



UGI Utilities, Inc.
1 UGI Drive
Denver, PA 17517

Jessica R. Rogers
Vice President – Rates & Regulatory Affairs

June 1, 2026

VIA ELECTRONIC FILING

Mr. Matthew Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

**RE: UGI Utilities, Inc. – Gas Division
Information Filed in Support of Purchased Gas Costs – 2026
Under 66 Pa. C.S. §1307(f) – June 1, 2026
Docket No. R-2026-3062192**

Dear Secretary Homsher:

On behalf of UGI Utilities, Inc. – Gas Division (“UGI Gas”), please find enclosed for filing the annual Purchased Gas Cost pro forma tariff supplement, supporting information and prepared Direct Testimonies, filed pursuant to the provisions of 66 Pa. C.S. § 1307(f) and 52 Pa. Code § 53.64(a).

The enclosed pro forma tariff has a proposed effective date of December 1, 2026, and is filed in the form of a supplement as prescribed by the Pennsylvania Public Utility Commission’s (“Commission”) regulations at 52 Pa. Code § 53.64(e). The supporting documentation prescribed by the Commission’s regulations at 52 Pa. Code §§ 53.64(c) and 53.65 was filed with the Commission on May 1, 2026.

Please note that the following exhibits to UGI Gas Statement No. 2 are **CONFIDENTIAL**: JJJ-Nos. 5, 8 & 9. UGI Gas is providing the **CONFIDENTIAL** version of these documents to the Commission via the Commission’s SharePoint site. They will only be served to parties upon execution of a Stipulated Protective Agreement. UGI Gas requests that the Commission treat these documents as proprietary and that they not be included in the public folder.

Mr. Matthew Homsher, Secretary

June 1, 2026

Page 2


Notice

UGI Gas began issuing customer notices of this filing by bill insert on May 15, 2026. This process is expected to be completed by June 16, 2026. In addition, copies of this document have been served upon the persons indicated on the attached Certificate of Service.

Inquiries concerning this tariff filing should be directed to Tracy Hazenstab, Sr. Manager – Utility Rates, either by phone at (814) 574-4168 or by email at thazenstab@ugi.com with copies to UGI Gas's counsel at the email addresses shown below.

Very truly yours,

Signed by:


8FC9DCAB126F4E3...
Jessica R. Rogers

Enclosures: Supporting Information
Certificate of Service

cc: Service List

Candis A. Tunilo, Esquire
UGI Corporation
500 North Gulph Road
King of Prussia, PA 19406
tuniloc@ugicorp.com

Lindsay A. Berkstresser, Esquire
Post & Schell
17 North 2nd Street, 12th Floor
Harrisburg, PA 17101
lberkstresser@postschell.com

Alice A. Wade, Esquire
Post & Schell
One Oxford Centre
301 Grant Street, Ste. 310
Pittsburgh, PA 15219
alice.wade@postschell.com

CERTIFICATE OF SERVICE

I hereby certify that I have, this 1st day of June, 2026, served a true and correct copy of the foregoing document in the manner and upon the persons listed below in accordance with requirements of 52 Pa. Code § 1.54 (relating to service by a participant):

VIA EMAIL:

Harrison W. Breitman, Esquire
Senior Assistant Consumer Advocate
Olivia M. Spergel, Esquire
Assistant Consumer Advocate
Office Of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1921
ra-oca@paoca.org
HBreitman@paoca.org
OSpergel@paoca.org

Steven C. Gray, Esquire
Senior Attorney
Assistant Small Business Advocate
Office of Small Business Advocate
555 Walnut Street
Forum Place, 1st Floor
Harrisburg, PA 17101
sgray@pa.gov

Adam J. Williams, Esquire
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
adawilliam@pa.gov

Signed by:

Jessica R. Rogers

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Jessica R. Rogers

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

DOCKET NO. R-2026-3062192

COMPUTATION OF ANNUAL PURCHASED GAS COST FILING

SUBMITTED PURSUANT TO

52 PA. CODE §§ 53.64(c), AND 53.65

OF THE COMMISSION'S REGULATIONS

AND 66 PA. C. S. § 1317

IN SUPPORT OF

66 PA. C. S. § 1307(f) PURCHASED GAS COSTS – 2026

FILED JUNE 1, 2026

UGI Utilities, Inc. – Gas Division
1307(f) Annual Purchased Gas Cost Filing – 2026
Docket No. R-2026-3062192

Table of Contents & Witness Index

Book 2 – Filed June 1, 2026

Supporting Schedules, Pro Forma Tariff Supplement and Direct Testimony Pursuant to § 53.64(a)

	<u>Witness</u>
Schedule A (Page 1) – Computation of Purchased Gas Cost Rate effective Dec. 1, 2026	Z. J. Shirk
Schedule B (Page 1) – Development of Projected Cost of Gas (C-factor)	Z. J. Shirk
Schedule B (Pages 2-13) – Projected Supply Volumes, Rates, Costs, 4/2026 – 11/2027	J. L. Jowers
Schedule C (Pages 1-6) – Development of Experienced Cost of Gas (E-factor)	Z. J. Shirk
<i>Pro Forma</i> Tariff Supplement to Gas – Pa. P.U.C. Nos. 7 and 7S	Z. J. Shirk
UGI Gas Statement No. 1, Direct Testimony of Zachary J. Shirk Principal Analyst – Rates	Z. J. Shirk
Exhibit: UGI Gas Exhibit ZJS-1	Z. J. Shirk
UGI Gas Statement No. 2, Direct Testimony of Jamie L. Jowers Sr. Manager – Energy Supply	J. L. Jowers
Exhibit(s): UGI Gas Exhibit JLJ-1 UGI Gas Exhibit JLJ-2 UGI Gas Exhibit JLJ-3 UGI Gas Exhibit JLJ-4 UGI Gas Exhibit JLJ-5 (CONFIDENTIAL) UGI Gas Exhibit JLJ-6 UGI Gas Exhibit JLJ-7 UGI Gas Exhibit JLJ-8 (CONFIDENTIAL) UGI Gas Exhibit JLJ-9 (CONFIDENTIAL)	J. L. Jowers

Book 1 – Filed May 1, 2026

Supporting Information Pursuant to 52 Pa. Code §§ 53.64(c) and 53.65, and 66 Pa. C.S. § 1317

	<u>Witness</u>
Section 1 – §53.64(c)(1) Sources of Gas Supply¹	J. L. Jowers
Section 1-A – §53.64(c)(1) Sources of Gas Supply²	J. L. Jowers
Attachment: 1-A-1 Experienced Volumes, Rates, Cost: 04/2025 – 03/2026	J. L. Jowers
Section 1-B – §53.64(c)(1) Sources of Gas Supply³	J. L. Jowers
Attachments: 1-B-1 Projected Volumes, Rates, Cost: 04/2026 – 11/2026	J. L. Jowers
1-B-2 Projected Volumes, Rates, Cost: 12/2026 – 11/2027	J. L. Jowers
Section 1-C – §53.64(c)(1) Other Sources of Gas Supply⁴	J. L. Jowers
Attachment: 1-C-1 Experienced and Projected Volumes: 04/2025 – 11/2027	J. L. Jowers
Section 2-A – §53.64(c)(3) Other Sources of Gas Supply	J. L. Jowers
Attachments: 2-A-1 Spot Purchase Bids & Acceptances	J. L. Jowers
2-A-2 Upstream Transportation Activities	J. L. Jowers
Section 2-B – §53.64(c)(3) Other Sources of Gas Supply	J. L. Jowers
Section 3 – §53.64(c)(4) FERC Proceedings	J. L. Jowers
Section 4 – §53.64(c)(5) Supply/Demand Projections	J. L. Jowers
Attachment: 4-1 Integrated Resource Plan Contract Year Supply/Demand Balance	J. L. Jowers / Z. J. Shirk
Section 5 – §53.64(c)(6) Fuel Procurement Practices	J. L. Jowers
Attachment: 5-1 Organizational Chart	J. L. Jowers
Section 6 – §53.64(c)(7) Off-System Sales	J. L. Jowers
Section 7 – §53.64(c)(8) Transportation Agreements⁵	J. L. Jowers
Attachment: 7-1 Service Agreements	J. L. Jowers
Section 8 – §53.64(c)(9) End User Transportation Volume⁶	Z. J. Shirk
Section 9 – §53.64(c)(10) System Map	J. L. Jowers
Section 10 – §53.64(c)(11) Rate Structure Changes	Z. J. Shirk

¹ Satisfies requirements of 52 Pa. Code § 60.8(3)

² Satisfies requirements of 52 Pa. Code § 60.8(3)

³ Satisfies requirements of 52 Pa. Code § 60.8(3)

⁴ Satisfies requirements of 52 Pa. Code § 60.8(3)

⁵ Satisfies requirements of 52 Pa. Code § 60.8(2)

⁶ Satisfies requirements of 52 Pa. Code § 60.8(1)

Section 11 – §53.64(c)(12)-(14) Peak Day	J. L. Jowers
Attachment: 11-1 Experienced 3-Day Peak Periods	J. L. Jowers
Section 12 – §53.64(i)(1) PGC Revenue/Expense	Z. J. Shirk
Attachment: 12-1 PGC Revenue – Expense Statement	Z. J. Shirk
Section 13 – §53.65 Affiliated Purchases	J. L. Jowers
Attachment: 13-1 Purchases from Affiliates	J. L. Jowers
Section 14 – 66 Pa. C.S. § 1317(c) Reliability Plans	J. L. Jowers
Attachments: 14-1 Capacity to Meet Firm Peak Day Requirements	J. L. Jowers
14-2 Load Duration Curve	J. L. Jowers

**UGI Utilities, Inc. - Gas Division
Rider B - Purchased Gas Cost (PGC) Rates
Effective December 1, 2026**

Supporting Documentation

**UGI Utilities, Inc. - Gas Division
Computation of the Cost of Gas
Applicable to Rates: R, N, & GL**

**Effective December 1, 2026
Computation Year Ending November 30, 2027**

C - Projected Cost	\$	379,038,444
S - Projected Sales - Mcf		60,079,068
C/ S Projected Cost per Mcf	\$	6.3090
E - Experienced Cost	\$	(87,938,170)
-E / S Experienced Cost per Mcf 1/	\$	1.4637
PGC= (C/S + E/S) @ 12/1/2025 - (per Mcf)	\$	7.7727
Currently Effective PGC - (per Mcf) 2/	\$	7.4235
PGC Change (per Mcf)	\$	0.3492
Residential Heating Percent Change		2.1%

1/ See Schedule C, Page 1 for the development of this rate.

2/ See Supplement No. 65 to Tariff UGI Gas - Pa. P.U.C. No. 7, effective March 1, 2026.

UGI Utilities, Inc. - Gas Division
Development of the Projected Cost: C
For the 2026 PGC Year

Effective December 1, 2026
Computation Year Ending November 30, 2027

Month	Year	Projected Sales (Mcf) S	Projected Revenue	Projected Cost C	Over/(Under) Collection
December	2026	9,195,629	\$ 60,161,023 1/	\$ 58,396,305	\$ 1,764,718
January	2027	11,426,280	\$ 72,088,401	\$ 77,107,250	\$ (5,018,849)
February	2027	10,771,925	\$ 67,960,073	\$ 59,113,991	\$ 8,846,082
March	2027	9,552,857	\$ 60,268,972	\$ 50,109,946	\$ 10,159,026
April	2027	5,619,212	\$ 35,451,606	\$ 19,132,614	\$ 16,318,991
May	2027	2,788,582	\$ 17,593,162	\$ 13,486,325	\$ 4,106,837
June	2027	1,518,288	\$ 9,578,879	\$ 11,405,945	\$ (1,827,066)
July	2027	1,024,369	\$ 6,462,744	\$ 10,721,874	\$ (4,259,129)
August	2027	1,037,863	\$ 6,547,875	\$ 10,952,263	\$ (4,404,388)
September	2027	1,046,997	\$ 6,605,502	\$ 10,612,781	\$ (4,007,279)
October	2027	1,908,916	\$ 12,043,354	\$ 15,965,875	\$ (3,922,521)
November	2027	4,188,152	\$ 26,423,050	\$ 42,033,275	\$ (15,610,225)
Total		60,079,068	\$ 381,184,642	\$ 379,038,444	\$ 2,146,198

1/ December 2026 reflects proration of the PGC rates.

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED DEMAND UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
DEMAND**

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	AVERAGE
Supply									
Options	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tetco FT-1 AMA Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco FT AMA Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier G CNG Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
LNG Supply - Supplier TBD	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier A Delivered Supply	3.0263	3.1272	3.0263	3.1272	3.1272	3.0263	3.1272	3.0263	3.0768
Supplier A Delivered Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	7.3657	0.9207
UGI Energy Svcs Delivered Supply	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929
UGI Energy Svcs Delivered Supply	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.8345	16.9000	16.8918
UGI Energy Svcs Delivered Supply	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266
UGI Energy Svcs Delivered Supply	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	29.8931	3.7366
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	32.0730	4.0091
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	4.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	25.7709	3.2214
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	43.3194	5.4149
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	39.9999	5.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	4.0000
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	41.6386	5.2048
UGI Energy Svcs Peaking Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	37.0079	4.6260
Storage Demand									
Columbia FSS	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650
EGTS GSS	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806
Tetco SS-1	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312
Transco GSS	4.1646	4.3034	4.1646	4.3034	4.3034	4.1646	4.3034	4.1646	4.2340
Transco SS2	10.2870	10.6299	10.2870	10.6299	10.6299	10.2870	10.6299	10.2870	10.4585
Transco LSS	6.0387	6.2400	6.0387	6.2400	6.2400	6.0387	6.2400	6.0387	6.1393
Transco ESS	1.0089	1.0425	1.0089	1.0425	1.0425	1.0089	1.0425	1.0089	1.0257
Transco LGA	3.4410	3.5557	3.4410	3.5557	3.5557	3.4410	3.5557	3.4410	3.4984
UGI Storage Co. Service II	0.6000	0.6200	0.6000	0.6200	0.6200	0.6000	0.6200	0.6000	0.6100
Storage Capacity									
Columbia FSS	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673
EGTS GSS	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258
Tetco SS-1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773
Transco GSS	0.0294	0.0304	0.0294	0.0304	0.0304	0.0294	0.0304	0.0294	0.0299
Transco SS2	0.0297	0.0307	0.0297	0.0307	0.0307	0.0297	0.0307	0.0297	0.0302
Transco LSS	0.0240	0.0248	0.0240	0.0248	0.0248	0.0240	0.0248	0.0240	0.0244
Transco ESS	0.1398	0.1445	0.1398	0.1445	0.1445	0.1398	0.1445	0.1398	0.1421
Transco LGA	0.6630	0.6851	0.6630	0.6851	0.6851	0.6630	0.6851	0.6630	0.6741
UGI Storage Co. Service II	0.0879	0.0879	0.0879	0.0879	0.0879	0.0879	0.0879	0.0879	0.0879
Transportation									
Columbia Gas SST	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390
Columbia Gas FTS	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390
Columbia Gas NTS	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780
EGTS FT	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464
EGTS FT	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464
EGTS FT	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464
Tennessee FT-A	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077
Tennessee FT-G	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910
Tennessee FT-G	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372
Tennessee FT-A	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372
Tetco FTS 5	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320
Tetco FT Riv	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590
Tetco FT Leb	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250
Tetco FT Leb	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275
Tetco FT Gulf	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991
Tetco FT Gulf	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017
Tetco FT Gulf-ELA	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990
Tetco CDS Leb	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480
Tetco CDS Gulf	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122
Tetco CDS Gulf	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118
Tetco FT M2-Delmont	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610
Tetco FT-1 Appalachia	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626
Tetco FT-1 AMA	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359
Transco FT	19.2499	19.8916	19.2499	19.8916	19.8916	19.2499	19.8916	19.2499	19.5707
Transco FT	19.8014	20.4614	19.8014	20.4614	20.4614	19.8014	20.4614	19.8014	20.1314
Transco FTF	6.0495	6.2512	6.0495	6.2512	6.2512	6.0495	6.2512	6.0495	6.1503
Transco FT AMA	4.6995	4.8562	4.6995	4.8562	4.8562	4.6995	4.8562	4.6995	4.7778
Transco FT-PS	35.5256	36.7098	35.5256	36.7098	36.7098	35.5256	36.7098	35.5256	36.1177
Transco FT-Pocono	1.9194	1.9834	1.9194	1.9834	1.9834	1.9194	1.9834	1.9194	1.9514
Transco FT-Leidy South	15.0504	15.5521	15.0504	15.5521	15.5521	15.0504	15.5521	15.0504	15.3012
Transco FT-Sentinel	16.6320	17.1864	16.6320	17.1864	17.1864	16.6320	17.1864	16.6320	16.9092

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASED GAS COSTS IN (\$)
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
DEMAND**

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	TOTAL
Supply									
Options	225,610	294,747	290,563	318,836	311,900	285,297	289,502	347,640	\$ 2,364,094
Tetco FT-1 AMA Fee	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	\$ 5,061,336
Tranco FT AMA Fee	389,148	389,148	389,148	389,148	389,148	389,148	389,148	389,148	\$ 3,113,184
Supplier G CNG Supply	0	0	0	0	0	0	0	0	\$ -
LNG Supply - Supplier TBD	0	0	0	0	0	0	0	0	\$ -
Supplier A Delivered Supply	50,739	52,431	50,739	52,431	52,431	50,739	52,431	50,739	\$ 412,680
Supplier A Delivered Supply	0	0	0	0	0	0	0	61,828	\$ 61,828
UGI Energy Svcs Delivered Supply	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	\$ 2,717,867
UGI Energy Svcs Delivered Supply	777,383	777,383	777,383	777,383	777,383	777,383	774,368	1,656,099	\$ 7,094,766
UGI Energy Svcs Delivered Supply	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	\$ 3,105,324
UGI Energy Svcs Delivered Supply	268,804	268,804	268,804	268,804	268,804	268,804	268,804	268,804	\$ 2,150,430
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	0	\$ -
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	706,433	\$ 706,433
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	3,414,653	\$ 3,414,653
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	1,298,333	\$ 1,298,333
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	561,083	\$ 561,083
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	205,767	\$ 205,767
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	200,000	\$ 200,000
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	80,608	\$ 80,608
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	6,752,828	\$ 6,752,828
UGI Energy Svcs Peaking Supply	0	0	0	0	0	0	0	2,694,141	\$ 2,694,141
Storage Demand									
Columbia FSS	488,818	488,818	488,818	488,818	488,818	488,818	488,818	488,818	\$ 3,910,545
EGTS GSS	180,496	180,496	180,496	180,496	180,496	180,496	180,496	180,496	\$ 1,443,964
Tetco SS-1	65,340	65,340	65,340	65,340	65,340	65,340	65,340	65,340	\$ 522,723
Tranco GSS	247,286	255,528	247,286	255,528	255,528	247,286	255,528	247,286	\$ 2,011,256
Tranco SS2	340,705	352,062	340,705	352,062	352,062	340,705	352,062	340,705	\$ 2,771,071
Tranco LSS	45,399	46,912	45,399	46,912	46,912	45,399	46,912	45,399	\$ 369,245
Tranco ESS	10,089	10,425	10,089	10,425	10,425	10,089	10,425	10,089	\$ 82,057
Tranco LGA	3,561	3,680	3,561	3,680	3,680	3,561	3,680	3,561	\$ 28,966
UGI Storage Co. Service II	2,930	3,028	2,930	3,028	3,028	2,930	3,028	5,275	\$ 26,179
Storage Capacity									
Columbia FSS	474,501	474,501	474,501	474,501	474,501	474,501	474,501	474,501	\$ 3,796,011
EGTS GSS	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	\$ 921,920
Tetco SS-1	17,039	17,039	17,039	17,039	17,039	17,039	17,039	17,039	\$ 136,309
Tranco GSS	85,454	88,302	85,454	88,302	88,302	85,454	88,302	85,454	\$ 695,023
Tranco SS2	108,203	111,810	108,203	111,810	111,810	108,203	111,810	108,203	\$ 880,051
Tranco LSS	19,849	20,511	19,849	20,511	20,511	19,849	20,511	19,849	\$ 161,441
Tranco ESS	11,722	12,113	11,722	12,113	12,113	11,722	12,113	11,722	\$ 95,337
Tranco LGA	2,745	2,836	2,745	2,836	2,836	2,745	2,836	2,745	\$ 22,325
UGI Storage Co. Service II	77,296	77,296	77,296	77,296	77,296	77,296	77,296	77,296	\$ 618,371
Transportation									
Columbia Gas SST	843,518	843,518	843,518	843,518	843,518	843,518	1,687,023	1,687,023	\$ 8,435,157
Columbia Gas FTS	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	\$ 13,206,699
Columbia Gas NTS	268,947	268,947	268,947	268,947	268,947	268,947	268,947	268,947	\$ 2,151,572
EGTS FT	11,893	11,893	11,893	11,893	11,893	11,893	11,893	11,893	\$ 95,142
EGTS FT	0	0	0	0	0	0	0	11,893	\$ 11,893
EGTS FT	0	0	0	0	0	0	0	336,965	\$ 336,965
Tennessee FT-A	187,262	187,262	187,262	187,262	187,262	187,262	187,262	187,262	\$ 1,498,094
Tennessee FT-G	14,389	7,195	5,996	4,796	4,796	7,195	8,574	10,108	\$ 63,049
Tennessee FT-G	0	0	0	0	0	0	0	3,885	\$ 3,885
Tennessee FT-A	13,169	13,169	13,169	13,169	13,169	13,169	13,169	13,169	\$ 105,350
Tetco FTS 5	49,549	49,549	49,549	49,549	49,549	49,549	49,549	49,549	\$ 396,393
Tetco FT Riv	61,036	61,036	61,036	61,036	61,036	61,036	61,036	61,036	\$ 488,288
Tetco FT Leb	899,891	899,891	899,891	899,891	899,891	899,891	899,891	899,891	\$ 7,199,125
Tetco FT Leb	51,710	51,710	51,710	51,710	51,710	51,710	51,710	51,710	\$ 413,680
Tetco FT Gulf	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	\$ 11,402,626
Tetco FT Gulf	28,175	28,175	28,175	28,175	28,175	28,175	28,175	28,175	\$ 225,398
Tetco FT Gulf-ELA	253,188	253,188	253,188	253,188	253,188	253,188	253,188	253,188	\$ 2,025,504
Tetco CDS Leb	158,480	158,480	158,480	158,480	158,480	158,480	158,480	158,480	\$ 1,267,840
Tetco CDS Gulf	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	\$ 13,364,842
Tetco CDS Gulf	204,216	204,216	204,216	204,216	204,216	204,216	204,216	204,216	\$ 1,633,725
Tetco FT M2-Delmont	22,971	22,971	22,971	22,971	22,971	22,971	22,971	22,971	\$ 183,770
Tetco FT-1 Appalachia	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	\$ 2,500,214
Tetco FT-1 AMA	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	\$ 2,927,590
Tranco FT	598,537	618,488	598,537	618,488	618,488	598,537	618,488	598,537	\$ 4,868,102
Tranco FT	90,413	93,427	90,413	93,427	93,427	90,413	93,427	90,413	\$ 735,361
Tranco FTF	152,774	157,867	152,774	157,867	157,867	152,774	157,867	152,774	\$ 1,242,562
Tranco FT AMA	107,008	110,575	107,008	110,575	110,575	107,008	110,575	107,008	\$ 870,329
Tranco FT-PS	0	0	0	0	0	0	0	0	\$ -
Tranco FT-Pocono	3,839	3,967	3,839	3,967	3,967	3,839	3,967	3,839	\$ 31,222
Tranco FT-Leidy South	36,121	37,325	36,121	37,325	37,325	36,121	37,325	36,121	\$ 293,784
Tranco FT-Sentinel	116,424	120,305	116,424	120,305	120,305	116,424	120,305	116,424	\$ 946,915
SUBTOTAL	\$ 14,967,679	\$ 15,097,414	\$ 15,024,239	\$ 15,119,105	\$ 15,112,169	\$ 15,020,171	\$ 15,934,039	\$ 33,138,410	\$ 139,413,325
Revenue Sharing Mechanism	(666,200)	(668,559)	(744,445)	(752,305)	(750,847)	(748,231)	(741,911)	(787,736)	\$ (5,860,236)
Choice Capacity Credit	(2,376,288)	(1,956,837)	(1,942,240)	(2,388,591)	(2,388,591)	(2,374,755)	(2,967,217)	(6,194,928)	\$ (22,189,446)
Transportation Capacity Credit	(1,161,629)	(1,139,968)	(1,139,968)	(1,726,021)	(2,730,924)	(2,740,075)	(2,740,075)	(2,740,075)	\$ (16,118,733)
Balancing Service Credit	(376,593)	(306,074)	(145,454)	(281,524)	(254,512)	(226,681)	(261,452)	(277,794)	\$ (2,130,084)
Administrative Costs	51,967	111,967	51,967	51,967	51,967	51,967	51,967	51,967	\$ 475,736
Total Demand Cost	\$ 10,438,935	\$ 11,137,943	\$ 11,104,099	\$ 10,022,630	\$ 9,039,262	\$ 8,982,396	\$ 9,675,351	\$ 23,189,844	\$ 93,590,461

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY VOLUMES IN DTH OR DTH/D
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
COMMODITY

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	TOTAL
<u>Supply Volumes</u>									
Term - Tetco M2	247,530	298,809	274,230	320,602	348,967	300,630	320,943	842,640	2,954,351
Term - Transco Leidy	297,150	663,679	642,870	648,551	624,681	604,530	563,115	468,900	4,513,476
Term - Transco Z6 Non-NY	300,000	310,000	300,000	310,000	310,000	300,000	310,000	300,000	2,440,000
Term - TCO Pool	145,170	71,672	128,430	139,314	71,796	54,270	39,432	279,780	929,864
Term - TGP Z4 Marcellus	169,440	186,496	117,240	119,815	130,913	126,840	155,527	270,510	1,276,781
Term - TGP Z4 St. 219	30,120	31,124	30,120	31,124	31,124	30,120	31,124	45,210	260,066
Term - TGP Z4 St. 313	105,030	115,630	88,590	82,832	76,539	57,810	57,381	49,950	633,762
Spot - Tetco M2 Dlvd	2,123,502	1,070,747	495,761	455,618	464,315	698,637	1,645,099	2,338,718	9,292,399
Spot - Transco Leidy Dlvd	637,051	321,224	148,728	136,686	139,295	209,591	493,530	701,616	2,787,721
Spot - TGP Z4 300-Leg Dlvd	424,700	214,150	99,152	91,124	92,863	139,727	329,020	467,744	1,858,480
Spot - TGP Z4 300-Leg Dlvd (2)	150,000	0	0	0	0	0	0	150,000	300,000
Spot - TCO Pool Dlvd	1,061,751	535,374	247,881	227,809	232,158	349,319	822,550	1,169,359	4,646,201
Asset Management Refill	1,305,235	1,305,235	1,305,235	1,305,235	1,305,235	1,305,235	1,305,237	0	9,136,647
<u>Withdrawn Volumes</u>									
EGTS GSS	0	0	0	0	0	0	0	170,000	170,000
Tetco SS1	0	0	0	0	0	0	0	0	0
Transco GSS	0	0	0	0	0	0	0	0	0
Transco SS-2	0	0	0	0	0	0	0	0	0
Transco LSS	0	0	0	0	0	0	0	0	0
Transco ESS	0	0	0	0	0	0	0	0	0
Transco LGA	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	0	0	0	0	0	0	0	79,847	79,847
TCO FSS	0	0	0	0	0	0	0	0	0
<u>Injected Volumes</u>									
EGTS GSS	560,454	638,922	637,052	638,922	638,922	637,052	638,692	0	4,390,018
Tetco SS1	8,132	86,335	83,550	86,335	86,335	59,250	51,398	0	461,335
Transco GSS	217,440	472,688	458,250	452,665	421,011	407,430	339,538	0	2,769,022
Transco SS-2	492,720	509,144	492,720	509,144	509,144	492,720	509,158	0	3,514,750
Transco LSS	100,440	103,788	100,440	103,788	103,788	100,440	103,788	0	716,472
Transco ESS	11,130	11,501	11,130	11,501	11,501	11,130	11,501	0	79,394
Transco LGA	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	112,500	139,500	106,400	99,200	93,000	90,000	76,836	0	717,436
TCO FSS	728,773	876,066	876,066	876,066	876,066	876,066	876,067	0	5,985,170
Total Demand Served	4,765,090	2,286,196	1,112,629	1,091,089	1,088,119	1,502,621	3,465,980	7,250,808	22,562,532
Total Choice Bundled Demand	0	0	0	0	0	0	0	83,466	83,466

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
COMMODITY**

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	AVERAGE
Supply Rate									
Term - Tetco M2	2.3123	1.9103	2.0567	2.3345	2.4082	2.3951	2.4658	2.8017	2.3356
Term - Transco Leidy	2.2729	1.8722	2.0182	2.2951	2.3686	2.3555	2.4260	2.7366	2.2931
Term - Transco Z6 Non-NY	2.4351	2.0343	2.1803	2.4572	2.5307	2.5176	2.5881	2.9480	2.4614
Term - TCO Pool	2.5310	2.1251	2.2730	2.5534	2.6279	2.6146	2.6860	3.0606	2.5590
Term - TGP Z4 Marcellus	2.2323	1.8324	1.9781	2.2544	2.3277	2.3147	2.3850	2.7994	2.2655
Term - TGP Z4 St. 219	2.4483	2.0484	2.1941	2.4704	2.5437	2.5306	2.6010	2.8747	2.4639
Term - TGP Z4 St. 313	2.5598	2.1599	2.3056	2.5819	2.6552	2.6422	2.7125	2.7109	2.5410
Spot - Tetco M2 Dlvd	2.3375	1.9986	2.1754	2.5138	2.5370	2.2890	2.2613	2.8017	2.3643
Spot - Transco Leidy Dlvd	2.2941	1.9311	2.0998	2.4371	2.5030	2.2256	2.1929	2.7366	2.3025
Spot - TGP Z4 300-Leg Dlvd	2.2624	1.8977	2.0108	2.3724	2.4357	2.1866	2.1564	2.7994	2.2652
Spot - TGP Z4 300-Leg Dlvd (2)	2.3124	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.8494	0.6452
Spot - TCO Pool Dlvd	2.5386	2.0737	2.2394	2.5534	2.5921	2.3776	2.3729	3.0606	2.4761
Asset Management Refill	2.4298	2.0247	2.1723	2.4522	2.5265	2.5132	2.5845	0.0000	2.0879
Withdrawal Rate									
EGTS GSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0269	0.0034
Tetco SS1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco GSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco SS-2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco LSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco ESS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0002
TCO FSS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Injection Rate									
EGTS GSS	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0000	0.0353
Tetco SS1	0.0420	0.0420	0.0420	0.0420	0.0420	0.0420	0.0420	0.0000	0.0368
Transco GSS	0.0537	0.0537	0.0537	0.0537	0.0537	0.0537	0.0537	0.0000	0.0470
Transco SS-2	0.0285	0.0285	0.0285	0.0285	0.0285	0.0285	0.0285	0.0000	0.0249
Transco LSS	0.0361	0.0361	0.0361	0.0361	0.0361	0.0361	0.0361	0.0000	0.0316
Transco ESS	0.0331	0.0331	0.0331	0.0331	0.0331	0.0331	0.0331	0.0000	0.0290
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
TCO FSS	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0000	0.0212
Total Com Vol	4,765,090	2,286,196	1,112,629	1,091,089	1,088,119	1,502,621	3,465,980	7,250,808	22,562,532
Total Com Cost	\$ 10,680,394	\$ 5,166,181	\$ 2,837,431	\$ 2,689,196	\$ 2,669,132	\$ 4,118,459	\$ 8,796,275	\$ 21,335,286	\$ 58,292,354
Com Unit Rate	\$ 2.24	\$ 2.26	\$ 2.55	\$ 2.46	\$ 2.45	\$ 2.74	\$ 2.54	\$ 2.94	\$ 2.58
Total Dem Cost	\$ 10,438,935	\$ 11,137,943	\$ 11,104,099	\$ 10,022,630	\$ 9,039,262	\$ 8,982,396	\$ 9,675,351	\$ 23,189,844	\$ 93,590,461
Dem Unit Rate	\$ 2.19	\$ 4.87	\$ 9.98	\$ 9.19	\$ 8.31	\$ 5.98	\$ 2.79	\$ 3.20	\$ 4.15
Total System Costs	\$ 21,119,329	\$ 16,304,123	\$ 13,941,531	\$ 12,711,826	\$ 11,708,394	\$ 13,100,855	\$ 18,471,626	\$ 44,525,131	\$ 151,882,816
System Unit Rate	\$ 4.43	\$ 7.13	\$ 12.53	\$ 11.65	\$ 10.76	\$ 8.72	\$ 5.33	\$ 6.14	\$ 6.73

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASE GAS COSTS IN (\$)
UNDER NORMAL WEATHER
8 MONTH PERIOD - APRIL THROUGH NOVEMBER
COMMODITY

	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	TOTAL
Supply Cost									
Term - Tetco M2	572,356	570,800	564,013	748,443	840,393	720,039	791,383	2,360,795	\$ 7,168,222
Term - Transco Leidy	675,406	1,242,555	1,297,450	1,488,488	1,479,618	1,423,976	1,366,111	1,283,192	\$ 10,256,797
Term - Transco Z6 Non-NY	730,515	630,641	654,095	761,732	784,517	755,283	802,308	884,412	\$ 6,003,504
Term - TCO Pool	367,424	152,311	291,919	355,729	188,671	141,895	105,915	856,290	\$ 2,460,154
Term - TGP Z4 Marcellus	378,237	341,742	231,913	270,108	304,728	293,591	370,928	757,261	\$ 2,948,507
Term - TGP Z4 St. 219	73,742	63,755	66,086	76,888	79,170	76,223	80,953	129,967	\$ 646,784
Term - TGP Z4 St. 313	268,854	249,754	204,254	213,862	203,228	152,743	155,645	135,408	\$ 1,583,749
Spot - Tetco M2 Dlvd	4,963,736	2,140,032	1,078,480	1,145,327	1,177,976	1,599,208	3,719,998	6,552,304	\$ 22,377,061
Spot - Transco Leidy Dlvd	1,461,453	620,323	312,295	333,113	348,657	466,471	1,082,264	1,920,043	\$ 6,544,619
Spot - TGP Z4 300-Leg Dlvd	960,847	406,400	199,370	216,184	226,187	305,522	709,507	1,309,395	\$ 4,333,413
Spot - TGP Z4 300-Leg Dlvd (2)	346,862	0	0	0	0	0	0	427,407	\$ 774,269
Spot - TCO Pool Dlvd	2,695,407	1,110,210	555,112	581,694	601,772	830,546	1,951,848	3,578,922	\$ 11,905,511
Asset Management Refill	3,171,444	2,642,713	2,835,341	3,200,670	3,297,649	3,280,378	3,373,376	0	\$ 21,801,571
Withdrawal Cost									
EGTS GSS	0	0	0	0	0	0	0	4,573	\$ 4,573
Tetco SS1	0	0	0	0	0	0	0	0	\$ -
Transco GSS	0	0	0	0	0	0	0	0	\$ -
Transco SS-2	0	0	0	0	0	0	0	0	\$ -
Transco LSS	0	0	0	0	0	0	0	0	\$ -
Transco ESS	0	0	0	0	0	0	0	0	\$ -
Transco LGA	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	0	0	0	0	0	0	0	120	\$ 120
TCO FSS	0	0	0	0	0	0	0	0	\$ -
Injection Cost									
EGTS GSS	22,586	25,749	25,673	25,749	25,749	25,673	25,739	0	\$ 176,918
Tetco SS1	342	3,626	3,509	3,626	3,626	2,489	2,159	0	\$ 19,376
Transco GSS	11,670	25,369	24,594	24,295	22,596	21,867	18,223	0	\$ 148,613
Transco SS-2	14,038	14,506	14,038	14,506	14,506	14,038	14,506	0	\$ 100,135
Transco LSS	3,626	3,747	3,626	3,747	3,747	3,626	3,747	0	\$ 25,865
Transco ESS	369	381	369	381	381	369	381	0	\$ 2,629
Transco LGA	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	0	0	0	0	0	0	0	0	\$ -
TCO FSS	17,636	21,201	21,201	21,201	21,201	21,201	21,201	0	\$ 144,841
Subtotal Cost	\$ 16,736,549	\$ 10,265,814	\$ 8,383,339	\$ 9,485,742	\$ 9,624,372	\$ 10,135,137	\$ 14,596,191	\$ 20,200,088	\$ 99,427,231
Injected Value	\$ (6,632,598)	\$ (6,451,279)	\$ (6,821,064)	\$ (7,858,109)	\$ (7,982,059)	\$ (7,304,847)	\$ (7,191,066)	\$ -	\$ (50,241,022)
Withdrawal Value	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 590,793	\$ 590,793
Choice Bundled Sale Credit	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (252,120)	\$ (252,120)
Net Financial Derivatives	\$ 576,443	\$ 1,351,646	\$ 1,275,157	\$ 1,061,563	\$ 1,026,820	\$ 1,288,169	\$ 1,391,150	\$ 796,526	\$ 8,767,472
Total Cost	\$ 10,680,394	\$ 5,166,181	\$ 2,837,431	\$ 2,689,196	\$ 2,669,132	\$ 4,118,459	\$ 8,796,275	\$ 21,335,286	\$ 58,292,354

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED DEMAND UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
DEMAND**

	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	AVERAGE
Supply													
Options	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Tetco FT-1 AMA Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Transco FT AMA Fee	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Supplier G CNG Supply	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
LNG Supply - Supplier TBD	34.0000	34.0000	32.6500	34.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	11.2208
Supplier A Delivered Supply	3.1272	3.1272	2.8246	3.1272	3.0263	3.1272	3.0263	3.1272	3.1272	3.0263	3.1272	3.0263	3.0684
Supplier A Delivered Supply	7.3657	7.3657	7.3657	7.3657	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	7.3657	3.0691
UGI Energy Svcs Delivered Supply	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929	9.3929
UGI Energy Svcs Delivered Supply	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.9000	16.8345	16.9000	16.8945
UGI Energy Svcs Delivered Supply	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266	15.5266
UGI Energy Svcs Delivered Supply	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167	17.9167
UGI Energy Svcs Peaking Supply	59.7500	59.7500	59.7500	59.7500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	19.9167
UGI Energy Svcs Peaking Supply	29.8931	29.8931	29.8931	29.8931	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	29.8931	12.4554
UGI Energy Svcs Peaking Supply	32.0730	32.0730	32.0730	32.0730	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	32.0730	13.3638
UGI Energy Svcs Peaking Supply	31.9999	31.9999	31.9999	31.9999	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	13.3333
UGI Energy Svcs Peaking Supply	25.7709	25.7709	25.7709	25.7709	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	25.7709	10.7379
UGI Energy Svcs Peaking Supply	43.3194	43.3194	43.3194	43.3194	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	43.3194	18.0497
UGI Energy Svcs Peaking Supply	39.9999	39.9999	39.9999	39.9999	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	39.9999	16.6666
UGI Energy Svcs Peaking Supply	31.9999	31.9999	31.9999	31.9999	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	31.9999	13.3333
UGI Energy Svcs Peaking Supply	41.6386	41.6386	41.6386	41.6386	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	41.6386	17.3494
UGI Energy Svcs Peaking Supply	37.0079	37.0079	37.0079	37.0079	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	37.0079	15.4200
Storage Demand													
Columbia FSS	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650	3.8650
EGTS GSS	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806	2.6806
Tetco SS-1	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312	8.5312
Transco GSS	4.3034	4.3034	3.8870	4.3034	4.1646	4.3034	4.1646	4.3034	4.3034	4.1646	4.3034	4.1646	4.2224
Transco SS2	10.6299	10.6299	9.6012	10.6299	10.2870	10.6299	10.2870	10.6299	10.6299	10.2870	10.6299	10.2870	10.4299
Transco LSS	6.2400	6.2400	5.6361	6.2400	6.0387	6.2400	6.0387	6.2400	6.2400	6.0387	6.2400	6.0387	6.1226
Transco ESS	1.0425	1.0425	0.9416	1.0425	1.0089	1.0425	1.0089	1.0425	1.0425	1.0089	1.0425	1.0089	1.0229
Transco LGA	3.5557	3.5557	3.2116	3.5557	3.4410	3.5557	3.4410	3.5557	3.5557	3.4410	3.5557	3.4410	3.4888
UGI Storage Co. Service II	0.6200	0.6200	0.5600	0.6200	0.6000	0.6200	0.6000	0.6200	0.6200	0.6000	0.6200	0.6000	0.6083
Storage Capacity													
Columbia FSS	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673	0.0673
EGTS GSS	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258	0.0258
Tetco SS-1	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773	0.3773
Transco GSS	0.0304	0.0304	0.0274	0.0304	0.0294	0.0304	0.0294	0.0304	0.0304	0.0294	0.0304	0.0294	0.0298
Transco SS2	0.0307	0.0307	0.0277	0.0307	0.0297	0.0307	0.0297	0.0307	0.0307	0.0297	0.0307	0.0297	0.0301
Transco LSS	0.0248	0.0248	0.0224	0.0248	0.0240	0.0248	0.0240	0.0248	0.0248	0.0240	0.0248	0.0240	0.0243
Transco ESS	0.1445	0.1445	0.1305	0.1445	0.1398	0.1445	0.1398	0.1445	0.1445	0.1398	0.1445	0.1398	0.1417
Transco LGA	0.6851	0.6851	0.6188	0.6851	0.6630	0.6851	0.6630	0.6851	0.6851	0.6630	0.6851	0.6630	0.6722
UGI Storage Co. Service II	0.0879	0.0879	0.0879	0.0879	0.1022	0.1022	0.1022	0.1022	0.1022	0.1022	0.1022	0.1022	0.0974
Transportation													
Columbia Gas SST	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390	13.3390
Columbia Gas FTS	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390	13.5390
Columbia Gas NTS	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780	13.7780
EGTS FT	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464
EGTS FT	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464
EGTS FT	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464	5.9464
Tennessee FT-A	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077	5.5077
Tennessee FT-G	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910	11.9910
Tennessee FT-G	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372
Tennessee FT-A	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372	4.1372
Tetco FTS 5	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320	7.4320
Tetco FT Riv	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590	15.2590
Tetco FT Leb	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250	15.6250
Tetco FT Leb	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275	12.9275
Tetco FT Gulf	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991	24.7991
Tetco FT Gulf	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017	24.8017
Tetco FT Gulf-ELA	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990	21.0990
Tetco CDS Leb	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480	15.8480
Tetco CDS Gulf	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122	25.3122
Tetco CDS Gulf	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118	25.3118
Tetco FT M2-Delmont	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610	6.9610
Tetco FT-1 Appalachia	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626	17.3626
Tetco FT-1 AMA	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359	11.4359
Transco FT	19.8916	19.8916	17.9666	19.8916	19.2499	19.8916	19.2499	19.8916	19.8916	19.2499	19.8916	19.2499	19.5173
Transco FT	20.4614	20.4614	18.4813	20.4614	19.8014	20.4614	19.8014	20.4614	20.4614	19.8014	20.4614	19.8014	20.0764
Transco FTF	6.2512	6.2512	5.6462	6.2512	6.0495	6.2512	6.0495	6.2512	6.2512	6.0495	6.2512	6.0495	6.1335
Transco FT AMA	4.8562	4.8562	4.3862	4.8562	4.6995	4.8562	4.6995	4.8562	4.8562	4.6995	4.8562	4.6995	4.7648
Transco FT-PS	36.7098	36.7098	33.1572	36.7098	35.5256	36.7098	35.5256	36.7098	36.7098	35.5256			

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASED GAS COSTS IN (\$) UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
DEMAND**

	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	TOTAL
Supply													
Options	510,296	735,168	649,815	409,313	0	0	0	0	0	0	0	0	\$ 2,304,591
Tetco FT-1 AMA Fee	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	632,667	\$ 7,592,004
TranSCO FT AMA Fee	389,148	389,148	389,148	389,148	389,148	389,148	389,148	389,148	389,148	389,148	389,148	389,148	\$ 4,609,776
Supplier G CNG Supply	112,600	108,400	103,900	112,600	0	0	0	0	0	0	0	0	\$ 437,500
LNG Supply - Supplier TBD	340,000	340,000	326,500	340,000	0	0	0	0	0	0	0	0	\$ 1,346,500
Supplier A Delivered Supply	52,431	52,431	47,357	52,431	50,739	52,431	50,739	52,431	52,431	50,739	52,431	50,739	\$ 617,328
Supplier A Delivered Supply	61,828	61,828	61,828	61,828	0	0	0	0	0	0	0	0	\$ 309,140
UGI Energy Svcs Delivered Supply	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	339,733	\$ 4,076,801
UGI Energy Svcs Delivered Supply	1,656,099	1,656,099	1,656,099	1,656,099	777,383	777,383	777,383	777,383	777,383	777,383	777,383	1,656,099	\$ 13,719,160
UGI Energy Svcs Delivered Supply	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	388,166	\$ 4,657,987
UGI Energy Svcs Delivered Supply	268,804	268,804	268,804	268,804	268,804	268,804	268,804	268,804	268,804	268,804	268,804	268,804	\$ 3,225,645
UGI Energy Svcs Peaking Supply	2,390,000	2,390,000	2,390,000	2,390,000	0	0	0	0	0	0	0	0	\$ 9,560,000
UGI Energy Svcs Peaking Supply	706,433	706,433	706,433	706,433	0	0	0	0	0	0	0	0	\$ 3,532,165
UGI Energy Svcs Peaking Supply	3,414,653	3,414,653	3,414,653	3,414,653	0	0	0	0	0	0	0	0	\$ 17,073,263
UGI Energy Svcs Peaking Supply	1,298,333	1,298,333	1,298,333	1,298,333	0	0	0	0	0	0	0	0	\$ 6,491,664
UGI Energy Svcs Peaking Supply	561,083	561,083	561,083	561,083	0	0	0	0	0	0	0	0	\$ 2,805,416
UGI Energy Svcs Peaking Supply	205,767	205,767	205,767	205,767	0	0	0	0	0	0	0	0	\$ 1,028,835
UGI Energy Svcs Peaking Supply	200,000	200,000	200,000	200,000	0	0	0	0	0	0	0	0	\$ 999,998
UGI Energy Svcs Peaking Supply	80,608	80,608	80,608	80,608	0	0	0	0	0	0	0	0	\$ 403,039
UGI Energy Svcs Peaking Supply	6,752,828	6,752,828	6,752,828	6,752,828	0	0	0	0	0	0	0	0	\$ 33,764,142
UGI Energy Svcs Peaking Supply	2,694,141	2,694,141	2,694,141	2,694,141	0	0	0	0	0	0	0	0	\$ 13,470,707
Storage Demand													
Columbia FSS	488,818	488,818	488,818	488,818	488,818	488,818	488,818	488,818	488,818	488,818	488,818	488,818	\$ 5,865,818
EGTS GSS	180,496	180,496	180,496	180,496	180,496	180,496	180,496	180,496	180,496	180,496	180,496	180,496	\$ 2,165,946
Tetco SS-1	65,340	65,340	65,340	65,340	65,340	65,340	65,340	65,340	65,340	65,340	65,340	65,340	\$ 784,085
TranSCO GSS	255,528	255,528	230,800	255,528	247,286	255,528	247,286	255,528	247,286	255,528	247,286	255,528	\$ 3,008,642
TranSCO SS2	352,062	352,062	317,992	352,062	340,705	352,062	340,705	352,062	340,705	352,062	340,705	352,062	\$ 4,145,250
TranSCO LSS	46,912	46,912	42,372	46,912	45,399	46,912	45,399	46,912	46,912	45,399	46,912	45,399	\$ 552,354
TranSCO ESS	10,425	10,425	9,416	10,425	10,089	10,425	10,089	10,425	10,089	10,425	10,089	10,425	\$ 122,750
TranSCO LGA	3,680	3,680	3,324	3,680	3,561	3,680	3,561	3,680	3,561	3,680	3,561	3,680	\$ 43,331
UGI Storage Co. Service II	5,451	5,451	4,924	5,451	2,930	3,028	2,930	3,028	3,028	2,930	3,028	2,930	\$ 47,455
Storage Capacity													
Columbia FSS	474,501	474,501	474,501	474,501	474,501	474,501	474,501	474,501	474,501	474,501	474,501	474,501	\$ 5,694,017
EGTS GSS	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	115,240	\$ 1,382,880
Tetco SS-1	17,039	17,039	17,039	17,039	17,039	17,039	17,039	17,039	17,039	17,039	17,039	17,039	\$ 204,463
TranSCO GSS	88,302	88,302	79,757	88,302	85,454	88,302	85,454	88,302	85,454	88,302	85,454	88,302	\$ 1,039,686
TranSCO SS2	111,810	111,810	100,990	111,810	108,203	111,810	108,203	111,810	108,203	111,810	108,203	111,810	\$ 1,316,470
TranSCO LSS	20,511	20,511	18,526	20,511	19,849	20,511	19,849	20,511	19,849	20,511	19,849	20,511	\$ 241,499
TranSCO ESS	12,113	12,113	10,940	12,113	11,722	12,113	11,722	12,113	11,722	12,113	11,722	12,113	\$ 142,615
TranSCO LGA	2,836	2,836	2,562	2,836	2,745	2,836	2,745	2,836	2,745	2,836	2,745	2,836	\$ 33,395
UGI Storage Co. Service II	77,296	77,296	77,296	77,296	89,825	89,825	89,825	89,825	89,825	89,825	89,825	89,825	\$ 1,027,785
Transportation													
Columbia Gas SST	1,687,023	1,687,023	1,687,023	1,687,023	843,518	843,518	843,518	843,518	843,518	843,518	1,687,023	1,687,023	\$ 15,183,250
Columbia Gas FTS	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	1,650,837	\$ 19,810,048
Columbia Gas NTS	268,947	268,947	268,947	268,947	268,947	268,947	268,947	268,947	268,947	268,947	268,947	268,947	\$ 3,227,359
EGTS FT	11,893	11,893	11,893	11,893	11,893	11,893	11,893	11,893	11,893	11,893	11,893	11,893	\$ 142,714
EGTS FT	11,893	11,893	11,893	11,893	0	0	0	0	0	0	0	0	\$ 59,464
EGTS FT	336,965	336,965	336,965	336,965	0	0	0	0	0	0	0	0	\$ 1,684,823
Tennessee FT-A	187,262	187,262	187,262	187,262	187,262	187,262	187,262	187,262	187,262	187,262	187,262	187,262	\$ 2,247,142
Tennessee FT-G	10,480	9,965	10,672	12,195	14,389	7,195	4,796	7,195	8,574	10,108	8,574	10,108	\$ 106,360
Tennessee FT-G	7,459	8,498	7,588	5,283	0	0	0	0	0	0	0	0	\$ 32,713
Tennessee FT-A	13,169	13,169	13,169	13,169	13,169	13,169	13,169	13,169	13,169	13,169	13,169	13,169	\$ 158,024
Tetco FTS 5	49,549	49,549	49,549	49,549	49,549	49,549	49,549	49,549	49,549	49,549	49,549	49,549	\$ 594,590
Tetco FT Riv	61,036	61,036	61,036	61,036	61,036	61,036	61,036	61,036	61,036	61,036	61,036	61,036	\$ 732,432
Tetco FT LeB	899,891	899,891	899,891	899,891	899,891	899,891	899,891	899,891	899,891	899,891	899,891	899,891	\$ 10,798,688
Tetco FT LeB	51,710	51,710	51,710	51,710	51,710	51,710	51,710	51,710	51,710	51,710	51,710	51,710	\$ 620,520
Tetco FT Gulf	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	1,425,328	\$ 17,103,939
Tetco FT Gulf	28,175	28,175	28,175	28,175	28,175	28,175	28,175	28,175	28,175	28,175	28,175	28,175	\$ 338,097
Tetco FT Gulf-ELA	253,188	253,188	253,188	253,188	253,188	253,188	253,188	253,188	253,188	253,188	253,188	253,188	\$ 3,038,256
Tetco CDS LeB	158,480	158,480	158,480	158,480	158,480	158,480	158,480	158,480	158,480	158,480	158,480	158,480	\$ 1,901,760
Tetco CDS Gulf	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	1,670,605	\$ 20,047,262
Tetco CDS Gulf	204,216	204,216	204,216	204,216	204,216	204,216	204,216	204,216	204,216	204,216	204,216	204,216	\$ 2,450,587
Tetco FT M2-Delmont	22,971	22,971	22,971	22,971	22,971	22,971	22,971	22,971	22,971	22,971	22,971	22,971	\$ 275,656
Tetco FT-1 Appalachia	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	312,527	\$ 3,750,322
Tetco FT-1 AMA	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	365,949	\$ 4,391,386
TranSCO FT	616,081	616,081	556,461	618,488	598,537	618,488	598,537	618,488	598,537	618,488	598,537	618,488	\$ 7,275,214
TranSCO FT	93,427	93,427	84,386	93,427	90,413	93,427	90,413	93,427	90,413	93,427	90,413	93,427	\$ 1,100,027
TranSCO FT	157,867	157,867	142,589	157,867	152,774	157,867	152,774	157,867	152,774	157,867	152,774	157,867	\$ 1,888,751
TranSCO FT AMA	110,575	110,575	99,874	110,575	107,008	110,575	107,008	110,575	107,008	110,575	107,008	110,575	\$ 1,301,926
TranSCO FT-PS	190,671	190,671	172,219	0	0	0	0	0	0	0	0	0	\$ 553,560
TranSCO FT-Pocono	3,967	3,967	3,583	3,967	3,839								

UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY VOLUMES IN DTH OR DTH/D
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
COMMODITY

	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	TOTAL
<u>Supply Volumes</u>													
Term - Tetco M2	932,852	1,402,285	1,021,552	645,110	247,530	298,809	274,230	320,602	348,967	300,630	320,943	842,640	6,956,150
Term - Transco Leidy	435,271	688,603	456,372	462,272	297,150	663,679	642,870	648,551	624,681	604,530	563,115	468,900	6,555,994
Term - Transco Z6 Non-NY	310,000	310,000	280,000	310,000	300,000	310,000	300,000	310,000	310,000	300,000	310,000	300,000	3,650,000
Term - TCO Pool	536,796	688,324	567,224	456,320	145,170	71,672	128,430	139,314	71,796	54,270	39,432	279,780	3,178,528
Term - TGP Z4 Marcellus	224,533	380,184	346,836	222,084	169,440	186,496	117,240	119,815	130,913	126,840	155,527	270,510	2,450,418
Term - TGP Z4 St. 219	46,717	46,717	42,196	46,717	30,120	31,124	30,120	31,124	31,124	30,120	31,124	45,210	442,413
Term - TGP Z4 St. 313	102,889	167,028	128,604	38,316	105,030	115,630	88,590	82,832	76,539	57,810	57,381	49,950	1,070,599
Spot - Tetco M2 Dlvd	1,906,671	2,679,257	1,614,767	2,025,654	1,949,443	1,110,018	639,557	471,638	515,095	511,210	1,466,192	1,923,827	16,813,331
Spot - Transco Leidy Dlvd	572,001	803,777	484,430	607,697	584,833	333,006	191,867	141,492	154,528	153,363	439,858	577,148	5,044,000
Spot - TGP Z4 300-Leg Dlvd	381,334	535,852	322,953	405,131	389,889	222,004	127,912	94,328	103,019	102,242	293,239	384,766	3,362,669
Spot - TGP Z4 300-Leg Dlvd (2)	155,000	155,000	140,000	155,000	150,000	0	0	0	0	0	0	150,000	905,000
Spot - TCO Pool Dlvd	953,335	1,339,629	807,384	1,012,828	974,722	555,010	319,779	235,820	257,547	255,605	733,096	961,914	8,406,669
Asset Management Refill	0	0	0	0	1,305,235	1,305,235	1,305,235	1,305,235	1,305,235	1,305,235	1,305,237	0	9,136,647
<u>Withdrawn Volumes</u>													0
EGTS GSS	746,220	1,308,455	1,272,248	887,187	0	0	0	0	0	0	0	170,000	4,384,110
Tetco SS1	76,570	140,895	140,505	103,365	0	0	0	0	0	0	0	0	461,335
Transco GSS	385,175	854,422	826,940	702,485	0	0	0	0	0	0	0	0	2,769,022
Transco SS-2	919,460	940,695	866,620	612,975	0	0	0	0	0	0	0	0	3,339,750
Transco LSS	193,068	193,068	175,930	135,472	0	0	0	0	0	0	0	0	697,538
Transco ESS	0	0	41,643	37,751	0	0	0	0	0	0	0	0	79,394
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	155,000	186,000	168,000	128,589	0	0	0	0	0	0	0	79,847	717,436
TCO FSS	1,768,800	1,867,850	1,436,325	904,327	0	0	0	0	0	0	0	0	5,977,302
<u>Injected Volumes</u>													0
EGTS GSS	0	0	0	0	554,546	638,922	637,052	638,922	638,922	637,052	638,692	0	4,384,110
Tetco SS1	0	0	0	0	8,132	86,335	83,550	86,335	86,335	59,250	51,398	0	461,335
Transco GSS	0	0	0	0	217,440	472,688	458,250	452,665	421,011	407,430	339,538	0	2,769,022
Transco SS-2	0	0	0	0	317,720	509,144	492,720	509,144	509,144	492,720	509,158	0	3,339,750
Transco LSS	0	0	0	0	81,506	103,788	100,440	103,788	103,788	100,440	103,788	0	697,538
Transco ESS	0	0	0	0	11,130	11,501	11,130	11,501	11,501	11,130	11,501	0	79,394
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	0
UGI Storage Co. Service II	0	0	0	0	112,500	139,500	106,400	99,200	93,000	90,000	76,836	0	717,436
TCO FSS	0	0	0	0	720,905	876,066	876,066	876,066	876,066	876,066	876,067	0	5,977,302
													0
Total Demand Served	9,519,728	13,029,070	9,716,623	8,826,140	4,624,683	2,364,739	1,400,222	1,123,130	1,189,677	1,127,767	3,108,166	6,432,341	62,462,286
Total Choice Bundled Demand	1,281,964	1,658,971	1,423,906	1,073,140	0	0	0	0	0	0	0	72,151	5,510,132

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED SUPPLY UNIT RATE IN \$/DTH
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
COMMODITY**

	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	AVERAGE
Supply Rate													
Term - Tetco M2	3.8224	4.4108	4.0345	2.9406	2.6108	2.3835	2.5153	2.6400	2.6734	2.4779	2.4042	2.8698	2.9819
Term - Transco Leidy	3.9403	4.6627	4.1542	2.8927	2.4708	2.2996	2.4763	2.6510	2.6591	2.3459	2.3052	2.9581	2.9847
Term - Transco Z6 Non-NY	5.5110	9.2665	7.8317	3.0412	2.5337	2.3902	2.5972	2.8952	2.9007	2.4491	2.3454	3.1041	3.9055
Term - TCO Pool	4.0557	4.6567	4.1554	3.0390	2.6255	2.4694	2.6139	2.7374	2.7646	2.5285	2.5094	3.2849	3.1200
Term - TGP Z4 Marcellus	3.8020	4.4173	4.0280	2.8848	2.4613	2.3332	2.4292	2.5884	2.5914	2.2765	2.2283	3.0279	2.9224
Term - TGP Z4 St. 219	3.8020	4.4299	4.0205	3.1410	2.7451	2.5618	2.6201	2.7718	2.8225	2.4674	2.4442	3.0104	3.0697
Term - TGP Z4 St. 313	3.6220	4.0734	3.6987	2.7770	2.5565	2.4544	2.5935	2.7489	2.7855	2.6318	2.6507	2.8099	2.9502
Spot - Tetco M2 Dlvd	3.8224	4.4108	4.0345	2.9406	2.6108	2.3835	2.5153	2.6400	2.6734	2.4779	2.4042	2.8698	2.9819
Spot - Transco Leidy Dlvd	3.9403	4.6627	4.1542	2.8927	2.4708	2.2996	2.4763	2.6510	2.6591	2.3459	2.3052	2.9581	2.9847
Spot - TGP Z4 300-Leg Dlvd	3.8020	4.4173	4.0280	2.8848	2.4613	2.3332	2.4292	2.5884	2.5914	2.2765	2.2283	3.0279	2.9224
Spot - TGP Z4 300-Leg Dlvd (2)	3.8520	4.4673	4.0780	2.9348	2.5113	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.0779	1.7434
Spot - TCO Pool Dlvd	4.0557	4.6567	4.1554	3.0390	2.6255	2.4694	2.6139	2.7374	2.7646	2.5285	2.5094	3.2849	3.1200
Asset Management Refill	0.0000	0.0000	0.0000	0.0000	2.3769	2.3616	2.4970	2.7117	2.7657	2.7443	2.8277	0.0000	1.5237
Withdrawal Rate													
EGTS GSS	0.0269	0.0269	0.0269	0.0269	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0269	0.0112
Tetco SS1	0.0752	0.0752	0.0752	0.0752	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0251
Transco GSS	0.0458	0.0458	0.0458	0.0458	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0153
Transco SS-2	0.0285	0.0285	0.0285	0.0285	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0095
Transco LSS	0.0286	0.0286	0.0286	0.0286	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0095
Transco ESS	0.0000	0.0000	0.0331	0.0331	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0055
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0015	0.0015	0.0015	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0006
TCO FSS	0.0242	0.0242	0.0242	0.0242	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081
Injection Rate													
EGTS GSS	0.0000	0.0000	0.0000	0.0000	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0403	0.0000	0.0235
Tetco SS1	0.0000	0.0000	0.0000	0.0000	0.0420	0.0420	0.0420	0.0420	0.0420	0.0420	0.0420	0.0000	0.0245
Transco GSS	0.0000	0.0000	0.0000	0.0000	0.0537	0.0537	0.0537	0.0537	0.0537	0.0537	0.0537	0.0000	0.0313
Transco SS-2	0.0000	0.0000	0.0000	0.0000	0.0285	0.0285	0.0285	0.0285	0.0285	0.0285	0.0285	0.0000	0.0166
Transco LSS	0.0000	0.0000	0.0000	0.0000	0.0361	0.0361	0.0361	0.0361	0.0361	0.0361	0.0361	0.0000	0.0211
Transco ESS	0.0000	0.0000	0.0000	0.0000	0.0331	0.0331	0.0331	0.0331	0.0331	0.0331	0.0331	0.0000	0.0193
Transco LGA	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
UGI Storage Co. Service II	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
TCO FSS	0.0000	0.0000	0.0000	0.0000	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0242	0.0000	0.0141
Total Com Vol	9,519,728	13,029,070	9,716,623	8,826,140	4,624,683	2,364,739	1,400,222	1,123,130	1,189,677	1,127,767	3,108,166	6,432,341	62,462,286
Total Com Cost	\$ 33,225,785	\$ 52,063,434	\$ 34,625,792	\$ 24,755,271	\$ 10,548,877	\$ 4,806,064	\$ 2,617,711	\$ 2,018,082	\$ 2,221,459	\$ 1,904,828	\$ 6,578,112	\$ 19,186,167	194,551,583
Com Unit Rate	\$ 3.49	\$ 4.00	\$ 3.56	\$ 2.80	\$ 2.28	\$ 2.03	\$ 1.87	\$ 1.80	\$ 1.87	\$ 1.69	\$ 2.12	\$ 2.98	\$ 3.11
Total Dem Cost	\$ 25,170,521	\$ 25,043,816	\$ 24,488,199	\$ 25,354,675	\$ 8,583,737	\$ 8,680,261	\$ 8,788,234	\$ 8,703,792	\$ 8,730,805	\$ 8,707,952	\$ 9,387,762	\$ 22,847,108	\$ 184,486,861
Dem Unit Rate	\$ 2.64	\$ 1.92	\$ 2.52	\$ 2.87	\$ 1.86	\$ 3.67	\$ 6.28	\$ 7.75	\$ 7.34	\$ 7.72	\$ 3.02	\$ 3.55	\$ 2.95
Total System Costs	\$ 58,396,305	\$ 77,107,250	\$ 59,113,991	\$ 50,109,946	\$ 19,132,614	\$ 13,486,325	\$ 11,405,945	\$ 10,721,874	\$ 10,952,263	\$ 10,612,781	\$ 15,965,875	\$ 42,033,275	\$ 379,038,444
System Unit Rate	\$ 6.13	\$ 5.92	\$ 6.08	\$ 5.68	\$ 4.14	\$ 5.70	\$ 8.15	\$ 9.55	\$ 9.21	\$ 9.41	\$ 5.14	\$ 6.53	\$ 6.07

**UGI UTILITIES, INC. - GAS DIVISION
PROJECTED PURCHASE GAS COSTS IN (\$)
UNDER NORMAL WEATHER
12 MONTH PERIOD - DECEMBER THROUGH NOVEMBER
COMMODITY**

	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	TOTAL
Supply Cost													
Term - Tetco M2	3,565,707	6,185,136	4,121,444	1,896,980	646,240	712,206	689,771	846,405	932,922	744,939	771,608	2,418,247	\$ 23,531,607
Term - Transco Leidy	1,715,092	3,210,748	1,895,879	1,337,197	734,196	1,526,216	1,591,959	1,719,321	1,661,073	1,418,194	1,298,074	1,387,056	\$ 19,495,004
Term - Transco Z6 Non-NY	1,708,400	2,872,616	2,192,889	942,763	760,116	740,976	779,146	897,506	899,222	734,744	727,087	931,230	\$ 14,186,695
Term - TCO Pool	2,177,094	3,205,316	2,357,018	1,386,740	381,148	176,987	335,704	381,359	198,490	137,224	98,950	919,062	\$ 11,755,091
Term - TGP Z4 Marcellus	853,673	1,679,397	1,397,067	640,663	417,047	435,140	284,797	310,131	339,251	288,748	346,554	819,087	\$ 7,811,555
Term - TGP Z4 St. 219	177,618	206,951	169,649	146,736	82,683	79,733	78,916	86,268	87,847	74,317	76,075	136,098	\$ 1,402,891
Term - TGP Z4 St. 313	372,661	680,379	475,670	106,403	268,506	283,802	229,761	227,693	213,201	152,145	152,100	140,356	\$ 3,302,676
Spot - Tetco M2 Dlvd	7,288,005	11,817,548	6,514,766	5,956,544	5,089,520	2,645,710	1,608,679	1,245,148	1,377,046	1,266,742	3,525,005	5,521,088	\$ 53,855,801
Spot - Transco Leidy Dlvd	2,253,847	3,747,770	2,012,439	1,757,862	1,445,001	765,790	475,126	375,098	410,901	359,781	1,013,946	1,707,266	\$ 16,324,828
Spot - TGP Z4 300-Leg Dlvd	1,449,830	2,367,033	1,300,866	1,168,712	959,645	517,988	310,721	244,160	266,966	232,752	653,412	1,165,046	\$ 10,637,130
Spot - TGP Z4 300-Leg Dlvd (2)	597,059	692,435	570,925	454,890	376,699	0	0	0	0	0	0	461,690	\$ 3,153,699
Spot - TCO Pool Dlvd	3,866,460	6,238,246	3,354,968	3,077,948	2,559,163	1,370,540	835,872	645,535	712,023	646,309	1,839,612	3,159,833	\$ 28,306,510
Asset Management Refill	0	0	0	0	3,102,363	3,082,436	3,259,123	3,539,430	3,609,839	3,581,941	3,690,881	0	\$ 23,866,014
Withdrawal Cost													
EGTS GSS	20,073	35,197	34,223	23,865	0	0	0	0	0	0	0	4,573	\$ 117,933
Tetco SSI	5,758	10,595	10,566	7,773	0	0	0	0	0	0	0	0	\$ 34,692
Transco GSS	17,629	39,107	37,849	32,153	0	0	0	0	0	0	0	0	\$ 126,738
Transco SS-2	26,195	26,800	24,690	17,464	0	0	0	0	0	0	0	0	\$ 95,149
Transco LSS	5,528	5,528	5,037	3,879	0	0	0	0	0	0	0	0	\$ 19,971
Transco ESS	0	0	1,379	1,250	0	0	0	0	0	0	0	0	\$ 2,629
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	233	279	252	193	0	0	0	0	0	0	0	120	\$ 1,076
TCO FSS	42,805	45,202	34,759	21,885	0	0	0	0	0	0	0	0	\$ 144,651
Injection Cost													
EGTS GSS	0	0	0	0	22,348	25,749	25,673	25,749	25,749	25,673	25,739	0	\$ 176,680
Tetco SSI	0	0	0	0	342	3,626	3,509	3,626	3,626	2,489	2,159	0	\$ 19,376
Transco GSS	0	0	0	0	11,670	25,369	24,594	24,295	22,596	21,867	18,223	0	\$ 148,613
Transco SS-2	0	0	0	0	9,052	14,506	14,038	14,506	14,506	14,038	14,506	0	\$ 95,149
Transco LSS	0	0	0	0	2,942	3,747	3,626	3,747	3,747	3,626	3,747	0	\$ 25,181
Transco ESS	0	0	0	0	369	381	369	381	381	369	381	0	\$ 2,629
Transco LGA	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
UGI Storage Co. Service II	0	0	0	0	0	0	0	0	0	0	0	0	\$ -
TCO FSS	0	0	0	0	17,446	21,201	21,201	21,201	21,201	21,201	21,201	0	\$ 144,651
Subtotal Cost	\$ 26,143,668	\$ 43,066,283	\$ 26,512,336	\$ 18,981,899	\$ 16,886,498	\$ 12,432,102	\$ 10,572,585	\$ 10,611,555	\$ 10,800,586	\$ 9,727,098	\$ 14,279,258	\$ 18,770,752	\$ 218,784,620
Injected Value	\$ -	\$ -	\$ -	\$ -	\$ (6,337,620)	\$ (7,626,038)	\$ (7,954,874)	\$ (8,593,474)	\$ (8,579,128)	\$ (7,822,269)	\$ (7,701,146)	\$ -	\$ (54,614,549)
Withdrawal Value	\$ 10,026,954	\$ 12,977,333	\$ 11,640,040	\$ 8,375,394	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 633,306	\$ 43,653,027
Choice Bundled Sale Credit	\$ (3,871,434)	\$ (5,009,966)	\$ (4,300,088)	\$ (3,240,801)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (217,891)	\$ (16,640,179)
Net Financial Derivatives	\$ 926,596	\$ 1,029,784	\$ 773,504	\$ 638,779	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3,368,663
Total Cost	\$ 33,225,785	\$ 52,063,434	\$ 34,625,792	\$ 24,755,271	\$ 10,548,877	\$ 4,806,064	\$ 2,617,711	\$ 2,018,082	\$ 2,221,459	\$ 1,904,828	\$ 6,578,112	\$ 19,186,167	\$ 194,551,583

UGI Utilities, Inc. - Gas Division
Computation of the Experienced Cost Factor: E
For the 2026 PGC Year

Effective December 1, 2026
Computation Year Ending November 30, 2027

SUPPLIER REFUND CREDITS

PGC

Prior	(Amortized Balance as of November 30, 2026)	Schedule C, Page 2	\$	227,105
Current	(Twelve Months Ended November 30, 2026)	Schedule C, Page 3	\$	11,488,793
Interest	(Twelve Months Ended November 30, 2026)	Schedule C, Page 3	\$	953,555

OVER / (UNDER) COLLECTION

Prior	(Amortized Balance as of November 30, 2026)	Schedule C, Page 4	\$	(6,454,348)
Current	(Twelve Months Ended November 30, 2026)	Schedule C, Page 6	\$	(87,149,922)
Interest	(Twelve Months Ended November 30, 2026)	Schedule C, Page 6	\$	<u>(7,003,353)</u>

TOTAL E **\$ (87,938,170)**

TOTAL S (Mcf) **60,079,068**

E/S Refund/(Collection) \$/Mcf **\$ (1.4637)**

UGI Utilities, Inc. - Gas Division
Prior Period Supplier Refund Balance (including interest)
To Be Included In the 2026 PGC Experienced Cost Factor

Month	Beginning Balance	Recovered / (Refunded)	Ending Balance
Balance as of November 30, 2025	\$ 79,696	\$ (326,900)	\$ (247,204)
2025 Compliance Filing Balance 1/		\$ 10,477,713	\$ 10,230,509
December-25	\$ 10,230,509	\$ (1,161,900)	\$ 9,068,609
January-26	\$ 9,068,609	\$ (1,972,147)	\$ 7,096,462
February-26	\$ 7,096,462	\$ (2,196,535)	\$ 4,899,927
March-26	\$ 4,899,927	\$ (1,620,024)	\$ 3,279,903
April-26	est. \$ 3,279,903	\$ (896,531)	\$ 2,383,372
May-26	est. \$ 2,383,372	\$ (444,874)	\$ 1,938,498
June-26	est. \$ 1,938,498	\$ (242,256)	\$ 1,696,242
July-26	est. \$ 1,696,242	\$ (163,452)	\$ 1,532,790
August-26	est. \$ 1,532,790	\$ (165,637)	\$ 1,367,152
September-26	est. \$ 1,367,152	\$ (167,191)	\$ 1,199,961
October-26	est. \$ 1,199,961	\$ (304,698)	\$ 895,263
November-26	est. \$ 895,263	\$ (668,158)	\$ 227,105

1/ See current supplier refund balance plus interest on Schedule C, Page 1 of the Compliance filing at Docket No. R-2025-3054938, filed November 26, 2025.

UGI Utilities, Inc. - Gas Division
List of Current Supplier Refunds
To Be Included In the 2026 PGC Experienced Cost Factor

<u>Supplier</u>	<u>Principal Amount</u>	<u>Date Rec'd</u>	<u>Rate %</u>	<u>Interest Weight</u>	<u>Interest Amount</u>
Texas Eastern	\$ 11,081	Nov-25	6%	19	\$ 1,053
Transco	\$ 3,999	Nov-25	6%	19	\$ 380
Tennessee	\$ 63,650	Nov-25	6%	19	\$ 6,047
Texas Eastern	\$ 37,144	Dec-25	6%	18	\$ 3,343
Texas Eastern	\$ 36	Dec-25	6%	18	\$ 3
Transco	\$ 46,992	Dec-25	6%	18	\$ 4,229
Columbia	\$ 4,909,537	Dec-25	6%	18	\$ 441,858
Texas Eastern	\$ 11,371	Jan-26	6%	17	\$ 967
Unauthorized Overrun	\$ 9,316	Jan-26	6%	17	\$ 792
Unauthorized Overrun	\$ 252	Jan-26	6%	17	\$ 21
Unauthorized Overrun	\$ 52,946	Jan-26	6%	17	\$ 4,500
Tennessee	\$ 15,797	Feb-26	6%	16	\$ 1,264
Texas Eastern	\$ 88,758	Feb-26	6%	16	\$ 7,101
Transco	\$ 57,129	Feb-26	6%	16	\$ 4,570
Unauthorized Overrun	\$ 1,428,025	Feb-26	6%	16	\$ 114,242
Unauthorized Overrun	\$ 162,998	Feb-26	6%	16	\$ 13,040
Unauthorized Overrun	\$ 1,182,559	Feb-26	6%	16	\$ 94,605
Texas Eastern	\$ 15,971	Mar-26	6%	15	\$ 1,198
Unauthorized Overrun	\$ 2,036,658	Mar-26	6%	15	\$ 152,749
Unauthorized Overrun	\$ 51,460	Mar-26	6%	15	\$ 3,860
Unauthorized Overrun	\$ 1,303,112	Mar-26	6%	15	\$ 97,733
<u>Total</u>	<u>\$ 11,488,793</u>				<u>\$ 953,555</u>

UGI Utilities, Inc. - Gas Division
Prior Over / (Under) Collection Balance (including interest)
To Be Included In the 2026 PGC Experienced Cost Factor

Month	Beginning Balance	Recovered / (Refunded)	Ending Balance
Balance as of November 30, 2025	\$ (11,135,455)	\$ 1,512,764	\$ (9,622,690)
2025 Compliance Filing Balance 1/		\$ (33,632,224)	\$ (43,254,914)
True-Up of November 2025 Estimate 2/		\$ (8,707,483)	\$ (51,962,398)
December-25	\$ (51,962,398)	\$ 5,092,250	\$ (46,870,148)
January-26	\$ (46,870,148)	\$ 8,334,523	\$ (38,535,625)
February-26	\$ (38,535,625)	\$ 9,280,348	\$ (29,255,278)
March-26	\$ (29,255,278)	\$ 7,395,831	\$ (21,859,446)
April-26	est. \$ (21,859,446)	\$ 4,524,095	\$ (17,335,351)
May-26	est. \$ (17,335,351)	\$ 2,244,934	\$ (15,090,417)
June-26	est. \$ (15,090,417)	\$ 1,222,478	\$ (13,867,939)
July-26	est. \$ (13,867,939)	\$ 824,815	\$ (13,043,124)
August-26	est. \$ (13,043,124)	\$ 835,842	\$ (12,207,282)
September-26	est. \$ (12,207,282)	\$ 843,684	\$ (11,363,598)
October-26	est. \$ (11,363,598)	\$ 1,537,574	\$ (9,826,024)
November-26	est. \$ (9,826,024)	\$ 3,371,675	\$ (6,454,348)

1/ See current over/(under) collection balance plus interest on Schedule C, Page 1 of the 2025 Compliance filing at Docket No. R-2025-3054938, filed November 26, 2025.

2/ Incremental balance plus associated interest at 7.50%.

UGI Utilities, Inc. - Gas Division
Development of the Current Over/(Under) Collection
For the Period Ending November 30, 2026

	<u>Sales - Mcf</u>	<u>Base Rate</u>	<u>Revenue</u>	<u>Cost</u>	<u>(Under)/Over Collection</u>	<u>Interest Rate 1/</u>	<u>Interest Weight</u>	<u>Interest</u>
April-25	5,453,568	6.2931	\$ 34,320,061	\$ 24,480,466	\$ 9,839,595	7.50%	14	\$ 860,965
May-25	2,784,674	6.2849	\$ 17,501,312	\$ 15,769,807	\$ 1,731,505	7.50%	13	\$ 140,685
June-25	1,721,722	6.2934	\$ 10,835,537	\$ 13,672,119	\$ (2,836,581)	7.50%	12	\$ (212,744)
July-25	1,064,688	6.2942	\$ 6,701,349	\$ 8,923,639	\$ (2,222,290)	7.50%	11	\$ (152,782)
August-25	930,299	6.2934	\$ 5,854,726	\$ 14,162,004	\$ (8,307,278)	7.50%	10	\$ (519,205)
September-25	1,077,228	6.2937	\$ 6,779,710	\$ 11,750,020	\$ (4,970,310)	7.50%	9	\$ (279,580)
October-25	1,589,918	6.2935	\$ 10,006,133	\$ 16,897,309	\$ (6,891,177)	7.50%	8	\$ (344,559)
November-25	3,791,769	6.2933	\$ 23,862,735	\$ 47,150,262	\$ (23,287,527)	7.50%	7	\$ (1,018,829)
<u>PGC Total</u>	<u>18,413,865</u>		<u>\$ 115,861,563</u>	<u>\$ 152,805,626</u>	<u>\$ (36,944,063)</u>			<u>\$ (1,526,050)</u>

1/ The interest rate is the prime rate in effect April 2, 2025 per the Wall Street Journal.

UGI Utilities, Inc. - Gas Division
Development of the Current Over/(Under) Collection
For the Period Ending November 30, 2026

	<u>Sales - Mcf</u>	<u>Base Rate</u>	<u>Revenue</u>	<u>Cost</u>	<u>(Under)/Over Collection</u>	<u>Interest Rate 1/</u>	<u>Interest Weight</u>	<u>Interest</u>
December-25	9,681,702	6.2653	\$ 60,658,723	\$ 73,278,812	\$ (12,620,090)	6.75%	18	\$ (1,277,784)
January-26	12,351,185	6.2326	\$ 76,980,525	\$ 150,574,896	\$ (73,594,371)	6.75%	17	\$ (7,037,462)
February-26	13,721,035	6.2323	\$ 85,513,694	\$ 79,285,578	\$ 6,228,116	6.75%	16	\$ 560,530
March-26	10,118,184	6.4581	\$ 65,344,743	\$ 49,825,061	\$ 15,519,682	6.75%	15	\$ 1,309,473
April-26	est. 5,599,820	6.7757	\$ 37,942,701	\$ 21,119,329	\$ 16,823,372	6.75%	14	\$ 1,324,841
May-26	est. 2,778,728	6.7757	\$ 18,827,828	\$ 16,304,123	\$ 2,523,705	6.75%	13	\$ 184,546
June-26	est. 1,513,155	6.7757	\$ 10,252,687	\$ 13,941,531	\$ (3,688,843)	6.75%	12	\$ (248,997)
July-26	est. 1,020,937	6.7757	\$ 6,917,560	\$ 12,711,826	\$ (5,794,267)	6.75%	11	\$ (358,520)
August-26	est. 1,034,586	6.7757	\$ 7,010,045	\$ 11,708,394	\$ (4,698,349)	6.75%	10	\$ (264,282)
September-26	est. 1,044,293	6.7757	\$ 7,075,813	\$ 13,100,855	\$ (6,025,043)	6.75%	9	\$ (305,018)
October-26	est. 1,903,174	6.7757	\$ 12,895,338	\$ 18,471,626	\$ (5,576,288)	6.75%	8	\$ (250,933)
November-26	est. 4,173,382	6.7757	\$ 28,277,585	\$ 44,525,131	\$ (16,247,545)	6.75%	7	\$ (639,747)
<u>PGC Total</u>	<u>64,940,181</u>		<u>\$ 417,697,242</u>	<u>\$ 504,847,164</u>	<u>\$ (87,149,922)</u>			<u>\$ (7,003,353)</u>

1/ The interest rate is the prime rate in effect April 2, 2026 per the Wall Street Journal.

UGI UTILITIES, INC. - GAS DIVISION

GAS TARIFF

INCLUDING THE GAS SERVICE TARIFF NO. 7

AND

THE CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules
Governing the
Furnishing of
Gas Service and Choice Aggregation Service
in the
Territory Described Herein

Issued: June 1, 2026

Effective for service rendered on
and after December 1, 2026.

Issued By:

Jessica R. Rogers
Vice President - Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

<https://www.ugi.com/tariffs>

NOTICE

This tariff makes increases and decreases to existing rates (see Page 2).

LIST OF CHANGES MADE BY THIS SUPPLEMENT
(Page Numbers Refer to Official Tariff)

Rider B - Purchased Gas Costs, Page 51

- The revenue sharing mechanism has been made permanent.

Rider B - Purchased Gas Costs, Page 52

- The Annual C-Factor has decreased.
- The Annual E-Factor has increased.
- The Total Purchased Gas Cost rate has increased.

Section 15, Price to Compare, Page 57

- The Annual C-Factor has decreased.
- The Annual E-Factor has increased.
- The Merchant Function Charge has increased.
- The Price to Compare Charge has increased.

Cover Page, UGI Utilities, Inc. - Gas Division - Gas Choice Supplier Tariff

- Issuance and effective dates updated.

Section 7.3, - Nomination Procedure, Page 118

- Peak Day allocation percentages updated.

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

Revenue Sharing Incentive Mechanism: The PGC rate determined in this section may be adjusted to reflect the operation of a Revenue Sharing Incentive Mechanism as defined hereafter.

Off-system Sales: If and when the Company makes an off-system sale of natural gas, either in the Company's market area or upstream of the Company's market area with or without the use of PGC assets, the net revenues from the sale shall be shared by both the Company and the Company's retail customers served pursuant to this section of the tariff. The net revenues of the sale shall mean the total revenues from the sale of gas to a third party, less (1) the sum of the cost of natural gas, transportation commodity charges, and fuel retainage, if the sale or exchange is made upstream of the Company's market area or (2) the average city gate commodity cost of all gas purchased and flowing on the first of the month, including the natural gas, transportation commodity, and fuel, if such sale is made at the Company's city gate or in the Company's market area. The sharing of such net revenues shall be allocated in accordance with the Revenue Sharing Allocation procedure in this section.

Exchanges of Natural Gas: If and when the Company and a third party agree to make a location exchange of natural gas in which both parties receive like quantities of gas, with no adverse economic effect on the Company's Customers, any revenues received by the Company for performing this service shall be shared by the Company and the Company's retail Customers served pursuant to this section of the Tariff. Any revenues received from the exchange of natural gas, either upstream of the Company's city gate, or at the Company's city gate, shall be allocated in accordance with the Revenue Sharing Allocation procedure in this Section.

Capacity Release on Interstate Pipelines: Capacity release revenue generated by administrative releases to third parties that fill the Company's storage shall be credited 100% to PGC customers. Other revenue received by the company for off system Capacity Release of interstate pipeline capacity will be credited in accordance with the Revenue Sharing Allocation procedure in this Section.

Storage Asset Management: If and when the Company has a third party manage gas supply assets paid for by the PGC, any revenues received from the third party ("Asset Management Fees") shall be allocated in accordance with the Revenue Sharing Allocation procedure in this Section.

Revenue Sharing Allocation: Effective December 1, 2012, the sum of the revenues derived from all Off-System Sales, Exchanges of Natural Gas, Capacity Release on interstate pipelines and Storage Asset Management, will be allocated 75% to the retail customers served and 25% to the Company.

(C)

(C) Indicates Change

RULES AND REGULATIONS

11. RIDER B - Continued

SECTION 1307(F) PURCHASED GAS COSTS

The amount retained by the Company will be an incentive to pursue additional sales and will be treated below the line for ratemaking purposes. For purposes of calculating this margin, the cost of gas will be equal to the monthly average commodity cost of gas plus variable transportation costs to deliver the gas to the off-system customer. The monthly average commodity cost of gas shall be defined as the monthly average commodity cost of gas purchases for all supplies scheduled at the beginning of the month; provided, however, that if an additional unscheduled purchase is made during the month specifically for an off-system sale, such purchase shall be considered to be the gas used to make the off-system sale and the commodity cost of such purchase will be assigned to off-system sales up to the volume of the purchase.

Filing with the PUC: Audit, Rectification

The Company's annual reconciliation statement shall be submitted to the Commission by May 1 of each year, or such other time as the PUC may prescribe.

Quarterly Adjustments

When making the December 1, March 1, June 1 and September 1 quarterly C-factor adjustments, the Company will refund or recover all actual and projected incremental over or under collections from December 1 through November 30 over either remaining PGC year sales volumes or annual PGC year sales volumes, however the March 1 adjustment for projected over or under collections shall only utilize the remaining PGC year sales volumes. Any quarterly PGC rate change on December 1, March 1 and June 1 will be capped at 25% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. Any quarterly PGC rate change on September 1 will be capped at 15% of the then-current PGC rate, with any amounts above this cap being brought forward for inclusion in the calculation of subsequent quarterly C-factor adjustments. The Company is authorized, at its sole discretion, to waive the quarterly cap on rate decreases only.

Rider B - Purchased Gas Cost (Mcf)

Annual C-Factor	\$ 6.3090	(D)
Annual E-Factor	\$ 1.4637	(I)
Total Purchased Gas Cost	<u>\$ 7.7727</u>	(I)

(D) Indicates Decrease
 (I) Indicates Increase

RULES AND REGULATIONS

15. PRICE TO COMPARE

The Price to Compare ("PTC") is composed of the Annual C-Factor, Annual E-Factor, Gas Procurement Charge and Merchant Function Charge. The PTC rate will change whenever any components of the PTC change. The current PTC rate is detailed below:

Price to Compare

	Rate R (CCF)	Rate N (MCF)	
Annual C-Factor	\$ 0.63090	\$ 6.3090	(D)
Annual E-Factor	\$ 0.14637	\$ 1.4637	(I)
Gas Procurement Charge	\$ 0.00660	\$ 0.0660	
Merchant Function Charge	\$ 0.01990	\$ 0.0435	(I)
Total Price to Compare	<u>\$ 0.80377</u>	<u>\$ 7.8822</u>	(I)

(D) Indicated Decrease
 (I) Indicates Increase

UGI UTILITIES, INC. - GAS DIVISION

GAS CHOICE SUPPLIER TARIFF NO. 7S

Rates and Rules
Governing the
Furnishing of
Gas Aggregation Service

Issued: June 1, 2026

Effective for service rendered on and
after December 1, 2026.

Issued By:

Jessica R. Rogers
Vice President - Rates & Regulatory Affairs
1 UGI Drive
Denver, PA 17517

<https://www.ugi.com/tariffs>

NOTICE

RULES AND REGULATIONS

7. NOMINATION PROCEDURE

- 7.1 Customer Choice Nomination Procedure. The Nomination Procedure specifies requirements for nominating, scheduling, balancing, and communicating information relating to Choice Supplier's gas deliveries for customers served under Rates RT and NT.
- 7.2 Contact Persons. A list of Company contact persons will be posted on the Company's Web Site, located at https://ugi.outsystemsenterprise.com/UGIContacts_FO/, or its successor, along with their department affiliation, email address, and telephone number.
- 7.3 Mandatory Assignment. As used in this tariff the term "Firm Commodity Supply Alternative" shall mean a Company purchase of natural gas, delivered directly to its distribution system or at points along Company pipeline capacity routes (Commodity Delivery Points), constituting a component of Company's PGC supply portfolio and an alternative to pipeline capacity contracts upstream of the Commodity Delivery Points or other firm sources of PGC supply. Firm Commodity Supply Alternative contractual arrangements may require the payment of demand charges or minimum take requirements. Except as provided below, Choice Supplier shall be required to accept releases of Company pipeline capacity combined with bundled city gate sales and, as applicable, peaking sales of gas from Company and sales of gas associated with Firm Commodity Supply Alternative arrangements, in accordance with the following assignments:

A monthly release of interstate pipeline capacity or allocation of Firm Commodity Supply Alternative in an amount equal to thirty-eight percent (38%) of the Peak Day Delivery Requirement ("PDDR") of the Choice Customers served by the Choice Supplier during the month shall be released or allocated at a price equal to the projected weighted average demand cost of all PGC capacity, storage, peaking and Firm Commodity Supply Alternative assets, divided by 0.250. Effective November 1, (C) 2020, to the extent the full Firm Commodity Supply Alternative is not fully nominated by Choice Supplier to satisfy its DDR, the remaining daily quantity may be nominated to a non-Choice transportation customer or pool of non-Choice transportation customers.

The Company shall also provide Choice Suppliers with a must-take Monthly Bundled Sale Quantity ("MBSQ") during each winter month of November through March, and the Choice Supplier would be permitted to nominate and purchase gas at the Company's city gates throughout each winter month, subject to the Maximum Daily Quantity ("MDQ") limits, up to the MBSQ. The MDQ equals twenty-four percent (24%) of the PDDR of the Choice Customers served by the Choice Supplier during the month multiplied by the percentage shown on the Company's Energy Management website. The minimum daily quantity is zero. Choice Suppliers are required to nominate to the Company a daily quantity for bundled sales no later than 2:00 P.M. Eastern Prevailing Time on each Intercontinental Exchange ("ICE") trading day for deliveries applicable to the ICE flow dates. If no nomination is received, the nomination quantity would default to zero. The Company reserves the right to issue Operational Flow Orders ("OFO") that can modify the daily bundled sale MDQ or require certain levels of deliveries from the released firm transportation contracts. These OFOs would be issued for operational reasons only. MBSQs would be based on the Company's storage withdrawal plan, to be updated annually, and communicated as a percentage of each Choice Supplier's pre-month normalized

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC
UTILITY COMMISSION

v.

UGI UTILITIES, INC. – GAS DIVISION

:
:
:
:
:
:

Docket No. R-2026-3062192

DIRECT TESTIMONY

OF

ZACHARY J. SHIRK

UGI GAS STATEMENT NO. 1

Date: June 1, 2026

1 **I. INTRODUCTION**

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

3 A. My name is Zachary J. Shirk. My business address is UGI Utilities, Inc., 1 UGI Drive,
4 Denver, PA 17517.

5

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

7 A. I am employed by UGI Utilities, Inc. (“UGI”) as a Principal Analyst – Rates. UGI is a wholly-
8 owned subsidiary of UGI Corporation (“UGI Corp.”). UGI has two operating divisions, the
9 Electric Division (“UGI Electric”) and the Gas Division (“UGI Gas” or the “Company”), each
10 of which is a public utility regulated by the Pennsylvania Public Utility Commission
11 (“Commission” or “PUC”).

12

13 **Q. Can you please describe your educational background and professional experience?**

14 A. Please see my resume, which is attached as UGI Gas Exhibit ZJS-1.

15

16 **Q. What are your responsibilities in your current role with UGI?**

17 A. I am responsible for various tariff filings and related computations for UGI Gas and UGI
18 Electric rate and regulatory filings before federal and state regulatory agencies. Before the
19 Commission, these matters include Annual 1307(f) Purchased Gas Cost (“PGC”) filings,
20 Generation Supply Rate filings, Energy Efficiency and Conservation Rider filings, Universal
21 Service Program Rider filings, State Tax Adjustment Surcharge filings, Distribution System
22 Improvement Charge filings, and Weather Normalization Adjustment filings. In addition, I
23 have assisted in the development of certain supporting schedules in base rate case proceedings
24 listed on UGI Gas Exhibit ZJS-1. Finally, I am currently responsible for the development and

1 preparation of the Purchased Gas Adjustment (“PGA”) and Actual Cost Adjustment surcharge
2 filings for UGI Gas’s Maryland division.

3
4 **II. PURPOSE OF TESTIMONY**

5 **Q. What is the purpose of your testimony?**

6 A. My testimony will address certain components of UGI Gas’s 2026 1307(f) filing and will
7 explain and support the development and computation of UGI Gas’s PGC rates proposed to
8 be effective on December 1, 2026. In addition, I will discuss UGI Gas’s Revenue Sharing
9 Incentive Mechanism (“RSIM”), and retainage rate (as defined herein).

10
11 **Q. Which portions of the Company’s 2026 1307(f) filing are you sponsoring?**

12 A. As shown in the Table of Contents and Witness Index list for UGI Gas Book 2 (filed on June
13 1, 2026), I am sponsoring the following:

- 14 • Schedule A (summary of PGC computation for the 12 months ending November
15 30, 2027);
- 16 • Schedule B – Page 1 (projected sales and costs (*i.e.*, computation of C-factor) for
17 the 12 months ending November 30, 2027);
- 18 • Schedule C (computation of E-factor for the 12 months ending November 30,
19 2027); and
- 20 • The *pro forma* Supplements to Gas Tariff – Pa. P.U.C. No. 7 and 7S, which have
21 been submitted in accordance with Section 53.64(a) of the Commission’s
22 regulations at 52 Pa. Code § 53.64(a).

23 Additionally, I am sponsoring the following sections of the preliminary supporting
24 information (“Book 1”) filed on May 1, 2026, in this proceeding in accordance with 52 Pa.

1 Code § 53.64(c): Sections 8, 10, 12, and related attachments, in addition to page 1 of
2 Attachment 4-1 in Section 4.
3

4 **III. PGC RATE PROPOSAL SUMMARY**

5 **Q. What background is informative when reviewing UGI Gas's 2026 PGC rate proposal?**

6 A. Through the 2025-2026 winter period, specifically November through January, UGI Gas
7 experienced unusually high commodity prices that resulted in a much larger than expected
8 under-collection.¹ The resulting calculation for the quarterly PGC rate update on March 1,
9 2026 showed that UGI Gas would exceed the 25% PGC rate change cap agreed to in the 2023
10 PGC Settlement at Docket No. R-2023-3040290. In light of a very cold winter and associated
11 affordability concerns for customers, UGI Gas filed an emergency petition to temporarily
12 lower the 25% PGC rate cap to 10%. The petition was approved by the Commission in an
13 order entered on February 19, 2026 in Docket No. P-2026-3060521. This emergency action
14 directly affects the under-collection balance reflected in the E-factor of the 2026 PGC rate
15 calculation described below.
16

17 **Q. Please describe the Company's PGC rate proposal in this proceeding.**

18 A. UGI Gas is proposing a PGC rate of \$7.7727 per Mcf, effective December 1, 2026.
19

20 **Q. How does this proposed PGC rate compare to the current PGC rate?**

21 A. The current PGC rate of \$7.4235 per Mcf became effective March 1, 2026, and is unchanged
22 for June 1, 2026. The calculated PGC rate of \$7.7727 per Mcf for December 1, 2026, is an
23 increase of \$0.3492 per Mcf, or 4.7%, from the current PGC rate. The December 1, 2026

¹ See Attachment 12-1 from the 2026 UGI Gas Book 1 filing for actual costs vs. revenue.

1 increase in the PGC rate is largely attributable to the under-collection experienced from the
2 2025-2026 winter, as described above.

3
4 **IV. DEVELOPMENT OF THE PGC RATES**

5 **Q. Please summarize the major components that comprise the PGC rate formula.**

6 A. The basic PGC rate formula is $(C-E)/S$, where the “C-factor,” or the Projected Cost of Gas
7 component, represents the projected cost of gas for the rate computation period beginning
8 December 1, 2026, through November 30, 2027; the “E-factor,” or the Experienced Cost
9 Factor, represents the experienced over/(under) collections due to variations between
10 projected gas costs and actual gas costs as well as the variances between projected gas sales
11 and actual gas sales; and the “S,” or the Projected Sales component, represents the projected
12 Mcf of gas to be billed to customers during the effective computation period. UGI Gas’s PGC
13 rate consists of the Projected Cost of Gas per Mcf (C/S) and the Experienced Cost per Mcf ($-$
14 E/S) (*e.g.*, the Gas Cost Adjustment Charge).

15
16 **Q. Please summarize the PGC rate computation supporting the schedules you prepared in
17 this filing.**

18 A. Schedules A, B, and C provide the detailed computation of the proposed December 1, 2026
19 PGC rates. In particular:

- 20
- Schedule A is the PGC computation schedule showing, at a summary level, the
21 computation of the PGC rate for Rate Schedules R – Residential Service, N – Non-
22 Residential Service and GL – Gas Lighting Service.

- 1 • Schedule B, Page 1, provides the development of the Projected Cost of Gas, or C-
2 factor, and Projected Sales for the computation period of December 1, 2026, through
3 November 30, 2027.
- 4 • Schedule B, Pages 2 through 13, provides the forecasted PGC supply portfolio by
5 month.
- 6 • Schedule C, Page 1, provides the computation of the Experienced Cost Factor, or E-
7 factor, which consists of the current and prior Supplier Refunds and current and prior
8 period over/(under) collections, including interest.
- 9 • Schedule C, Page 2, provides the remaining ending balance of the “prior” Supplier
10 Refunds previously reflected in last year’s 1307(f) proceeding. The ending balance is
11 included in the E-factor computation shown on Schedule C, Page 1.
- 12 • Schedule C, Page 3, provides a list of “current” Supplier Refunds, representing
13 Supplier Refunds that were received by the Company from November 2025 – March
14 2026. Additionally, any refunds not recorded in prior PGC filings are included. Both
15 the current Supplier Refunds and interest amounts are included in the E-factor
16 computation shown on Schedule C, Page 1.
- 17 • Schedule C, Page 4, provides the development of the prior under/over collection
18 balance, which is included in the E-factor computation shown on Schedule C, Page 1.
- 19 • Schedule C, Page 5, provides the monthly and total under/over collections and interest
20 computation for the Historic Period of April 1, 2025, through November 30, 2025.
- 21 • Schedule C, Page 6, provides the projected under/over collections and interest
22 computation on a month-by-month basis for the current PGC computation period of
23 December 1, 2025, through November 30, 2026. The under/over collections and

1 interest shown for this period are included in the E-factor computation shown on
2 Schedule C, Page 1.

3
4 **Q. Please summarize the computation of the calculated PGC rate for the 12 months**
5 **beginning December 1, 2026.**

6 A. As shown on Schedule A, the calculated PGC rate of \$7.7727 per Mcf is equal to the Projected
7 Cost of Gas per Mcf (C/S), \$6.3090, plus the Experienced Cost of Gas per Mcf (-E/S),
8 \$1.4637. The Projected Cost of Gas, or “C-factor,” of approximately \$379.0 million is divided
9 by Projected Sales (S) of approximately 60.1 Bcf, resulting in the Projected Cost per Mcf
10 (C/S) of \$6.3090. The Experienced Cost Factor, or “E-factor,” of (\$87.9) million under
11 collection is divided by Projected Sales, resulting in the Experienced Cost per Mcf (-E/S)
12 value of \$1.4637.

13
14 **Q. Please explain the development of the total C-Factor.**

15 A. The Projected Cost of Gas is shown on a month-by-month basis and in total for the 12-month
16 period December 1, 2026, through November 30, 2027, on Schedule B, Page 1. Projected
17 Capacity Release Credits, Off-System Sales Credits, Exchange Credits, Asset Management
18 Fee Credits, and Administrative Costs are all included in the C-factor computation. Schedule
19 B, Pages 2 through 13, detail these projected costs by month.

20
21 **Q. Please explain the development of the Projected Sales or “S” amount.**

22 A. On an annual basis, UGI Gas projects sales volumes for the upcoming PGC computation
23 periods. The PGC sales forecast ending November 30, 2027, was used to estimate the monthly
24 demand volumes provided in Attachments 1-B-1 and 1-B-2 of the Book 1 supporting

1 information filed on May 1, 2026, in this docket. In general, the process to forecast PGC sales
2 considers various factors, including trending and regression analysis, customer growth,
3 normal weather conditions, and levels of Customer Choice volumes. Schedule B, Page 1,
4 shows the Projected Sales, or “S” amount, for the period beginning December 1, 2026, through
5 November 30, 2027. Those sales projections form the basis for UGI Gas’s forecasted PGC
6 supply portfolio by month, and the resulting supply mix as shown on Schedule B, Pages 2
7 through 13. UGI Gas used a similar methodology to project sales volumes for the interim
8 period of April 1, 2026, through November 30, 2026. Projected sales for this period are
9 detailed monthly on Schedule C, Page 6, and are utilized to determine the annual E-Factor.

10
11 **Q. How have Customer Choice volumes been reflected in the Projected Sales amount?**

12 A. Estimated Customer Choice volumes of 20.4 Bcf have been excluded from PGC retail sales
13 in developing the Projected Sales for the December 1, 2026 – November 30, 2027 period.
14 Thus, the Projected Sales amount of 60.1 Bcf is net of the excluded Customer Choice volumes.

15
16 **Q. Please explain the development of the E-factor.**

17 A. The E-factor computation consists of two basic components: Supplier Refunds and over/under
18 collections. Interest is included in both components.

19
20 **Q. Please explain the Supplier Refunds included in the E-factor computation.**

21 A. The Supplier Refunds and over/under collection amounts are further classified as “prior” or
22 “current.” “Prior” refers to the remaining balances of amounts for refund/recovery from the
23 prior year’s 1307(f) proceeding that have not been fully refunded to or recovered from PGC
24 customers due to variations in sales volumes. “Current” refers to the amounts for

1 refund/recovery that were not previously incorporated in the prior year's PGC rate
2 components and will be reflected for the first time in the current 1307(f) proceeding.
3

4 **Q. What is the Supplier Refund amount included in the E-factor computation?**

5 A. The prior Supplier Refund Balance of \$227,105 reflects the ending balance projected as of
6 November 30, 2026. This balance is detailed in Schedule C, Page 2, and is included in the E-
7 factor computation on Schedule C, Page 1. As shown on Schedule C, Page 1, the current
8 Supplier Refund total is \$11,488,793. As shown on Schedule C, Page 3, the interest on the
9 current Supplier Refunds will be returned at the rate of six percent (6%). The related total
10 interest amount of \$953,555 is included in the E-factor computation on Schedule C, Page 1.
11

12 **Q. Please explain the over/under collection amount included in the E-Factor.**

13 A. Schedule C, Page 1, provides the development of the prior and current over/under collection
14 amounts plus interest projected as of November 30, 2026. The current under collection of
15 (\$87,149,922) and the associated interest of (\$7,003,353) is detailed at Schedule C, Page 6.
16 The prior period under collection amount of (\$6,454,348) is shown on Schedule C, Page 1,
17 and detailed on Schedule C, Page 4. This amount is presently charged to the PGC customer
18 class through the operation of the E-Factor.
19

20 **Q. Please explain how the applicable interest rate is determined to compute the total
21 interest expense related to the over/under collection amount in the E-factor.**

22 A. UGI Gas's current tariff allows for the refunding of interest on over collections and recovery
23 of interest on under collections consistent with the provisions of 66 Pa. C.S. § 1307(f)(5).
24 Additionally, in UGI Gas's 2019 Joint Petition for Settlement of Section 1307(f) Rate

1 Investigation at Docket Nos. R-2019-3009647, et al. (“2019 PGC Settlement”), which was
2 approved by Commission Order entered on October 24, 2019, it was agreed that:

3 On a going forward basis, beginning with the filing of its
4 proposed tariff on or before June 1, 2020 in its next annual
5 PGC filing, UGI Gas will use the prime rate in effect 60 days
6 prior (April 2) to the annual PGC filing date (June 1). The
7 60-day prime rate will be applied to the over/undercollection
8 balances for the PGC period December 1 of the prior year
9 through November 30 of the PGC year.²

10 Consistent with this provision, for the PGC computation period, UGI Gas is recovering
11 interest at the prime rate for commercial borrowing as reported in The Wall Street Journal,
12 which is 6.75%, effective April 2, 2026. The total amount of monthly interest expense is then
13 calculated on Schedule C, Page 6, and carried into the E-factor computation on Schedule C,
14 Page 1. Additionally, as shown on Schedule C, Page 5, for the Historic Period, UGI Gas was
15 recovering interest at the prime rate for commercial borrowing as reported in the Wall Street
16 Journal, which was 7.50%, effective April 2, 2025.³

17
18
19 **Q. Please summarize the development of the total interest expense included in the E-factor**
20 **for UGI Gas.**

21 A. As shown on Schedule C, Page 5, the Company computed the monthly interest amounts in the
22 Historic Period utilizing an interest rate of 7.50%. As shown on Schedule C, Page 6, the
23 Company computed the monthly interest amounts in the current PGC computation period
24 utilizing an interest rate of 6.75%. The total amount of monthly interest expense calculated
25 over the current PGC computation period, December 2025 through November 2026, is shown

² See *Pa. PUC v. UGI Utilities, Inc. – Gas*, Docket No. R-2019-3009647, Joint Petition for Settlement of Section 1307(f) Rate Investigation, ¶19 (filed August 16, 2019) (approved by Order entered October 24, 2019).

³ The interest expense for the months April 2025 through November 2025 was already included in the November 26, 2025 compliance filing using the interest rate from the prior year’s 1307(f) filing at Docket No. R-2025-3054938.

1 on Schedule C, Page 6, in the amount of (\$7,003,353), which is included in the E-factor
2 computation shown on Schedule C, Page 1.

3
4 **Q. Please explain the development of the Total Sales used to calculate the Experienced Cost
5 of Gas per Mcf (-E/S).**

6 A. The projected sales used to calculate the Experienced Cost of Gas per Mcf were determined
7 using the Projected Sales as described above and shown on Schedule A, Page 1.

8
9 **V. REVENUE SHARING INCENTIVE MECHANISM**

10 **Q. Please describe the current RSIM for UGI Gas.**

11
12 A. Net margins derived from natural gas off-system sales, exchanges, and capacity releases
13 (excluding Choice and operational releases) are allocated 75% to the PGC customers and 25%
14 to the Company, with the 25% being treated below-the-line for ratemaking purposes.⁴ The
15 current RSIM went into effect on December 1, 2012, and is in effect through November 30,
16 2026, pursuant to the Commission Order entered in Docket No. R-2021-3025652 (Order
17 entered October 7, 2021).

18
19 **Q. Is UGI Gas making any proposals related to the current sharing mechanism in this PGC
20 Filing?**

21 A. Yes. The current RSIM is set to expire November 30, 2026. UGI Gas proposes to make the
22 current sharing mechanism a permanent part of the Company's tariff.

23

⁴ Choice and operational release revenues are credited 100% to the PGC customers.

1 **VI. RETAINAGE RATES**

2 **Q. Does the Company retain a percentage of gas delivered on behalf of transportation**
3 **service customers to reflect lost and unaccounted for (“LAUF”) and company use gas**
4 **(collectively, the “retainage rate”)?**

5 A. Yes, it does. In the Company’s 2009 PGC proceedings,⁵ the Commission approved the use
6 of a retainage rate, calculated as follows:

7 [C]alculate the retainage rate for applicable transportation rate schedules as of
8 December 1 each year by using a three-year rolling average of actual lost and
9 unaccounted for gas (“LAUF”) and company use gas through September 30th
10 of each year.

11

12 **Q. Has UGI Gas complied with the 2009 settlement language?**

13 A. Yes. Consistent with the settlement terms, UGI Gas updates its retainage rate each year based
14 on a three-year rolling average of LAUF and company use gas for the three prior years ending
15 September 30. Effective December 1, 2025, the retainage rate for all customers was calculated
16 based on the three-year period ending September 30, 2025. Currently, this rate is 1.5% and
17 will be in effect until December 1, 2026.

18

19 **Q. Was UGI Gas’s method of computing its retainage rate adjusted as part of a**
20 **Commission-approved settlement in its 2010 PGC proceedings?**

21 A. Yes. In the 2010 PGC settlements,⁶ the Company agreed to “exclude volumes associated with
22 service to its Rate XD transportation customers receiving retainage discounts in calculating

⁵ See *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2009-2105911 (Order entered December 23, 2009) (Former South Rate District); *Pa. PUC v. UGI Penn Natural Gas, Inc.*, Docket No. R-2009-2105904 (Order entered October 8, 2009) (Former North Rate District); and *Pa. PUC v. UGI Central Penn Gas, Inc.*, Docket No. R-2009-2105909 (Order entered October 15, 2009) (Former Central Rate District).

⁶ See *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2010-2172933 (Order entered November 23, 2010) and *Pa. PUC v. UGI Penn Natural Gas, Inc.*, Docket No. R-2010-2172928 (Order entered November 23, 2010).

1 its retainage rate in its compliance filing”⁷ and to “provide a schedule in its compliance filing
2 showing how it calculated its retainage rate using a three-year rolling average.”⁸ Consistent
3 with the terms of the 2010 PGC settlements, UGI Gas excluded volumes associated with
4 service to Rate XD customers receiving retainage discounts in calculating its retainage rate
5 and will provide a schedule showing its retainage rate computation with its compliance filing
6 in this proceeding.

7
8 **Q. Please describe the Commission’s regulations at 52 Pa. Code § 59.111 addressing LAUF
9 or Unaccounted for Gas (“UFG”) reporting requirements and standards.**

10 A. 52 Pa. Code § 59.111 became effective in August of 2013. This regulation adopts a uniform
11 definition of UFG, requires natural gas distribution companies (“NGDCs”) to file annual
12 reports on or before September 30 documenting UFG levels for the 12 months ending August
13 31, and establishes UFG standards, which NGDCs address in annual PGC proceedings. UGI
14 will file its next annual UFG report on or before September 30, 2026.⁹

15
16 **Q. Does this conclude your direct testimony?**

17 A. Yes, it does.

⁷ *Id.* at ¶35.

⁸ *Id.* at ¶34.

⁹ See Settlements in *Pa. PUC v. UGI Central Penn Gas, Inc.*, Docket No. R-2015-2480937 (Order entered October 22, 2015) (former Central Rate District); *Pa. PUC v. UGI Utilities, Inc. – Gas Division*, Docket No. R-2015-2480950 (Order entered October 22, 2015) (former South Rate District); and *Pa. PUC v. UGI Penn Natural Gas*, Docket No. R-2015-2480934 (Order entered October 22, 2015) (former North Rate District).

UGI GAS EXHIBIT ZJS-1

(Resume and Educational Background)

Zachary J. Shirk
Principal Analyst – Rates

Work Experience

UGI Utilities, Inc., Denver, PA

2025 – Present	Principal Analyst – Rates
2021 – 2025	Senior Supervisor – Energy Supply Scheduling
2018 – 2021	Analyst II – Energy Supply
2016 – 2018	Analyst I – Energy Supply

Education

BS, Chemical Engineering, University of Delaware, Newark, DE

Assisted in Preparing

2025 UGI Gas Base Rate Case	Docket No. R-2024-3052716
2022 UGI Gas Base Rate Case	Docket No. R-2021-3030218
2020 UGI Gas Base Rate Case	Docket No. R-2019-3015162

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC :
UTILITY COMMISSION :
 : Docket No. R-2026-3062192
v. :
 :
UGI UTILITIES, INC. – GAS DIVISION :

DIRECT TESTIMONY
OF
JAMIE L. JOWERS

UGI GAS STATEMENT NO. 2

Dated: June 1, 2026

Table of Contents

I.	Introduction.....	1
II.	Historic and Projected Gas Purchases.....	3
III.	UGI Gas’s Procurement Policy and Peak Day Demand	4
IV.	Winter Recap and Winter Storm Fern.....	10
V.	Portfolio Optimization Study	17
VI.	Choice Program Update.....	25
VII.	Recent Contract Renewals	26
VIII.	Supply RFPs	30
IX.	Participation in FERC Proceedings	35
X.	Renewable Natural Gas – Pilot Program Update.....	38
XI.	Hedging Policy Review	42

1 **I. Introduction**

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

3 A. My name is Jamie L. Jowers. My business address is UGI Utilities, Inc., 1 UGI Drive,
4 Denver, PA 17517.

5
6 **Q. By whom are you employed, and in what capacity?**

7 A. I am employed by UGI Utilities Inc. (“UGI”) as Sr. Manager – Energy Supply. UGI is a
8 wholly owned subsidiary of UGI Corporation (“UGI Corp.”). UGI has two operating
9 divisions, the Electric Division (“UGI Electric”) and the Gas Division (“UGI Gas” or the
10 “Company”), each of which is a public utility regulated by the Pennsylvania Public Utility
11 Commission (“Commission” or “PUC”).

12
13 **Q. Please briefly describe your responsibilities in your current capacity.**

14 A. As Sr. Manager – Energy Supply, I am responsible for natural gas and electric supply
15 planning, procurement, and scheduling for UGI Electric and UGI Gas. Additionally, I am
16 responsible for the development and administration of delivery requirements for licensed
17 natural gas suppliers (“NGSs”) who serve pools of Choice Customers on UGI Gas’s system
18 that elect to procure natural gas supply services from Choice NGSs.

19
20 **Q. What is your educational background?**

21 A. Please see my resume, which is attached as UGI Gas Exhibit JJJ-1.

22

1 **Q. Were portions of the information filed by UGI Gas in this proceeding prepared by**
2 **you or under your direct supervision and control?**

3 A. Yes. I supervised the preparation of portions of the Company’s Preliminary Information
4 filed on May 1, 2026 (hereinafter referred to as “Book 1”), including supporting
5 information shown in the Table of Contents and Witness Index. Additionally, in this June
6 1, 2026 Purchased Gas Cost (“PGC”) filing (hereinafter referred to as “Book 2”), I am
7 sponsoring Pages 2 through 13 of Schedule B (development of projected purchased gas
8 cost).

9
10 **Q. What is the purpose of your testimony?**

11 A. The purpose of my testimony is to supply the information specified in 66 Pa. C.S. § 1317(a)
12 in order to demonstrate that UGI Gas is pursuing a least cost fuel procurement policy,
13 consistent with its obligation to provide safe, adequate and reliable service to its customers
14 so that the Commission may determine that the Company’s rates are just and reasonable
15 pursuant to 66 Pa. C.S. § 1318.

16
17 **Q. What topics will you address in your direct testimony?**

18 A. My testimony addresses: (1) historic and projected gas purchases; (2) UGI Gas’s
19 procurement policy and peak day demand; (3) Winter Recap including a discussion of
20 Winter Storm Fern; (4) Portfolio Optimization Study; (5) Choice program update; (6)
21 recent contract renewals; (7) supply request for proposals (“RFPs”); (8) the Company’s
22 participation in proceedings before the Federal Energy Regulatory Commission (“FERC”);

1 (9) Renewable Natural Gas (“RNG”) pilot program update; and (10) UGI Gas’s hedging
2 pilot program update.

3
4 **Q. Are you sponsoring any exhibits?**

5 A. Yes. I am sponsoring the following Sections in Book 1, which correspond to the required
6 information specified in Section 1317:

- 7 • Sections 1-3.
- 8 • Page 2 of Attachment 4-1 in Section 4.
- 9 • Sections 5, 6, 7, 9, 11, 13 and 14.

10 Also, I am sponsoring the exhibits identified as UGI Gas Exhibits JLJ-1 through JLJ-9.

11 The Company notes that 3 of its exhibits – UGI Gas Exhibits JLJ-5, JLJ-8, and JLJ-9 –
12 are marked CONFIDENTIAL.

13
14 **II. Historic and Projected Gas Purchases**

15 **Q. Please generally describe the information contained in Book 1, which was filed on**
16 **May 1, 2026.**

17 A. Book 1 contains information related to the Company’s PGC that is required to be filed
18 pursuant to Section 1317(a) of the Pennsylvania Public Utility Code. The information is
19 necessary for the Commission to make specific findings that UGI Gas is pursuing a least
20 cost fuel procurement policy, consistent with its obligation to provide safe, adequate, and
21 reliable service to its customers. The fourteen sections in Book 1 provide data related to
22 the Company’s sources of gas supply, supply/demand projections, fuel procurement
23 practices, peak day methodology, reliability plans, and PGC costs.

1 **Q. Please describe the PGC rate periods relevant to this proceeding.**

2 A. This proceeding covers the Company's PGC costs for the historic period (April 1, 2025 –
3 March 31, 2026), the interim period (April 1, 2026 – November 30, 2026) and the PGC
4 projected period (December 1, 2026 – November 30, 2027).

5
6 **Q. Which portions of Book 1 contain the cost of gas purchases for the three previously
7 identified periods?**

8 A. Attachment 1-A-1 contains the historic cost of gas for the period April 1, 2025 through
9 March 31, 2026. Attachment 1-B-1 contains the cost of gas for the interim period April 1,
10 2026 through November 31, 2026. Attachment 1-B-2 contains the projected cost of gas
11 for the period December 1, 2026 through November 30, 2027.

12
13 **Q. What is the total cost applicable to the PGC for the historic period and the
14 projected period?**

15 A. The PGC costs for the historic period were \$505.6 million. For the projected period, the
16 projected PGC costs are \$379.0 million.

17

18 **III. UGI Gas's Procurement Policy and Peak Day Demand**

19 **Q. What is UGI Gas's projected firm peak day demand for the upcoming 2026-2027
20 winter season?**

21 A. For the upcoming 2026-2027 winter season, the projected firm peak day demand, inclusive
22 of reserve requirement, is 2.29 billion cubic feet (BCF), which includes 2.223 BCF of
23 design-cold firm requirements and 0.057 BCF of capacity reserve requirements. UGI Gas
24 also presents its total projected capacity requirement to meet firm peak day demand through

1 the 2030-2031 winter season (shown in Table 1 below) of 2.337 BCF. This five-year
2 planning horizon serves as the basis for seeking long-term contract options as described
3 further in this section of my testimony, inclusive of this intermediate-year's winter season
4 requirements. After filing Book 1, UGI Gas discovered an issue with the sendout data that
5 is used in the calculation of the projected peak day. The error, determined to be an incorrect
6 pressure look up in a meter sendout calculation, understated the sendout from October 2025
7 through March 2026 at a UGI district station in the North region of the distribution system.
8 As such, the regression analysis that is used to calculate the projected peak day
9 requirements was also understated. As a result, UGI Gas Exhibit JLJ-2 includes the
10 updated Attachment 14-1, detailing the updated Projected Peak Day and associated
11 Capacity Requirements.

12
13 **Q. What are UGI Gas's projected firm peak day demands and capacity requirements**
14 **over the next five years?**

15 A. The Company's five-year projected firm peak day demand and reserve requirements are
16 set forth in Table 1 below. The table includes the Company's currently contracted firm
17 capacity and the associated projected long-term length or shortfall positions, assuming
18 extension of all existing contracts during each period as described in greater detail below.

1

Table 1: Projected Peak Demand & Capacity (Dth) for 2026-2031

Winter	Projected Firm Peak Day Demand	Capacity Reserve Requirement (5%)¹	Capacity Requirements	Current Contracted Firm Capacity/ Supply	Projected Length/ (Shortfall)
2026-27	2,233,479	57,718	2,291,197	2,343,253	52,056
2027-28	2,244,439	58,266	2,302,705	2,343,253	40,548
2028-29	2,255,399	58,814	2,314,213	2,343,253	29,040
2029-30	2,266,359	59,362	2,325,721	2,343,253	17,532
2030-31	2,277,319	59,910	2,337,229	2,343,253	6,024

2

3 **Q. Briefly describe the general methodology UGI Gas uses to project firm peak day**
4 **demand.**

5 A. As part of its PGC, UGI Gas evaluates its contracts in order to ensure it can meet the
6 anticipated design-cold peak day demand of its Core Market customers and firm
7 transportation customers during the 2026-2027 winter and through the 2030-2031 winter.
8 This five-year planning horizon was adopted as part of the UGI Gas 2024 PGC at Docket
9 No. R-2024-3048828. Additionally, in undertaking the peak day evaluation, the Company
10 uses design-cold temperatures established as part of the Company’s prior PGC case
11 settlements at Docket Nos. R-00072335, R-00072334, and R-2009-2105909 for the former
12 South, North, and Central Rate Districts, respectively. These design-cold temperatures are
13 -3.6 degrees Fahrenheit for the former South Rate District and a portion of the former

¹ The Capacity Reserve Requirement is calculated as 5% of the combined PGC-1 and Choice customer demand requirements as described in UGI Gas Exhibit JLJ-2.

1 Central Rate District, -6 degrees Fahrenheit for the former North Rate District, and -14
2 degrees Fahrenheit for the remainder of the former Central Rate District

3 Since design-cold peak day temperatures are not experienced each year, and firm
4 customer demand is dynamic, peak day demand forecasts are based on a multi-linear
5 regression analysis of the Core Market's daily demand. The results of the analysis are used
6 to model the Company's demand at the established design-cold temperatures mentioned
7 above. The calculated standard error measure from the regression analyses is then applied
8 to the results to achieve a 95% confidence interval for each former Rate District (i.e., South,
9 Central, North). The standard error is a measure of the accuracy of the model's prediction.
10 The forecast is then adjusted for growth and the known and anticipated contractual peak
11 day firm requirements of the Company's large firm transportation customers.

12
13 **Q. Why does the Company use design-cold temperatures in its peak day analysis?**

14 A. The Company uses design-cold temperatures to ensure that UGI Gas can meet firm
15 customer demand in reasonably foreseeable but critically cold conditions. These
16 temperatures are representative of the range limit under which the Company's portfolio is
17 expected to continue reliable performance. Historical weather events, such as Winter Storm
18 Uri in 2021, which affected a significant portion of the country, and this year's Winter
19 Storm Fern, registered extreme low temperatures and long duration events with high
20 natural gas demand. These types of weather events can pose a significant risk to reliable
21 service based on the overall demand on the UGI Gas system. Therefore, it is important to
22 anticipate extreme-cold events that exceed the weather experienced in most winters.

23

1 **Q. How does UGI Gas include customer growth in its projected peak day demands for**
2 **Winter 2025-2026 through Winter 2030-2031.**

3 A. UGI Gas has experienced year-over-year growth in the number of Core Market customers
4 it serves and expects that growth to continue for the foreseeable future. In developing its
5 projected peak day demands, UGI Gas adds a projection to the results of its annual design
6 day analysis to account for expected customer additions based on their anticipated peak
7 day usage requirements. In its five-year peak day demand projection, the Company
8 assumes the growth rate will continue, based on the historic trend it has experienced. If
9 the Company did not include this expected Core Market customer growth, it would
10 underestimate peak day demand for projected years.

11
12 **Q. Do large firm transportation customers have an impact on the Company's firm peak**
13 **day demand forecast?**

14 A. All Rate DS customers, Rate LFD customers, and Rate XD customers are included in the
15 peak day demand forecast, up to firm contract demand levels. The Company's large firm
16 transportation customers combined Daily Firm Requirements ("DFRs") for the Rate LFD
17 and XD customers, and Maximum Daily Quantities ("MDQs") for the Rate DS customers,
18 represent the firm obligations of transportation customers for supply service from the
19 Company. The addition of large firm transportation customers to the Company's
20 distribution system are reviewed on a case-by-case basis for the availability of firm
21 capacity. As a result, the Company has not included any additional changes beyond the
22 current firm obligations to transportation customers for future periods as part of its firm
23 peak day demand forecast. New large firm transportation customer requests will be an
24 incremental variance to the planning approach reflected in this PGC proceeding.

1 **Q. Please explain the capacity planning function and how it applies to UGI Gas’s large**
2 **firm transportation customers.**

3 A. Capacity planning is the process of procuring supply and capacity assets to satisfy
4 forecasted peak day or contractual demand. For the large firm transportation customers,
5 their forecasted peak demand is either their DFR or MDQ. UGI Gas acts as the capacity
6 planner for the Rate DS customers, as those customers are assigned UGI Gas supply assets
7 to serve 100% of their MDQs. The Rate LFD customers exercise an annual election option
8 to choose UGI Gas or their respective Agent or NGS as their capacity planner. Finally, for
9 the Rate XD customers UGI Gas is the capacity planner for a fixed amount of capacity²,
10 but the remainder of the capacity needed to serve Rate XD is obtained by the customer
11 through their NGS or Agent as capacity planner.

12
13 **Q. How is the Company utilizing its five-year planning horizon as part of its**
14 **procurement practices?**

15 A. The Company uses the fifth year of the five-year peak day demand forecast to identify
16 whether a shortfall is likely to occur. If a shortfall is identified, the fifth year is used to
17 establish a capacity target and optimal step-up capacity targets for intermediate years
18 (“Five-Year Plan”). The analysis this year does not demonstrate a need for additional peak
19 day capacity, and therefore, UGI Gas did not take steps to acquire additional peak day
20 capacity or supplies. To address the capacity length for the prompt winter, UGI Gas will
21 release the excess capacity, and evaluate other mid-term opportunities that may create
22 additional value for UGI Gas PGC customers. The slightly lower peak day requirements

² See *Pa. PUC v. UGI Utilities, Inc.*, Docket No. R-009532297 (Order entered August 21, 1995).

1 compared to previous years are a potential anomaly based on recent winter behavior, and
2 the Company will continue to re-evaluate the data in future PGC proceedings.

3
4 **IV. Winter Recap and Winter Storm Fern**

5 **Q. How did the 2025-2026 winter heating season compare to the prior two winters in**
6 **terms of temperature, demand and natural gas prices?**

7 A. The 2025-2026 winter heating season was materially colder, with increased volatility and
8 overall demand, and this resulted in significantly higher commodity costs than either of the
9 two preceding winters — a stark contrast that is critical context for understanding the
10 supply costs reflected in UGI Gas's PGC filing.

11 The three-winter arc tells a clear story. Winter 2023-2024 was one of the mildest
12 on record. Cumulative heating degree days for that season were 11.9% below the 30-year
13 normal and 5% warmer than the prior winter, with every region of the country finishing
14 warmer than normal. This resulted in the largest natural gas storage surplus in nine years
15 by the end of March 2024. Henry Hub averaged \$2.21/MMBtu in 2024 — the lowest
16 average annual price in inflation-adjusted terms ever recorded.³

17 Winter 2024-2025 represented a meaningful reversal. The 2024-2025 heating
18 season was 9% colder than 2023-2024 as measured by average heating degree days. The
19 residential and commercial sectors consumed 15% more natural gas in January and
20 February 2025 compared to the same period in 2024.⁴ U.S. natural gas consumption set a
21 new winter monthly record of 126.6 Bcf/day in January 2025, and full-year 2025

³ U.S. Energy Information Administration, "*Spot Henry Hub natural gas prices hit a historic low in 2024*," January 8, 2025.

⁴ U.S. Energy Information Administration, "*U.S. natural gas inventories in underground storage ended winter at a three-year low*," Today in Energy, April 28, 2025

1 consumption averaged a record 92.0 Bcf/day — a 2% increase over 2024. Henry Hub
2 averaged \$3.52/MMBtu for full-year 2025, a 56% increase from 2024's record low annual
3 average.⁵
4

5 **Q. Please describe the natural gas market conditions this past winter.**

6 A. November 2025 marked the beginning of a sustained cold weather pattern that placed
7 upward pressure on natural gas prices nationally and in the Northeast. An early-season
8 Arctic blast moved south through the eastern United States in mid-November, bringing
9 historic cold as far south as Florida.

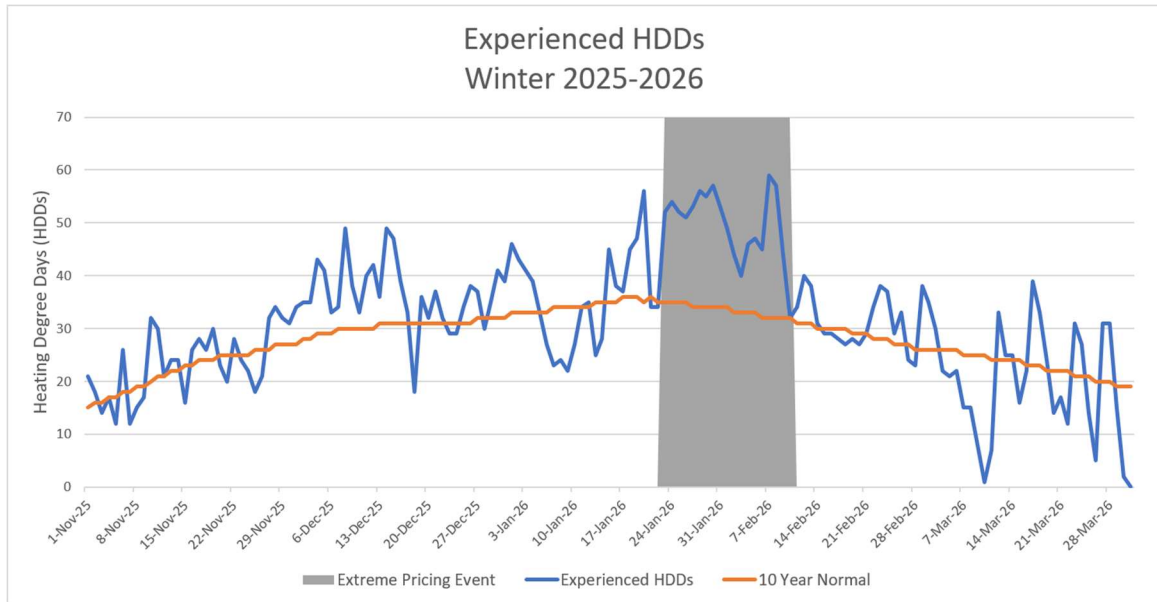
10 December 2025 brought a significant intensification of the cold weather pattern and
11 an accompanying acceleration in both demand and price. A multi-wave Arctic outbreak
12 sustained below-normal temperatures across the central and eastern United States, with
13 temperatures in the UGI Gas region more than 22.5% colder than normal for the month.
14 The United States saw the highest natural gas demand on record for the 14-day period
15 between November 27 and December 10, 2025, with industrial and power sector natural
16 gas requirements over the same period also the highest on record.

17 A cold start to the winter progressed to one of the most consequential two-month
18 periods in the recent history of the U.S. natural gas market in January and February 2026—
19 a month of historic natural gas system and market stress brought on by Winter Storm Fern
20 followed by a month of rapid, if uneven, normalization. The two months must be
21 understood together, as the severity of January's market disruption directly shaped the
22 pricing environment that persisted into February and that is reflected in UGI Gas's supply

⁵ U.S. Energy Information Administration, *"In 2025, U.S. natural gas spot prices increased from 2024's record low,"* Today in Energy, [2026]

1 costs for both months. UGI Gas experienced significantly colder than normal temperatures
2 during this period, as seen in the below graph. Overall, November through March was 9.3%
3 colder than normal across the UGI Gas distribution system.
4

5 **Figure 1: Experience Heating Degree Days, Winter 2025-2026**



6

7

8 **Q. Please describe Winter Storm Fern.**

9 A. Winter Storm Fern made landfall in late January 2026 and rapidly became a historic event
10 for the North American natural gas market. The storm brought widespread extreme cold
11 across at least 37 states, with wind chills as low as -50°F persisting across the eastern two-
12 thirds of the country and temperatures far below normal continuing into early February.
13 The duration and geographic scope of the cold weather distinguished Winter Storm Fern
14 from prior events: every day from January 24 through January 31, 2026 ranked within the
15 top 20 all-time peak natural gas demand days in the history of the U.S.
16

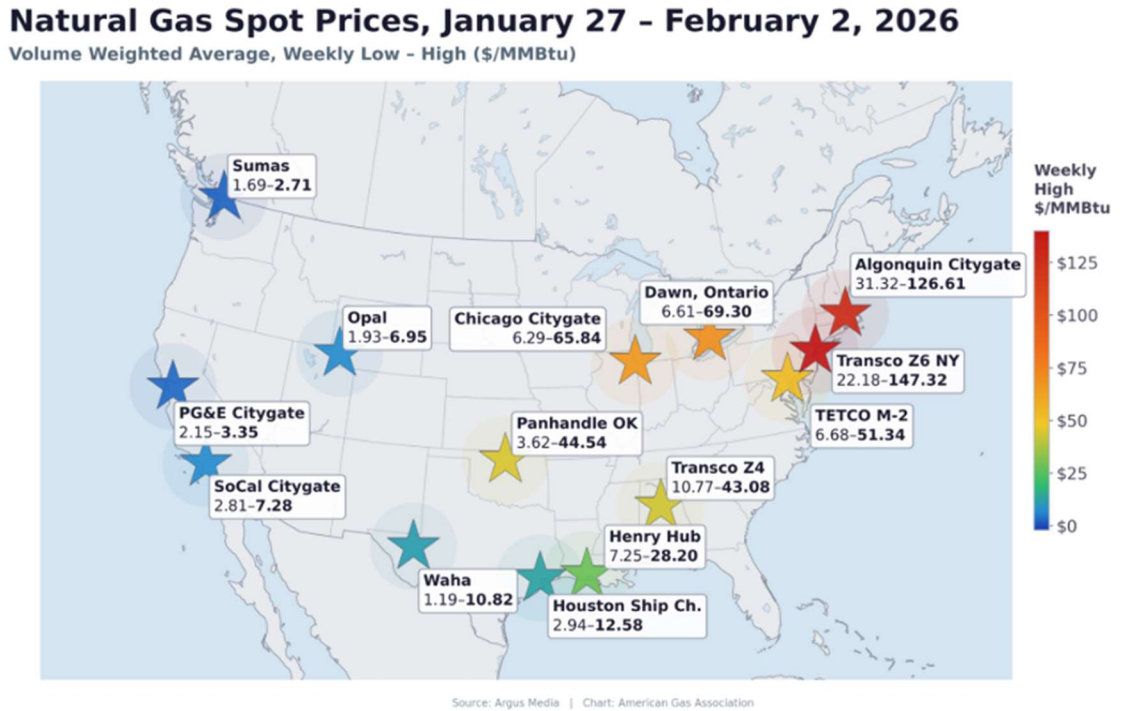
1 **Q. What were the impacts to the energy industry as a result of Winter Storm Fern?**

2 A. The significant and widespread cold weather resulted in freeze offs across the country in
3 the major producing regions, ultimately impacting up to 17 BCF/day of production during
4 a period of extremely high demand. The lower production and high demand triggered high
5 to historically high natural gas prices across the county. The Henry Hub spot price surged
6 from approximately \$3.11/MMBtu in early January 2026 to a nominal all-time record of
7 \$30.72/MMBtu on January 26, 2026 — shattering the previous record of \$23.86/MMBtu
8 set during Winter Storm Uri. The monthly average Henry Hub price for January 2026
9 settled at \$7.72/MMBtu, an 81% increase from December's average of \$4.26/MMBtu and
10 the highest nominal monthly average since September 2022.⁶ The prices in the more
11 constrained Northeast gas markets experienced the most significant impact. Market
12 locations that serve UGI Gas saw daily spot prices as high as \$124/MMBtu on January 26,
13 2026. UGI Gas Exhibit JLJ-3 demonstrates the extreme change in daily natural gas pricing,
14 particularly on Transco receipt points that also serve the New York and New England
15 regions, where LDCs and power generators often compete for constrained pipeline
16 capacity. Northeast pricing locations, due to constraints in pipeline capacity and high
17 demands throughout the region, experienced the highest price impacts relative to other
18 pricing hubs across the country, as seen in Figure 2 below. Northeast spot prices remained
19 elevated well above pre-storm pricing through most of February 2026.

20
21
22

⁶ Natural Gas Intelligence, January 2026 Arctic Blast Broke Natural Gas Price Records from Gulf Coast to Northeast, Chris Newman

1 **Figure 2: Regional Average Pricing Relative to Winter Storm Fern.**



2

3 **Q. How did UGI Gas manage the supply challenges experienced?**

4 A. During this weather event, and the cold that lingered for several weeks following, all
5 interconnecting pipelines issued Operational Flow Orders (“OFOs”) and restrictions,
6 including ratable take restrictions.⁷ UGI Gas Exhibit JLJ-4 demonstrates the duration of
7 significant pipeline restrictions, which lasted for nearly a month. For several weeks,
8 Columbia Gas Pipeline (“Columbia”) required delivery operators to maintain ratable takes
9 for several market areas, including Market Area 72-23, located in the Lehigh Valley and
10 eastern portion of the Reading distribution system. The Company interrupted Rate IT
11 customers proactively to increase operational flexibility, especially during the Columbia

⁷ Under a ratable takes restriction, an interstate pipeline limits the physical amount of gas that can be delivered at a specific delivery point to 1/24 of the maximum daily scheduled quantity.

1 ratable take restriction to MA 72-23, and held other customer classes in that area to their
2 daily flow requirements (“DFR”) during the restriction.

3 UGI Gas supply, operations and central gas control employees actively managed
4 the capacity portfolio around the clock for several weeks, maintaining the daily and hourly
5 demand and supply positions to ensure reliability to customers. The most extreme daily
6 market prices occurred on Transco, so significant effort was taken to divert as much supply
7 as possible from Transco and maximize flows through Tennessee Gas Pipeline, Texas
8 Eastern and Columbia. Ultimately, the UGI Gas distribution system performed
9 exceptionally well during this historic long duration cold weather event, without any
10 significant service interruptions to firm customers.

11
12 **Q. Describe the gas cost impacts of Winter Storm Fern.**

13 A. UGI Gas experienced supply cost impacts as a result of Winter Storm Fern, largely due to
14 the design of the portfolio that requires a substantial amount of gas to be purchased in the
15 daily market during colder than normal weather. As a result, there were few or no options
16 available to avoid buying high priced gas.

17 The extreme pricing, along with the amount of natural gas purchased to meet
18 customer load on the system, resulted in gas costs, mostly attributed to Winter Storm Fern
19 totaling \$150.6MM in January and \$85.5M in February, compared to the projected costs
20 those months of \$79.2MM and \$59.9MM respectively. As described in the direct testimony
21 of Zachary J. Shirk, UGI Gas Statement No. 1, the high demand during the colder than
22 normal winter, coupled with the extremely high prices during Winter Storm Fern, would
23 have increased PGC costs for customers up to the 25% PGC rate change cap agreed to in

1 the Company's 2023 PGC Settlement at Docket No. R-2023-3040290 at the quarterly PGC
2 Rate update on March 1, 2026.

3
4 **Q. What steps did the Company take in the wake of Winter Storm Fern to further
5 protect customers from impacts caused by severe weather events?**

6 A. In the immediate aftermath of Winter Storm Fern, in order to mitigate the impact to
7 customers of the storm-related supply pricing, UGI Gas filed an emergency petition to
8 temporarily lower the 25% PGC rate cap to 10% at Docket No. P-2026-3060521 as
9 described in the direct testimony of Zachary J. Shirk, UGI Gas Statement No. 1. This was
10 approved by the Commission on February 19, 2026. Additionally, UGI Gas also
11 commissioned a study to evaluate whether adjustments to its purchasing practices and
12 portfolio structure would better balance reliability and affordability on a going forward
13 basis.

14 Specifically, the market prices experienced during this winter, and particularly
15 during and immediately after Winter Storm Fern, were higher than UGI Gas has
16 experienced in the past. UGI Gas has used the same purchase structure as part of its
17 portfolio for many years despite a changing natural gas marketplace driven by constrained
18 pipelines on peak days due, in part, to gas fired power generation. UGI Gas conducted a
19 comprehensive Portfolio Optimization study to evaluate the Company's risk of anomalous
20 but significant events like Winter Storm Fern, Elliot or Uri. The study resulted in a set of
21 recommendations for UGI Gas to improve and balance the price stability and overall cost
22 of its natural gas supply portfolio and to reduce the risk of extreme price impacts due to

1 winter storm events. I will describe the results of the study in the next section of my
2 testimony.

3
4 **V. Portfolio Optimization Study**

5 **Q. Please describe the Portfolio Optimization Study.**

6 A. The Gas Supply Portfolio Optimization Study is an independent, comprehensive evaluation
7 of UGI Gas's natural gas procurement practices, supply portfolio composition, weather
8 modeling, and risk management framework, conducted by Gelber & Associates ("Gelber").
9 The study was commissioned in response to the increasing severity and market volatility
10 associated with episodic winter cold events — most recently Winter Storm Fern and the
11 extended January-February 2026 cold weather period described in Section IV of this
12 testimony — which have underscored the importance of ensuring that UGI Gas's portfolio
13 planning and procurement practices are fully aligned with evolving market conditions and
14 industry best practices.

15
16 **Q. How did UGI Gas procure consulting services for this study?**

17 A. UGI Gas issued a formal Request for Proposals in March 2026, soliciting bids from
18 consulting firms and experts in commercial natural gas market economics. The RFP
19 specified a comprehensive scope of work that included review of procurement procedures,
20 supply portfolio optimization, weather and usage trend analysis, procurement and hedging
21 guidance, and identification of opportunities to modernize and optimize the portfolio
22 consistent with industry best practices. Bidders were asked to provide detailed
23 qualifications, work history, references, descriptions of the technology and models they

1 would employ, and a proposed process and timeline for completing the assessment in time
2 for inclusion in this PGC proceeding.

3
4 **Q. How many proposals did UGI Gas receive, and how was the winning bidder selected?**

5 A. UGI Gas received proposals from three qualified consulting firms. Following evaluation
6 of each proposal on the basis of technical qualifications, relevant experience, proposed
7 methodology, and cost, UGI Gas selected Gelber. Gelber's bid reflected a combination of
8 substantial professional experience in gas portfolio management, competitive pricing and
9 an established working knowledge of UGI Gas's supply and risk management operations.
10 The Portfolio Optimization Study is provided in Confidential UGI Gas Exhibit JLJ-5.

11
12 **Q. What did Gelber's review of UGI Gas's procurement practices and hedging strategy
13 find?**

14 A. Gelber found that UGI Gas's procurement and hedging framework is structured and
15 disciplined, with clear timing, layering practices, and decision criteria. The review
16 confirmed that UGI Gas's procurement practices are structured and compliant. However,
17 Gelber identified a significant and recurring pattern: long-term demand forecasts used in
18 seasonal hedge plans generated a year in advance are consistently and materially below
19 actual realized demand. Short-term forecasts demonstrate notably higher accuracy, while
20 long-range projections consistently underperform.

21 Gelber attributed this structural underestimation bias to UGI Gas's current
22 methodology, which relies heavily on design-warm-day baselines. This approach
23 suppresses modeled sensitivity to colder-than-normal conditions and contributes to
24 systematic understatement of likely actual demand. Gelber's analysis of the most recent

1 five years showed a regularity and extent of forecast gap between plan and actual demand
2 that is material to portfolio performance, as the underestimation of demand increases
3 reliance on short-term daily market purchases during the periods — peak winter cold events
4 — when market prices are most volatile and cost risk is highest.

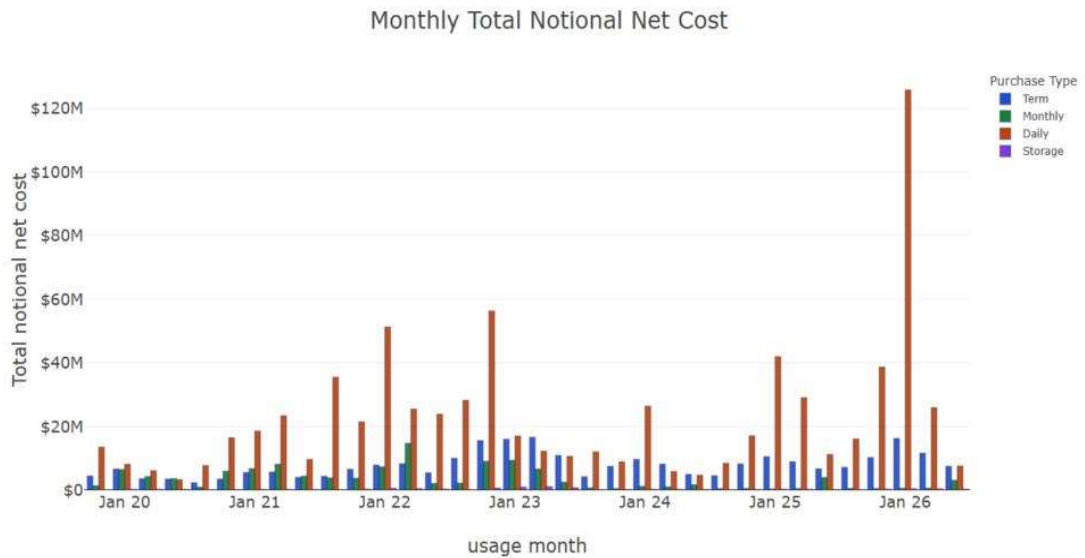
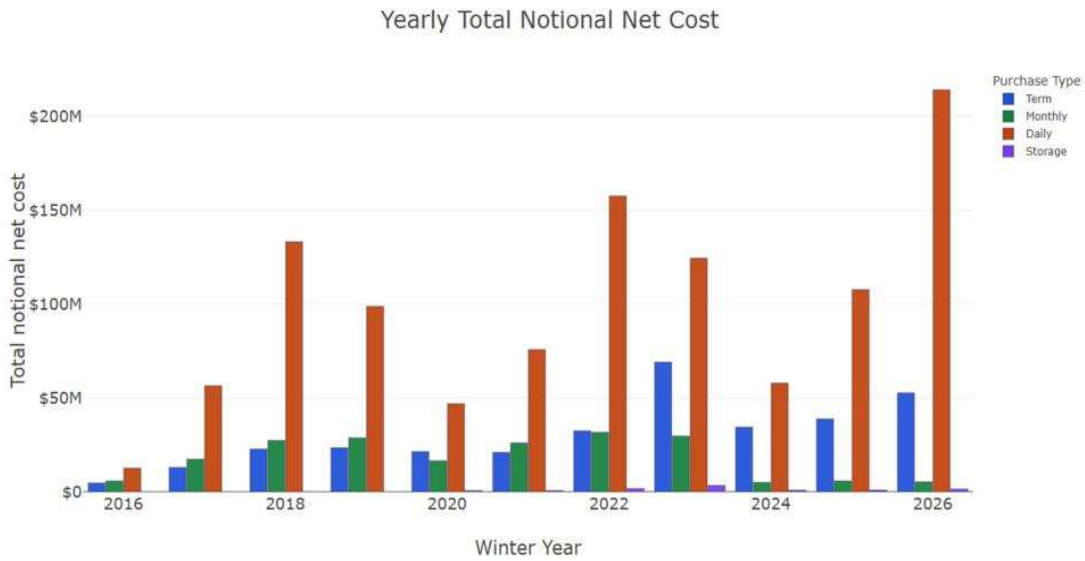
5
6 **Q. What did Gelber's review of UGI Gas's supply portfolio composition and**
7 **performance find?**

8 A. Gelber's quantitative analysis of UGI Gas's supply portfolio found that overall supply costs
9 are driven largely by daily market purchases, particularly during the winter season,
10 demonstrated in Figure 3.

11

12

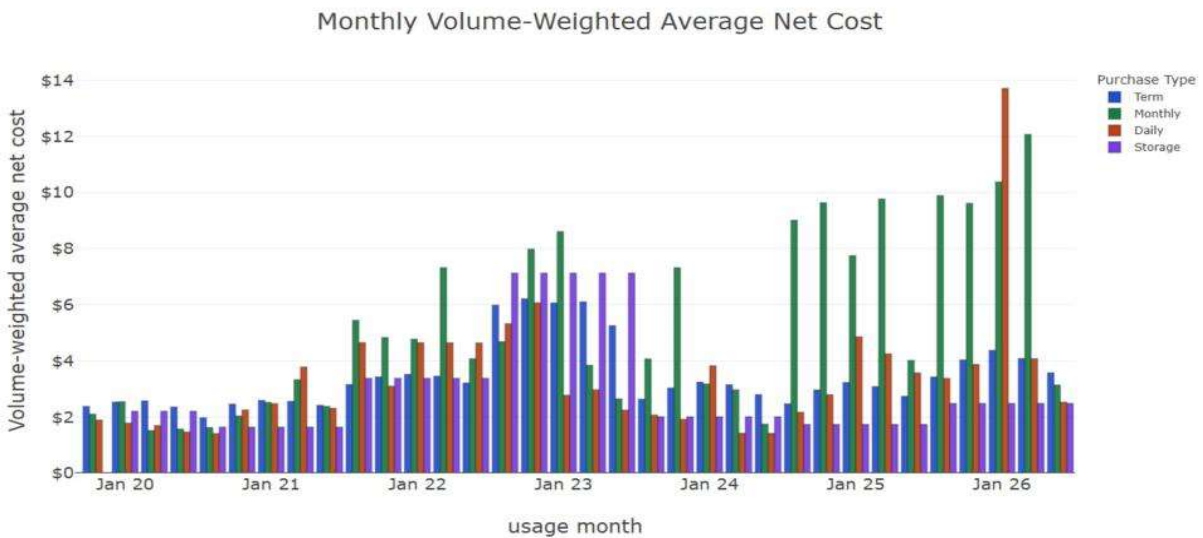
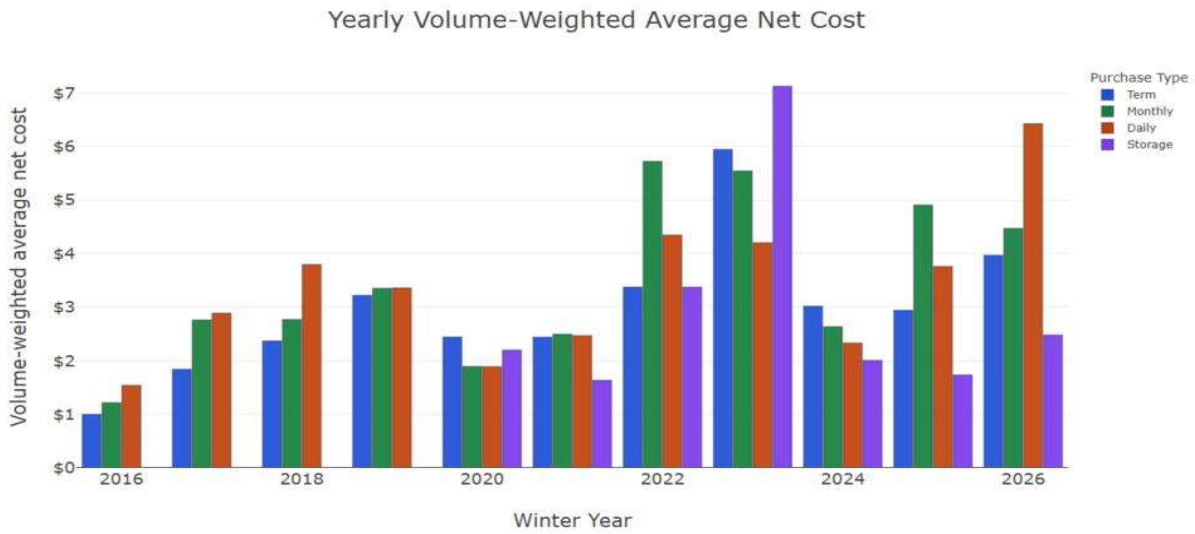
1 **Figure 3: Portfolio Composition Cost Overview for Winter Season**



2

3 A comparison of average unit costs across term, monthly, daily, and storage supply
4 purchase types showed that term purchases loosely track short-term monthly planned
5 purchases, with monthly purchases typically somewhat higher and showing lower costs
6 only a small percentage of the time, demonstrated in Figure 4.

1 **Figure 4: Unit Cost Comparison of Purchase Types – Winter Months**



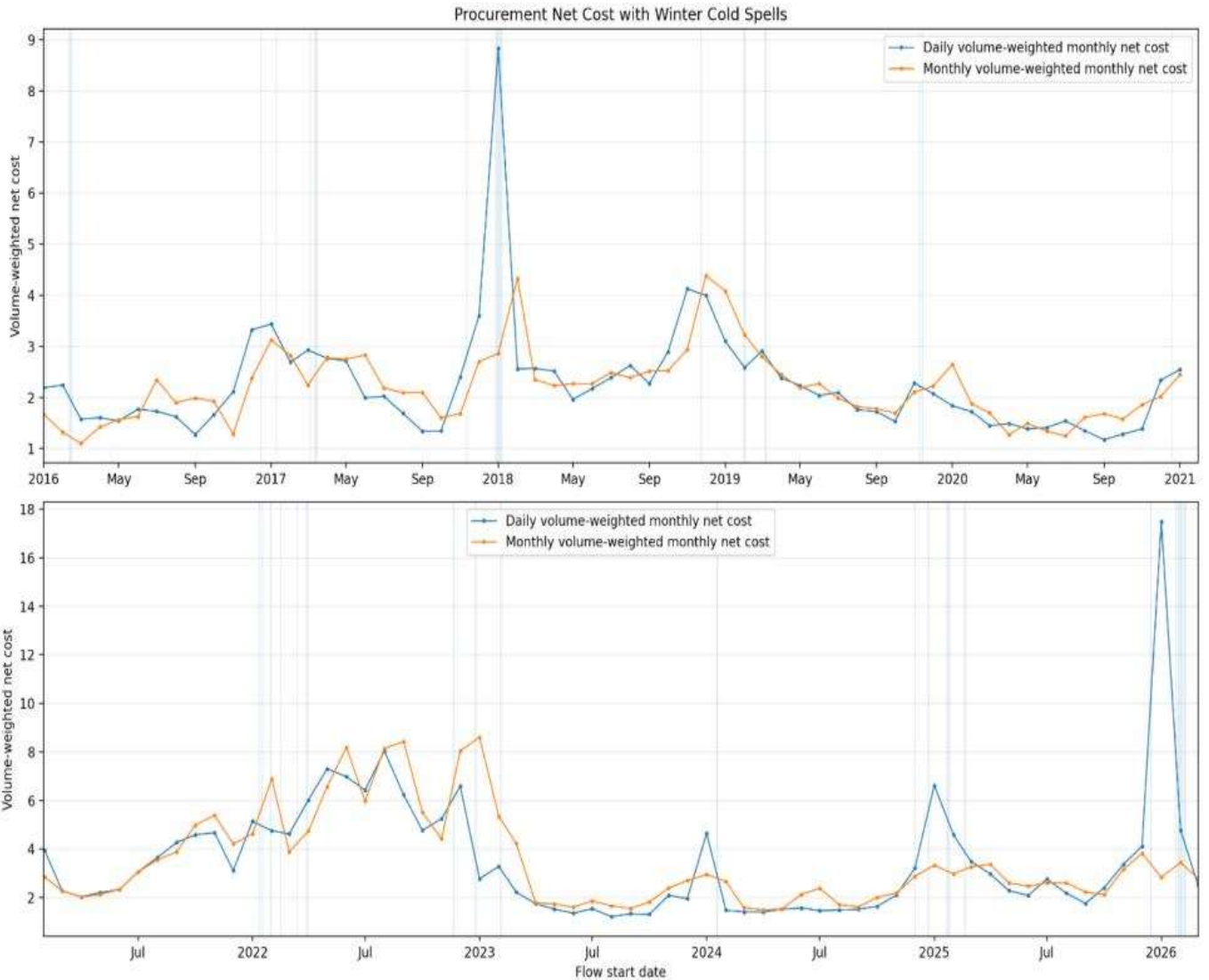
2

3 While the most recent winter season showed daily prices exceeding monthly prices during
 4 certain months, the longer-term pattern indicates that daily prices are typically lower,
 5 however they experience substantial volatility and rise sharply during cold weather events.

6 Critically, Gelber's data showed in Figure 5 that the price impacts of extreme cold-
 7 weather events have increased over the past three years, making cold-weather volatility

1 more costly when it does occur and reinforcing the importance of reducing exposure to
2 unhedged daily market purchases during peak winter months.

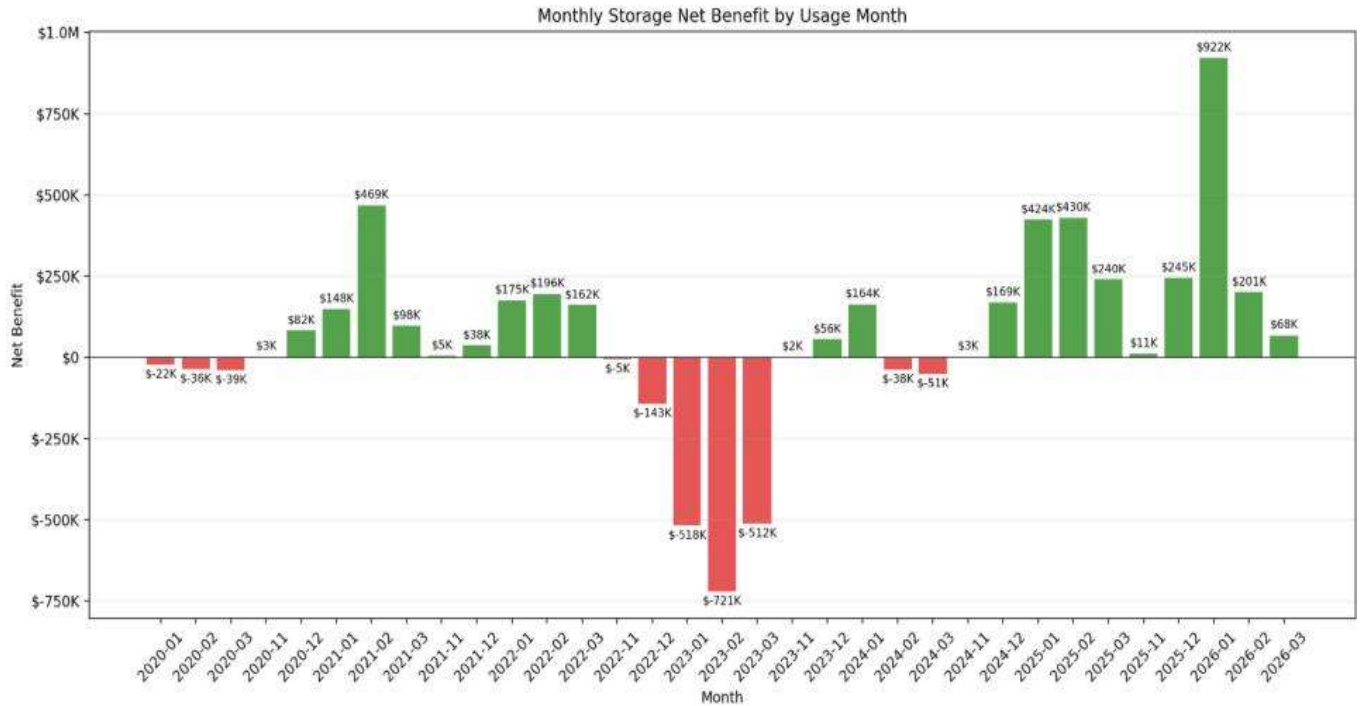
3 **Figure 5: Cost Comparison Overlay with Weather Events**



4
5 Gelber's analysis also confirmed the cost advantage of storage, as shown in Figure
6 6. Summer-season storage injections consistently prove more cost-effective than winter-
7 season purchases, with only a single outlier year in 2022-2023 — attributable to the market
8 disruption associated with the conflict in Ukraine. The pricing spread between lower-cost
9 summer supply and winter-season purchases averages approximately \$0.85/Dth, validating

1 the strategic value of storage in mitigating winter market exposure and supporting the
 2 recommendation to maximize storage utilization during peak winter months.

3 **Figure 6: Financial Benefits from Using Storage Supply**



4
 5 **Q. What recommendations did Gelber make, and how does UGI Gas intend to respond?**

6 A. Gelber made five recommendations as a result of their study: (1) Reduce reliance on winter
 7 monthly and daily purchases; (2) Extend the hedge program purchasing window; (3)
 8 Explore opportunities to increase storage supply options; (4) Strengthen short-term
 9 planning and procurement; and finally (5) Improve long-term forecasting inputs.

10 Gelber made three recommendations specifically to improve the form and function
 11 of the Company's current hedge planning process. First, to reduce reliance on winter
 12 monthly and daily purchasing, Gelber recommends that UGI Gas increase the volume of
 13 the long-term winter hedging program beyond the current ninety-five of monthly design
 14 warm demand, to up to one hundred and twenty percent, thereby directly reducing the

1 monthly and daily purchasing volume. Gelber recommends further simulation analysis to
2 determine the optimal long-term hedge volume increase. UGI Gas agrees with this
3 recommendation and will conduct further analysis to determine the new parameters for
4 long-term hedges. Second, Gelber proposes the Company extend the hedging program
5 purchasing window beyond a one-year horizon, to a two-year period. This will enable the
6 Company to further diversify pricing conditions. Third, Gelber recommends evaluating the
7 natural gas market for storage opportunities whenever possible, as their analysis shows the
8 consistent value and price stability that storage contracts provide to UGI Gas customers.

9 The final two recommendations from Gelber focus on strengthening short-term
10 planning and procurement by modernizing the Company's monthly set up processes, files,
11 and long-term forecasting inputs from the Company's third-party demand forecasting
12 provider from spreadsheet-based data processes to more advanced data capture and
13 analytics. The study posits that both of these efforts will continue to improve the quality
14 and efficacy of the Company's layered purchasing program.

15 The Company proposes accepting all recommendations from the Gelber study and
16 will establish a multi-phased approach to incorporating these changes into the hedging
17 program. Gelber, in their capacity as UGI Gas's existing hedging manager, will continue
18 their analysis and simulations to determine an optimal long-term hedging volume target
19 relative to projected design warm demand. UGI Gas views this as the most immediately
20 impactful recommendation, given the exposure on the daily market during Winter Storm
21 Fern described earlier. In addition, UGI Gas and Gelber will integrate the two-year hedge
22 purchasing window into the next hedge purchasing period. Both changes will be integrated
23 into the next winter hedge planning cycle, planning for Winter 2028-2029. In addition, the

1 Company will continue to monitor storage and storage capacity opportunities in the market
2 through open season postings, RFPs, and direct outreach to parties active in the storage
3 capacity market. Finally, UGI Gas will work both internally and with the third-party
4 forecasting provider to improve the tools and inputs to the Company's hedge planning
5 activities.

6 In conclusion, the study results from Gelber propose targeted modifications to the
7 Company's practices that are anticipated to provide tangible long-term cost benefits to UGI
8 Gas customers, and improve the resilience of the portfolio to mitigate unpredictable, yet
9 inevitable, future shocks to the market.

10 11 **VI. Choice Program Update**

12 **Q. Please summarize the changes being made to UGI Gas's Choice Supplier tariff.**

13 A. The Company is filing a tariff change to update the peak day allocation percentages of the
14 Company's supply portfolio that is provided to NGSs serving Choice customers. These
15 allocations include firm transportation capacity, storage in the form of a bundled sale, and
16 peaking service. The proposed changes to the Company's Supplier tariff are reflected in
17 the pro forma Tariff Supplement to Tariff Gas-Pa. P.U.C. No. 7 and 7S, filed in this
18 proceeding on June 1, 2026.

19
20 **Q. Why are there changes being made to the peak day allocations?**

21 A. UGI Gas acts as the capacity planner for its Core Market Customers, which include both
22 PGC and Choice customers. In this role, the Company maintains a portfolio designed to
23 meet the design-firm requirements for its Core Market customers. NGSs serving customers
24 participating in the Company's Choice program receive an allocation of the Company's

1 firm transportation capacity and an allocation of delivered supply, storage supplies, and
2 peaking supplies. UGI Gas is updating the peak day allocation percentages of these supply
3 assets to reflect the 2026-2027 supply portfolio, as shown on Attachment 14-1 of Book 1.
4

5 **VII. Recent Contract Renewals**

6 **Q. Please describe the agreements that comprise the Company's supply portfolio.**

7 A. The Company manages a portfolio of firm transportation, delivered supplies, storage, and
8 peaking agreements. Many of these agreements were initiated through long-term contracts
9 that permit the Company to continue service upon expiration of the initial term through
10 automatic "evergreen" renewals, by exercising a Right of First Refusal ("ROFR") or by
11 exercising a right to extend the service for an agreed upon term and price adjustment.
12

13 **Q. Please describe the agreements in the Company's supply portfolio that were renewed.**

14 A. Table 2 summarizes the contracts that were renewed during the historic review period (i.e.
15 April 1, 2025 to March 31, 2026). UGI Gas Exhibit JLJ-6 provides a detailed list of each
16 agreement that includes the service type, annual cost, and renewal term.
17

1

Table 2: Summary of Contract Renewals During Historic Period

Supplier	Renewal Type	Service	Maximum Daily Quantity (Dth)
Supplier J	Evergreen	Delivered Supply	600
Supplier M	Extension	Delivered Supply	1,680
Texas Eastern	Evergreen	Transportation/Storage	237,898
Transco	Evergreen	Transportation/Storage	117,054
UGIES	Extension	Peaking	45,404

2

3 **Q. Please describe the Company’s rationale for renewing these service agreements.**

4 A. The Company will renew service agreements that are needed to meet the Company’s
5 design firm capacity requirements, are reliable, and are at the lowest cost. As the demand
6 for natural gas supply has significantly increased in recent years, so has the need for
7 additional pipeline infrastructure. As a result, the interstate pipelines serving the Company
8 are generally fully subscribed and cannot provide new service without construction of an
9 expansion project. When interstate pipelines initiate construction projects for new supply,
10 they are typically more expensive than the Company’s existing services, require a lead
11 time of many years, and are subject to FERC approval. In recent years it has become
12 increasingly difficult for new interstate pipeline capacity to be constructed, so renewing
13 existing capacity and storage contracts is very important to the Company in meeting its
14 firm service obligations.

15

16

1 **Q. Please describe the services that were renewed through evergreen provisions.**

2 A. The Company holds firm transportation and storage agreements with Tennessee, Texas
3 Eastern, and Transco that provide primary firm supply required to meet the Company's
4 firm demand requirements. The contracts for these services include evergreen provisions
5 that automatically extend the agreements upon expiration of the termination date unless
6 the Company chooses to terminate the agreements. The Company chose to extend the
7 service agreements based on its belief that the pricing terms are reasonable.

8

9 **Q. Please describe the services that were renewed through a ROFR.**

10 A. The Company renewed the following services by exercising ROFR provisions in existing
11 contracts:

12

Table 3: Contracts Renewed Through ROFR

Contract	MDQ	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension
EGTS FT - 200796	2,000	3/31/2026	3/31/2025	\$72	2 Years

13

14 **Q. Please describe the services that are being contemplated to be renewed through a
15 ROFR within the next year.**

16 A. The Company is planning on renewing the following services by exercising ROFR
17 provisions in existing contracts:

18

1

Table 4: Future Contract Renewals Through ROFR

Contract	MDQ	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension
Columbia FTS - 230222	10,782	10/31/2027	4/30/2027	\$162	5 Years
Columbia FTS - 230211	2,432	10/31/2027	4/30/2027	\$162	5 Years
Columbia FTS - 230212	2,432	10/31/2027	4/30/2027	\$162	5 Years
Columbia FTS - 230213	2,432	10/31/2027	4/30/2027	\$162	5 Years
Columbia FTS - 230214	2,434	10/31/2027	4/30/2027	\$162	5 Years
EGTS FT - 200796	2,000	3/31/2028	3/31/2027	\$72	5 Years

2

3 **Q. Please describe the agreements in UGI Gas’s supply portfolio that are proposed to be**
4 **renewed within the next year.**

5 A. UGI Gas Exhibit JLJ-7 provides a detailed list of each agreement that the Company plans
6 to renew within the next year, including the service type, annual cost, and renewal term.

7

8 **Q. Will UGI Gas issue an RFP to replace any of the agreements in its portfolio within**
9 **the next year?**

10 A. The Company has not identified any agreements that will not continue to meet its least cost
11 obligations; thus, it is planning for renewal of these upcoming contracts without the need
12 to issue an RFP.

13

1 **VIII. Supply RFPs**

2 **Q. Has the Company issued any RFPs for natural gas supplies since the last PGC**
3 **proceeding?**

4 A. Yes. The Company has issued several RFPs since the last PGC proceeding. Specifically,
5 as discussed further in this section of my testimony, the Company issued RFPs for Asset
6 Management Agreements for portions of UGI Gas's TETCO FT capacity, Transco FT
7 capacity and Columbia FSS capacity; and an RFP for a mobile LNG solution.

8

9 **A. UGI Gas's RFP Process**

10 **Q. Please describe the Company's supply RFP process.**

11 A. On an annual basis as part of the process for preparing for its PGC, the Company evaluates
12 its capacity and supply portfolio needs. As part of this process, the Company updates its
13 design day study each April, and if a capacity shortfall is projected, the Company will issue
14 an RFP to address the identified shortfall. As described previously in my testimony, the
15 Company is not currently forecasting a capacity shortfall, and therefore it did not conduct
16 a capacity RFP this year. During this process, the Company also conducts RFPs for targeted
17 supply needs or opportunities, including mobile LNG services, RNG and certified natural
18 gas. As part of prior PGC proceedings, the Company has adjusted its process related to
19 bidding periods, payment terms, and advanced notification to potential suppliers in order
20 to support robust RFP participation. The Company posts the RFPs on its Energy
21 Management Website and circulates them to a distribution list of potential suppliers to
22 solicit interest.

23

1 **B. AMA RFP**

2 **Q. What is an Asset Management Agreement?**

3 A. An Asset Management Agreement (“AMA”) is a contractual relationship through which a
4 party consents to manage delivery arrangements, including supply, as well as the
5 transportation of gas, for another party. In an AMA, the owner of firm interstate pipeline
6 capacity or storage assets releases its capacity to the asset manager for a specified term. By
7 entering into an AMA, the owner of the capacity receives an administrative fee while still
8 benefitting from the ability to call on the operational capabilities of the capacity to fulfill
9 system supply requirements. In situations where UGI Gas is releasing capacity as part of
10 an AMA, rights to recall the capacity or storage asset are maintained, and financial security
11 is required, in order to safeguard UGI Gas customers from non-performance which could
12 impact reliability.

13 Under UGI Gas’s incentive sharing mechanism, the administrative fee paid by an
14 asset manager to UGI Gas is shared with PGC customers. Specifically, 75% of the fee is
15 credited to the PGC and 25% is retained by UGI Gas. As a result of UGI Gas securing an
16 asset manager for its capacity, PGC customers will experience reduced PGC costs versus
17 what would otherwise have been experienced without the AMA, without any change in the
18 Company’s ability to access critical peak day capacity when it is needed to serve customers.

19
20 **Q. Did UGI Gas have any AMAs on interstate pipeline capacity during the historic
21 period?**

22 A. Yes. UGI Gas had three AMAs during the historic period. The first for 10,000 Dth of
23 Transco FT capacity for the period from April 1, 2025, through March 31, 2026, the second

1 for 3,400,000 Dth of EGTS storage capacity for the period of November 15, 2024 through
2 November 30, 2027, and the third for 20,000 Dth of TETCO FT capacity for the period of
3 January 1, 2025 through December 31, 2025. These three AMAs were identified in the
4 Company's 2025 PGC proceeding.
5

6 **Q. Did UGI Gas issue any RFPs for additional AMAs in the historic period?**

7 A. Yes, UGI Gas issued an RFP on February 19, 2026, to continue the AMA associated with
8 the 10,000 Dth of capacity on Transco that was set to expire March 31, 2026. UGI Gas
9 received many responses to its AMA RFP with competitive bids. It selected the highest
10 bidder and awarded the AMA for the period of April 1, 2026 through March 31, 2027. In
11 addition, UGI Gas also issued an RFP on February 25, 2026, to continue the AMA
12 associated with the 20,000 Dth of capacity on Texas Eastern that was set to expire on
13 December 31, 2025. UGI Gas received competitive offers, and the Company awarded the
14 AMA to the highest bidder. The Texas Eastern AMA runs from April 1, 2026 to March
15 31, 2027. Finally, UGI Gas issued an RFP on August 27, 2025, to continue the AMA for
16 7,050,541 Dth of Columbia FSS storage capacity. UGI Gas received competitive offers,
17 and the Company awarded the AMA to the highest bidder. The Columbia FSS AMA spans
18 a three-year term from November 1, 2025 to October 31, 2028. The results from the three
19 AMA RFPs are included with my testimony as CONFIDENTIAL UGI Gas Exhibit JJJ-8.
20

21 **Q. What is the total benefit to the PGC from the three AMAs?**

22 A. PGC customers will receive a total of \$9,360,187 in revenue credits over the term of the
23 three AMAs, calculated consistent with the Company's Revenue Sharing Incentive

1 Mechanism (“RSIM”) contained in Rider B – Section 1307(f) Purchase Gas Cost of Tariff
2 Gas-Pa. P.U.C. No. 7 and 7S. The credit to the PGC is reflected in Book 1 in Attachment
3 1-B-1 and Attachment 1-B-2 at line item “Non-Choice Cap Rel/Sharing Mech Credit.”
4

5 **C. Mobile LNG RFP**

6 **Q. Did UGI Gas issue an RFP for mobile LNG?**

7 A. Yes. UGI Gas issued an RFP for mobile LNG service to Dickson City on May 5, 2026. In
8 2024, the Company acquired a mobile LNG service to supply the Uniondale 282 system.
9 The service provided the Company with LNG supplies, LNG storage and vaporization
10 equipment, and staffing to run the LNG facility. The most recent service agreement
11 expired on March 31, 2026. The Company plans to continue to use mobile LNG supply to
12 support the continued provision of reliable service to the Uniondale 282 system. The
13 bids were due for this RFP on May 15, 2026.

14
15 **Q. What were the results of that RFP?**

16 A. The Company received 3 responses from 3 bidders. Proposals included two bids for mobile
17 LNG and one bid for compressed natural gas.
18

19 **Q. Did UGI Gas select a winning bidder for the Uniondale 282 system?**

20 A. Yes. UGI Gas accepted the proposal from UGIES to provide up to 10,000 Dth/day in LNG
21 supply and pressure support for the Uniondale 282 system. This pressure support will fully
22 address any reliability concerns for the upcoming winter 2026-2027 period.
23

1 **Q. What is the cost of the LNG option?**

2 A. The cost of the LNG option includes an estimated cost of \$1,355,950 per year through
3 2030. The reservation charge will be reflected in rates as of the in-service date, which is
4 anticipated to be December 2026. The Company notes that Book 1 includes the total costs
5 for the Uniondale 282 project in schedule 1-B-2 at line item LNG Supply – Supplier TBD.
6

7 **D. Certified Natural Gas RFP**

8 **Q. Please describe the 2026 RFP for Certified Natural Gas.**

9 A. UGI Gas issued an RFP on May 4, 2026, seeking bids for certified natural gas supply. In
10 addition to its standard RFP terms, the Company asked bidders to identify the certification
11 company and grade of certification available, and whether the supplier uses a third-party
12 registry to facilitate administrative tracking.
13

14 **Q. How many responses were received on the Certified Gas RFP?**

15 A. The Company received one bid for certified gas supply with multiple delivery points and
16 volumes.
17

18 **Q. Is the Company requesting Commission approval for any of the bids received?**

19 A. The Company is not requesting Commission approval for any components of the certified
20 gas bid received. The received bid indicated there is still a substantial price premium for
21 certified gas at all purchase locations compared to traditional natural gas supplies, so the
22 Company has decided not to pursue a certified gas purchase at this time. However, UGI
23 Gas intends to maintain communications with the bidder and other certified gas suppliers

1 and will evaluate shorter-term or daily certified gas offerings when making future supply
2 purchase decisions.

3
4 **IX. Participation in FERC Proceedings**

5 **Q. Please describe UGI Gas's participation in FERC proceedings.**

6 A. UGI Gas's primary FERC activities include participation in Natural Gas Act Section 4
7 base rate proceedings, rulemakings and certificate proceedings before FERC. UGI Gas
8 also engages in direct negotiations with the pipeline. FERC orders in any proceedings
9 impacting pipelines could change UGI Gas's purchased gas costs during the next twenty
10 months.

11 **Q. Have any new significant proceedings been filed at FERC since the 2025 PGC
12 proceeding that could impact UGI Gas's PGC customers?**

13 A. There have not been any new filings made pursuant to 15 U.S.C. § 717c ("Section 4") at
14 FERC since the 2025 PGC proceeding. However, UGI Gas did continue to participate in
15 two Section 4 proceedings identified in the 2025 PGC that have since reached resolution.
16 I will describe the settlement in those proceedings in this section of my testimony. In
17 addition, UGI Gas has continued to monitor and participate in major dockets that have
18 industrywide significance. For example, UGI Gas has been actively involved in ongoing
19 settlement discussions regarding the calculation of Tennessee Gas Pipeline's fuel loss
20 percentages. Tennessee's 2021 Fuel Tracker filing was disputed by select system shippers
21 and has been subject to litigation over the past five years. Throughout the course of
22 litigation, Tennessee has continued filing annual fuel trackers utilizing the same
23 methodology as the 2021 fuel filing. In September 2025, the U.S. Court of Appeals for the

1 D.C. Circuit vacated FERC’s approval of Tennessee’s 2021 fuel filing and remanded the
2 matter back to FERC. In late 2025, Tennessee initiated settlement discussions with all
3 system shippers to find a mutually agreed-upon fuel methodology going forward and to
4 address the financial impacts of the interim filings that applied the same methodology as
5 the vacated 2021 fuel filing.

6
7 **A. Transcontinental Gas Pipe Line Company Section 4 Rate Case**

8 **Q. Please provide an update to the Transcontinental Gas Pipe Line Company**
9 **(“Transco”) Section 4 Proceeding at Docket No. RP24-1035.**

10 A. The Transco rate case proceeding reached a comprehensive settlement of all issues, which
11 was filed at FERC on October 29, 2025, and approved by FERC order issued on December
12 30, 2025.

13
14 **Q. What were the terms of the settlement reached in Transco’s Section 4 Proceeding?**

15 A. The parties achieved a settlement addressing both rate and tariff issues. Settlement terms
16 include operational prerequisites for the issuance of bracketed OFOs⁸, as well as annual
17 greenhouse gas and reliability reporting. Additionally, Transco agreed to a rate case
18 moratorium through August 31, 2027.

19
20
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22

⁸ Bracketed OFOs restrict both under deliveries and over deliveries from pipelines, essentially “bracketing” the supply and demand positions typically between +/- 2%.

1 **Q. What were the resulting impacts to the Company’s transportation costs on Transco?**

2 A. As a result of the settlement, the Company’s storage and transportation demand costs on
3 Transco decreased, on average, by 14% from the proposed rates, or around \$2.8 million
4 annually.

5
6 **Q. Did UGI Gas receive a refund associated with the lower settlement rates?**

7 A. Yes, UGI Gas received a refund of \$4,160,331 from Transco in March 2026. This refund
8 was calculated based on the difference between the proposed rates, which went into effect
9 subject to refund on March 1, 2025, and the rates reflected in the settlement. A portion of
10 the refund is allocated to Choice and Non-Choice Transportation customers through the
11 monthly WACOG rate. The remainder of the refund with applicable interest will be
12 allocated to PGC customers via the December 1, 2026 rate update.

13

14 **B. Columbia Gas Transmission Section 4 Rate Case**

15 **Q. Please provide an update on the Columbia Gas Transmission (“TCO”) Section 4**
16 **proceeding at Docket No. RP24-1103.**

17 A. The TCO rate case proceeding reached a comprehensive settlement of all issues, which
18 was filed at FERC on August 13, 2025, and approved in an Order issued on October
19 30, 2025.

20

21 **Q. What were the terms of the settlement reached in TCO’s Section 4 Proceeding?**

22 A. The parties in this case were able to reach settlement terms on both rate and tariff issues,
23 due in part to the extensive efforts of the LDC shipper group. As a condition of the
24 settlement, TCO agreed to withdraw its proposed two-zone rate design and its proposal to

1 increase penalties. Critical to the LDCs, TCO agreed to maintain shippers' rights to
2 automatic contract extensions and withdrew its proposal on hourly flow restrictions. TCO
3 also agreed to a rate case moratorium through March 31, 2028.

4
5 **Q. What were the resulting impacts to the Company's transportation costs on TCO?**

6 A. As a result of the settlement, the Company's storage and demand costs on TCO decreased
7 42% from the as-filed rates that had been implemented subject to refund on April, 1, 2025,
8 equating to around \$33.3 million annually.

9
10 **Q. Did UGI Gas receive a refund associated with the lower settlement rates?**

11 A. Yes, UGI Gas received a refund of \$5,201,190 from TCO in November 2025. This refund
12 reflects the difference between proposed rates and settled rates for the two-month period
13 the proposed rates were in effect, April and May 2025. Pro-rata portions of the refund
14 were allocated to Choice and Non-Choice Transportation customers through the monthly
15 WACOG calculation. UGI Gas issued direct refunds to XD customers that receive
16 Columbia capacity. The remainder of the refund, with applicable interest will be allocated
17 to PGC customers through the December 1, 2026 PGC rate update.

18
19 **X. Renewable Natural Gas – Pilot Program Update**

20 **Q. Can you provide an update on the Renewable Natural Gas Pilot Program?**

21 A. Yes. UGI Gas purchased 301,788 dth of RNG from April 2025 through March 2026. The
22 total cost of the RNG during that period was \$5,101,665. PGC customers received an offset
23 of \$3,704,393 through Renewable Identification Number ("RIN") monetization over that

1 same period, calculated pursuant to the settlement in Docket Number R-2021-3025652.
2 The net cost of RNG to PGC customers during this period was \$1,463,217. The RIN
3 monetization offset resulted in no net cost impact to the PGC above otherwise applicable
4 supply market pricing, as calculated pursuant to the settlement provisions established for
5 this RNG purchase. The BTU content of the RNG purchased as part of the pilot program
6 was 974 BTU/CF.

7
8 **Q. What is the initial termination date of the current Renewable Natural Gas Pilot**
9 **Program?**

10 A. The Master RNG Agreement that governs the current RNG supply purchase and
11 subsequent RIN monetization is set to expire on April 30, 2027. There are no automatic
12 renewal or extension rights in the contract.

13
14 **Q. Is UGI Gas proposing to extend the Renewable Natural Gas Pilot Program?**

15 A. Yes. In an effort to evaluate the next phase of the RNG Pilot Program, UGI Gas issued an
16 RFP to gauge current market availability and price offerings of RNG supply.

17
18 **Q. Please describe the 2026 RFP for Renewable Natural Gas.**

19 A. UGI Gas issued an RFP on May 4, 2026, seeking bids for renewable natural gas supply.
20 UGI Gas specifically requested RNG supplies that could be purchased on an
21 interconnecting interstate pipeline or delivered directly into the Company's distribution
22 system. UGI Gas considered bids for any available volumes of RNG supply, with or

1 without associated environmental attributes. The Company also allowed bidders to submit
2 proposals for monetization of environmental attributes.

3
4 **Q. How many responses did the Company receive?**

5 A. The Company received offers from eight bidders, with RNG production coming from
6 twelve in-service RNG facilities and four RNG facilities still in the planning, permitting,
7 or construction phase. Of the bids received, seven consisted of directly connected projects,
8 and eleven bids contained projects located on one of the identified upstream interstate
9 pipelines. All of the offers included environmental attributes bundled with the supply, and
10 multiple bidders included optional proposals for RIN monetization.

11
12 **Q. How did the Company evaluate the bids received?**

13 A. Though the RFP was designed to solicit a wide range of RNG proposals, UGI Gas used
14 more stringent criteria to evaluate the bids received. The Company decided not to consider
15 any offers for RNG supply that were not directly connected to UGI Gas's distribution
16 system, as these options would require the use of the Company's existing pipeline capacity
17 to transport the gas to an interconnecting meter. Additionally, UGI Gas removed any RNG
18 facilities not currently in service from this bid evaluation. UGI Gas will maintain
19 communication with the counterparties that submitted bids for future RNG projects and
20 plans to reevaluate these RNG supply options when the projects have been completed.
21 Finally, UGI Gas verified that all remaining bids conformed with the Company's RFP
22 requirements, complied with the enhanced force majeure provisions, and provided firm
23 supply deliveries or replacement supply options, if needed.

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Q. Is UGI Gas requesting approval for any of the RNG bids received?

A. Yes. The Company is requesting Commission approval to accept all of the RNG bids with direct delivery into UGI Gas’s distribution system that are available within the next 12 months. Specifically, UGI Gas is seeking approval to execute a 2-year RNG purchase agreement with Supplier 1 and an 8-year RNG purchase agreement with Supplier 2. Additionally, UGI Gas is requesting approval to monetize the associated RINs from both RNG purchases and apply the RSIM to any revenue received. A summary of the selected bids is provided in CONFIDENTIAL UGI Gas Exhibit JLJ-9.

Q. Why is UGI Gas interested in incorporating additional RNG into its PGC supply portfolio?

A. UGI Gas is uniquely situated in that there are several RNG facilities directly connected to its distribution system. The benefit of direct connection is that it provides access to locally produced natural gas supplies that do not require transportation on an interstate pipeline, eliminating the transportation costs and increasing local supply resiliency. UGI Gas believes that fostering RNG production within its service territory provides significant economic and environmental benefits for local communities and the Commonwealth. Additionally, by continuing to procure RNG supplies and the associated environmental attributes, UGI Gas is contributing to the growth of carbon-reduction efforts across the industry and encouraging future direct connections within its service territory, which will ultimately reduce the price of RNG over time.

1 **Q. What is the anticipated cost of the selected RNG supplies?**

2 A. The selected RNG supplies equate to about 6,600 Dth/day of supply delivered into UGI
3 Gas's distribution system and have a projected annual cost of \$51.9 million to PGC
4 customers. The weighted average cost of the selected RNG options is \$21.46/Dth.

5
6 **Q. What is the anticipated cost impact to the PGC of monetizing the associated RINs?**

7 A. UGI Gas believes that by monetizing the RINs itself and applying the RSIM to RIN
8 revenues, PGC customers will receive a greater cost benefit than the current cost-offset
9 methodology in the first phase of the pilot. A conservative estimate of RIN monetization
10 revenue determined an annual credit of \$40 million that would be allocated back to PGC
11 customers. This results in a net annual RNG cost of \$11.9 million to the PGC, or a net
12 weighted average cost of \$4.93/Dth. This price is within the range of traditionally sourced
13 gas purchased by the Company for inclusion in the PGC.

14

15 **XI. Hedging Policy Review**

16 **Q. Please describe the Company's commitments regarding its hedging program**
17 **stemming from the settlement in the 2024 PGC proceeding at Docket No. R-2024-**
18 **3048828.**

19 A. In the 2024 PGC proceeding⁹, UGI Gas committed to a 4-year hedging pilot program.
20 Specifically, the Company agreed to the following:

⁹ See *Joint Petition for Settlement of Section 1307(f) Rate Investigation* from Docket No R-2024-3048828 (Order entered October 10, 2024).

- 1 a. The Company will implement the recommendations provided in Gelber &
2 Associates' Trigger Price Study ("Study"), conducted per the 2023 PGC Settlement
3 (Docket No. R-2023-3040290) by way of a 4-year pilot commencing on January 1,
4 2025. The recommendations from the Study, described on pages 36-37 of UGI Gas
5 St. No. 2, include:
- 6 b. Change the strategy of the current hedge program from an even distribution of
7 monthly hedge purchases to a plan that is flexible and has "trigger hedge" amounts
8 that are more heavily weighted towards months where the futures prices have
9 historically been lower than other purchasing months; and
- 10 c. Revise the current schedule for hedge purchases from fixed days on a weekly basis
11 to a market data-driven and informed, analytical determination of the most effective
12 days within each month to purchase hedge positions.
- 13 d. During the pilot, UGI Gas will compare the actual cost of the hedging activities set
14 forth in the Study's recommendations against the performance that would have
15 otherwise occurred under the Company's existing programmatic approach to
16 hedging purchases.
- 17 e. UGI Gas will hire a consultant, through an RFP process, to implement these
18 recommendations and collect and analyze the data needed to compare the pilot
19 against UGI Gas's programmatic methodology. The Company will recover these
20 consultant costs, related to implementing the recommendations of the Study, as well
21 as analyzing and comparing the pilot data to UGI Gas's programmatic hedging
22 approach in PGC rates.
- 23

1 **Q. Has the Company implemented the Pilot program?**

2 A. Yes. The Company commenced the pilot program in January 2025 and continues to make
3 purchases based on the modified hedging practices while tracking the performance that
4 would have occurred under the Company's historic methodology.

5

6 **Q. Does this conclude your direct testimony?**

7 A. Yes.

UGI GAS EXHIBIT JLJ-1

(Resume and Educational Background)

JAMIE L. JOWERS

SR. MANAGER – ENERGY SUPPLY

WORK EXPERIENCE

August 2025 – Present **Sr. Manager, Energy Supply**

UGI Utilities, Inc., Denver, PA

January 2025 – August 2025 **Manager, Energy Supply**

UGI Utilities, Inc., Denver, PA

2020 – 2025 **Sr. Supervisor, Energy Supply and Regulatory Planning**

UGI Utilities, Inc., Denver, PA

2017 – 2020 **Energy Supply Analyst II – Energy Planning & Procurement**

UGI Utilities, Inc., Denver, PA

2015 – 2017 **Energy Supply Analyst I – Short Term Planning & Scheduling**

UGI Utilities, Inc., Reading, PA

2014 **Intern – Contracts Administration**

PPL Energy Plus, LLC., Allentown, PA

EDUCATION

MBA, The Pennsylvania State University, Malvern, PA (2023)

BS, Energy Business and Finance, The Pennsylvania State University, State College, PA (2015)

PREVIOUS TESTIMONY

UGI 2025 Commodity and Purchased Gas Proceeding MD PSC Case No. 9516(h)

UGI GAS EXHIBIT JLJ-2

(Revised Attachment 14-1)

**UGI Utilities, Inc. - Gas Division
Combined
Projected Peak Day Capacity Requirements and Supply Options
(Dth/D)**

Supplier	Upstream Pipeline	Rate Schedule	2026-2027	2027-2028	2028-2029	2029-2030	2030-2031
Columbia		SST / FSS	126,473	126,473	126,473	126,473	126,473
Columbia		FTS	121,932	121,932	121,932	121,932	121,932
Columbia		NTS	19,520	19,520	19,520	19,520	19,520
Texas Eastern		FT/FT-1	182,204	182,204	182,204	182,204	182,204
Texas Eastern		CDS	84,068	84,068	84,068	84,068	84,068
Texas Eastern	EGTS	FTS-5	6,667	6,667	6,667	6,667	6,667
Texas Eastern	EGTS	FT / GSS I	2,000	2,000	2,000	2,000	2,000
Texas Eastern	EGTS	FT / FTS-5	2,000	2,000	2,000	2,000	2,000
Texas Eastern		SS-1	7,659	7,659	7,659	7,659	7,659
EGTS		FT	2,000	2,000	2,000	2,000	2,000
Texas Eastern / UGI Energy Services		Delivered Supply	40,003	40,003	40,003	40,003	40,003
Supplier G LNG Supply		Peaking Services	500	500	500	500	500
Supplier TBD LNG Supply		Peaking Services	10,000	10,000	10,000	10,000	10,000
Tennessee		FT	40,068	40,068	40,068	40,068	40,068
Tennessee		Delivered Supply	25,160	25,160	25,160	25,160	25,160
UGI Storage Company		NNS	8,792	8,792	8,792	8,792	8,792
Transco		FT	70,192	70,192	70,192	70,192	70,192
Transco		FTF/FT	22,770	22,770	22,770	22,770	22,770
Transco		SS-2	33,120	33,120	33,120	33,120	33,120
Transco		GSS	59,378	59,378	59,378	59,378	59,378
Transco		LGA	1,035	1,035	1,035	1,035	1,035
Transco		PS-FT	5,073	5,073	5,073	5,073	5,073
Transco		LSS	7,518	7,518	7,518	7,518	7,518
Transco		FT-Pocono	2,000	2,000	2,000	2,000	2,000
Transco		FT-Sentinel	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)
Local Production - Supplier D		Direct Connection	600	600	600	600	600
Transco / UGI Energy Services		Delivered Supply	134,163	134,163	134,163	134,163	134,163
UGI Energy Services		Peaking Services	479,187	479,187	479,187	479,187	479,187
Subtotal			1,487,082	1,487,082	1,487,082	1,487,082	1,487,082
Third Party Capacity - Large Customers			856,171	856,171	856,171	856,171	856,171
Total Firm Capacity			2,343,253	2,343,253	2,343,253	2,343,253	2,343,253

PGC-1 Requirements	902,706	913,666	924,626	935,586	946,546
CHOICE Requirements	251,662	251,662	251,662	251,662	251,662
Subtotal	1,154,368	1,165,328	1,176,288	1,187,248	1,198,208
Firm Transportation Requirements	1,079,111	1,079,111	1,079,111	1,079,111	1,079,111
Growth	10,960	10,960	10,960	10,960	10,960
Total Requirements	2,233,479	2,244,439	2,255,399	2,266,359	2,277,319
Reserve Requirements	57,718	58,266	58,814	59,362	59,910
Total Requirements and Reserve	2,291,197	2,302,705	2,314,213	2,325,721	2,337,229

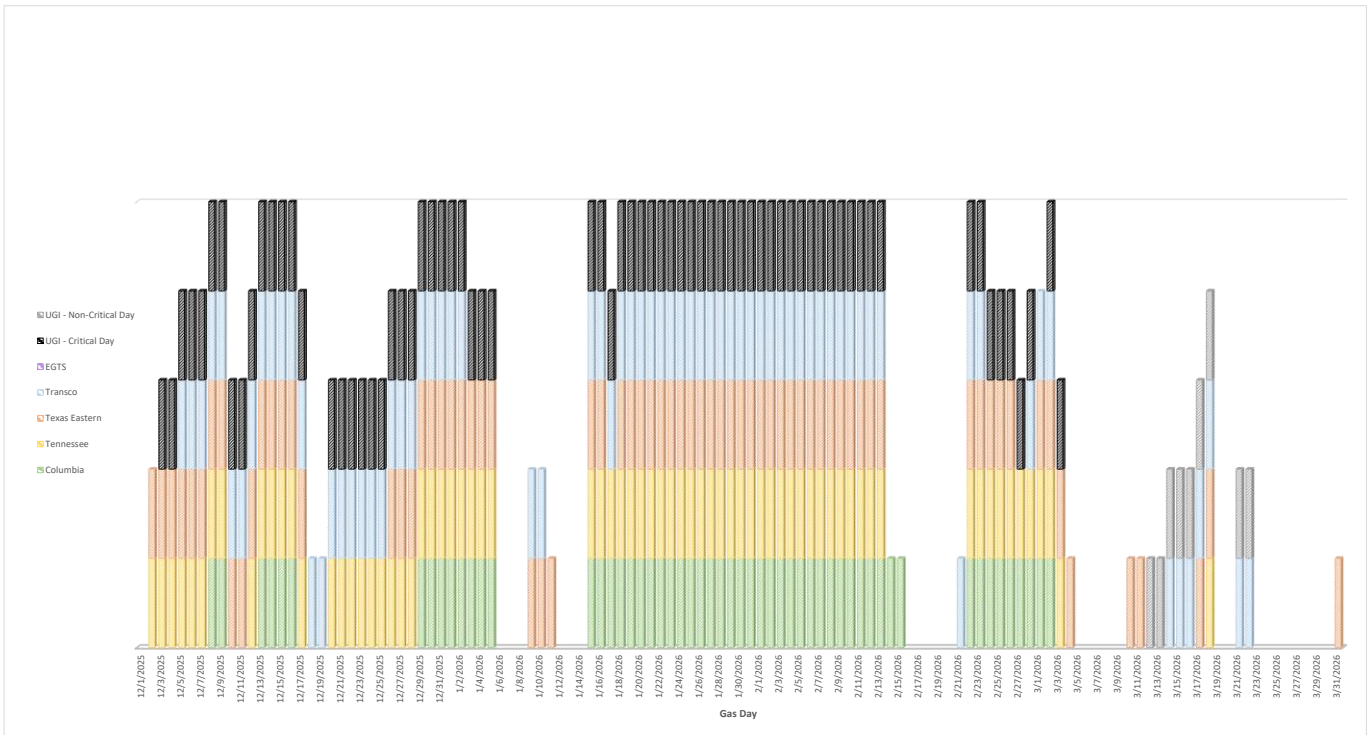
Long/(Short)	52,056	40,548	29,040	17,532	6,024
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UGI GAS EXHIBIT JLJ-3

(Fern Pricing)

UGI GAS EXHIBIT JLJ-4

(Pipeline Restrictions)



UGI GAS EXHIBIT JLJ-5

CONFIDENTIAL

(Optimization Report)

(page intentionally omitted from the public version)

UGI GAS EXHIBIT JLJ-6
(Summary of Contract Renewals)

Summary of Contract Renewals

Contract	MDQ	Effective Date	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension	Extension Process
EGTS FT - 200796	2,000	1/1/2005	3/31/2026	3/31/2025	\$72	2 Years	Extension notice provided
Texas Eastern CDS - 800239	25,000	6/1/1993	10/31/2026	10/31/2025	\$304	1 Year	Automatic evergreen rollover
Texas Eastern CDS - 800397	41,000	11/1/1993	10/31/2026	10/31/2025	\$304	1 Year	Automatic evergreen rollover
Texas Eastern CDS - 820019	10,000	11/1/2000	10/31/2026	10/31/2025	\$190	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800468	10,000	11/1/1995	10/31/2027	10/31/2025	\$188	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 830067	10,000	12/1/1999	10/31/2027	10/31/2025	\$188	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800504	4,000	11/1/1995	10/31/2026	10/31/2025	\$183	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800373	20,000	11/1/1994	10/31/2027	10/31/2025	\$188	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800240	25,000	6/1/1993	10/31/2026	10/31/2025	\$298	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800394	32,475	11/1/1993	10/31/2026	10/31/2025	\$298	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 910181	12,000	11/1/2004	10/31/2026	10/31/2025	\$253	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 910417	11,713	11/1/2003	10/31/2026	10/31/2025	\$188	1 Year	Automatic evergreen rollover
Texas Eastern FTS-5 - 330910	6,667	6/1/1993	3/31/2028	3/31/2026	\$89	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 911580	5,880	11/1/1994	4/15/2027	4/15/2025	\$188	1 Year	Automatic evergreen rollover
Texas Eastern CDS - 800376	8,068	10/1/1993	10/31/2027	10/31/2025	\$298	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 800404	1,136	11/1/1994	10/31/2026	10/31/2025	\$298	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 830060	4,000	3/24/1999	11/30/2027	11/30/2025	\$155	1 Year	Automatic evergreen rollover
Texas Eastern FT-1 - 911153	3,300	11/1/2014	10/31/2026	10/31/2025	\$84	1 Year	Automatic evergreen rollover
Texas Eastern SS-1 - 400190	7,659	5/1/1994	4/30/2028	4/30/2025	\$98	1 Year	Automatic evergreen rollover
Transco FT - 1002594	5,072	2/1/1992	3/31/2029	3/31/2026	\$234	1 Year	Automatic evergreen rollover
Transco FT - 1002595	2,081	4/10/1990	3/31/2029	3/31/2026	\$234	1 Year	Automatic evergreen rollover
Transco FT - 1013596	22,770	10/1/1996	3/31/2027	3/31/2026	\$57	1 Year	Automatic evergreen rollover
Transco FT-PS - 1005004	1,346	8/1/1991	3/31/2029	3/31/2026	\$108	1 Year	Automatic evergreen rollover
Transco SS-2 - 1003973	7,245	7/25/1990	3/31/2027	3/31/2026	\$126	1 Year	Automatic evergreen rollover
Transco ESS - 9162496	10,000	11/1/1993	10/31/2025	4/30/2025	\$27	1 Year	Automatic evergreen rollover
Transco FT - 1021106	500	7/10/1997	10/31/2025	4/30/2025	\$23	1 Year	Automatic evergreen rollover
Transco FT - 9180223	12,279	12/1/2015	7/31/2028	7/31/2025	\$234	1 Year	Automatic evergreen rollover
Transco FT-PS - 1004999	3,416	8/1/1991	3/31/2029	3/31/2026	\$108	1 Year	Automatic evergreen rollover
Transco LSS - 1000796	7,518	10/1/1993	3/31/2027	3/31/2026	\$234	1 Year	Automatic evergreen rollover
Transco SS-2 - 1004032	25,875	4/1/1990	3/31/2027	3/31/2026	\$126	1 Year	Automatic evergreen rollover
Transco FT - 1021107	1,500	11/1/1997	3/31/2027	9/30/2025	\$23	1 Year	Automatic evergreen rollover
Transco FT- PS - 1005005	311	8/1/1991	7/31/2028	7/31/2025	\$108	1 Year	Automatic evergreen rollover
Transco FT - 1003692	10,712	2/1/1992	3/31/2029	3/31/2026	\$234	1 Year	Automatic evergreen rollover
Transco FT - 1006503	4,566	10/1/1993	10/31/2026	10/31/2025	\$241	1 Year	Automatic evergreen rollover
Transco FT - 1012119	828	11/16/1995	3/31/2027	3/31/2026	\$234	1 Year	Automatic evergreen rollover
Transco LG-A - 1000783	1,035	11/1/1974	3/31/2026	9/30/2025	\$74	1 Year	Automatic evergreen rollover
UGI Energy Services - Peaking - UGIU-P-1012	23,632	11/1/2016	3/31/2026	3/31/2025	\$153	5 Years	Extension notice provided
UGI Energy Services - Peaking - PNG-P-1003	21,772	11/1/2016	3/31/2026	3/31/2025	\$132	5 Years	Extension notice provided
Supplier D - Local Production	600	11/1/2020	10/31/2025	7/31/2025	N/A	1 Year	Extension notice provided
Supplier N - Local Production	1,680	7/1/2023	3/31/2026	None	N/A	1 Year	Extension notice provided

UGI GAS EXHIBIT JLJ-7

(Summary of Future Contract Renewals)

Summary of Future Contract Renewals

Contract	MDQ	Effective Date	Term End Date	Notice Date	Demand Rates (\$/Dth)	Term Extension	Extension Process	Contract Benefit
Columbia FTS - 230222	10,782	11/1/2012	10/31/2027	4/30/2027	\$162	5 Years	Extension notice provided	1, 2, 4
Columbia FTS - 230211	2,432	11/1/2004	10/31/2027	4/30/2027	\$162	5 Years	Extension notice provided	1, 5
Columbia FTS - 230212	2,432	11/1/2004	10/31/2027	4/30/2027	\$162	5 Years	Extension notice provided	2, 3, 4
Columbia FTS - 230213	2,432	11/1/2004	10/31/2027	4/30/2027	\$162	5 Years	Extension notice provided	2, 3, 4
Columbia FTS - 230214	2,434	11/1/2004	10/31/2027	4/30/2027	\$162	5 Years	Extension notice provided	2, 3, 4
EGTS FT - 200796	2,000	1/1/2005	3/31/2028	3/31/2027	\$72	5 Years	UGI Gas is actively negotiating an extension	2, 4
Texas Eastern CDS - 800239	25,000	6/1/1993	10/31/2027	10/31/2026	\$304	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern CDS - 800397	41,000	11/1/1993	10/31/2027	10/31/2026	\$304	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern CDS - 820019	10,000	11/1/2000	10/31/2027	10/31/2026	\$190	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800468	10,000	11/1/1995	10/31/2028	10/31/2026	\$188	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 830067	10,000	12/1/1999	10/31/2028	10/31/2026	\$188	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800504	4,000	11/1/1995	10/31/2027	10/31/2026	\$183	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800373	20,000	11/1/1994	10/31/2028	10/31/2026	\$188	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 800240	25,000	6/1/1993	10/31/2027	10/31/2026	\$298	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern FT-1 - 800394	32,475	11/1/1993	10/31/2027	10/31/2026	\$298	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 910181	12,000	11/1/2004	10/31/2027	10/31/2026	\$253	1 Year	Automatic evergreen rollover	2, 3, 4
Texas Eastern FT-1 - 910417	11,713	11/1/2003	10/31/2027	10/31/2026	\$188	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FTS-5 - 330910	6,667	6/1/1993	3/31/2029	3/31/2027	\$89	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern FT-1 - 911580	5,880	11/1/1994	4/15/2028	4/15/2027	\$188	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern CDS - 800376	8,068	10/1/1993	10/31/2028	10/31/2026	\$298	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern FT-1 - 800404	1,136	11/1/1994	10/31/2027	10/31/2026	\$298	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 830060	4,000	3/24/1999	11/30/2028	11/30/2026	\$155	1 Year	Automatic evergreen rollover	2, 4
Texas Eastern FT-1 - 911153	3,300	11/1/2014	10/31/2027	10/31/2026	\$84	1 Year	Automatic evergreen rollover	1, 2, 4
Texas Eastern SS-1 - 400190	7,659	5/1/1994	4/30/2029	4/30/2027	\$98	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1002594	5,072	2/1/1992	3/31/2030	3/31/2027	\$234	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1002595	2,081	4/10/1990	3/31/2030	3/31/2027	\$234	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1013596	22,770	10/1/1996	3/31/2028	3/31/2027	\$57	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT-PS - 1005004	1,346	8/1/1991	3/31/2030	3/31/2027	\$108	1 Year	Automatic evergreen rollover	1, 2, 4
Transco SS-2 - 1003973	7,659	7/25/1990	3/31/2028	3/31/2027	\$126	1 Year	Automatic evergreen rollover	
Transco ESS - 9162496	10,000	11/1/1993	10/31/2027	4/30/2027	\$27	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1021106	500	7/10/1997	10/31/2027	4/30/2027	\$23	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 9180223	12,279	12/1/2015	7/31/2029	7/31/2026	\$234	1 Year	Automatic evergreen rollover	2, 4
Transco FT-PS - 1004999	3,416	8/1/1991	3/31/2030	3/31/2027	\$108	1 Year	Automatic evergreen rollover	1, 2, 4
Transco LSS - 1000796	7,518	10/1/1993	3/31/2028	3/31/2027	\$234	1 Year	Automatic evergreen rollover	1, 2, 4
Transco SS-2 - 1004032	25,875	4/1/1990	3/31/2028	3/31/2027	\$126	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1021107	1,500	11/1/1997	3/31/2027	9/30/2026	\$23	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT-PS - 1005005	311	8/1/1991	7/31/2029	7/31/2026	\$108	1 Year	Automatic evergreen rollover	1, 2, 4
Transco FT - 1003692	10,712	2/1/1992	3/31/2030	3/31/2027	\$234	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1006503	4,566	10/1/1993	10/31/2027	10/31/2026	\$241	1 Year	Automatic evergreen rollover	2, 4
Transco FT - 1012119	828	11/16/1995	3/31/2028	3/31/2027	\$234	1 Year	Automatic evergreen rollover	2, 4
Transco LG-A - 1000783	1,035	11/1/1974	3/31/2027	9/30/2026	\$74	1 Year	Automatic evergreen rollover	1, 2, 4
Tennessee FT-A - 362539	3,183	11/1/2020	10/31/2027	10/31/2026	\$50	5 Years	Extension notice provided	1, 2, 4
Supplier D - Local Production	600	11/1/2020	10/31/2026	7/31/2026	N/A	1 Year	Extension notice provided	1, 5
Supplier N - Local Production	1,680	7/1/2023	3/31/2027	None	N/A	1 Year	Extension notice provided	1, 5

<p>Contract Benefits Key: 1 - Low Contract Cost* 2 - Provides Service Flexibility 3 - Is Callable at No-Notice 4 - Hard to replace, fully subscribed capacity 5 - Local Production/Supply Diversity</p>

*Threshold established at the Weight Average Cost of Demand for DS customers as of June 1, 2026.

UGI GAS EXHIBIT JLJ-8

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(Summary of Transco AMA RFP Responses)

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UGI GAS EXHIBIT JLJ-9

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(Requested RNG Supply Offerings)

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