30, 2020, Equitrans filed to abandon, either by sale or in place, gathering assets that are no longer economically practical. Unusually, due to the number of utility customers, Equitransrequested approval for abandonment in one year's time after FERC approval. The utility customers affect several utilities in West Virginia (including Peoples Gas WV) and Peoples Natural Gas Company in Pennsylvania.

On May 19, 2020 the Public Service Commission of West Virginia ("PSCWV") filed a motion for extension of time, stating that it required an additional 30 days to file comments. The PSCWV noted that 3,500 utility customers were affected in West Virginia and FERC staff was not equipped to evaluate the filing by the May 28, 2020 deadline due to the Covid-19 related "Stay-At-Home" Order. Equitrans responded on May 20, 2020, asking that FERC grant only a 14 day extension.

On May 22, 2020, the WV Consumer Advocate Division ("CAD") filed comments focused on the Crawford Affidavit, agreed to by Equitable Resources in the 2008 Base Rate Gas of Equitable Gas Company (predecessor of Peoples Gas WV). Equitable Resources was, at that time, the parent company of Equitable and Equitrans. The affidavit acknowledges authority over abandonment of gathering systems to the PSCWV when utility customers are affected.

On May 28, 2020, Peoples Natural Gas and Peoples Gas WV filed a protest. The service to 2,500 Peoples Gas WV customers and 1,000 Peoples Natural Gas customers is affected by the proposed abandonment, with many customers potentially losing service altogether. Peoples argued that Equitrans has provided service to these customers for decades and cannot simply abandon that obligation. Peoples further argued that the obligation to serve customers was already underway in a PSCWV proceeding and Equitrans should be subject to that proceeding rather than undermining it by seeking FERC approval.

On June 12, 2020, Equitrans argued that it had given ample time to find a solution, including an offer for Peoples LDCs or other utilities to acquire the assets, despite their poor condition, to continue to serve customers. Equitrans argued that, to avoid taking responsibility for its customers, Peoples was using delay tactics. Equitrans also argued that the Crawford Affidavit did not apply once the Company reorganized and that the act of reorganization voided the Crawford Affidavit.

On June 29, 2020, Peoples LDCs clarified that rather than delaying, it believed that the PSCWV holds jurisdiction in West Virginia and that the FERC cannot issue a filing prior to an order from the state regulatory body. Peoples LDCs further argued that Equitrans' claim that the FERC does not have jurisdiction over gathering assets was not germane to the situation and that the FERC cannot supersede the PSCWV when it doesn't have jurisdiction.

The PSCWV argued on June 29, 2020 that the PSCWV jurisdiction rested in the Crawford Affidavit and did not accept Equitrans' argument that it was invalidated by the Equitrans' reorganization.

On December 9, 2020, Peoples LDCs filed with the FERC to state that, in the PSCWV case, the PSCWV ruled that Equitrans does need approval by the state authority to abandon facilities that affect customers and asked the FERC not to give Equitrans fuel to challenge the PSCWV order by continuing to use jurisdictional uncertainty.

As of December 31, 2020, the case was still pending with both Commissions.

National Fuel Gas Supply Corporation (Peoples Natural Gas only)

Section 4 Rate Case Filing
RP19-1426

Summary: On July 31, 2019, National Fuel filed for a Section 4 Rate Increase that would increase base rates over 50%. In addition, it requested approval of a Modernization tracker as the National Fuel plans to aggressively replace pipe due to the PHMSA Mega Rule.

The majority of shippers, including Peoples Natural Gas, filed protests on August 13, 2019. On August 30, 2019, the FERC accepted and suspended National Fuel's revised rates for the maximum period.

While still in negotiations, National Fuel placed proposed rates into effect on February 1, 2020, subject to refund.

On February 19, 2020 (and corrected on February 26, 2020), National Fuel filed to place interim rates into effect retroactively to February 1, 2020, having substantially reached settlement with shippers. The interim rates proposed were identical to the settled rates to be submitted, thus eliminating the need for refunds. The settlement rates increased costs for Peoples Natural Gas ratepayers by approximately $230,000 per year.

On March 13, 2020, National Fuel filed its settlement agreement with shippers reflecting the interim rates filed on February 19, 2020, as well as other provisions, including the elimination of the X-54 storage service, terms for a replacement to the Pipeline Safety/Greenhouse Gas ("PS/GHG") surcharge, and stayout and comeback provisions in which National Fuel's next rate case should provide for rates to go into effect between February 1 2024 and February 1, 2025.

FERC approved the settlement on June 1, 2020.

PS/GHG Surcharge True Up
RP20-659

Summary: On March 16, 2020, National Fuel filed a one-time true-up surcharge for the remaining balance uncollected in its PS/GHG tracker (Modernization tracker per FERC policy). The mechanism expired on February 1, 2020 by its original design and the true-up surcharge was used to clear the remaining balance.

Indicated Shippers (Direct Energy Business Marketing and Shell Energy North America) filed comments on March 30, 2020. Indicated Shippers argued that National

Fuel, though it has a PS/GHG tracker, did not have a tariff rate for this true up mechanism and may therefore have been in violation of Section 4 of the National Gas Act. They further argued that, although the current tariff required this true up adjustment, it must still make a tariff change filing to charge this new rate. Finally, Indicated Shippers argued that the PS/GHG tracker expired due to the filing of National Fuel's rate case (RP19-1426) but the rate case settlement provided for the tracker anew and, therefore, no true up was necessary.

On April 6, 2020, National Fuel argued that the terms of the rate provision and tariff language required it to file the true up and that it couldn't roll the cost on to the new PS/GHG tracker from a rate that had already expired to a new one that had not yet begun.

On June 1, 2020, the FERC found that the pipeline had correctly implemented the true up surcharge and approved it.

Abandonment of X-54 Storage Service
RP20-1169

Summary: On September 4, 2020, National Fuel filed to remove X-54 storage service from its tariff proposed in its 2019 Rate Case (RP19-1426). National Fuel argued that the exchange service with Transco pipeline, the sole customer under the non-conforming service, was no longer necessary. FERC approved the removal of the service on September 24, 2020.

<u>Texas Eastern Transmission, LP (Peoples Natural Gas & Peoples Gas)</u>

Section 4 Rate Case Filing
RP19-343

Summary: On November 30, 2018, Texas Eastern filed for a Section 4 rate increase of $362 million. As related to transportation service for Peoples Gas, the rate for firm transportation service within Zone M2 was proposed to increase by 9%. For transportation service purchased by Peoples Natural Gas, the Zone M1 to Zone M3 rate was proposed to increase by 49%.

Numerous protests were filed, including that of the Peoples LDCs on December 12, 2018. On December 31, 2018, the FERC accepted and suspended Texas Eastern's revised rates to be effective June 1, 2019, subject to refund.

Parties negotiated throughout most of 2019 to reach a settlement. Given the changes to flow since the previous rate case 28 years earlier, rate design, specifically the allocation of costs to the various Texas Eastern zones, was an important issue.

Parties, including FERC staff, reached agreement and the settlement was filed on October 28, 2019. The settlement was supported or not opposed by all parties save one, an independent power producer who initially opposed the settlement. On December 19, 2019, that shipper withdrew its opposing comments and was no longer a contesting party.

The settlement was approved by the FERC on February 25, 2020. Texas Eastern made its compliance filing on April 21, 2020, with refunds dating back to June 1, 2019 to reflect the settlement rates.

ASA Methodology Change
RP20-1194
RP21-234

Summary: On September 16, 2020, Texas Eastern filed to adjust the language in the General Terms and Conditions related to the ASA (retainage) calculation. Per the terms of the rate case settlement (RP19-343) Texas Eastern will separately calculate the rate component by transportation path.

FERC accepted the new language on October 23, 2020. Texas Eastern made a compliance filing on November 20, 2020.

PCB Surcharge update
RP21-153

Summary: On October 30, 2020, Texas Eastern filed to update its Polychlorinated Biphenyl ("PCB") tracker. Per settlement with shippers, Texas Eastern could not add more than five million dollars of cost in a given year. The annual costs for PCB remediation were in excess of five million, thus, the maximum allowable was requested in the tracker.

On November 2, 2020, EQT Energy protested, arguing that Texas Eastern did not use the correct PCB cost data, and had used inaccurate data in prior years. According to EQT Energy, Texas Eastern did not use the correct year to compute costs per settlement terms, and the errors from prior years affected the current filing as well as caused the continued use of the incorrect annual data. The correct "year," according to the settlement, is December 31 through November 30 of the following year. EQT Energy further argued that monitoring was required to determine if Texas Eastern was in compliance with other terms of the settlement, most notably that it not reallocate PCB costs from shippers that are not obligated to pay them through negotiated rates.

On November 20, 2020, the FERC accepted and suspended the PCB tracker rates pending further review.

As of December 31, 2020, this issue was still under review at FERC.

SCHEDULE B

CP21-8	Equitrans filed to abandon Hunter's Cave storage well
RP20-376	Columbia files minor modification of storage ratchets
RP20-382	Columbia CCRM Tracker update
RP20-449	Equitrans Sunrise Fuel Tracker update
RP20-525	Equitrans update to Peoples Natural Gas AVC negotiated rate
RP20-530	National Fuel Retainage Tracker update
RP20-563	Equitrans annual update to AVC storage retainage tracker
RP20-587	Columbia disclosure of Operational Transactions
RP20-615	Columbia RAM (Fuel and Retainage) Tracker update
RP20-620	Columbia EPCA Tracker update
RP20-622	Columbia TCRA Tracker update
RP20-751	Columbia OTRA Tracker update
RP20-799	Texas Eastern filed penalty revenue credits
RP20-839	Texas Eastern ASA Tracker update
RP20-906	Columbia reached a rate settlement with LNG shippers
RP20-956	Texas Eastern filed a prearranged settlement for the Farmersville lateral
RP20-988	Texas Eastern ASA tracker update
RP20-995	Columbia TCRA Tracker update
RP20-1009	Dominion filed Overrun Penalty Distribution
RP20-1245	Dominion EPCA Tracker update
RP20-1246	Dominion TCRA Tracker update
RP21-78	Texas Eastern Penalty Revenue Distribution
RP21-137	Equitrans reported operational sales and purchases
RP21-142	Columbia OTRA Tracker update
RP21-170	Texas Eastern ASA Tracker update
RP21-243	National Fuel TSCA Tracker update

Peoples Natural Gas
1307(f) - 2021

Section 53.64(c)(5):

A listing and updating, if necessary, of projections of gas supply and demand provided to the 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.

* * * * * * * * * *

Attached are Forms-IRP-GAS filed on February 28, 2020 and June 1, 2020 pursuant to the Commission's regulations at 52 Pa. Code § 59.81 for Peoples Natural Gas Company.

PEOPLES™

375 North Shore Drive
Pittsburgh, Pennsylvania 15212

Carol Scanlon
Manager, Rates and Regulation

Peoples Service Company LLC
Phone: 412-208-6931
Email: Carol.Scanlon@peoples-gas.com

February 28, 2020

Ms. Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
2nd Floor, Room N201
400 North Street
Harrisburg, Pennsylvania 17120

Re: 2019 INTEGRATED RESOURCE PLANNING – Peoples Natural Gas Company LLC M-2020-_________

Dear Secretary Chiavetta:

Enclosed is the original of the Peoples Natural Gas Company LLC's Integrated Resource Planning (IRP) Forms 1A, 2A – Table 1 and 2A – Table 2 to be filed with the Pennsylvania Public Utility Commission ("Commission").

If you have any questions about these reports, please contact me.

Sincerely,

Carol Scanlon

Carol Scanlon

Enclosures
CC: Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Bureau of Technical Utility Services
Office of Consumer Advocate
Office of Small Business Advocate

FORM-IRP-GAS-1A: ANNUAL GAS REQUIREMENTS
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

Combined	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Firm Sales:						
Retail Residential	46,426	43,050	41,895	41,518	41,518	41,518
Retail Commercial	8,981	8,387	8,502	8,502	8,502	8,502
Retail Industrial	287	256	234	234	234	234
Electric Power Generation						
Exchange with Other Utilities						
Unaccounted For Gas 1/	4,846	7,717	5,116	5,092	5,092	5,092
Company Use 1/	854	849	849	849	849	849
Other (Unbilled Estimate)	-	-	-	-	-	-
Subtotal Firm Sales	61,394	60,259	56,596	56,195	56,195	56,195
Interruptible Sales:						
Retail	-	-	-	-	-	-
Electric Power Generation	-	-	-	-	-	-
Company's Own Plant	-	-	-	-	-	-
Subtotal Interruptible Sales	-	-	-	-	-	-
SUBTOTAL FIRM AND INTERRUPTIBLE	-	-	-	-	-	-
SALES:	61,394	60,259	56,596	56,195	56,195	56,195
Transportation:						
Firm Residential 2/	9,851	9,425	8,972	8,892	8,892	8,892
Firm Commercial	22,323	21,789	22,371	22,371	22,371	22,371
Firm Industrial	34,195	38,063	33,792	33,792	33,792	33,792
Interruptible Residential						
Interruptible Commercial	-	-	-	-	-	-
Interruptible Industrial	-	-	-	-	-	-
Electric Power Generation	-	-	-	-	-	-
Other - Off-System Transport	1,657	1,250	-	-	-	-
Subtotal Transportation	68,025	70,527	65,135	65,055	65,055	65,055
TOTAL GAS REQUIREMENTS	129,419	130,786	121,731	121,250	121,250	121,250
Increase (Decrease)		1,367	(9,055)	(481)	-	-
Percent Change (%)		1.1%	-6.9%	-0.4%	0.0%	0.0%

1/ Reflects total system unaccounted for gas and company use. Because the historical UFG shown in this report is based on a calendar period calculation it does not accurately reflect actual UFG levels, which should be calculated on a summer-to-summer period.
2/ Includes unbilled residential & commercial volumes.

FORM-IRP-GAS-2A: NATURAL GAS SUPPLY
TABLE 1: ANNUAL SUPPLY
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Gas Supply for Sales Service						
Supply Contracts (Other)	28,671	22,942	30,318	30,585	30,585	30,585
Spot Purchases	25,120	32,775	18,764	18,600	18,600	18,600
Storage Withdrawals	21,444	20,269	17,988	17,960	17,960	17,960
LNG/SNG/Propane Purchases	-		-	-	-	-
Company Production	-		-	-	-	-
Local Purchases	7,693	5,554	4,645	4,329	4,329	4,329
Exchanges with other LDCs	-		-	-	-	-
Other	-		-	-	-	-
Total Gas Supply for Sales	82,928	81,540	71,715	71,474	71,474	71,474
Total Transportation Service	73,072	72,248	67,869	67,785	67,785	67,785
TOTAL SALES GAS SUPPLY AND TRANSPORTATION SERVICE	156,000	153,788	139,584	139,259	139,259	139,259
Deductions						
Curtailments	-		-	-	-	-
Underground Storage Injections	(23,099)	(20,981)	(17,852)	(18,007)	(18,007)	(18,007)
LNG Liquefaction			-	-	-	-
Sales to other LDCs	(1,826)	(763)	-	-	-	-
Off-System Transport	(1,656)	(1,250)	-	-	-	-
Total Deductions	-		-	-	-	-
NET GAS SUPPLY	129,419	130,794	121,732	121,252	121,252	121,252

FORM-IRP-GAS-2A: NATURAL GAS SUPPLY
TABLE 2: PEAK DAY SUPPLY
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Gas Supply for Sales Service						
No - Notice	18	3	77	77	77	77
Supply Contracts (Other)	19	0	459	461	461	461
Spot Purchases	444	410	52	52	52	52
Storage Withdrawals	330	356	399	409	409	409
LNG/SNG/Propane Purchases	0		0	0	0	0
Company Production	0		0	0	0	0
Local Purchases	37	16	27	24	24	24
Exchanges with other LDCs	6	-10	0	0	0	0
Other	0		0	0	0	0
Total Gas Supply for Sales	854	775	1013	1023	1023	1023
Total Transportation Service	239	391	267	262	262	262
TOTAL SALES GAS SUPPLY AND TRANSPORTATION SERVICE	1092	1166	1280	1284	1284	1284
Deductions						
Curtailments	0	0	0	0	0	0
Underground Storage Injections	0	0	0	0	0	0
LNG Liquefaction	0	0	0	0	0	0
Sales to other LDCs	0	0	0	0	0	0
Off-System Sales	0	0	0	0	0	0
Total Deductions	0	0	0	0	0	0
NET GAS SUPPLY	1092	1166	1280	1284	1284	1284

1/ Current and Forecast years represent system design day rather than historic peak day.

Carol Scanlon
Manager, Rates and Regulation

Peoples Service Company LLC
Phone: 412-208-6931
Email: Carol.Scanlon@peoples-gas.com

June 1, 2020

Ms. Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
2nd Floor, Room N201
400 North Street
Harrisburg, Pennsylvania 17120

Re: 2020 INTEGRATED RESOURCE PLANNING – Peoples Natural Gas Company LLC M-2020-3015221

Dear Secretary Chiavetta:

Enclosed is the original of the Peoples Gas Company LLC's Integrated Resource Planning (IRP) Forms 1B, 2B, 2C, 3, 4A and 4B.

If you have any questions about these reports, please contact me.

Sincerely,

Carol Scanlon

Carol Scanlon

Enclosures
CC: Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Bureau of Technical Utility Services
Office of Consumer Advocate
Office of Small Business Advocate

FORM-IRP-GAS-1B: PEAK DAY GAS REQUIREMENTS
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

	Historical Data		**Current Year**	**Three Year Forecast**		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Firm Sales:						
Retail Residential	461	466	562	568	568	568
Retail Commercial	89	92	127	112	112	112
Retail Industrial	2	2	3	2	2	2
Electric Power Generation					-	-
Exchange with Other Utilities						
Unaccounted For Gas 1/	40	50	52	60	60	60
Company Use 1/	12	7	9	8	8	8
Other (Off-System/Unbilled Estimate)					-	-
Subtotal Firm Sales	604	617	753	750	750	750
Interruptible Sales:						
Retail						
Electric Power Generation						
Company's Own Plant						
Subtotal Interruptible Sales	-		-		-	-
SUBTOTAL FIRM AND INTERRUPTIBLE SALES:	604	617	753	750	750	750
Transportation:						
Firm Residential	99	98	119	119	119	119
Firm Commercial	196	281	271	259	259	259
Firm Industrial	193	167	138	154	154	154
Interruptible Residential						
Interruptible Commercial	-		-		-	-
Interruptible Industrial	-		-		-	-
Electric Power Generation	0				-	-
Subtotal Transportation	488	546	529	532	532	532
TOTAL GAS REQUIREMENTS	1,092	1,163	1,282	1,282	1,282	1,282
Increase (Decrease)		71	119	1	-	-
Percent Change (%)		6%	10%	0%	0%	0%

1/ Reflects total system unaccounted for gas and company use.

FORM-IRP-GAS-2B: NATURAL GAS TRANSPORTATION
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

	Historical Data				Current Year		Three Year Forecast					
Index Year	-2		-1		0		1		2		3	
Actual Year	2018 2/		2019 2/		2020 2/		2021 2/		2022 2/		2023 2/	
City Gate Transportation Contracts:	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak
Dominion Transmission - FTNN	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee Gas Pipeline 4/	1,781	28	1,490	28	9,125	25	9,125	25	9,125	25	9,125	25
Texas Eastern Transmission 4/	2,626	18	2,067	27	5,110	41	5,110	41	5,110	41	5,110	41
National Fuel Gas Supply	695	7	474	3	2,190	6	2,190	6	2,190	6	2,190	6
Equitrans Allegheny Valley Connector	32,149	228	26,150	200	42,345	194	42,345	194	42,345	194	42,345	194
Equitrans Mainline Contract	14,361	130	18,739	191	49,947	130	49,947	130	49,947	130	49,947	130
TOTAL	51,613	410	48,920	449	108,717	396	108,717	396	108,717	396	108,717	396
Upstream Transportation Contracts:												
Equitrans	23,793	223	19,847	205	42,345	192	42,345	192	42,345	192	42,345	192
TOTAL	23,793	223	19,847	205	42,345	192	42,345	192	42,345	192	42,345	192
Storage-Related Transportation Contracts:												
Dominion Transmission - FTNN/GSS 3/	1,247	5	1,417	12	1,053	10	1,053	10	1,053	10	1,053	10
Dominion Transmission - GSS	2,421	19	2,028	38	2,384	38	2,384	38	2,384	38	2,384	38
National Fuel Gas Supply	597	7	697	10	716	9	716	9	716	9	716	9
Equitrans Allegheny Valley Connector	6,468	125	5,740	137	24,102	134	24,102	134	24,102	134	24,102	134
Equitrans Mainline Storage	9,721	157	9,600	133	20,327	157	20,327	157	20,327	157	20,327	157
TOTAL	20,453	312	19,482	330	48,582	348	48,582	348	48,582	348	48,582	348

1/ For each group of contracts, rank entries in order of magnitude for the current year and include a sheet noting the transportation provider and termination date for each contract reported. Reporting should proceed along rank ordering until 75% of total is accounted for, or until ten contracts have been listed, whichever occus first.

2/ The volumes shown for Dominion Transmission, Tennessee Gas Pipeline, Texas Eastern and AVC are net of the assignment of some capacity rights to Priority One transportation customers.

3/ Reflects firm transporation of gas withdrawn from DTI GSS storage under DTI FTNN/GSS contract.

4/ Not all Firm Contract - Includes Delivered Supply

FORM-IRP-GAS-2C: NATURAL GAS STORAGE
REPORTING UTILITY: Peoples Natural Gas Company LLC
(volumes in MMcf)

	Historical Data				Current Year		Three Year Forecast					
Index Year	-2		-1		0		1		2		3	
Actual Year	2018 2/		2019 2/		2020 2/		2021 2/		2022 2/		2023 2/	
Storage Contracts:1/	Winter	Peak	Winter	Peak	Winter	Peak	Winter	Peak	Winter	Peak	Winter	Peak
EQT ML Storage	11,473	157	9,211	123	10,943	157	10,943	157	10,943	157	10,943	157
EQT - Allegheny Valley Connector	6,350	127	5,449	138	6,645	134	6,645	134	6,645	134	6,645	134
Dominion Transmission GSS	2,382	38	2,081	38	2,385	38	2,385	38	2,385	38	2,385	38
Peoples Natural Gas	1,530	24	1,058	27	1,471	32	1,471	32	1,471	32	1,471	32
Dominion Transmission FTNN/GSS	1,795	22	1,466	11	1,911	16	1,911	16	1,911	16	1,911	16
National Fuel Gas Supply	719	8	703	9	719	9	719	9	719	9	719	9
Other												
TOTAL	24,249	375	19,968	346	24,074	386	24,074	386	24,074	386	24,074	386

1/ Rank entries in order of magnitude for the current year and include a sheet noting the storage provider and termination date for each contract period. Reporting should proceed along rank ordering until 75% of total is accounted for, or until ten contracts have been listed, whichever occurs first.

2/ The volumes shown for Dominion Transmission, EQT AVC and Peoples' on-system storage exclude the assignment of some capacity rights to Priority One transportation customers.

FORM-IRP-GAS-3: NUMBER OF CUSTOMERS (YEAR END)
REPORTING UTILITY: Peoples Natural Gas Company LLC

	Historical Data		**Current Year**	**Three Year Forecast**		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Sales Service:						
Retail Residential	482,435	476,863	477,648	478,433	479,218	480,003
Retail Commercial	31,485	32,647	32,694	32,741	32,788	32,835
Retail Industrial	80	90	78	78	78	78
Other	-	-	-	-	-	-
Subtotal Sales Service	514,000	509,600	510,420	511,252	512,084	512,916
Electric Power Generation	-	-	-	-	-	-
Transportation Service	116,082	122,511	122,511	122,511	122,511	122,511
CUSTOMER TOTAL	630,082	632,111	632,931	633,763	634,595	635,427
Increase (Decrease)		2,029	820	832	832	832
Percent Change (%)		0.3%	0.1%	0.1%	0.1%	0.1%

FORM-IRP-GAS-4A: ANNUAL SUPPLY AND REQUIREMENTS SUMMARY
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Gas Supply:						
Supply Contracts 1/	34,709	27,784	35,099	34,867	34,867	34,867
Spot Purchases	25,120	32,012	18,764	18,600	18,600	18,600
Subtotal Gas Supply	59,829	59,796	53,863	53,467	53,467	53,467
Transportation	71,416	70,998	67,869	67,785	67,785	67,785
TOTAL GAS SUPPLY	131,245	130,794	121,732	121,252	121,252	121,252
Requirements:						
Firm Requirements	61,394	60,259	56,596	56,195	56,195	56,195
Interruptible Requirements	-	-	-	-	-	-
Subtotal Firm & Interruptible	61,394	60,259	56,596	56,195	56,195	56,195
Transportation	68,025	70,527	65,135	65,055	65,055	65,055
Load Reductions	-	-	-	-	-	-
TOTAL GAS REQUIREMENTS	129,419	130,786	121,731	121,250	121,250	121,250
Surplus (Deficiency)	1,826	8	1	2	2	2

1/ Includes the following other categories of supply: Pipeline Deliveries, Storage Withdrawals, Storage Injections, Local Purchases, and Exchanges with Other LDC's. Refer to IRP Form 2a - Table 1 for specific supply volumes.

FORM-IRP-GAS-4B: PEAK DAY SUPPLY & REQUIREMENTS SUMMARY
REPORTING UTILITY: Peoples Natural Gas Company LLC
(Volumes in MMcf)

	Historical Data		Current Year	Three Year Forecast		
Index Year	-2	-1	0	1	2	3
Actual Year	2018	2019	2020	2021	2022	2023
Gas Supply:						
Supply Contracts 1/	410	365	962	971	971	971
Spot Purchases	444	410	52	52	52	52
Subtotal Gas Supply	854	775	1,013	1,023	1,023	1,023
Transportation	239	391	267	262	262	262
TOTAL GAS SUPPLY	1,092	1,166	1,280	1,284	1,284	1,284
Requirements:						
Firm Requirements	604	617	753	750	750	750
Interruptible Requirements	-	-	-	-	-	-
Subtotal Firm & Interruptible	604	617	753	750	750	750
Transportation	488	546	529	532	532	532
Load Reductions	-	-	-	-	-	-
TOTAL GAS REQUIREMENTS	1,092	1,163	1,282	1,282	1,282	1,282
Surplus (Deficiency)	(0)	3	(1)	2	2	2

1/ Includes the following other categories of supply: Storage Withdrawals, Storage Injections, Local Purchases, and Exchanges with Other LDC's. Refer to IRP Form 2a - Table 2 for specific supply volumes.

Peoples Natural Gas
1307(f) - 2021

Section 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, 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.

* * * * * * * *

Peoples Natural Gas' current fuel procurement practices can best be summarized as follows: it is Peoples Natural Gas' policy to manage its procurement practices to obtain the lowest overall gas cost consistent with Peoples Natural Gas' need to provide reliable service to its customers in the long term while maintaining peak day deliverability. Peoples Natural Gas pursues this policy within the limitations of its facilities and existing contracts. Specifically, the policy allows for making prudent investments to enhance Peoples Natural Gas' facilities where practicable and securing greater flexibility in contracts where possible on an ongoing basis. Therefore, Peoples Natural Gas' supply portfolio includes Pennsylvania supplies under long-term contracts and interstate index-based supplies. This portfolio is further enhanced through the use of storage by Peoples Natural Gas both on the interstate system and on Peoples Natural Gas' own system.

Peoples Natural Gas' Gas Supply Department is adequately staffed with qualified and well-trained personnel who receive regular updates on conforming to the Company's least cost purchasing policy. The experience level ranges from significant experience to developing experience for new personnel to take control in the future. In addition to their industry experience, personnel responsible for gas supply and planning attend seminars, conferences and short courses that address supply strategies and methodologies. Additionally, they communicate continuously with gas suppliers, producers, marketers and interstate pipeline representatives in matters pertaining to Peoples Natural Gas' fuel procurement policy. These personnel receive frequent updates of current trends and new developments within the natural gas industry.

Section 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.

* * * * * * * * * * *

Peoples Natural Gas made the following off-system sales.

Off-System Sales	**Peoples Natural Gas**
	Mcf
February 2020	753,604
March	216,662
April	33,199
May	35,616
June	41,499
July	13,358
August	9,708
September	32,968
October	45,890
November	340,745
December	441,952
January 2021	737,433
Total	**2,702,634**

Peoples Natural Gas made the following capacity releases during the historic period. Note that the capacity releases in the attachment do not include capacity released at zero cost to marketers under Peoples Natural Gas' Energy Choice program.

Capacity Releases	**Peoples Natural Gas** 1/,2/	
	Dth	**$**
February 2020	22,650	$ 244,120
March	20,650	$ 242,200
April	22,750	$ 240,692
May	29,150	$ 240,940
June	28,950	$ 240,560
July	20,150	$ 240,788
August	29,300	$ 242,315
September	18,650	$ 239,600
October	19,750	$ 241,084
November	20,650	$ 261,000
December	21,750	$ 262,564
January 2021	22,908	$ 264,000
Total	**277,308**	**$ 2,959,863**

1/ All dollars presented are in total, before sharing.
2/ Capacity releases are on Equitrans (AVC), DETI and TETCO.

Peoples Natural Gas
1307(f) - 2021

Section 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.

* * * * * * * * * * * * * * *

Peoples Natural Gas had 111,743 transportation agreements in place at year-end 2020. During 2020, Peoples Natural Gas transported 64,192,139 Mcf resulting in $174,522,033 in transportation revenues.

Peoples Natural Gas
1307(f) - 2021

Section 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 the provisions of 52 Pa. Code 5.423 (relating to orders to limit availability of proprietary information).

* * * * * * * * * * *

The table below depicts monthly end-user transportation throughput for the twelve months ended December 31, 2020. An individualized list of these customers is not attached due to the large number of transportation customers. Customer specific information can be made available upon request and the execution of a confidentiality agreement.

	Total Number	Mcf			
	of Accounts	RS	CS	IS	Total
Jan 2020	122,311	1,561,946	3,271,166	3,592,457	8,425,569
Feb 2020	122,231	1,505,267	3,070,749	3,550,099	8,126,115
Mar 2020	121,628	965,534	2,266,176	3,123,909	6,355,618
Apr 2020	120,925	758,204	1,749,315	2,308,354	4,815,872
May 2020	120,008	499,893	1,218,415	1,894,168	3,612,476
Jun 2020	118,886	210,352	729,458	2,249,609	3,189,419
Jul 2020	117,785	153,708	632,645	2,904,552	3,690,905
Aug 2020	116,534	142,290	673,889	2,615,971	3,432,150
Sep 2020	115,506	187,863	751,759	2,755,764	3,695,386
Oct 2020	114,131	453,623	1,300,193	2,902,676	4,656,492
Nov 2020	112,829	794,516	1,969,199	3,174,989	5,938,704
Dec 2020	111,743	1,453,135	3,298,691	3,501,608	8,253,434
		8,686,330	20,931,652	34,574,157	64,192,139

Peoples Natural Gas
1307(f) – 2021

Section 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" 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 such customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to the provisions of 52 Pa. Code 5.423.

* * * * * * * * * * *

For security reasons Peoples Natural Gas has requested Highly Confidential treatment of the answer to this question. Peoples Natural Gas' system map will be made available for inspection upon request and the execution of a confidentiality agreement.

Refer to the two attachments for Peoples Natural Gas' storage facility maximum daily injection and withdrawal rates and interstate and intrastate connections.

Peoples Natural Gas has one transportation customer that represents 5% or more of the total system throughput in a month.

Attachment No. 1

Peoples Natural Gas
1307(f) - 2021

Storage Facilities

FACILITY	MAXIMUM[1] WITHDRAWAL RATE - Mcf/Day	DESIGN DAY WITHDRAWAL RATE - Mcf/Day	MAXIMUM[1] INJECTION RATE - Mcf/Day	MAXIMUM[2] CAPACITY - Mcf	MAXIMUM POOL PRESSURE - Psig
Murrysville	40,000	32,000	18,000	984,124	950

Storage Services

FACILITY	MAXIMUM WITHDRAWAL RATE Dth/Day	MAXIMUM INJECTION RATE Dth/Day	MAXIMUM CAPACITY Dth	EXPIRATION
DTI-GSS	40,000	25,556	4,600,000	3/31/2034
DTI-GSS	40,000	15,845	2,480,000	3/31/2034
NFGS-ESS	9,793	4,404	748,611	3/31/2022
AVC-GSS	200,000	62,000	8,600,000	12/31/2033
EQT-60SS	137,010	74,733	7,473,296	3/31/2034
EQT-115SS	50,536	26,417	5,283,357	3/31/2034

[1] Maximum withdrawal and injection rates are dependent on the “working” gas inventory and pool pressure at specific times of the season. For example, the maximum withdrawal rates shown above would be under ideal operating conditions when the storage pools are 100% full. As the winter season progresses, lower inventory would result in lower pool pressures, and therefore the maximum withdrawal rate would not be probable.

[2] Total November through March “working” gas capacity (excludes base gas).

INTERSTATE OR INTRASTATE CONNECTIONS

		Peoples' Maximum Pressure Psig	Operating Capacity Range of Connection Mcf/Day
DTI			
Midland		274	0 - 30,000
Stull		600	0 - 60,000
Seven Fields		275	100 - 1,000
Gibsonia	coming thru DTI Ln-35	125	0 - 20,000
Coxcomb		400	0 - 35,000
Oakford		640	0 - 120,000
Elliot		960	0 - 25,000
Limestone Discharge		500	0-9,000
TENNESSEE			
Pitt Terminal		274	4,000 - 34,000
Pulaski XS-294		50	0 - 3,000
TEXAS EASTERN			
Rockwood		210	0 - 10,000
Ebensburg		401	0 - 30,000
Claysburg		200	100 - 1,000
Beaver Run (Delmont)		250	0 - 25,000
NFG			
Slippery Rock		400	100 - 6,000
Grove City		180	1,000 - 7,000
Stoneboro Medium		80	100 - 1,500
Stoneboro Low		1	10 - 100
Bullion		18	20 - 100
COLUMBIA OF PA			
McKee		18	10 - 150
McKinley		18	10 - 150
Harlansburg		10	10 - 150
East Brook Rd.		33	100 - 900
Chandler		40	300 - 633
New Wilmington		50	1,500 - 4,000
Nilan		50	1 - 100
Mapletown		50	150 - 1,500
Point Marion	Emergency	50	0 - 360
Prospect	Backup	44	0 - 600
Portersville	Backup	44	0 - 500
SouthPointe	Emergency	60	0 - 4,000
Peoples Gas			
Burtner Road	Backup - into PNG	20	0 - 81
Hannahstown	Backup - into PNG	20	0 - 281
Knoch High School	Backup - into PNG	20	0 - 734
Rebecca Street	Backup - into PNG	81	0 - 1,900
Roenigk Property	Backup - into PNG	81	0 - 3,700
Moorehead Rd.	Backup - into PNG	20	0 - 960

INTERSTATE OR INTRASTATE CONNECTIONS

		Peoples' Maximum Pressure Psig	Operating Capacity Range of Connection Mcf/Day
Beaver Street - Mars	Into PG	60	0 - 8,000
Blairsville	Into PNG	180	0 - 5,000
Stoney Run	Bi-directional	80/188	1 - 5,000
White Township	Into PG	130	0 - 1,000
Tanoma	Backup - into PG	188	0 - 5,000
Fyock Road	Into PG	60	0 - 3,000
ACME	Into PG	44	0 - 1,000
Alcoa	Into PNG	100	0 - 3,000
Chickasaw	Into PNG	40	0 - 6,000
McCullough (Into Shoemaker Comp Sta)	Into PNG	40	0-3,000
Natrona Heights #1 (Into the M-67)	Into PNG	100	0-6,000
Natrona Heights #2 (Into the D-101)	Into PNG	30	0-6,000
Slease (Into Crooked Creek Comp Sta)	Into PNG	60	0-8,000
Oak St Station	Into PNG	1	0-250
Uzmack Station	Into PNG	35	0-500
Poplar Street	Into PNG	1	0-500
Adams Point	Into PNG	60	0 - 1,000
MS-1000097	Into PG	1	0 - 100
EQUITRANS			
ADAMS ST RD 8		50	0 - 1,950
AMERICAN STEEL RD 63		10	3,562
ASHBAUGH PNG IC		100	0-2,000
BALL FARM RD 37		25	143
BEATTYS RD RD 129		25	2,818
BELLE VERNON RD 189		40	386
Blonski - TP7575		274	0 - 20,000
BRENNAN ROAD (RB 105)		25	10,633
BRUSH RUN RD 100		25	3,282
BUCAR REGULATION AND METERING		400	44,720
BUNOLA RD 183		60	3,760
CAMPBELLS RUN RD RA 166		25	143
CECIL INDUSTRIAL PARK PNG IC		12	1,582
CHESTNUT RIDGE RD 134		15	283
CHURCH HILL RD 266		5	5,189
CLEVER ROAD A RUN RA 111		500	15,000
CLEVER ROAD B RUN RA 111		500	35,000
CLYDE NR 2 (R D 27)		1	0 - 500
COAL BLUFF RD RD 93		60	10,241
COAL PIT RD RA 99		25	583
COKEBURG NR 1 (R D 118)		60	6,537
CONEMAUGH PNG IC		401	0 - 50,000
COURTNEY NR 1 RD 106		1	0 - 500
COYLE CURTAIN RD RD 135		20	13,252
CRAVEN HILLS RD 65		12	0 - 500
CROOKHAM RD 47		25	3,562
CROSBY PNG IC FROM TP-4555		401	0 - 5,000
DEAN ROAD (RB 108)		60	6,372

INTERSTATE OR INTRASTATE CONNECTIONS

		Peoples' Maximum Pressure Psig	Operating Capacity Range of Connection Mcf/Day
DILLON PNG IC		160	0-3,500
DROUET PNG IC		82	0-13,000
ELLSWORTH/BLOCKINLIN RD 120		25	5,712
EMERALD MINE BATH HOUSE		14"WC	5,130
ENGLISH ROAD (RB 106)		15	5,471
EVERGREEN RD - 133		1	0 -500
FAWCETT RD 91		15	2,808
FLAUGHERTY RUN PNG IC		40	0 - 5,000
FREEPORT ROAD (RB 109)		25	8,608
GALLERY SHOPPES PNG IC		60	0-300
GAMBLE FARM PNG IC		60	0 - 2,500
GASTONVILLE D120 A CARNEGIE		25	14,037
GASTONVILLE D120 B CARNEGIE		25	12,281
GASTONVILLE D147 A MARLAND ST		25	15,210
GASTONVILLE D147 B MARLAND ST		15	15,210
GIBSON PNG IC		135	0 - 15,000
GIRTY PNG IC USM FROM TP-371		203	1 - 15,000
GREENFIELD RA 14 (BRUMAGE RD)		15	0 - 1,000
GREENGATE MALL PNG IC		50	0-600
GREENLEE RD 132		25	3,760
HARMONY RD (TO PERRYMONT) A RUN		60	3,229
HARMONY RD (TO PERRYMONT) B RUN		25	16,934
HAWKEN FARM RD 188		25	26,232
HAWS PIKE PNG IC		43	1,500
HEATH ROAD PNG IC		25	0-500
HILL TOP RD RA 102		25	6,683
HOLLIDAY PROPERTY PNG IC		80	0-4,800
HUNDRED GARRISON M S	Supply into Goodwin	40	0 - 2,500
HUNDRED GARRISON MS	Supply into WV	28	0 - 2,500
HUPP FARM RD 31		25	10,347
INGRAM FARM RD 187		25	10,347
JOHNSON ST RD 116		60	8,530
Jones Farm USM A Run		400	0 - 50,000
Jones Farm USM B Run		400	0 - 50,000
KEARNS FARM RD 3		12	386
LIGGET RD 57		60	7,335
LONG FARM RD 43		60	7,348
LYTLE RD RD 182		30	32,213
MADEY EAST 2ND AVENUE PNG IC		1	0-100
MAYAK FARM RD 122		25	0 - 2,500
MAYVIEW CUSTODY		30	4,176
MCCREERY FARM PNG IC		60	0 - 1,000
MCKEESPORT STATION		274	0 -115,000
MITCHELL FARM RD 125		30	4,142
MONONGAHELA RD 12 WALNUT ST MON		30	2,070
MOON RUN RA 105		30	0-8,000
MOREDOCK		25	0-500
MOTYCKI RD 222		60	31,646

INTERSTATE OR INTRASTATE CONNECTIONS

	Peoples' Maximum Pressure Psig	Operating Capacity Range of Connection Mcf/Day
N ALLEGHENY A RUN RB 92	25	0 - 7,000
NEELY SCHOOL RD RB 39	25	0 - 3,000
NELSON FARM RD 139	60	0 -1,000
OAK RIDGE	99	0-5000
ORNDOFF FARM RD 169 RUN A	60	0 - 2,500
PARDUS PNG IC	80	0 - 10,000
PNG - HIMSEL	400	0 - 50,000
PNG- SMAIL	400	0 - 25,000
PNG VINCO INTERCONNECT RUN 1	401	0 - 132,000
PRATT TRANS TO FIELD (GOODWIN)	40	0 -2,500
QUAKER SALES PNG IC	50	80
RADEBAUGH PNG IC	30	4,800
REED PNG IC	80	11,000
REIS RUN B RUN RB 55	60	4,462
RITKO PNG IC	335	0 - 5,000
ROBERTS FARM	50	0 - 5,000
ROBIN STATION ROAD PNG IC	80	2,500
ROLLING MEADOW RD 190	25	14,730
ROOSEVELT RD RB 104 A RUN	25	3,295
ROOSEVELT RD RB 104 B RUN	14"WC	5,842
ROUTE 837 RD 64	25	3,236
RUSSELL INDUSTRIES PRESTLEY RD	25	305
SELLERS	60	3,699
SEVEN SPRINGS PNG IC	401	0-15,000
SIENNA WOODS PNG IC	60	0-10,000
SPRINGER ROAD PNG IC	40	6,500
ST VINCENT GROVE PNG IC	80	17,500
STATE CORRECTIONAL INSTITUTE	60	1,397
STILLEY HEIGHTS RD 133	60	1,065
STONEBRIDGE PNG IC	60	720
SWEENEY STATION TURBINE	44	3,300
Tepe Distribution A Run	140	120,000
Tepe Distribution B Run	100	14,400
Tepe Distribution C Run	100	24,000
THISTLEWAITE	40	2,200
THOMAS ROAD CHURCH PNG IC	60	0 - 2,500
TOMBAUGH	99	0 - 5,000
WARRENDALE ROAD (RB 107)	140	14,400

Peoples Natural Gas
1307(f) - 2021

Section 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 that are primarily non-heating, interruptible or transportation customers.

* * * * * * * * * * * *

At this time, the need for any rate structure or rate allocation changes is still being evaluated. If any changes are made in the final filing, they will be fully explained and justified through testimony.

Peoples Natural Gas does not have any interruptible sales services and does not differentiate between heating and non-heating customers.

Transportation customers pay a balancing or standby charge that recovers interstate storage and/or capacity costs. These costs are allocated to transportation customers based on their balancing requirements on peak day.

Peoples Natural Gas
1307(f) - 2021

Section 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.

* * * * * * * * * * *

Refer to the attached schedule. Peoples Natural Gas did not interrupt any customers during these peak periods.

PEOPLES NATURAL GAS
HISTORICAL CONSECUTIVE THREE-DAY PEAK DATA
(All Volumes in Mcf)

HEATING SEASON	CONSECUTIVE THREE-DAY PEAK	TEMPERATURE DEGREES (F) HIGH	AVG.	LOW	VOLUMES Retail RS	SGS	MGS	LGS	Transportation RS	SGS	MGS	LGS	CU & UFG	TOTAL
2019-2020	Jan. 19	22	18	13	332,428	45,594	21,435	546	74,878	32,016	91,361	169,448	40,406	808,112
	Jan. 20	25	21	16	326,589	44,793	21,059	537	73,563	31,453	89,756	166,471	39,696	793,916
	Jan. 21	32	21	10	342,881	47,028	22,109	563	77,233	33,022	94,234	174,776	41,676	833,522
2018-2019	Jan. 30	2	-2	-5	466,082	59,132	33,555	1,240	97,638	41,301	132,488	274,637	56,990	1,163,063
	Jan. 31	9	4	-1	414,152	52,544	29,816	1,101	86,760	36,699	117,727	244,038	50,640	1,033,477
	Feb. 1	17	12	6	385,890	48,958	27,782	1,026	80,839	34,194	109,693	227,384	47,185	962,951
2017-2018	Jan. 4	14	7	-1	419,291	47,652	27,040	999	90,185	33,282	106,765	221,316	47,361	993,891
	Jan. 5	9	4	-1	461,275	52,412	29,742	1,099	99,215	36,607	117,431	243,426	52,102	1,093,309
	Jan. 6	11	3	-5	455,593	51,768	29,376	1,085	97,993	36,157	115,988	240,434	51,461	1,079,856
2016-2017	Jan.6	15	10	5	348,501	41,421	23,505	868	74,566	28,930	92,805	192,378	41,448	844,422
	Jan.7	16	12	7	367,254	43,650	24,769	915	78,579	30,487	97,799	202,729	43,679	889,861
	Jan.8	15	10	5	387,984	46,114	26,168	967	83,014	32,208	103,319	214,173	46,146	940,093
2015-2016	Feb.11	17	11	5	371,034	43,814	24,863	918	81,296	30,602	98,167	203,492	45,950	900,136
	Feb.12	20	13	5	361,720	42,714	24,239	895	79,255	29,833	95,703	198,384	44,798	877,541
	Feb.13	11	5	-2	403,314	47,626	27,026	998	88,368	33,264	106,708	221,196	49,944	978,444

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Section 53.64(c)(13)

Identification and support for any peak day methodology used to project future gas demands and studies supporting the validity of such methodology.

* * * * * * * * * * *

The Peoples Natural Gas design day demand computational methodology utilizes a regression model based on daily send-out data for the most recent 48-month time period.

Peoples Natural Gas used total daily sendout as the dependent variable and found a good fit using independent variables thoroughly examined by the Company over the course of the last year. The independent variables are temperature, winter month of the year, type of day (weekday/weekend) and a binary cold weather variable for the previous day at above 46 HDDs. Trend and wind speed were not examined in this case because the regression results from previous filings indicate that when the variables show correlation, they are not predictive. Using the regression model, the Company calculated total design day requirements using an average daily temperature of minus 9 degrees Fahrenheit. This temperature has been used as the design day temperature in many prior Peoples Natural Gas 1307(f) proceedings where gas costs based on this design day were approved by the Commission.

The calculated total design day requirements are then allocated to rate classes (RS, SGS, MGS and LGS) based on historical normalized usage factors for base load and heat load.

Refer to Peoples Natural Gas Exhibit No. 1 for the Company's currently calculated design day and Peoples Natural Gas Statement No. 4 - the Direct Testimony of Jason Dalton, for further explanation of the Company's approach.

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Section 53.64(c)(14)

Analysis and data demonstrating, on a historic and projected future basis, the minimum gas entitlements needed to provide reliable and uninterrupted service to priority one customers during peak periods.

* * * * * * * * * * *

Response:

Peoples Natural Gas' response to 53.64(c)(12) provides the most recent five-year history of consecutive three-day peak demand experienced on the combined system, as broken down by customer class. Projected design peak usage by customer class is presented as part of Peoples Natural Gas Exhibit No. 1 along with the supply assets used to meet those needs.

Peak demand period interstate gas supply and the corresponding firm transportation and storage capacity available to Peoples Natural Gas on the interstate pipeline system, the details of which are set forth in the Peoples Natural Gas responses to 53.64(c)(1) and (6), are needed to meet the peak demand requirements of the Company's weather-sensitive customer base. In addition, volumes withdrawn from on-system storage facilities are used to supplement the interstate-sourced gas supplies during periods of peak demand. For description of how these assets are used, refer to Peoples Natural Gas Statement No. 2.

Section 53.64(i)(1):

(i) Utilities shall comply with the following:

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

(i) The total revenues received under 66 Pa.C.S. § 1307(a), (b) or (f), including fuel revenues received, whether shown on the bill as 66 Pa.C.S. § 1307(a), (b) or (f) charges or rolled in as base rates.

(ii) The total gas expenses incurred.

(iii) The difference between the amounts in subparagraphs (i) and (ii).

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

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

* * * * * * * * * *

<u>Response</u>:

(i), (ii), (iii). Refer to the attachment.

(iv) The actual purchased gas costs incurred differ from the projected gas costs because of the fluctuating prices for gas supplies and interstate pipeline services. As the gas supply prices change, the volumes purchased from each source of supply also change. Differences are also affected by the actual volumes of gas consumed by customers as compared to projected consumption.

(v) All purchased gas costs incurred during the Historical Period are pursuant to the least cost procurement policy approved by the Commission in Peoples Natural Gas' 1307(f)-2020 proceeding. Also refer to the response to 53.64(c)(6) in this proceeding.

PEOPLES NATURAL GAS COMPANY
Gas Cost Revenues and Expenses
February 2020 through January 2021

		Purchased Gas Revenues 3/	Purchased Gas Expenses 3/	Over / (Under) Collections
February 1/	2020	$38,701,672	$33,362,373	$5,339,299
March 1/		$25,056,560	$27,679,487	($2,622,927)
April		$17,240,642	$15,259,624	$1,981,018
May		$12,684,594	$12,651,263	$33,330
June		$5,871,346	$9,121,064	($3,249,718)
July		$4,224,492	$8,403,683	($4,179,191)
August		$3,801,206	$9,536,312	($5,735,106)
September		$4,683,175	$10,325,652	($5,642,477)
October		$12,877,976	$10,276,596	$2,601,381
November		$22,549,596	$22,083,637	$465,959
December		$41,525,945	$33,008,386	$8,517,559
January 2/	2021	$40,080,571	$35,974,270	$4,106,302
		$229,297,775	**$227,682,347**	**$1,615,429**

1/ Gas cost revenues and expenses do not reflect the LIFO to WACCOG credit that was being flowed back to ratepayers from January - March 2020. Those amounts were reconciled separately as per the PUC Order in Docket No. P-2019-3007889. See below for February and March 2020 activity.

	Credit Revenues	Credit Expenses	Over / (Under) Collections
February 2020	($3,912,954)	($3,709,855)	($203,098)
March 2020	($2,472,448)	($3,098,860)	$626,412
Total Feb 2020-Jan 2021	**$222,912,374**	**$220,873,631**	**$2,038,742**

2/ January 2021 revenues and expenses are estimated.
3/ Revenues include AVC revenues and do not include GCA revenues. Costs include AVC costs.

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Section 53.65 Special Provisions Relating to Section 1307(f) Gas Utilities with Affiliated Interests

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.

(2) Estimates of the quantity of gas, transportation or storage available to the utility from all sources.

(3) Efforts made by the utility to obtain gas, transportation or storage from nonaffiliated interests.

(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.

(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.

(6) To the extent that the information required in this section has been submitted under § 53.64 (relating to filing requirements for natural gas distributors with gross intrastate annual operating revenues in excess of $40 million), the utility need only designate information which applies to affiliated interests.

Response:

Peoples Natural Gas Company LLC ("Peoples Natural Gas") purchases gas, transportation or storage from an affiliated interest, as defined at 66 Pa. C.S. §2101, in only one limited circumstance where no other viable option exists. The purchase is as follows:

Peoples Natural Gas currently purchases gas transportation service from its affiliate, Peoples Gas Company LLC ("Peoples Gas"), pursuant to a Gas Transportation Service Agreement under Rate Schedule LGS. This Gas Transportation Service Agreement was originally entered into by Equitable Gas Company ("Equitable") (which has since been acquired by Peoples Natural Gas) and Peoples TWP LLC (which is now Peoples Gas). Therefore, the transportation service that Peoples Natural Gas purchases from Peoples Gas pre-dates the acquisition of the former Equitable and has been in place for many years. As a result of Peoples

Natural Gas' acquisition of Equitable in December 2013, this service became an affiliated arrangement between Peoples Natural Gas and Peoples Gas.

This service enables Peoples Natural Gas to transport gas, acquired from an independent third party, across the Peoples Gas system for delivery into the Peoples Natural Gas system. The currently effective rate includes a $0.14 Volumetric Delivery Rate per Mcf, full retainage and full balancing. In addition, a monthly Customer Charge (i.e. demand charge) of $7,500 applies. Comparable service would be difficult to obtain considering the critical supply delivery points that Peoples Gas offers into the Peoples Natural Gas system.

While not being *purchases* of gas, Peoples Natural Gas and Peoples Gas are parties to a number of affiliated interest, natural gas exchange agreements filed with and approved by the Commission. The first of these exchange agreements was filed and approved at Docket No. G-2011-2265150. The agreement provides for the exchange of equivalent volumes of gas between Peoples Natural Gas and Peoples Gas where the receipt of gas from the other party would provide for more efficient operation of the recipient's system and will improve service reliability for both companies. The exchange is made without charge. Under the exchange arrangement, Peoples Gas receives gas from Peoples Natural Gas at the Beaver Street interconnection located in Mars, PA. In exchange, Peoples Natural Gas receives equivalent volumes of gas from Peoples Gas at various specified interconnections.

The filing was approved by Secretarial Letter issued on March 15, 2012. The exchange agreement has been amended three times since it was originally approved. The first two amendments added new interconnection points. Each of these amendments was filed with the Commission and each was approved on July 13, 2012, and January 29, 2013, respectively.

The third amendment was filed on November 21, 2013, when the Companies filed an Amended and Restated Gas Exchange Agreement (the "A&R GEA"). The A&R GEA is intended to accommodate the ongoing long-term infrastructure improvement plans of the Companies. Over the next twenty (20) years, the Companies plan to replace their entire systems of unprotected bare steel pipe and associated facilities. With geographically overlapping distribution systems and a goal of avoiding pipeline replacement where there is a more efficient means of continuing service to customers, the Companies anticipate additional opportunities for new interconnection points and gas exchanges that enhance efficient operation. The A&R GEA permits the Companies to install up to 15 new interconnection points, per calendar year, without filing for further approval, provided that, among other things, each new interconnection point does not exceed $250,000 in costs and each new interconnection point results in projected cost savings to the installing Company. The filing was approved by Secretarial Letter issued on May 27, 2014.

On June 26, 2014, Peoples Gas and Peoples Natural Gas filed a petition for Accounting and Regulatory Approvals and approval of an affiliated interest agreement associated with the intercompany exchange of gas and gas supply interconnections at Docket Nos. P-2014-2429346 and G-2014-2448807. Among other things, this petition requested approval of another exchange agreement between the Companies that will encourage efficient pipeline replacement by, for

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example, allowing one company to abandon a pipeline that is due for replacement and continuing service to the customers formerly connected to that pipeline by connecting them to a duplicative pipeline owned by the other company. The resulting gas exchange will use the delivery points from the above-referenced A&R GEA to balance deliveries under the new agreement. The Parties to that proceeding reached a settlement to resolve all issues, which was approved by Commission Order entered on December 18, 2014.

Peoples Natural Gas and Peoples Gas are also parties to another affiliated interest, gas exchange agreement that was filed for Commission approval on August 6, 2015, at Docket No. G-2015-2496814. This is a Service Expansion Gas Exchange and Interconnection Agreement to facilitate the extension of natural gas service to new Peoples Gas customers at the least possible cost. It allows interconnection of Peoples Natural Gas' distribution lines with new distribution facilities to be built by Peoples Gas to connect new customers. Peoples Gas will pay for the costs of the interconnections. These interconnection points will facilitate the expansion of service by Peoples Gas to new customers located in areas where Peoples Gas has authority to serve but where it is more economical for Peoples Gas to interconnect with existing facilities of Peoples Natural Gas for delivery of natural gas. Peoples Natural Gas will provide gas at such interconnection points to serve such customers in exchange for receipt of gas from Peoples Gas in equal quantities at existing interconnection points between Peoples Gas and Peoples Natural Gas. The filing was approved by Secretarial Letter issued on December 30, 2015.

Peoples Natural Gas Company

Analysis of OCA Proposal to Implement a Separate Gathering Retainage Rate

March 1, 2021

Scope: In the settlement of Peoples Natural Gas Company LLC's ("Peoples Natural Gas" or the "Company") 2020-1307(f) proceeding, the Company agreed to analyze the implications and equity of the Pennsylvania Office of Consumer Advocate's (OCA) proposal to adopt an additional retainage charge on the gas supplies acquired by customers that purchase local production supplies that would not be imposed on customers that acquire interstate delivered supplies. The Company also agreed to present a report of its analysis in its 2021-1307(f) pre-filing. In addition to the analysis described above, the settlement suggested that the report may address issues related to OCA's proposal related to a gathering retainage charge phase-in period. The Company is not required to propose any changes to its retainage charges as a result of this report. In the 2021-1307(f) proceeding, all parties are free to make proposals or oppose any proposals made by any other party.

BACKGROUND

OCA Proposal From 1307(f)-2020

The settlement provision related to the analysis and report evolved from the OCA's proposal in the 2020-1307(f) that Peoples Natural should implement a separate retainage charge for supplies procured on its gathering system. Retainage is the means by which the Company assigns cost responsibility for and recovers company use and lost and unaccounted for gas ("UFG") from customers other than system sales customers.[1] OCA specifically proposed that Peoples Natural Gas should have: (1) a distribution retainage charge of 3.1% that would be applicable to all sales and transportation customers; and (2) a gathering retainage charge of 7.4% that would be applicable to local production gathering volumes serving Peoples Natural Gas' sales and transportation customers. Peoples Natural Gas proposed a number of modifications to the OCA's calculation of retainage charges that would have resulted in a distribution retainage charge of 3.9% and a gathering retainage charge of 6.2%, and the OCA accepted these modifications. The

[1] *The Company also has a separate retainage that is assigned to and recovered from producers.*

OCA's proposal, as modified, would have resulted in a combined 10.1% retainage rate on any local production volumes delivered into the gathering system.

Process

The Company's analysis had two major components: information gathering and analysis of that information. When this issue came up in prior 1307(f) proceedings, the Company's response has been based on the prospective effect on the Company or the Company's belief of the prospective effect on other stakeholders. For this analysis, the Company endeavored to obtain real information from those other stakeholders, specifically, Natural Gas Suppliers ("NGSs") and producers. This process included preparing and issuing surveys to 36 NGSs and requesting a survey response from the Pennsylvania Independent Oil and Gas Association ("PIOGA"). Further, the Company reviewed the sources of supply and demand on the system, evaluated the administrative implications, evaluated who would pay for the separate gathering retainage charge, and evaluated the potential short and long-term supply impact of the separate gathering retainage charge.

INFORMATION GATHERING

Delivery Of Local Production Into Peoples Natural Gas' System

There are approximately 4,600 local production meters attached to the Peoples Natural Gas system that account for approximately 27% of the total gas supply that flows into Peoples Natural Gas. Peoples Natural Gas defines local production as gas that flows directly from producer facilities into Peoples Natural Gas' system. Peoples Natural Gas classifies this local production by Conventional and Unconventional production.

Conventional production is from traditional shallow gas wells. Since the start of the Marcellus boom , conventional shallow well production on the Peoples Natural Gas system has declined by a total of 35% from 2014 to 2020, or (approximately 2.16 Bcf/year), with the number of active production meters dropping by a little more than 1,000 over that same time period. The number of new tap requests for conventional wells has dropped substantially as well. There were only four (4) new conventional well taps requested in 2020.

Unconventional local production is production from horizontal Marcellus or Utica wells, coal bed methane or landfill gas. Unconventional local production has increased by more than 150% between 2014 and 2020. A Marcellus well tends to produce a significant amount of gas into the system the first six to nine months after coming online but drops considerably from that peak with production then leveling out or declining at a slower rate. The Company has found it difficult to accurately predict if and when a producer will request a new tap for a Marcellus well and how much that well may produce.

Use of Local Production

NGSs are projected to purchase approximately 25.7 Bcf or 85% of all local production that is produced into Peoples Natural Gas' system during the projected 1307(f) period (October 2021 – September 2022), and they will utilize this supply to fulfil part of the supply requirements of the Energy Choice transportation customers they serve. Gross conventional production will make up 19.3 Bcf of these purchases, and unconventional production will make up 6.4 Bcf. The other 15%, or 4.5 Bcf, of the local production produced into Peoples Natural Gas' system will be purchased by Peoples Natural Gas to serve its 1307(f) system supply sales customers and is made up of 3.9 Bcf and 0.6 Bcf of conventional and unconventional production, respectively.

This local production purchased by NGSs is first aggregated into Local Gas Aggregation ("LGA") Pools in Peoples Natural Gas' Supply Management system called Gastar. An LGA Pool is the aggregation of locally produced gas injected directly into the Company's lines. Most LGA pools are operated by NGSs who sell commodity supply to customers on Peoples Natural Gas' system. However, there are also a few producers who operate an LGA Pool and sell their local production to NGSs. The local production aggregated in the LGA Pools is then moved (nominated in Gastar) to an NGS's customer pool which is either a Priority One Pool ("P1 Pool") or a Non-Priority One Pool ("NP-1 Pool").

Transportation customers are assigned their portion of total system losses, UFG, through a tariff-based volumetric retainage rate. Because of the success of the pooling programs on Peoples Natural Gas system, the most effective way for Peoples Natural Gas to recover retainage has been to collect it from the pool operators.

Pricing of Local Production and Interstate Supplies

NGSs need to balance on a daily basis the estimated daily requirements of their customer pools with local production supplies, interstate pipeline deliveries, or most often, a combination of both. Any local gas projected to be produced within a month must be utilized by the NGS in that month. Any local production not nominated out of the LGA pool at the end of the month is cashed-out.

The local production currently under agreement with NGS/LGA Pools meets roughly 37% of the total requirements of the NGSs' P1 and NP1 Pools. This means that NGSs must bring in the remaining 63% of their P1 and NP1 Pool requirements from the interstate pipelines.

Attachment No. 1 demonstrates the approximate cost difference between interstate pipeline supplies entering the Peoples Natural Gas system from the least expensive path, Eastern Gas Transmission and Storage, Inc. ("EGTS")[2], and from the most expensive path, Equitrans, L.P. ("Equitrans"), showing a $0.14 per Mcf difference in burnertip cost between the two paths. Peoples Natural Gas has limited delivery point gate space on EGTS to receive additional EGTS supplies and that frequently forces NGSs to bring in supply from one of the more expensive pipelines in order to meet their customers' requirements. This allocation of pipeline "gate space" is performed prior to the start of each month.

Gas delivered from an interstate pipeline is subject to a volumetric delivery charge and a retainage charge on the pipeline. It is also subject to the Peoples Natural Gas imposed retainage rate. Currently, that retainage is based on the overall system loss on Peoples Natural Gas – gathering, distribution and transmission – where, if the OCA proposal is adopted, that gas will be subject to a retainage rate based only on the distribution and transmission systems losses. Thus, impacting price by both imposing a separate retainage on conventional local gas and reducing the retainage on interstate gas.

The local production that Peoples Natural Gas purchases for system supply is purchased at a number of different pricing scenarios with most being purchased at a standard offer price equal to either 100% if paying per Dth or 103% if paying per Mcf of the first-of-the-month ("FOM") DTI Appalachia Index, net of Peoples' producer retainage charge, meaning that Peoples does not pay

[2] *Effective November 2, 2020, interstate pipeline Dominion Energy Transmission, Inc. ("DETI") has changed its name to Eastern Gas Transmission and Storage, Inc. ("EGTS"). Accordingly, throughout this PRE-FILING of Materials, DETI and EGTS will be used interchangeably and refer to the same company.*

the producer for the volumes that are retained pursuant to the producer retainage charge. As a result, the cost of that retainage falls on, or is netted back to, the producer. Peoples Natural Gas does not net the remaining system UFG volumes from the volumes delivered by producers because it has never been the ratemaking intent that the cost would fall onto the producers. Instead, Peoples Natural Gas includes that UFG into its general gas supply requirements. As a result, system UFG is recovered from both retail and transportation customers. Since there is no indication that the cost of the separate gathering retainage charge is specifically targeted to the local producers, Peoples Natural Gas would not seek to collect this retainage from or net its cost back to the producers providing system supply.

It is Peoples Natural Gas' understanding that NGSs' purchase agreements with producers are usually one year in length but can be for any term or evergreen. It is also Peoples Natural Gas' understanding that the price paid by the NGS/LGA Pool operators to the producer for their production is usually based on a FOM index price such as Dominion Appalachia and is applied to the net production after the producers gathering retainage is collected.

1307(f) sales customers pay for their portion of UFG through system supply purchases included in the annual 1307(f) gas cost recovery mechanism.

Peoples Natural Gas may lower its standard pricing offer in an attempt to force producers to absorb the additional gathering fuel but producers would be free to market their supplies to NGSs in an effort to obtain the best price for their production.

ANALYSIS

Impact Of Separate Gathering Retainage Charge On Recovery Of UFG From Transportation And Sales Customers

After collecting data on sales and transportation volumes and pricing, Peoples Natural Gas analyzed that data to assess how the current recovery of UFG gas from transportation customers, on the one hand, and sales customers, on the other hand could change with the implementation of a separate gathering retainage charge. (Attachment No. 2)

Attachment No. 2 provides three scenarios:

1) Current Method: recovery of UFG from transportation and system supply customers at the current overall retainage rate of 5.4%;

2) Proposed Method: impacts on recovery of UFG with the implementation of a separate 6.2% gathering retainage charge and no change in sources or quantities of gas; and

3) Proposed Method if Less Local Supplies Are Utilized by NGSs: impacts on recovery of UFG with the implementation of a separate 6.2% gathering retainage charge and a projected reduction of three (3) Bcf in NGS purchases of gathering system local production.

Scenario #1 – Current Retainage Recovery

Scenario #1 shows the current retainage charges and recoveries on the Peoples Natural Gas system. Lines 3 and 4 show the current sales and transportation burner tip requirements of 50.39 Bcf and 65.09 Bcf, respectively. Line 5 represents the total amount of UFG Peoples Natural Gas would expect to realize based on its 2020 1307(f) proceeding UFG rate of 5.2%. These amounts on Lines 3-5 are kept constant in all three scenarios.

Lines 7 – 11 show additional deductions from UFG, for recoveries collected from any party at a rate other than the tariff rate. Line 8 is retainage from customers with discounted retainage rates. Line 9 shows retainage collected from producers on the Peoples Natural Gas system. Line 10 shows retainage collected from producers on the Goodwin and Tombaugh systems (PNG Gathering LLC). Line 11 is the resulting amount of retainage collected from either tariff rate transportation customers or sales customers. These figures are also held constant in all three scenarios.

Lines 12 – 16 Conventional Local Production - NGSs purchase this production to meet a portion of their customers' requirements. The amount shown is equal to the amount of gas produced at the production meter, reduced by the current producer retainage charge shown on Line 9. This net amount is received into an LGA pool where the distribution retainage is applied, resulting in the net amount of conventional production available for the NGSs to meet their customers' requirement target.

Lines 17 – 19 Unconventional Local Production - Marcellus and Landfill gas is delivered primarily into the distribution and transmission systems. In 2020, NGSs purchased approximately 5.37 Bcf, or 90%, of all unconventional production delivered to the Peoples Natural Gas system. For the Projected Period, that quantity is expected to increase to 6.42

Bcf due to two new unconventional sources that came online late in 2020. This 6.42 Bcf is shown on Line 17 and is then reduced by the distribution retainage of 5.4%, resulting in the net amount of 6.07 Bcf (Line 19) available for the NGSs to meet their customers' requirement target.

Lines 20 – 22 Interstate Supply – These are receipts into the distribution system from various interstate pipeline interconnects and represent the majority (roughly 60%) of supply NGSs utilize to meet their customers' requirement target. Since local production generally flows continuously at a steady rate into Peoples Natural Gas' gathering and distribution system, NGSs utilize it as a baseload supply and utilize interstate supply in order to balance their total available supplies with the requirements of their customers. The gross amount of interstate supply nominated to the various interconnect points is then reduced by the distribution retainage resulting in the net amount of interstate supply available for the NGSs to meet their customers' requirement target.

Lines 23 – 25 Retainage Collected from NGSs is consequently the difference between total gross receipts less net transport deliveries and for scenario #1 that amount is 2.37 Bcf or 5.4%.

Line 26 shows the overall UFG amount of 5.33 Bcf that Peoples Natural Gas projects to collect based on the overall system wide retainage rate of 5.4% from max rate transportation customers and sales customers. This same amount is also shown on Line 11.

Finally, Line 27 shows the remaining UFG amount that Peoples Natural Gas would recover from 1307(f) sales customers, 2.95 Bcf or 5.5%.

Scenario #2 – Separate Gathering Retainage Collected

Scenario #2 follows Scenario #1, with the exception that Scenario #2 reflects the implementation of 1) a separate 6.2% gathering retainage charge (Line 14) and 2) the associated distribution retainage charge of 3.9% (Lines 15, 18, 21). The separate gathering retainage charge results in greater retainage and less local production being available to the NGSs to meet customers' requirements, which in turn requires the NGSs to source additional interstate supply to balance total supply with their customers' requirement target.

Lines 25 and 27 show the changes in UFG recovery from transportation and sales customers. Line 25 shows the UFG recovery required from transportation customers would be 2.85 Bcf, or 6.4%, an increase of 0.48 Bcf when compared to the transportation UFG recovery in Scenario #1. Line 27 shows the UFG recovery required from sales customers would be 2.48Bcf, or 4.7%, a reduction of 0.47 Bcf compared to the UFG recovered from sales customers in Scenario #1.

Scenario #3 – Separate Gathering Retainage Collected if Transporters Purchase Three (3) Bcf less Gathered Production

Scenario #3 again follows Scenario #2, with the exception that Scenario #3 reflects a projected three (3) Bcf or a 16% reduction in the amount of conventional local production secured by transportation customers (Line 13) and a commensurate increase in the amount of interstate supply (Line 16) secured to meet the transportation requirement target. Peoples Natural Gas anticipates a potential reduction in the amount of gathered local production purchased by NGSs for the following reasons:

* Continual decline in traditional local production (average annual decline over last 6 years approximately 2.16 Bcf);

* Local production moves to another NGDC, midstream or interstate pipeline due to the increased cost of producing into People Natural Gas' system.

* Producers shut in local production due to low price.

* NGSs replace gathering production with interstate supplies.

* Before NGSs would absorb cost of additional gathering retainage they would bring in lowest cost interstate available.

* Producer receives better price from system supply.

Lines 25 and 27 show the changes in UFG recovery required from transportation and sales customers. Line 25 shows the UFG recovery from transportation customers would be 2.66 Bcf, or 6.0%, a decrease of 0.19 Bcf compared to the transportation UFG recovery in Scenario #2. Line 27 shows the UFG recovery required from sales customers would be 2.66 Bcf, or 5.0%, an increase of 0.18 Bcf when compared to the sales UFG recovery in Scenario #2.

The significance of Scenario #3 is that it shows the possibility that the introduction of a separate gathering retainage rate may not fully produce the intended benefits to sales customers as expected because NGSs have the ability to shift sources of supply.

If the conventional production dropped by five (5) Bcf, or 27%, which would not be unreasonable given the numerous reasons above explaining why it may decline, and the fact that conventional production has already been declining by approximately 2.16 Bcf/yr, the UFG recovery required from 1307(f) sales customers would be 2.79 Bcf, or 5.2%, an increase of 0.31 Bcf when compared to the sales UFG recovery in Scenario #2.

<u>Analysis of Informational Surveys</u>

1. <u>NGS Survey – Questions and Summary of Responses</u>

As part of its analysis, Peoples Natural Gas sent out a survey to 36 NGSs and LGA Pool Operators to get their views on potential impacts of a separate gathering retainage charge. An LGA Pool is the means by which NGSs and/or producers can aggregate all of the local production meters they purchase gas from into one pool from which they can nominate gas volumes to serve their own NP1/P1 customer pools or sell the aggregated production to other NGS NP1 or P1 pools.

The survey and responses are included as Attachment No. 3. Peoples Natural Gas received eight responses to the survey, four from NGSs that operate LGA pools and both NP1 and P1 customer pools, one from an LGA pool operator, and three from producers who sell their gas into LGA pools.

2. <u>Producer Survey – Questions and Summary of Responses</u>

Peoples Natural Gas also sent the same survey to PIOGA for the views of the producer community. PIOGA declined to respond.

<u>Who Would Pay The Separate Gathering Retainage Rate If It Were Implemented?</u>

A key component of an analysis of the implications and equity of a separate gathering retainage charge is who will ultimately incur the charge. Based upon the Company's knowledge of how local gas and interstate supplies are delivered to its system and upon feedback from the NGS and producer surveys, the Company created the following hypothetical assessment of which entity (Producer/NGS/Transport Customer/Sales Customer) would bear the additional costs of a separate gathering retainage charge.

This hypothetical assessment assumes a separate “additional” (additional to the distribution retainage charge of 3.9% applicable to all volumes moving on the Peoples Natural Gas system) retainage charge of 6.2% that would be applicable to all conventional local production volumes delivered into Peoples Natural Gas’ system. Peoples Natural Gas would continue its current pooling programs and assess the 6.2% separate gathering retainage charge on the local production delivered into an LGA Pool. Thus, for example, if an LGA Pool receives 100 Mcf of local production in a month, it will be credited with 93.8 Mcf of gas available for delivery to its NP-1 or P-1 customer pools.

NGS Options – As already noted, most LGA Pools are operated by NGSs. In 2020, 84% of conventional local production was delivered into LGA Pools operated by NGSs. As a result, assessing the separate gathering retainage charge on LGA Pools is, in most cases, the same as assessing the separate gathering retainage charge on the NGSs. An NGS or LGA Pool operator purchasing conventional local production could:

A) Net back the cost of the additional retainage charge to the local gas producer –

   The NGS could continue to purchase net supply received from the producer since the NGS Surveys suggest that is how most agreements between NGSs and producers are structured.

B) Absorb the cost of the additional retainage charge -

   If the NGS does not have the ability under its gas purchase agreement to pass these costs onto the producer, the NGS may need to absorb this additional retainage charge until they are able to exit or renegotiate their purchase agreement with the producer.

C) Pass on the cost of the additional retainage charge to a second purchaser –

   The NGS may be able to pass on some or all of the additional retainage charge to a second purchaser, including the end use customer, by charging a higher price for its supply.

D) Buy local production gas from a different producer offering lower cost local production; or

E) Replace the local production gas with interstate pipeline supply connected to the Peoples Natural Gas market –

Local production usually has a price advantage over Interstate Supply because producers are willing to accept a price slightly lower than what they expect the NGS could acquire off the interstate in exchange for the NGS marketing their supply to the end-use market over an extended period of time. But since market prices are and have been at depressed levels, producers are likely to start pushing back on absorbing this additional gathering retainage charge or they may shut in their production or move it to a different system to obtain a better price.

If this occurs, NGSs would look to replace this local production with interstate pipeline deliveries, which would not only avoid the separate gathering retainage charge but would also now be more beneficial due to a lower distribution-only retainage rate. However, there is limited gate space availability for NGSs to bring in supplies through the lowest cost interstate pipelines, notably EGTS and TETCO, which may require the NGSs to bring interstate supply into Peoples Natural Gas through the Equitrans system, which has approximately a $0.13 /Mcf cost premium over EGTS and which almost equates to the additional cost of the separate gathering retainage rate. Therefore, one may assume that these market factors would lead NGSs to reconsider the amount of local gas to purchase versus obtaining interstate gas beyond what gate space is readily available through the lowest cost interstate pipelines. In doing so, it may steer the NGSs and producers towards negotiating the additional gathering retainage charges to be shared amongst them.

<u>Producer Options</u> – A producer delivering local production into the Peoples Natural Gas system and selling their supplies to an LGA pool operator could:

A) Absorb the cost of the additional gathering retainage charge –

Assuming the separate gathering retainage charge would be roughly $0.13/Mcf at current market conditions (and that the current *producer* retainage charge is roughly $0.05/Mcf), would be a large burden for many small Pennsylvania producers. The smaller producers have limited options to avoid the charge, and absorption of the additional gathering retainage charge may cause some producers to either shut-in production or go out of business. Larger Pennsylvania producers may have the economic strength to absorb the additional gathering retainage charge, or to avoid the charge altogether by moving their production to another system, either their own gathering systems or third party midstream pipelines.

B) Pass on some or all of the cost of the additional retainage charge to a first purchaser –

Depending on contractual obligations, some producers may be able to pass on some or all of the additional gathering retainage charge to first purchasers, such as LGA pool operators (who are predominantly NGSs). As discussed above in the NGS options section, local producers may be able to increase the asking price for their gas to more closely track the replacement cost an NGS may experience if it has to acquire interstate supplies. In that case, the NGS would then either absorb the additional cost or pass it along to a second purchaser, including residential shopping customers.

C) Move production to another system –

Some producers may have the option of moving their production to another system such as another utility or midstream pipeline to avoid the additional gathering retainage charge. For larger producers this may be easier because their scale allows them to operate their own gathering systems, which provides them better opportunities to tie into one of these other systems. In this case, local production into the Peoples Natural Gas gathering system will decline. If the amount of decline reaches a point where a supply shortage may develop in that part of Peoples Natural Gas system, then Peoples Natural Gas would approach the producers in that area and offer higher than market rates for local gas purchases to entice the producer not to abandon or move their production to another system.

D) Shut-in/abandon production -

Some producers may voluntarily shut-in production or go out of business and involuntarily shut-in production. This could have the same implications as described in the scenario above where production is moved to another system. It can also reach a point where it is no longer economical for Peoples Natural Gas to maintain parts of the gathering system if little to no gas is flowing through it.

E) Try to sell their production to Peoples Natural Gas for system Supply

Many producers on the Peoples Natural Gas system sell local production to both NGS/LGA Pool operators and to Peoples Natural Gas for system supply. If the producer who sells to an NGS/LGA Pool operator finds itself being forced to absorb the cost of the new gathering retainage rate, it could seek to sell that local production to Peoples Natural Gas for system supply. Since the Company does not net back to the gas seller – whether selling local production or interstate supplies - any system UFG costs, but rather includes those costs in the 1307(f) gas costs and then allocates to transportation customers their share of UFG costs to be recovered through the system retainage charge, local producers selling to Peoples Natural Gas for system supply would avoid the imposition of the separate gathering retainage charge. Peoples Natural Gas could lower its standard offer price in an attempt to force local producers to absorb the additional, separate gathering retainage charge, but those producers would be free to market their gas to NGSs in an effort to obtain the best price for their production.

Additional Considerations

As presented in the NGS Options and the Producer Options sections above, there are various outcomes possible with the implementation of a separate gathering retainage charge. Looking back to the Company's 2020-1307(f) proceeding, the key reason for the recommendation of a separate gathering retainage charge by OCA was due to the observed higher level of UFG on the gathering system compared to the level of UFG on the distribution system. OCA stated that since transportation customers use a proportionately greater amount of the gathering system based on their throughput volumes than sales customers do, then it is unreasonable to charge each group of customers the same retainage charge.

In order to explore this aspect further, refer to the scenarios presented in Attachment No. 2 and discussed above. Scenario #1 detailed the amount of UFG volume that system supply would procure under the current method of charging an overall retainage rate of 5.4% to sales and transportation customers alike. The result is that system supply would procure 2.95 Bcf for UFG.

By comparison, scenario #2 detailed the amount of UFG volume that system supply would procure under the proposed method of charging a separate gathering retainage of 6.2% in addition to a distribution retainage of 3.9%. In this instance, the result is that system supply would procure 2.48 Bcf for UFG. Overall, this indicates a savings of 0.47 Bcf for sales customers.

However, taking this analysis a step further by evaluating the dollar savings per sales customer if Scenarios #2 is implemented, results in a savings of ($0.0175) per Mcf as shown below. For the average residential customer, using 86 Mcf per year, this would equate to an annual savings of $1.51.

Line No.	Description	Amount
1	Volume Savings for Sales Customers by Implementing Scenario #2	(0.47) Bcf
2	Conversion to Mcf (Line 1 x 1,000,000)	(470,000) Mcf
3	Current PGC Commodity Rate Effective Jan 1, 2021	$1.8812 per Mcf
4	Total Dollar Savings for Sales Customers by Implementing Scenario #2 (Line 2 x Line 3)	$(884,164)
5	Projected Annual Sales Volumes (2020-1307(f) Proceeding)	50,390,108 Mcf
6	Savings per Mcf for Sales Customers by Implementing Scenario #2 (Line 4/ Line 5)	$(0.0175) Mcf
7	Average Annual Residential Usage	86 Mcf
8	**Average Annual Savings per Sales Customer by Implementing Scenario #2 (Line 6 x Line 7)**	**$(1.51)**

Recall that Scenario #2 does not include any change in sources or quantities of gas. Yet, for the many reasons provided, the Company anticipates a potential reduction in the total amount of gathered local production purchased by NGSs. Therefore, the following evaluates the change from Scenario #1 to Scenario #3, which projects a three (3) Bcf or 16% reduction in the amount of conventional local production secured by transportation customers and a commensurate increase in the amount of interstate supply. The Company believes this is probable, particularly if the separate gathering retainage charge is implemented.

Line No.	Description	Amount
1	Volume Savings for Sales Customers by Implementing Scenario #3	(0.29) Bcf
2	Conversion to Mcf (Line 1 x 1,000,000)	(290,000) Mcf
3	Current PGC Commodity Rate Effective Jan 1, 2021	$1.8812 per Mcf
4	Total Dollar Savings for Sales Customers in Scenario #3 (Line 2 x Line 3)	($545,548)
5	Projected Annual Sales Volumes (2020-1307(f) Proceeding)	50,390,108 Mcf
6	Savings per Mcf for Sales Customers in Scenario #3 (Line 4/ Line 5)	($0.0108) Mcf
7	Average Annual Residential Usage	86 Mcf
8	**Average Annual Savings per Sales Customer in Scenario #3 (Line 6 x Line 7)**	**($0.93)**

As demonstrated, the dollar impact to residential sales customers can range from a maximum possible savings of $1.51 annually, the optimal case, to a savings of only $0.93 or lower if the effects on NGSs' purchases are even more pronounced.

As a practical matter, the savings for a sales customer in scenario #2 is minimal even ignoring the other potential impacts in making such a change. The potential short-term savings to sales customers, even in the best-case scenario, does not warrant implementation of a separate gathering retainage charge, especially considering the detrimental long-term effects that are discussed herein.

Additionally, if the implementation of a separate gathering retainage charge would shift the supply mix delivered into the Peoples Natural Gas from local production to interstate gas, the amount of local gas produced into the system would be reduced. As a result, not only would separate gathering retainage charge volumes decline, but gathering revenues would also fall until the Company's next base rate case, and in that next rate case, there would be less gathering revenues to contribute towards the gathering cost of service.

Operational And Administrative Implications of Implementation Of A Separate Gathering Retainage Charge On The Peoples Natural Gas System

Currently, Peoples Natural Gas utilizes an LGA pool process that contains all local production wells producing into the Peoples Natural Gas system that is not sold to the Company for system supply customers. There are 20 LGA pools.

Peoples Natural Gas would have to make some changes to its GASTAR system.

Gastar is the Company's gas management software system that manages all of the local production meter data and the processing of that data. It also acts as the Company's Electronic Bulletin Board which NGSs utilize to manage their supplies into the Peoples Natural Gas system to meet the requirements of their customer Pools. If Peoples Natural Gas were to adopt a new separate gathering retainage charge applied to NGS/LGA Pool operators who purchase conventional local production, then Peoples would have to develop a way to apply this new retainage in Gastar. Peoples believes it could manage the application of this new separate gathering retainage by applying this new retainage rate to all local production entering LGA Pools and then crediting back any retainage collected in those pools not applicable to unconventional wells using a retainage refund procedure. This would be the most efficient way to effect this change and it would eliminate the need for costly reprograming of the Gastar software.

LONGER-TERM EFFECTS OF A SEPARATE GATHERING RETAINAGE CHARGE

The long-term effect of a separate gathering retainage charge may potentially be a substantial decrease in conventional production delivered into the Peoples Natural Gas system if producers take the brunt of a separate gathering retainage rate. The first consideration will be whether gas can economically be produced at the price netted back to the wellhead. A subsequent consideration will be the longer-term net back. So far, Peoples Natural Gas' study of its gathering system UFG has shown that line loss is not proportionally related to throughput, meaning that line loss will not change in the same percentage as throughput changes. Therefore, it is likely that if the volumes of gas flowing through the gathering system decreases, line loss may not decrease by the same percentage amount. Peoples Natural Gas believes line loss would decline by a smaller percentage, which increases the amount of retainage that needs to be collected from the remaining producers, causing a ripple effect until no gas is produced into the gathering system. At that point, Peoples Natural Gas would have to determine if the ongoing value of the gathering system to ratepayers or system operations would make abandonment a prudent option.

Phase-In of a Separate Gathering Retainage Charge

As part of the Settlement, the Company agreed to address the appropriateness of a gathering retainage charge phase-in period, regardless of the Company's conclusions as to whether such a charge is equitable. Ostensibly, major changes in policy and operations lend themselves to a phase-in approach. If the Company were to implement a separate gathering retainage charge it would agree that a phase-in approach would likely be most appropriate.

CONCLUSION

As portrayed in this analysis, there are several possible outcomes that could result from the implementation of a separate gathering retainage charge. The Company believes that the current application of an overall system wide retainage rate is the most appropriate way to recover UFG from sales and transportation customers. The main reason for this conclusion is the fact that only a minimal amount of savings for a sales customer would be achieved in the best case scenario if the OCA's proposal in the 2020-1307(f) proceeding is implemented. The initial reason for OCA's proposal in the 2020-1307(f) proceeding was due to the observed higher level of UFG on the gathering system compared to the level of UFG on the distribution system. OCA stated that since transportation customers use a proportionately greater amount of the gathering system based on their throughput volumes than sales customers do, it is unreasonable to charge each group of customers the same retainage charge. However, as detailed in this analysis and Attachment No. 2, the optimal savings or shifting in costs from a sales customer, if the OCA's proposal is fully implemented, is $1.51 annually. This optimal case scenario does not include any change in sources or quantities of gas. Yet, as described in this analysis, it is probable that implementation of a separate gathering retainage rate will result in a reduction of conventional production in both the short term and the long term. A reduction in conventional production of 16% - 27%, which the analysis concludes is very possible, could substantially reduce that already minor benefit. The end result of this analysis shows that not only are the savings minimal for a sales customer by implementing a separate gathering retainage charge, but also that it continues to be reasonable to charge an overall system wide retainage rate to sales and transport customers alike.

INTERSTATE SUPPLY COSTS

			DTI Index based		TETCO M2 Index	
Purchase Month						
FOM (Dth) >>	**Avg. Index Oct '21 - Sept '22**		**$ 2.0400**		**$ 2.0340**	
		Fuel %	ETGS	ETRN (TEPE)	TETCO M2-M2	TETCO M2-M3
	Into EQT/DTI/M2		**$ 2.0400**	**$ 2.0400**	**$ 2.0340**	**$ 2.0340**
EQT	Commodity			$ 0.012		
EQT	PSCR			$ 0.137		
EQT (EGC, Tariff)	Fuel (1.72%)	1.72%		$ 0.036		
DTI	Fuel (1.95%)	1.95%	$ 0.041			
DTI	Commodity		$ 0.017			
TETCO, M2-M2	Fuel	1.36%			$ 0.028	
TETCO, M2-M2	Commodity				$ 0.040	
TETCO, M2-M3	Fuel	2.30%				$ 0.048
TETCO, M2-M3	Commodity					$ 0.085
	Sum of Variables		$ 0.058	$ 0.185	$ 0.068	$ 0.133
Delivered (Dth)- To PNG City Gate			**$ 2.10**	**$ 2.23**	**$ 2.10**	**$ 2.17**
	PNG BTU FACTOR	1.042				
	PNG City Gate Cost per Mcf		**$ 2.19**	**$ 2.32**	$ 2.19	$ 2.26
	PNG Distribution Retainage	5.4%	$ 0.118	$ 0.125	$ 0.118	$ 0.122
Burnertip Cost per Mcf @ 0.054			$ 2.30	$ 2.44	$ 2.31	$ 2.38
	PNG Distribution Retainage	3.9%	$ 0.085	$ 0.090	$ 0.085	$ 0.088
Burnertip Cost per Mcf @ 0.039			$ 2.27	$ 2.41	$ 2.28	$ 2.35
	$/Mcf savings from Lower Retainage		$ 0.03	$ 0.03	$ 0.03	$ 0.03

LOCAL GATHERING SUPPLY COST

		$/Mcf
DTI FOM App Index $2.04 Dth		
Percentage Above Index Producer Negotiates	103%	$2.10
Producers Retainage Cost	2.30%	($0.05)
Producers RATE AGS Cost		($0.26)
Net $/Mcf Paid to Producer of Gas Produced		$1.79
New Separate Gathering Fuel	6.20%	**($0.13)**
Net $/Mcf Paid to Producer if Producer Absorbs New Gath Fuel		$1.67
City Gate Cost to NGS Today		$2.10
PNG Distribution Fuel 0.054	5.4%	$0.11
Burnertip Cost to NGS		$2.21
City Gate Cost to NGS if **Producer Absorbs** New Gath Fuel		$2.10
PNG Distribution Fuel 0.039	3.9%	$0.08
Burnertip Cost to NGS		$2.18
City Gate Cost to NGS if **NGS Absorbs** New Gath Fuel		$2.23
PNG Distribution Fuel 0.039	3.9%	$0.09
Burnertip Cost to NGS		$2.32

Line #		Scenario #1 Current Retainage Collected		
1	PNG System		Bcf	
2		Total System Requirements	Use	UFG
3		Sales Burnertip	50.39	
4		Transport Burnertip	65.09	
5	5.2%	PNG Overall UFG		6.31
6		Total Requirements (Line 3 + 4 + 5)	121.79	
7		UFG Recoveries Not Received Through End-User Tariff Rate		
8		Discounted Customers	(23.51)	(0.27)
9		Producers PNG		(0.59)
10		Producers Goodwin/Tombaugh		(0.13)
11		Net To Recover (Lines 5 + 8 + 9 + 10)		5.33
12		NGS Transportation Supply		
13		Conventional Supply Net of Producer Retainage	18.76	
14	0.0%	Gathering Retainage Held Back @ 0%		0.00
15	5.4%	Distribution Retainage Held Back @ 5.4%		(1.01)
16		Net Available For Target (Lines 13+ 14 + 15)	17.75	
17		Gross Unconventional Local Production	6.42	
18	5.4%	Distribution Retainage Held Back @ 5.4%		(0.35)
19		Net Available For Target (Lines 17 + 18)	6.07	
20		Gross City Gate Interstate Supply	18.76	
21	5.4%	Distribution Retainage Held Back @ 5.4%		(1.01)
22		Net Available For Target (Lines 20 + 21)	17.75	
23		Total Non-Discounted Transport Receipts (Lines 13+17+20)	43.94	
24		Total Non-Discounted Transport Deliveries (Lines 16+19+22)	41.57	
25	5.4%	Retainage From Non-Discounted Transport (Line 23 - Line 24)		2.37
26		PNG Overall UFG To Be Recovered (Line 11)		5.33
27	5.5%	Remaining UFG Recovered From Sales (Line 26 - Line 25)		**2.95**

Line #		Scenario #2 1/ Separate Gathering Retainage Collected		
1	PNG System		Bcf	
2		Total System Requirements	Use	UFG
3		Sales Burnertip	50.39	
4		Transport Burnertip	65.09	
5	5.2%	PNG Overall UFG		6.31
6		Total Requirements (Line 3 + 4 + 5)	121.79	
7		UFG Recoveries Not Received Through End-User Tariff Rate		
8		Discounted Customers	(23.51)	(0.27)
9		Producers PNG		(0.59)
10		Producers Goodwin/Tombaugh		(0.13)
11		Net To Recover (Lines 5 + 8 + 9 + 10)		5.33
12		NGS Transportation Supply		
13		Conventional Supply Net of Producer Retainage	18.76	
14	6.2%	Gathering Retainage Held Back @ 6.2%		(1.16)
15	3.9%	Distribution Retainage Held Back @ 3.9%		(0.69)
16		Net Available For Target (Lines 13+ 14 + 15)	16.91	
17		Gross Unconventional Local Production	6.42	
18	3.9%	Distribution Retainage Held Back @ 3.9%		(0.25)
19		Net Available For Target (Lines 17 + 18)	6.17	
20		Gross City Gate Interstate Supply	19.24	
21	3.9%	Distribution Retainage Held Back @ 3.9%		(0.75)
22		Net Available For Target (Lines 20 + 21)	18.49	
23		Total Non-Discounted Transport Receipts (Lines 13+17+20)	44.42	
24		Total Non-Discounted Transport Deliveries (Lines 16+19+22)	41.57	
25	6.4%	Retainage From Non-Discounted Transport (Line 23 - Line 24)		2.85
26		PNG Overall UFG To Be Recovered (Line 11)		5.33
27	4.7%	Remaining UFG Recovered From Sales (Line 26 - Line 25)		**2.48**

1/ As proposed in the 2020- 1307(f) case including the Company's modifications to OCA's calculation.

Line #		Scenario #3 Separate Gathering Retainage Collected if Transporter Purchase 3 Bcf Less Conventional Production		
1	PNG System		Bcf	
2		Total System Requirements	Use	UFG
3		Sales Burnertip	50.39	
4		Transport Burnertip	65.09	
5	5.2%	PNG Overall UFG		6.31
6		Total Requirements (Line 3 + 4 + 5)	121.79	
7		UFG Recoveries Not Received Through End-User Tariff Rate		
8		Discounted Customers	(23.51)	(0.27)
9		Producers PNG		(0.59)
10		Producers Goodwin/Tombaugh		(0.13)
11		Net To Recover (Lines 5 + 8 + 9 + 10)		5.33
12		NGS Transportation Supply		
13	**3.0**	Conventional Supply Net of Producer Retainage Less 3 Bcf	15.76	
14	6.2%	Gathering Retainage Held Back @ 6.2%		(0.98)
15	3.9%	Distribution Retainage Held Back @ 3.9%		(0.58)
16		Net Available For Target (Lines 13+ 14 + 15)	14.21	
17		Gross Unconventional Local Production	6.42	
18	3.9%	Distribution Retainage Held Back @ 3.9%		(0.25)
19		Net Available For Target (Lines 17 + 18)	6.17	
20		Gross City Gate Interstate Supply	22.05	
21	3.9%	Distribution Retainage Held Back @ 3.9%		(0.86)
22		Net Available For Target (Lines 20 + 21)	21.19	
23		Total Non-Discounted Transport Receipts (Lines 13+17+20)	44.24	
24		Total Non-Discounted Transport Deliveries (Lines 16+19+22)	41.57	
25	6.0%	Retainage From Non-Discounted Transport (Line 23 - Line 24)		2.66
26		PNG Overall UFG To Be Recovered (Line 11)		5.33
27	5.0%	Remaining UFG Recovered From Sales (Line 26 - Line 25)		**2.66**

PEOPLES

NGS ONLY SUMMARY

August 25, 2020

To: Natural Gas Suppliers and LGA Pool Operators

Subject: Separate Gathering Retainage Rate – Survey Questions

Scope: In the settlement of Peoples Natural Gas Company's latest 1307(f) proceeding, the Company agreed to analyze the implications and equity of the Pennsylvania Office of Consumer Advocate (OCA's) proposal to adopt an additional retainage charge on the gas supplies delivered into PNG's gathering system. The Company will present a report of its analysis in its 2021 1307(f) filing. In addition to the analysis described above, the report will address issues related to OCA's proposal related to a gathering retainage charge phase-in period. The Company is not required to propose any changes to its retainage charges as a result of this report. In next year's 1307(f) proceeding, all parties are free to make proposals or oppose any proposals made by any other party.

As part of the Company's analysis, we are requesting the input of NGSs and LGA Pool Operators who are actively supplying gas on the PNG system. We would like one response per organization so feel free to forward this to the appropriate person to complete. We would like all responses emailed back to mina.speicher@peoples-gas.com by close of business Friday, September 4th.

1. If Peoples Natural Gas (PNG) were to implement a separate 6.8% retainage rate for gas coming from our gathering system in addition to a 3.5% retainage rate for all gas coming onto the system, would that affect your gas purchasing strategy? If so, please explain.

   Response 1: (Company A) Yes. Depending on the supplies purchased, this would impact the unit rate paid to suppliers utilizing the gathering service. It would make gathered supplies more expensive to procure and less economical as compared to interstate supplies delivered to PNG city gates. This would negatively impact the local producers behind the PNG system.

   (Company B) Yes, we would have to consider whether the charges can be passed along to the customer, if our production would benefit from going to an alternative market and what the additional upstream costs would be to deliver Interstate gas.

   (Company C) Our strategy would definitely have to be reviewed depending upon the party responsible for the additional retainage rate fee and comparing production gas pricing versus pipeline gas and available gate space.

   (Company D) Direct Energy purchases local supply and considers it a strategic piece of our portfolio. It would not directly impact Direct Energy's purchasing strategy of on system supply, but could indirectly affect our ability to secure supply on system, if on system production is deemed uneconomic by producers due to increased retainage. Additionally, it may require a higher pricing structure from producers in order to keep production online, which would cause us to increase our prices to end markets in order to be able to economically purchase production.

2. If PNG were to implement a new 6.8% gathering retainage rate in addition to its current retainage rate, would this affect your business due to existing contract obligation with customers and/or producers? If so, how would it affect your business, and how many months lead-time would you need in order to change those contract obligations?

   Response 2: (Company A) No. Most of the purchases made are net of all gathering and retainage fees implemented by PNG. However, it would require advance communication to local producers such that the unit rate and payment is adjusted to account for the retainage rate. 1-2 months of lead time would be required to communicate and mutually agree with local producers on the proposed retainage changes.

(Company B) Possibly, we would need to pass those charges through to the customer which would be damaging from a relationship perspective.

(Company C) Our producer and customer agreements do include language to pass through any charges resulting from tariff changes. The sooner the notification the better.

(Company D) If PNG were to implement a new gathering retainage rate, it would raise the risk of production being deemed uneconomic and shut in by producers v. flowing the volumes to sales. This would lead to increased requests for off system gas to meet our end market demands. Given many agreements we have with producers are annual term, starting in November or April of the year, therefore, we would always have some exposure with producer volumes being disincentivized to be on system regardless of the lead time. Additionally, with recontracting, producer economics may dictate higher prices needed to keep production online, which would cause us to have to increase our cost to end markets to be able to continue serving the markets we serve economically.

3. What effect would the additional gathering retainage rate have on local gas pricing and supply availability?

Response 3: (Company A) See responses to question 1. Local production would be less economical and negatively impact the local producers behind the PNG system.

(Company B) It could make some local production uneconomical to produce which could drive overall prices higher for the customer.

(Company C) It would increase local production pricing. It could lead to possible shut in of supply.

(Company D) It is likely to diminish supply availability by further challenging local production economics, while also increasing local gas pricing to end users and producers will require higher prices in order to keep supply online.

4. Would you be able to pass on the additional gathering retainage back to the producer?

Response 4: (Company A) Yes.

(Company B) These are costs that have been born by consumers for a long time as they are the ultimate beneficiary of locally produced gas. We would intend to pass the charges through to the customer.

(Company C) Most likely.

(Company D) Initially Direct Energy would be able to pass through the retainage to the producer, however, it does diminish the producer's willingness to maintain production, which could mean that Direct Energy will incur costs purchasing off system gas and bringing it on system.

5. Would you be able to pass on the additional retainage charge to your customers?

Response 5: (Company A) No.

(Company B) Yes, contractually in some cases.

(Company C) Most likely but would not like to do so as pricing would increase versus pipeline supply options and we would be at a disadvantage.

(Company D) Customers may face incremental charges due to producers requiring higher priced premiums to keep production online.

6. Between you as NGS/LGA Pool, your customer, and the producer, who do you believe would ultimately pay for the higher gathering retainage rate?

Response 6: (Company A) The producer.

(Company B) The customer should ultimately pay.

(Company C) Producer.

(Company D) Likely all parties will bear some responsibility for the increased retainage rate as producers will face increased loss, customer's will face higher cost supplies, and Direct Energy will be attempting to manage the cost difference to the best of its ability.

7. Would the additional gathering retainage rate make you more or less competitive against other NGSs? Please explain your response.

Response 7: (Company A) No change considering retainage and gathering fees are recovered from the producer.

(Company B) Less competitive as we would have to consider another fee to include in our price structure.

(Company C) Less competitive if other NGSs utilized piepleine gas to supply their customers.

(Company D) It would likely cause Direct Energy to have to rethink its strategy of purchasing on system gas if on system gas increased to a point that it was not strategic for Direct Energy to purchase. Additionally, depending on the pass through of costs, Direct Energy would likely lose some market share.

8. Describe the impact, if any, that the additional gathering retainage charge would have on the availability, price, deliverability, etc., of alternative sources of gas supplies (for example, gas supplies delivered to Peoples from an upstream interstate pipeline).

Response 8: (Company A) Upstream supplies would become relatively cheaper compared to local production due to the additional retainage rate assessed to local production. This assumes that the producer will not accept a lower unit rate as a result of the change. From a producer's perspective, the unit rate paid for production supply is diminished. In an already stressed market for conventional local production behind the PNG system, it could potentially result in wells getting shut in due to negative marginal return on production supplies, resulting in less availability of local production and a heavier reliance on upstream interstate supplies.

(Company B) The preferred upstream interstate pipeline would be Dominion Energy Transmission but deliveries are already limited and would force suppliers to bring in more expensive supply from

Equitrans, Tennessee Gas and/or Texas Eastern.

(Company C) The price increase due to the increased retainage rate would definitely be greater than pipeline delivered gas assuming gate space was available.

(Company D) The cost to deliver gas to Peoples would potentially be cheaper v. purchasing on system supply, which could cause more gas to be transported from upstream interstate pipelines onto Peoples v. local supply.

PEOPLES

PRODUCER ONLY SUMMARY

August 25, 2020

To: Natural Gas Suppliers and LGA Pool Operators

Subject: Separate Gathering Retainage Rate – Survey Questions

Scope: In the settlement of Peoples Natural Gas Company's latest 1307(f) proceeding, the Company agreed to analyze the implications and equity of the Pennsylvania Office of Consumer Advocate (OCA's) proposal to adopt an additional retainage charge on the gas supplies delivered into PNG's gathering system. The Company will present a report of its analysis in its 2021 1307(f) filing. In addition to the analysis described above, the report will address issues related to OCA's proposal related to a gathering retainage charge phase-in period. The Company is not required to propose any changes to its retainage charges as a result of this report. In next year's 1307(f) proceeding, all parties are free to make proposals or oppose any proposals made by any other party.

As part of the Company's analysis, we are requesting the input of NGSs and LGA Pool Operators who are actively supplying gas on the PNG system. We would like one response per organization so feel free to forward this to the appropriate person to complete. We would like all responses emailed back to mina.speicher@peoples-gas.com by close of business Friday, September 4th.

1. If Peoples Natural Gas (PNG) were to implement a separate 6.8% retainage rate for gas coming from our gathering system in addition to a 3.5% retainage rate for all gas coming onto the system, would that affect your gas purchasing strategy? If so, please explain.

   Response 1:

   (Company A) N/A

   (Company B) As a gas supplier on the Peoples system this would have a detrimental effect on our business for it would create a price disadvantage and favor out-of-state suppliers whose gas flows from the interstate pipeline into Peoples' distribution system

   (Company C) Not Applicable – we are a natural gas producer

   (Company D) Yes we operates a LGA pool operator mainly focusing on aggregating small conventional producers' production. If the proposed gathering charge is imposed on these producers that would be an additional burden on wells that are barely economical currently. I believe this would cause 100"s of wells to be shut in and plugged which could cause PNG a reliability issue to serve customers in certain markets on a peak day and limit the amount of gas that is being produced into the pool for resale to marketers who operate NP Pools

2. If PNG were to implement a new 6.8% gathering retainage rate in addition to its current retainage rate, would this affect your business due to existing contract obligation with customers and/or producers? If so, how would it affect your business, and how many months lead-time would you need in order to change those contract obligations?

   Response 2:

   (Company A) Any additional fee applied to our Indiana gas, especially considering the current price environment, places us several steps closer to shutting in our production and possibly plugging the well. Plugging and pad reclamation costs could range from $65-$140k. Additionally, there would be further costs related to pipeline decommissioning.

(Company B) A new 6.8% gathering retainage rate would be harmful to our business. We have contractual obligations with customers that would require at a minimum a 12-month lead time to address. In many situations such cost increases would make Pennsylvania produced gas more costly that out-of-state gas and we would fail to retain the patronage of our existing customers.

(Company C) Not Applicable – we are a natural gas producer

(Company D) We would have to pass the charges back to the producers which would damage relationships and also would make local gas possibly uncompetitive with interstate gas

3. What effect would the additional gathering retainage rate have on local gas pricing and supply availability?

Response 3

(Company A) N/A

(Company B) The additional gathering retainage rate would increase the cost of local gas supply, and therefore make local gas supply non-competitive with out-of-state supply

(Company C) The price for locally supplied gas would increase due to the additional gathering retainage increase. This would result in additional surplus of locally supplied gas due to the loss of demand as price sensitive transportation customers would be incented to purchase gas supplied from interstate pipelines. It would have a detrimental effect on local producers and the Pennsylvania natural gas industry as it would result in a necessary price deduction (to maintain equality with interstate pricing) of the locally supplied gas which would most likely and unjustly be bore by the local producer.

(Company D) it would reduce the availability of local gas (see response #1) supply which will have to be supplemented with higher price supply from the interstate pipelines which will cause the prices to increase to the residential, commercial and industrial customers and which also could cause PNG peak day delivery problems if more gas in certain market area being delivered from the Interstate pipelines.

4. Would you be able to pass on the additional gathering retainage back to the producer?

Response 4:

(Company A) N/A

(Company B) SME-AMS Energy is a local producer so any increase in fees would be harmful to our business

(Company C) This is something that the local producer (conventional producer) cannot bear at any time and especially in the current market environment. The potential costs of an additional gathering retainage rate applied to only local conventional gas defies all economic logic and places conventional producers at a severe competitive disadvantage with interstate suppliers. Why would the OCA who is concerned about the well-being of residents living in Pennsylvania disparage local natural gas producers who procure, employ and pay taxes in their state? The only benefactors in the OCA's proposal are the interstate suppliers at the likely cost to local conventional producers. The loss of locally supplied demand will in all probability necessitate local conventional producers to pay the proposed gathering retainage which will result in in an even lower price realized back to the conventional producer. This would ultimately lead to less procurements of goods and services, higher industry unemployment (due to cost restructuring) and less taxes being paid to the State of Pennsylvania, as well as insolvency of the conventional natural gas industry. It is not the function of the OCA to pick winners and losers in our industry but if their proposed gathering retainage charge applicable to local gas only is approved than that in a sense is what they are doing.

(Company D) We would try to pass it on to the NP pool operators in turn who hopefully would pass it on the customers whom have been benefitting from the low cost of locally produced gas for years. As previously stated the producers will not be able to absorb the additional costs.

5. Would you be able to pass on the additional retainage charge to your customers?

Response 5:

(Company A) N/A

(Company B) A new 6.8% gathering retainage rate would be harmful to our business. We have contractual obligations with customers that would require at a minimum a 12-month lead time to address. In many situations such cost increases would make Pennsylvania produced gas more costly that out-of-state gas and we would fail to retain the patronage of our existing customers. Such increases cannot be "passed on" to customers without a realistic expectation that customers will object to pricing increases.

(Company C) There is no feasible way for a local conventional production company to pass a retainage charge onto its customers.

(Company D) Since we operate a NP Pool, my customers are other LGA pool operators or NP pool operators and we would try to pass it on but unless the consuming customers are responsible for these charges (as they currently are) do not think we can pass it on to other pool operators.

6. Between you as NGS/LGA Pool, your customer, and the producer, who do you believe would ultimately pay for the higher gathering retainage rate?

Response 6:
(Company A) The transportation cusomters should pay, as per Peoples' tariff.

(Company B) Higher retainage rates will be borne by producers and customers both to some degree.

(Company C) The local conventional gas producer would be forced to pay the higher gathering retainage rate.

(Company D) The customer

7. Would the additional gathering retainage rate make you more or less competitive against other NGSs? Please explain your response.

Response 7:
(Company A) N/A

(Company B) A new 6.8% gathering retainage rate would be harmful to our business. We have contractual obligations with customers that would require at a minimum a 12-month lead time to address. In many situations such cost increases would make Pennsylvania produced gas more costly that out-of-state gas and we would fail to retain the patronage of our existing customers.

(Company C) Less competitive as we would realize less net dollars back as compared to interstate Suppliers

(Company D) NGS"s who rely on interstate gas and have firm capacity will be more competitive than LGA pool operators

8. Describe the impact, if any, that the additional gathering retainage charge would have on the availability, price, deliverability, etc., of alternative sources of gas supplies (for example, gas supplies delivered to Peoples from an upstream interstate pipeline).

Response 8:
(Company A) Any additional fee applied to our Indiana gas, especially considering the current price environment, places us several steps closer to shutting in our production and possibly plugging the well. Plugging and pad reclamation costs could range from $65-$140k. Additionally, there would be further costs related to pipeline decommissioning.

(Company B) Retainage charge increases would make Pennsylvania produced gas more costly that out-of-state gas from upstream interstate pipelines.

(Company C) At the onset of the additional gathering retainage charge on local gas, the interstate supplier would be able to sell their product for less resulting in increased demand from price conscious transportation customers. As we are not familiar with Peoples interconnect restraints specifically, at the point of delivery of interstate gas and downstream capacities we are unable to obtain regarding availability and deliverability.

(Company D) The cheapest upstream pipeline would be Dominion Energy but there are limitations on daily delivery volumes. Alternative pipelines would be Equitrans, TETCO, TCO and Tennessee gas which would be more expensive and the customers would have to pay increase supply costs (higher basis) in order to assure the reliable gas deliveries, in absence of local gas.