June 3, 2024

Ms. Kari French
Director, Oversight & Safety Division
Railroad Commission of Texas
1701 N. Congress Ave., 9th Floor
Austin, TX 78701

Re: Case No. 00017471; *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central-Gulf Service Area*

Dear Ms. French:

Enclosed are ten copies of Texas Gas Service Company's, a Division of ONE Gas, Inc., Statement of Intent to change gas utility rates within the unincorporated areas of the Central-Gulf Service Area, including supporting exhibits and a flash drive that contains the electronic files. The electronic files have been uploaded to RRC CASES for filing.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Best regards,

Kate Norman

Kate Norman
Attorney for Texas Gas Service Company

KWN:ssm
Enclosures

cc: Sarah Montoya-Foglesong, Market Oversight Section Director
Judy Jenkins Hitchye
Stacey McTaggart

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

TEXAS GAS SERVICE COMPANY'S STATEMENT OF INTENT TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA

Texas Gas Service Company ("TGS" or the "Company"), a Division of ONE Gas, Inc. ("ONE Gas") and a "gas utility" under Texas Utilities Code § 101.003(7), respectfully files this Statement of Intent, pursuant to Subchapter C of Chapter 104 of the Texas Utilities Code and the rules of the Railroad Commission of Texas ("Commission"), to change gas utility rates within the unincorporated (or environs) areas of the Central-Gulf Service Area ("CGSA"). Contemporaneously with this filing, TGS is also filing Statements of Intent to Change Rates with the municipalities with original jurisdiction in the CGSA.[1]

The Company requests that the proposed rate schedules and tariffs for the CGSA, attached as **Exhibit A** to this Statement of Intent and incorporated herein by reference, become effective on July 8, 2024, which is 35 days from the date of this filing. In support of its request, the Company respectfully shows as follows:

I. INTRODUCTION AND SUMMARY OF THE RATE REQUEST

TGS calculated the revenue requirement for this filing using the system-wide cost of providing service to all customers within the incorporated and unincorporated areas of the CGSA. The new rates will affect all customers in the CGSA. Current rate schedules include residential,

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[1] The CGSA Cities include: Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas.

commercial, commercial transportation, industrial, industrial transportation, public authority, public authority transportation, public school space heating, public school space heating transportation, electrical cogeneration, electrical cogeneration transportation, compressed natural gas, compressed natural gas transportation and unmetered gas light service.

For the 12-month period ended December 31, 2023, the Company's overall, combined revenue requirement for the CGSA on a system-wide basis totaled approximately $191.2 million, as adjusted. The total revenue TGS received during the test year from customers within the CGSA was approximately $165.4 million, leaving a revenue deficiency on a combined basis of approximately $25.8 million.

If approved, the requested rates will increase TGS's revenues in the CGSA by $25.8 million, which is an increase of 9.83% including gas costs, or 15.59% excluding gas costs. Because the proposed changes will increase TGS's total aggregate revenues within the CGSA by more than 2.5%, the proposed rate changes constitute a "major change" in rates as that term is defined by Texas Utilities Code § 104.101. Additionally, the proposed rates will not exceed 115% of the average of all rates for similar services of all municipalities served by the Company within the same county.

As part of this Statement of Intent, the Company is requesting: (1) Commission approval of new depreciation rates for Direct and Division distribution and general plant within the CGSA; (2) a finding from the Commission that expenses for Winter Storm Uri and COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (3) a prudence determination for capital investment made in the CGSA through December 31, 2023, including capital investment in the Company's Interim Rate Adjustment ("IRA") filings made since the last rate case in the CGSA, pursuant to Texas Utilities Code § 104.301; (4) approval to include Excess Deferred Income Taxes ("EDIT") in base rates, with discontinuance of the EDIT Rider to return EDIT to customers; and (5) approval to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law. The exact amount of the rate case expenses will not be known until the case is complete.

The rate schedules and tariffs, attached hereto as **Exhibit A** to the Rate Filing Package and made a part hereof, support the rate changes proposed by the Company. Additionally, the Company is proposing: (1) a new Small and Large Residential rate design and related rate schedules based on customer usage patterns; (2) a new Small and Large Commercial rate design and related rate schedules based on customer usage patterns; (3) a new Renewable Natural Gas ("RNG") Credits Program rate schedule; (4) new Rate Schedules RCE and RCE-ENV for a rate case expense surcharge to recover all reasonable rate case expenses incurred by the Company and cities in connection with the Statement of Intent filing that has been made with the cities and the Commission; and (5) revisions to the Rules of Service for consistency with Commission rules and other Company service areas. Additional proposed revisions to the Company's rate schedules and tariffs are detailed in Section E of this Statement of Intent.

II. JURISDICTION

TGS is a gas utility as that term is defined in § 101.003(7) of the Texas Utilities Code. Pursuant to Texas Utilities Code § 102.001(a), the Commission has exclusive original jurisdiction to set the rates TGS requests for customers in the unincorporated areas of the CGSA. Consistent with such jurisdiction, the proposed rates identified in **Exhibit A** are applicable to the Company's natural gas service within the unincorporated areas of the CGSA.

III. DETAILS OF PROPOSED CHANGES

A. Rate Filing Package

In addition to this Statement of Intent, the Rate Filing Package consists of the following:

- SOI Exhibit A — Proposed Rate Schedules and Tariffs
- SOI Exhibit B — Proposed Revenue Change by Class
- SOI Exhibit C — Average Bill Impact by Class
- SOI Exhibit D — Direct Testimony
- SOI Exhibit E — Proposed Notice
- SOI Exhibit F — Proposed Protective Order
- SOI Exhibit G — Cost of Service Schedules
- SOI Exhibit H — Workpapers

B. Test Year

The Company's proposed cost of service for the CGSA as set forth in this Statement of Intent and Rate Filing Package is based on the 12-month period ended December 31, 2023, updated for known changes and conditions that are measurable with reasonable accuracy.

C. Effective Date

The Company requests that the Commission order the proposed rates to be effective for bills rendered on and after July 8, 2024.

D. Class and Number of Customers Affected

The proposed changes to the Company's rate schedules will affect all customers in the CGSA. The table below shows the approximate number of existing customers by class who will be affected by the proposed rate changes:

Customer Class	CGSA Customers	
	Incorporated	Environs
Residential	281,253	30,284
Commercial	12,743	433
Industrial	25	0
Public Authority	777	54
Public School Space Heating	6	1
Compressed Natural Gas	1	0
Electric Cogeneration	0	0
Unmetered Gas Light	1	0
Commercial Transportation	313	11
Industrial Transportation	28	9
Public Authority Transportation	412	8
Public School Space Heating Transportation	76	2
Compressed Natural Gas Transportation	3	1
Electric Cogeneration Transportation	1	0
Irrigation	0	2
Special Contract Transportation	11	2

Exhibits B and **C**, attached, show the amount of the proposed change and the effect of the proposed change on an average bill for each class of customers.

E. Proposed Rate Schedules and Tariffs

TGS seeks approval of the rate schedules and tariffs for the CGSA, attached to this Statement of Intent as **Exhibit A** and incorporated herein by reference. The following identifies the proposed revisions to rate schedules and tariffs:

1. All proposed incorporated and environs Rate Schedules for General Sales and Transportation Customers include revisions to the “Other Adjustments” section to: add references to Rate Schedules RCE, RCE-ENV and PSF, remove references to Rate Schedule EDIT-Rider, remove references to Rate Schedule HARV-Rider, add a revision to the “Cost of Service Rate” section to clarify the Company’s delivery charge, revise the “Territory” section in General Sales rate schedules, and to edit the “Availability” section in the Transportation rate schedule for consistency with other Company service areas.

2. Residential Rate Schedules 10, 15, 1Y and 1Z: designate 10 and 1Z as Small Residential, add new 15 and 1Y Large Residential rate schedules and revise the “Applicability” section for consistency with other Company service areas.

3. Commercial Rate Schedules 20, 25, 2Y and 2Z: designate 20 and 2Z as Small Commercial, add new 25 and 2Y Large Commercial rate schedules and revise the "Applicability" section for consistency with other Company service areas.

4. Public Authority Rate Schedules 40 and 4Z: revise the "Applicability" section for consistency with other Company service areas.

5. Unmetered Gas Light Rate Schedules 70 and 7Z: revise the "Applicability" section for consistency with other Company service areas.

6. Electric Generation (previously known as Electric Cogeneration) Rate Schedules C-1 and C-1-ENV: revise the "Applicability" section that provides a mechanism to provide natural gas service to non-residential customers for the purpose of electric generation, and revise the "Applicability" section for consistency with other Company service areas.

7. Transportation Rate Schedules T-1, T-1-ENV and T-TERMS: add rates for Electric Generation service; remove rates for Public School Space Heating; revise section 1.2 with the addition of definitions for "Agreement," "Firm Service" and "Force Majeure" to provide clarity for Customer and Company rights and responsibilities during a curtailment event; add a definition for "Electric Generation Service" to align with Commission Rule 7.455 to include distributed generation and backup power systems that are registered with the applicable balancing authorities; revise sections 1.4 and 1.6 to clarify Qualified Supplier and Company responsibilities for designating receipt points; add clarifying language to section 1.5(g) for Customer's responsibility to provide written notice to the Company; revise the "Applicability," "Availability," "Additional Charges," and "Subject To" sections in T-1 and T-1-ENV and sections 1.1, 1.2, 1.4, 1.5, 1.6 and 1.7 in T-TERMS for consistency with other Company service areas; and add sections 1.3 and 1.8 for consistency with other Company service areas.

8. Cost of Gas Clauses 1-INC and 1-ENV: expand language in section B.3 to include other renewable sources of natural gas and Environmental Attributes associated with the purchase of RNG to make the language consistent with approved Cost of Gas clauses in Docket No. OS-22-00009896 ("Docket No. 9896"); and add clarifying language for the use of financial instruments in sections B.3, B.7 and B.10 to make consistent with the recently approved Cost of Gas clauses in Docket No. 9896 and Docket No. OS-23-00014399 ("Docket No. 14399").

9. Rate Schedule RNG: a new rate schedule for which the Company is requesting approval that allows for the inclusion of a designated amount of RNG credits in the Cost of Gas Clause and establishment of a RNG Credits Program tariff, Rate

Schedule RNG Credits Program, through which interested customers can opt to offset a portion of their gas usage with RNG Credits.

10. Rate Schedule WNA: reflect revisions to the "Applicability" section to reference new Rate Schedules for Large Residential and Large Commercial; update weather factors for each class consistent with weather normalization calculation in this case; and revise the "Applicability" and "Filing with the Cities and the Railroad Commission of Texas (RRC)" sections for consistency with the other Company service areas.

11. Rate Schedules RCE and RCE-ENV: provides a mechanism to recover all reasonable rate case expenses incurred by the Company and cities in connection with the Statement of Intent filings that have been made with the cities and the Commission.

12. Rules of Service: reflect revisions for consistency with the Commission's Quality of Service Rules and the approved Rules of Service in Docket Nos. 9896 and 14399. In addition, the Company proposes:

    a. Updating the Company's contact information on page 1 for customer inquiries;

    b. Updating § 1.3, Definitions, to include all updates to terminology in the Rules of Service as revised to make consistent with approved Rules of Service in Docket Nos. 9896 and 14399; as well as to add definitions for "Firm Service" and "Force Majeure" to provide clarity for Customer and Company rights and responsibilities during a curtailment event; add definition for "Master Meter;" change the former "Electrical Cogeneration Service" to reflect the new reference "Electric Generation Service" and to include distributed generation and backup power systems that are registered with the applicable balancing authorities in the scope of this definition; and update "Excess Flow Valve" to expand the definitions;

    c. Revisions to § 3 and § 4.5 to include language for the availability of rate schedules on the Company's website;

    d. Revisions to § 4.4 to remove a reference to the Company's previous filed curtailment plan and to § 4.4(iv) to include curtailment language consistent with the new Commission Rule 7.455;

    e. Addition of § 4.7 to clarify the process for customer complaints;

    f. Revisions to § 4.8 to add language regarding force majeure situations to the limitation of liability provision;

g. Revisions to § 4.6, § 7.4, § 7.7, § 9.1 and § 9.6 to provide for electronic billing and notice;

h. Revisions to § 5 to move Refusal of Service provisions to § 6;

i. Revisions to § 9.9 (previously § 20.1) to update the language to reflect the current plan description for Average Payment Plan;

j. Making an administrative correction to § 12.9;

k. Revisions to § 8 and § 11 (previously § 10 and § 8, respectively) to include language consistent with Commission Rule § 7.458 and to clarify security deposits and requirements for customer-owned facilities;

l. Revisions to § 15 (previously § 21), Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas; and

m. Withdraw the rules of service addenda CGSA-Env 7-45 and CGSA-Env 7-46, as these provisions have been included within the proposed CGSA Rules of Service in § 7.7 and § 8.3(e).

13. Withdraw the following rate schedules: Public School Space Heating (48 and 4H); and Excess Deferred Income Tax Credit, Rate Schedule EDIT-Rider.

F. Effect of Proposed Rate Changes

The specific proposed changes to the Company's rates are shown in the following side-by-side comparison of existing and proposed rates for customers in the CGSA:

	Current Rates Incorporated and Unincorporated/Environs		
Customer Class	CGSA Incorporated Rates	CGSA Environs Rates	Proposed CGSA Rates
Residential			
No. of Customers Affected	281,253	30,284	
Customer Charge	$25.47	$25.47	
Volumetric Charge (per Ccf)	$0.32626	$0.32626	
Small Customer Charge			$25.50
Small Volumetric Charge (per Ccf)			$0.69448
Large Customer Charge			$39.00
Large Volumetric Charge (per Ccf)			$0.23425

Customer Class	Current Rates Incorporated and Unincorporated/Environs CGSA Incorporated Rates	 CGSA Environs Rates	Proposed CGSA Rates
Commercial			
No. of Customers Affected	12,743	433	
Customer Charge	$96.08	$96.08	
Volumetric Charge (per Ccf)	$0.12679	$0.12679	
Small Customer Charge			$85.00
Small Volumetric Charge (per Ccf)			$0.15710
Large Customer Charge			$100.00
Large Volumetric Charge (per Ccf)			$0.10765
Commercial Transportation			
No. of Customers Affected	313	11	
Customer Charge	$308.08	$308.08	$297.51
Volumetric Charge (per Ccf)	$0.12679	$0.12679	$0.12679
Industrial			
No. of Customers Affected	25	0	
Customer Charge	$1,005.41	$1,005.41	$572.02
Volumetric Charge (per Ccf)	$0.12707	$0.12707	$0.12707
Industrial Transportation			
No. of Customers Affected	28	9	
Customer Charge	$1,205.41	$1,205.41	$772.02
Volumetric Charge (per Ccf)	$0.12707	$0.12707	$0.12707
Public Authority			
No. of Customers Affected	777	54	
Customer Charge	$160.70	$160.70	$156.05
Volumetric Charge (per Ccf)	$0.12549	$0.12549	$0.12549
Public Authority Transportation			
No. of Customers Affected	412	8	
Customer Charge	$183.70	$183.70	$179.05
Volumetric Charge (per Ccf)	$0.12549	$0.12549	$0.12549
Public School Space Heating (Reclassed to Public Authority)			
No. of Customers Affected	6	1	
Customer Charge	$213.70	$213.70	$156.05
Volumetric Charge (per Ccf)	$0.10012	$0.10012	$0.12549

	Current Rates Incorporated and Unincorporated/Environs		
Customer Class	CGSA Incorporated Rates	CGSA Environs Rates	Proposed CGSA Rates
Public School Space Heating Transportation (Reclassed to Public Authority Transportation)			
No. of Customers Affected	76	2	
Customer Charge	$313.70	$313.70	$179.05
Volumetric Charge (per Ccf)	$0.10012	$0.10012	$0.12549
Electric Generation (Previously Known as Electric Cogeneration)			
No. of Customers Affected	0	0	
Customer Charge	$183.70	$183.70	$175.98
Volumetric Charge (per Ccf)			
First 5,000 Ccf/Month	$0.07720	$0.07720	$0.07427
Next 35,000 Ccf/Month	$0.06850	$0.06850	$0.06590
Next 60,000 Ccf/Month	$0.05524	$0.05524	$0.05314
All Over 100,000 Ccf/Month	$0.04016	$0.04016	$0.03864
Electric Generation Transportation (Previously Known as Electric Cogeneration Transportation)			
No. of Customers Affected	1	0	
Customer Charge	$183.70	$183.70	$175.98
Volumetric Charge (per Ccf)			
First 5,000 Ccf/Month	$0.07720	$0.07720	$0.07427
Next 35,000 Ccf/Month	$0.06850	$0.06850	$0.06590
Next 60,000 Ccf/Month	$0.05524	$0.05524	$0.05314
All Over 100,000 Ccf/Month	$0.04016	$0.04016	$0.03864
Compressed Natural Gas			
No. of Customers Affected	1	0	
Customer Charge	$812.71	$812.71	$594.88
Volumetric Charge (per Ccf)	$0.06684	$0.06684	$0.06684
Compressed Natural Gas Transportation			
No. of Customers Affected	3	1	
Customer Charge	$837.71	$837.71	$619.88
Volumetric Charge (per Ccf)	$0.06684	$0.06684	$0.06684
Unmetered Gas Light			
No. of Customers Affected	1	0	
Customer Charge	$0.00	$0.00	$0.00
Public Authority Volumetric Charge (per Ccf)	$0.12549	$0.12549	$0.12549

	Current Rates Incorporated and Unincorporated/Environs		
Customer Class	CGSA Incorporated Rates	CGSA Environs Rates	Proposed CGSA Rates
Residential Volumetric Charge (per Ccf)	$0.69448	$0.69448	$0.69448
Commercial Volumetric Charge (per Ccf)	$0.15710	$0.15710	$0.15710
Industrial Volumetric Charge (per Ccf)	$0.12707	$0.12707	$0.12707

Exhibit C shows the average bill impact by customer class.

G. Witness Testimony

Attached as **Exhibit D** to the Statement of Intent is the direct testimony supporting the Company's requested revenue requirement. The attached testimony includes the following witnesses:

- *Jeff Husen* is Vice-President of Rates and Regulatory Affairs for ONE Gas. Mr. Husen provides an overview of the Statement of Intent filing, including an explanation of the relief TGS is requesting, and sponsors the Company's annual capital investment reports included with the Company's IRA filings to support the Company's requested prudence determination.
- *Alejandro Limón* is Vice-President of Operations for TGS. Mr. Limón provides an overview of operations within the CGSA; addresses the reasonableness and necessity of capital investment and Operations and Maintenance (O&M) expenses; addresses ONE Gas' response to Winter Storm Uri and COVID-19; and addresses the Company's Pipeline Integrity Testing Program.
- *Marie Michels* is the Manager of Rates and Regulatory Analysis for TGS. Ms. Michels provides an overview of the cost of service and overall revenue requirement calculation and supports TGS's Direct rate base and Direct expense adjustments; addresses the Company's compliance with certain regulatory and statutory requirements; affiliate cost recovery issues related to Utility Insurance Company ("UIC"); the Company's recovery of pipeline integrity testing costs; the Company's recovery of rate case expenses; and describes the proposed CGSA rate schedules and tariffs as well as rate schedules and tariffs currently in effect for the CGSA.
- *Stacey McTaggart* is the Rates and Regulatory Director for TGS. Ms. McTaggart describes the Company's proposed EDIT adjustment to return excess deferred income taxes to customers; new RNG Credits Program rate schedule; TGS's recovery of costs associated

with COVID-19 and Winter Storm Uri and another regulatory asset; and Rule 8.209 accruals.

- *Stacey Borgstadt* is the Director of Rates and Regulatory Compliance for ONE Gas. Ms. Borgstadt addresses the cost allocation methodology used to determine TGS's share of allocated costs and certain Corporate expense adjustments; supports certain TGS Division and Corporate capital investment that is included in the CGSA revenue requirement as well as Corporate depreciation and amortization expense; and explains Direct, TGS Division and Corporate expense adjustments related to payroll, employee benefits, and incentive compensation.
- *Megan Gough* is the Manager of Compensation for ONE Gas. Ms. Gough addresses the reasonableness of ONE Gas' compensation philosophy and structure, as well as related costs for base pay, incentive plans, benefits, and incentive compensation related to efforts during Winter Storm Uri.
- *Cyndi King* is the Director of Treasury and Finance for ONE Gas. Ms. King supports the recovery of a return on the Company's prepaid pension asset.
- *Jaime Shelton* is the Director of Risk and Insurance for ONE Gas. Ms. Shelton describes ONE Gas' captive insurance company, UIC.
- *Kenneth Eakens* is the Director of Tax Compliance and Financial Reporting for ONE Gas. Mr. Eakens describes the calculation of the Company's EDIT.
- *Timothy S. Lyons* is a Partner with the firm ScottMadden, Inc. Mr. Lyons sponsors TGS's lead-lag study that determines TGS's cash working capital requirement to be included in rate base.
- *Janet M. Simpson* is an accountant and Managing Member of Utility Regulatory Consulting, LLC. Ms. Simpson presents TGS's Accumulated Deferred Income Tax (ADIT) calculations.
- *Dr. Ronald E. White* is an engineer and President of Foster Associates Consultants, LLC. Dr. White sponsors a study of the depreciation rates for TGS plant located in the CGSA and for common facilities shared among all TGS service areas, including Corporate assets.
- *Dr. Bruce H. Fairchild* is a financial accountant and former professor and regulator. Dr. Fairchild is a principal with Financial Concepts and Applications, Inc. Dr. Fairchild supports TGS's requested return on equity, cost of debt, capital structure, and overall return on invested capital.
- *Teresa Serna* is a Rates Specialist for TGS. Ms. Serna describes the class cost of service study and supports TGS's proposed class revenue allocation.
- *Zane Drummond* is a Rates Analyst for TGS and supports TGS's revenue adjustments.
- *Paul H. Raab* is an independent economic consultant, and describes and supports TGS's proposed rate design.

IV. RATE CASE EXPENSES

Pursuant to Texas Utilities Code § 104.051 and Commission Rule 7.5530, TGS requests recovery of all reasonable and necessary rate case expenses from affected customers through a surcharge to the final approved rates.

V. PUBLIC NOTICE AND REQUEST FOR APPROVAL OF FORM OF NOTICE

The Company will promptly undertake to notify the public of the proposed changes in its gas rates consistent with the requirements of Texas Utilities Code § 104.103 and Commission Rules 7.230 and 7.235. The public notice that TGS proposes to provide regarding the proposed change in rates for the CGSA is attached as **Exhibit E** to the Statement of Intent. TGS asks that the Commission's Examiners and Administrative Law Judge approve its form of notice prior to publication or distribution to customers, and the Company will submit proof of notice promptly upon completion thereof.

VI. COMPANY REPRESENTATIVES FOR NOTIFICATION

TGS's authorized representatives are:

Anthony Brown
Stacey L. McTaggart
Judy Jenkins Hitchye
Texas Gas Service Company
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512-370-8264
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and

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shelley.morgan@crtxlaw.com

Please serve all pleadings, motions, orders, and other documents filed in this proceeding upon TGS's authorized representatives at the above-stated addresses.

VII. REQUEST FOR APPROVAL OF PROTECTIVE ORDER

The Company's Rate Filing Package includes certain confidential materials. In addition, the scope of discovery in this case may require the production of additional confidential material. Accordingly, TGS attaches as **Exhibit F** to this Statement of Intent a proposed Protective Order and respectfully requests that the Commission issue an order approving the Protective Order. TGS will provide confidential material upon execution of Exhibit A attached to the Protective Order.

VIII. CONCLUSION

TGS requests that: (1) rates are approved for the CGSA consistent with those proposed herein, to become effective for bills rendered on and after July 8, 2024; (2) the Commission approve new depreciation rates for Direct and Division distribution and general plant; (3) the Commission find that expenses for Winter Storm Uri and COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (4) capital investment made in the CGSA through December 31, 2023, including capital investment in the Company's IRA filings made since the last rate case in the CGSA pursuant to Texas Utilities Code § 104.301, is deemed prudent; (5) EDIT is included in base rates, with discontinuance of the EDIT Rider to return EDIT to customers; (6) the Commission approve proposed edits to the Company's tariffs and rate schedules, including the newly proposed RNG Credits Program; (7) all reasonable rate case expenses incurred in connection with this Statement of Intent filing are authorized for recovery by the Company; and (8) for such further relief to which the Company may be entitled.

Respectfully submitted,

By: Kate Norman

Judy Jenkins Hitchye
State Bar No. 24095769
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ATTORNEYS FOR TEXAS GAS SERVICE COMPANY

SMALL RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a small residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential customer includes an individually-metered residential unit or dwelling that is operated by a public housing agency acting as an administrator of public housing programs under the direction of the U.S. Department of Housing and Urban Development and builders prior to sale or re-sale of a property for domestic purposes.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $25.50 plus

All Ccf per monthly billing period @ $0.69448 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 352 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 352 Ccf or Greater	Large Residential, Rate Schedule 15

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

SMALL RESIDENTIAL SERVICE RATE
(Continued)

Conservation Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

LARGE RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a large residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential customer includes an individually-metered residential unit or dwelling that is operated by a public housing agency acting as an administrator of public housing programs under the direction of the U.S. Department of Housing and Urban Development and builders prior to sale or re-sale of a property for domestic purposes.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $39.00 plus

All Ccf per monthly billing period @ $0.23425 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 352 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 352 Ccf or Greater	Large Residential, Rate Schedule 15

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

LARGE RESIDENTIAL SERVICE RATE
(Continued)

Conservation Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

SMALL COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all small commercial customers and to customers not otherwise specifically provided for under any other rate schedule.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $85.00 plus

All Ccf per monthly billing period @ $0.15710 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 3,640 Ccf	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,640 Ccf or Greater	Large Commercial, Rate Schedule 25

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Conservation Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

SMALL COMMERCIAL SERVICE RATE
(Continued)

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

LARGE COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all large commercial customers and to customers not otherwise specifically provided for under any other rate schedule.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $100.00 plus

All Ccf per monthly billing period @ $0.10765 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 3,640 Ccf	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,640 Ccf or Greater	Large Commercial, Rate Schedule 25

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Conservation Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

LARGE COMMERCIAL SERVICE RATE
(Continued)

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 30**
Central-Gulf Service Area **Page 1 of 1**

INDUSTRIAL SERVICE RATE

APPLICABILITY

Applicable to any qualifying industrial customer whose primary business activity at the location served is included in one of the following classifications of the Standard Industrial Classification Manual of the U.S. Government.

Division B - Mining - all Major Groups
Division D - Manufacturing - all Major Groups
Divisions E and J - Utility and Government - facilities generating power for resale only

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$572.02 plus
All Ccf per monthly billing period @	$0.12707 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Supersedes Rate Schedule Dated	Bills Rendered On and After
January 15, 2024	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 40**
Central-Gulf Service Area **Page 1 of 1**

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to any qualifying public authority, public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$156.05 plus
All Ccf per monthly billing period @	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Supersedes Rate Schedule Dated	Bills Rendered On and After
January 15, 2024	TBD

UNMETERED GAS LIGHT SERVICE RATE

APPLICABILITY

Applicable to any Customer on Texas Gas Service Company, a Division of ONE Gas, Inc.'s system requiring natural gas service for gas lighting only, without the use of metering device. Gas service is only available to Customers utilizing standard gas lighting equipment manufactured with an orifice burner assembly or equivalent that is intended for lighting of sidewalks and other walkways. The Company, in its sole discretion, shall determine if Customer's lighting equipment qualifies for this tariff and shall contract with Customer for the appropriate monthly charge based upon Customer's complete installation of gas lighting equipment. Gas service under this rate schedule is available only with the Company as the sole supplier of gas for Customer and is not available for resale to others or for standby or supplemental service.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

The total hourly rated consumption of all gas lighting equipment included, expressed in Ccf at the location, shall be multiplied by 730 for gas lighting equipment that runs continuously or 365 for gas lighting equipment with a light sensor, to determine the average monthly consumption of the service. The result, rounded to the next highest Ccf, shall then be billed the rates provided in this rate schedule:

Residential	$0.69448 per Ccf
Commercial	$0.15710 per Ccf
Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

UNMETERED GAS LIGHT SERVICE RATE
(Continued)

CONDITIONS

The Customer shall ensure that the installation of lighting equipment conforms to industry safety standards. The Company reserves the right to review Customer's installation of lighting equipment from time to time to determine if it conforms to terms and conditions as set forth in this tariff and the executed service agreement with the Customer. Customer shall notify Company in writing within 30 days of any change in number of gas lights or other material changes made to the gas lighting installation.

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

ELECTRIC GENERATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any customer customer who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc, to use natural gas for the purpose of electric generation. Electric generation is defined as facilities registered with the applicable balancing authority including bulk power system assets, co-generation facilities, distributed generation, and or backup power systems.

TERRITORY

This rate shall be available in the incorporated areas of the Central-Gulf Service Area, which includes, Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $175.98 plus

A delivery charge per monthly billing period @

For the First	5,000 Ccf/Month	$0.07427 per Ccf
For the Next	35,000 Ccf/Month	$0.06590 per Ccf
For the Next	60,000 Ccf/Month	$0.05314 per Ccf
All Over	100,000 Ccf/Month	$0.03864 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of the Cost of Gas Clause, Rate Schedule 1-INC.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedules PIT and PIT-Rider if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

ELECTRICAL GENERATION SERVICE RATE
(Continued)

CONDITIONS

1. Gas taken under this rate shall be used exclusively for the purpose of electric generation as defined in the Applicability section of this rate schedule and not for other purposes. The gas taken under this rate will be separately metered.

2. For the purpose of this rate, the annual load factor must be 60 percent or greater. The annual load factor is defined as the customer's total annual consumption divided by the customer's peak month consumption times twelve. If less than 60 percent load factor occurs for a twelve-month period, the rate charged will revert back to the rate that the customer would have otherwise been served under. A continuous twelve-month period of 60 percent or better load factor must precede a return to the electric generation rate.

3. Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

Applicable to any non-residential customer of Texas Gas Service Company, a Division of ONE Gas, Inc., (the "Company") for usage where customer purchases natural gas which will be compressed and used as a motor fuel. Service will be separately metered. This rate does not include compression by the Company beyond normal meter sales pressure.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$594.88 plus
All Ccf per monthly billing period @	$0.06684 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

Subject to all applicable laws and orders and the Company's rules and regulations on file with the regulatory authority.

The Company's Average Payment Plan, also known as the Average Payment Plan (APP Plan), is not available to customers served on this rate schedule.

This rate does not include any road use fees, permits, or taxes etc. It provides for the delivery of uncompressed natural gas only.

Customer must provide affidavit to the Company certifying that the gas delivered will be compressed for use as motor fuel.

The Customer's compressor station is subject to inspection by Company engineers.

SMALL RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a small residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential customer includes an individually-metered residential unit or dwelling that is operated by a public housing agency acting as an administrator of public housing programs under the direction of the U.S. Department of Housing and Urban Development and builders prior to sale or re-sale of a property for domestic purposes.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $25.50 plus

All Ccf per monthly billing period @ $0.69448 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 352 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 352 Ccf or Greater	Large Residential, Rate Schedule 1Y

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

SMALL RESIDENTIAL SERVICE RATE
(Continued)

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

LARGE RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a large residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential customer includes an individually-metered residential unit or dwelling that is operated by a public housing agency acting as an administrator of public housing programs under the direction of the U.S. Department of Housing and Urban Development and builders prior to sale or re-sale of a property for domestic purposes.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $39.00 plus

All Ccf per monthly billing period @ $0.23425 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer’s service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 352 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 352 Ccf or Greater	Large Residential, Rate Schedule 1Y

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer’s next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

LARGE RESIDENTIAL SERVICE RATE
(Continued)

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

SMALL COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all small commercial customers and to customers not otherwise specifically provided for under any other rate schedule.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $85.00 plus

All Ccf per monthly billing period @ $0.15710 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 3,640 Ccf	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,640 Ccf or Greater	Large Commercial, Rate Schedule 2Y

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

SMALL COMMERCIAL SERVICE RATE
(Continued)

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

LARGE COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all large commercial customers and to customers not otherwise specifically provided for under any other rate schedule.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $100.00 plus

All Ccf per monthly billing period @ $0.10765 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 3,640 Ccf	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,640 Ccf or Greater	Large Commercial, Rate Schedule 2Y

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

LARGE COMMERCIAL SERVICE RATE
(Continued)

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

INDUSTRIAL SERVICE RATE

APPLICABILITY

Applicable to any qualifying industrial customer whose primary business activity at the location served is included in one of the following classifications of the Standard Industrial Classification Manual of the U.S. Government.

Division B - Mining - all Major Groups
Division D - Manufacturing - all Major Groups
Divisions E and J - Utility and Government - facilities generating power for resale only

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$572.02 plus
All Ccf per monthly billing period @	$0.12707 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

Subject to all applicable laws and orders, and the Company’s rules and regulations on file with the regulatory authority.

Supersedes Rate Schedule Dated	Bills Rendered On and After
January 15, 2024	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 4Z**
Central-Gulf Service Area **Page 1 of 1**

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to any qualifying public authority, public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$156.05 plus
All Ccf per monthly billing period @	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Supersedes Rate Schedule Dated
January 15, 2024

Bills Rendered On and After
TBD

UNMETERED GAS LIGHT SERVICE RATE

APPLICABILITY

Applicable to any Customer on Texas Gas Service Company, a Division of ONE Gas, Inc.'s system requiring natural gas service for gas lighting only, without the use of metering device. Gas service is only available to Customers utilizing standard gas lighting equipment manufactured with an orifice burner assembly or equivalent that is intended for lighting of sidewalks and other walkways. The Company, in its sole discretion, shall determine if Customer's lighting equipment qualifies for this tariff and shall contract with Customer for the appropriate monthly charge based upon Customer's complete installation of gas lighting equipment. Gas service under this rate schedule is available only with the Company as the sole supplier of gas for Customer and is not available for resale to others or for standby or supplemental service.

TERRITORY

Environs of the Central-Gulf Service Area which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

The total hourly rated consumption of all gas lighting equipment included, expressed in Ccf at the location, shall be multiplied by 730 for gas lighting equipment that runs continuously or 365 for gas lighting equipment with a light sensor, to determine the average monthly consumption of the service. The result, rounded to the next highest Ccf, shall then be billed the rates provided in this rate schedule:

Residential	$0.69448 per Ccf
Commercial	$0.15710 per Ccf
Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Taxes: Plus applicable taxes and fees related to above.

UNMETERED GAS LIGHT SERVICE RATE
(Continued)

CONDITIONS

The Customer shall ensure that the installation of lighting equipment conforms to industry safety standards. The Company reserves the right to review Customer's installation of lighting equipment from time to time to determine if it conforms to terms and conditions as set forth in this tariff and the executed service agreement with the Customer. Customer shall notify Company in writing within 30 days of any change in number of gas lights or other material changes made to the gas lighting installation.

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

ELECTRIC GENERATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any customers who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc. to use natural gas for the purpose of electric generation. Electric generation is defined as facilities registered with the applicable balancing authority including bulk power system assets, co-generation facilities, distributed generation, and or backup power systems.

TERRITORY

This rate shall be available in the unincorporated areas of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of $175.98

A delivery charge per monthly billing period @

For the First	5,000 Ccf/Month	$0.07427 per Ccf
For the Next	35,000 Ccf/Month	$0.06590 per Ccf
For the Next	60,000 Ccf/Month	$0.05314 per Ccf
All Over	100,000 Ccf/Month	$0.03864 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of the Cost of Gas Clause, Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedules PIT and PIT-Rider if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

ELECTRIC GENERATION SERVICE RATE
(Continued)

CONDITIONS

1. Gas taken under this rate shall be used exclusively for the purpose of electric generation as defined in the Applicability section of this rate schedule and not for other purposes. The gas taken under this rate will be separately metered.

2. For the purpose of this rate, the annual load factor must be 60 percent or greater. The annual load factor is defined as the customer's total annual consumption divided by the customer's peak month consumption times twelve. If less than 60 percent load factor occurs for a twelve-month period, the rate charges will revert back to the rate that the customer would have otherwise been served under. A continuous twelve-month period of 60 percent or better load factor must precede a return to the electric generation rate.

3. Subject to all applicable laws and orders, and the Company’s rules and regulations on file with the regulatory authority.

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

Applicable to any non-residential customer of Texas Gas Service Company, a Division of ONE Gas, Inc., (the "Company") for usage where customer purchases natural gas which will be compressed and used as a motor fuel. Service will be separately metered. This rate does not include compression by the Company beyond normal meter sales pressure.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$594.88 plus
All Ccf per monthly billing period @	$0.06684 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

Subject to all applicable laws and orders and the Company's rules and regulations on file with the regulatory authority.

The Company's Average Payment Plan, also known as the Average Payment Plan (APP Plan), is not available to customers served on this rate schedule.

This rate does not include any road use fees, permits, or taxes etc. It provides for the delivery of uncompressed natural gas only.

Customer must provide an affidavit to the Company certifying that the gas delivered will be compressed for use as motor fuel.

The Customer's compressor station is subject to inspection by Company engineers.

COST OF GAS CLAUSE

A. APPLICABILITY

This Cost of Gas Clause shall apply to all gas sales service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") in all incorporated areas of its Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

B. DEFINITIONS

1. Cost of Gas - The rate per billing unit or the total calculation under this clause, consisting of the Commodity Cost, the Customer Rate Relief Component, the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, and the revenue associated fees (including franchise fees) and taxes.

2. Commodity Cost - The Cost of Purchased Gas multiplied by the Purchase/Sales Ratio plus an adjustment to correct any known and quantifiable under or over collection prior to the end of the reconciliation period for the objective of minimizing the impact of under or over collection by the reconciliation factor in the next year.

3. Cost of Purchased Gas - The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average cost for gas purchased by the Company from all sources where applicable. Such cost shall include not only the purchase cost of natural gas, but shall also include all reasonable costs for services such as gathering, treating, processing, transportation, capacity and/or supply reservation, applicable line loss charges, storage, balancing including penalties, swing services, and any other related costs and expenses necessary for the movement of gas to the Company's city gate delivery points and customers. The Cost of Purchased Gas may also include costs related to the purchase and transportation of Renewable Natural Gas (RNG). The Cost of Purchased Gas may also include the cost of "Environmental Attributes" purchased and retired in association with the purchase of RNG. The Cost of Purchased Gas shall also include the value of gas withdrawn from storage and shall include gains and losses from the utilization of natural gas financial instruments that are executed by the Company for the purpose of mitigating price volatility. Companies affiliated with, or sharing services with, the Company shall not be allowed to charge fees for transactions related to natural gas financial instruments utilized for purposes in this Cost of Gas Clause and hence cannot realize a profit in this regard.

4. Customer Rate Relief Component - The rate per billing unit charged in accordance with and specified on Rate Schedule CRR, the Customer Rate Relief Rate Schedule, which is a non-bypassable charge as defined in Tex. Util. Code § 104.362(7).

5. Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of RNG, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx),

COST OF GAS CLAUSE (Continued)

nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions.

6. Reconciliation Component - The amount to be returned to or recovered from sales customers each month from October through June as a result of the Reconciliation Audit.

7. Reconciliation Audit - An annual review of the Company's books and records for each 12-month period ending with the production month of June to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its sales customers during the period, including gains or losses on the use of natural gas financial instruments; (b) the revenues received from operation of the provisions of this Cost of Gas Clause reduced by the amount of revenue associated fees (including franchise fees) and taxes paid by the Company on those revenues; (c) the total amount of surcharges or refunds made to sales customers during the period and any other revenues or credits received by the Company as a result of relevant gas purchases or operation of this Cost of Gas Clause; (d) the total amount accrued for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

8. Purchase/Sales Ratio - A ratio determined by dividing the total volumes purchased for sales customers during the 12-month period ending June 30 by the sum of the sales volumes sold to sales customers. For the purpose of this computation all volumes shall be stated at 14.65 psia. Such ratio as determined shall in no event exceed 1.0526 i.e. 1/(1 - 0.05) unless expressly authorized by the applicable Regulatory Authority.

9. RNG is the term used to describe pipeline-quality biogas produced from various biomass sources through a biochemical process that has been processed to purity standards and is interchangeable with conventional natural gas.

10. Reconciliation Account - The account maintained by the Company to assure that over time it will neither over nor under collect revenues as a result of the operation of the Cost of Gas Clause. Entries shall be made monthly to reflect: (a) the total amounts paid to the Company's supplier(s) for gas applicable to sales customers as recorded on the Company's books and records (per Section B(3) above), including gains or losses on the use of natural gas financial instruments; (b) the revenues produced by the operation of this Cost of Gas Clause reduced by the amount of fees (including franchise fees) and taxes; (c) refunds, payments, or charges provided for herein or as approved by the Regulatory Authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s), (e) total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

COST OF GAS CLAUSE (Continued)

11. Uncollectible Cost of Gas – The amounts actually written off after the effective date of this rate schedule related to cost of gas will be tracked along with any subsequent recovery/credits related to the Cost of Gas Clause. Annually the charge offs minus recoveries will be included in the annual reconciliation and factored into the resulting Reconciliation Component.

C. COST OF GAS

In addition to the cost of service as provided under its gas sales rate schedules, the Company shall bill each sales customer for the Cost of Gas incurred during the billing period. The Cost of Gas shall be clearly identified on each customer bill.

D. DETERMINATION AND APPLICATION OF THE RECONCILIATION COMPONENT

If the Reconciliation Audit reflects either an over-recovery or under-recovery of revenues, such amount, plus or minus the amount of interest calculated pursuant to Section E below, if any, shall be divided by the sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the October billing cycle through the June billing cycle preceding the filing of the Reconciliation Audit. The Reconciliation Component so determined to collect any revenue shortfall or to return any excess revenue shall be applied, subject to refund, for a 9 month period beginning with the October billing cycle and continuing through the next June billing cycle at which time it will terminate.

E. INTEREST ON FUNDS

Concurrently with the Reconciliation Audit, the Company shall determine the amount by which the Cost of Gas was over or under collected for each month within the period of audit. The Company shall debit or credit to the Reconciliation Account for each month of the reconciliation period: (1) an amount equal to the outstanding over collected balance multiplied by interest of 6 percent per annum compounded monthly; or (2) an amount equal to the outstanding under collected balance multiplied by interest of 6 percent per annum compounded monthly. The Company shall also be allowed to recover a carrying charge calculated based on the arithmetic average of the beginning and ending balance of gas in storage inventory for the prior calendar month times the authorized rate of return.

F. SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's supplier are retroactively reduced and a refund of any previous payments is made to the Company, the Company shall make a similar refund to its sales customers. Similarly, the Company may surcharge its sales customers for retroactive payments made for gas previously delivered into the system. Any surcharge or refund amount will be included in the Reconciliation Account.

Refunds or charges shall be entered into the Reconciliation Account as they are collected from or returned to the customers. For the purpose of this Section F, the entry shall be made on the same basis used to determine the refund or charge component of the Cost of Gas and shall be subject to the calculation set forth in Section (E) Interest on Funds, above.

COST OF GAS CLAUSE (Continued)

G. COST OF GAS STATEMENT

The Company shall file a Cost of Gas Statement with the Regulatory Authority by the beginning of each billing month. The Cost of Gas Statement shall set forth: (a) the estimated Cost of Purchased Gas; (b) that cost multiplied by the Purchase/Sales Ratio; (c) the amount of the Cost of Gas caused by any surcharge or refund; (d) the Customer Rate Relief Component; (e) the Reconciliation Component; (f) the revenue associated fees (including franchise fees) and taxes to be applied to revenues generated by the Cost of Gas; (g) the Cost of Gas calculation, including gains and losses from hedging activities for the month; and (h) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

H. ANNUAL RECONCILIATION REPORT

The Company shall file an Annual Reconciliation Report with the Regulatory Authority which shall include but not necessarily be limited to:

1. A tabulation of volumes of gas purchased and costs incurred listed by account or type of gas, supplier and source by month for the 12 months ending June 30.

2. A tabulation of gas units sold to sales customers and related Cost of Gas Clause revenues.

3. A tabulation of all other costs and refunds made during the year and their effect on the Cost of Gas Clause to date.

4. A description of the hedging activities conducted each month during the 12 months ending June 30, including the types of transaction used, resulting gains and losses, any changes in the hedging program implemented during the period and the rationale for the changes. The report should include the customer impact of hedging activities stated as costs to the average residential and commercial customer during the period.

5. A description of the imbalance payments made to and received from the Company’s transportation customers within the service area, including monthly imbalances incurred, the monthly imbalances resolved, and the amount of the cumulative imbalance. The description should reflect the system imbalance and imbalance amount for each supplier using the Company’s distribution system during the reconciliation period.

6. A tabulation of Uncollectible Cost of Gas during the period and its effect on the Cost of Gas Clause to date.

This report shall be filed concurrently with the Cost of Gas Statement for October. If the Regulatory Authority thereafter determines that an adjustment to the Reconciliation Component is required, such adjustment shall be included in the Reconciliation Component for the next annual Reconciliation Audit following the date of such determination.

COST OF GAS CLAUSE

A. APPLICABILITY

This Cost of Gas Clause shall apply to all gas sales service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") in all unincorporated areas of its Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bastrop, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

B. DEFINITIONS

1. Cost of Gas - The rate per billing unit or the total calculation under this clause, consisting of the Commodity Cost, the Customer Rate Relief Component, the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, and the revenue associated fees and taxes.

2. Commodity Cost - The Cost of Purchased Gas multiplied by the Purchase/Sales Ratio plus an adjustment to correct any known and quantifiable under or over collection prior to the end of the reconciliation period for the objective of minimizing the impact of under or over collection by the reconciliation factor in the next year.

3. Cost of Purchased Gas - The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average cost for gas purchased by the Company from all sources where applicable. Such cost shall include not only the purchase cost of natural gas, but shall also include all reasonable costs for services such as gathering, treating, processing, transportation, capacity and/or supply reservation, applicable line loss charges, storage, balancing including penalties, swing services, and any other related costs and expenses necessary for the movement of gas to the Company's city gate delivery points and customers. The Cost of Purchased Gas may also include costs related to the purchase and transportation of Renewable Natural Gas (RNG). The Cost of Purchased Gas shall also include the cost of "Environmental Attributes" purchased and retired in association with the purchase of RNG. The Cost of Purchased Gas shall not include the cost of financial instruments unless the use of such financial instruments is approved in advance and in writing by the Director of the Oversight and Safety Division of the Railroad Commission of Texas. Such approval would be requested as part of the Company's annual gas purchase plan, which shall be submitted annually to the Commission no later than June 15.

4. Customer Rate Relief Component - The rate per billing unit charged in accordance with and specified on Rate Schedule CRR, the Customer Rate Relief Rate Schedule, which is a non-bypassable charge as defined in Tex. Util. Code § 104.362(7).

5. Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of RNG, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of

COST OF GAS CLAUSE (Continued)

any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions.

6. Reconciliation Component - The amount to be returned to or recovered from sales customers each month from October through June as a result of the Reconciliation Audit.

7. Reconciliation Audit - An annual review of the Company's books and records for each 12-month period ending with the production month of June to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its sales customers during the period, including gains or losses on the use of natural gas financial instruments; (b) the revenues received from operation of the provisions of this Cost of Gas Clause reduced by the amount of revenue associated fees and taxes paid by the Company on those revenues; (c) the total amount of surcharges or refunds made to sales customers during the period and any other revenues or credits received by the Company as a result of relevant gas purchases or operation of this Cost of Gas Clause; (d) the total amount accrued for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

8. RNG - the term used to describe pipeline-quality biogas produced from various biomass sources through a biochemical process that has been processed to purity standards and is interchangeable with conventional natural gas.

9. Purchase/Sales Ratio - A ratio determined by dividing the total volumes purchased for sales customers during the 12 month period ending June 30 by the sum of the sales volumes sold to sales customers. For the purpose of this computation all volumes shall be stated at 14.65 psia. Such ratio as determined shall in no event exceed 1.0526 i.e. 1/(1 - 0.05) unless expressly authorized by the applicable Regulatory Authority.

10. Reconciliation Account - The account maintained by the Company to assure that over time it will neither over nor under collect revenues as a result of the operation of the Cost of Gas Clause. Entries shall be made monthly to reflect: (a) the total amounts paid to the Company's supplier(s) for gas applicable to sales customers as recorded on the Company's books and records (per Section B(3) above), including gains or losses on the use of approved natural gas financial instruments; (b) the revenues produced by the operation of this Cost of Gas Clause reduced by the amount of fees and taxes; (c) refunds, payments, or charges provided for herein or as approved by the Regulatory Authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s); (e) total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

11. Uncollectible Cost of Gas – The amounts actually written off after the effective date of this rate schedule related to cost of gas will be tracked along with any subsequent recovery/credits related to the Cost of Gas Clause. Annually the charge offs minus recoveries will be included in the annual reconciliation and factored into the resulting Reconciliation Component.

COST OF GAS CLAUSE (Continued)

C. COST OF GAS

In addition to the cost of service as provided under its gas sales rate schedules, the Company shall bill each sales customer for the Cost of Gas incurred during the billing period. The Cost of Gas shall be clearly identified on each customer bill.

D. DETERMINATION AND APPLICATION OF THE RECONCILIATION COMPONENT

If the Reconciliation Audit reflects either an over-recovery or under-recovery of revenues, such amount, plus or minus the amount of interest calculated pursuant to Section E below, if any, shall be divided by the sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the October billing cycle through the June billing cycle preceding the filing of the Reconciliation Audit. The Reconciliation Component so determined to collect any revenue shortfall or to return any excess revenue shall be applied, subject to refund, for a 9 month period beginning with the October billing cycle and continuing through the next June billing cycle at which time it will terminate.

E. INTEREST ON FUNDS

Concurrently with the Reconciliation Audit, the Company shall determine the amount by which the Cost of Gas was over or under collected for each month within the period of audit. The Company shall debit or credit to the Reconciliation Account for each month of the reconciliation period: (1) an amount equal to the outstanding over collected balance multiplied by interest of 6 percent per annum compounded monthly; or (2) an amount equal to the outstanding under collected balance multiplied by interest of 6 percent per annum compounded monthly. The Company shall also be allowed to recover a carrying charge calculated based on the arithmetic average of the beginning and ending balance of gas in storage inventory for the prior calendar month times the authorized rate of return.

F. SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's supplier are retroactively reduced and a refund of any previous payments is made to the Company, the Company shall make a similar refund to its sales customers. Similarly, the Company may surcharge its sales customers for retroactive payments made for gas previously delivered into the system. Any surcharge or refund amount will be included in the Reconciliation Account.

Refunds or charges shall be entered into the Reconciliation Account as they are collected from or returned to the customers. For the purpose of this Section F, the entry shall be made on the same basis used to determine the refund or charge component of the Cost of Gas and shall be subject to the calculation set forth in Section (E) Interest on Funds, above.

COST OF GAS CLAUSE (Continued)

G. COST OF GAS STATEMENT

The Company shall file a Cost of Gas Statement with the Regulatory Authority by the beginning of each billing month. The Cost of Gas Statement shall set forth: (a) the estimated Cost of Purchased Gas; (b) that cost multiplied by the Purchase/Sales Ratio; (c) the amount of the Cost of Gas caused by any surcharge or refund; (d) the Customer Rate Relief Component; (e) the Reconciliation Component; f) the revenue associated fees and taxes to be applied to revenues generated by the Cost of Gas; (g) the Cost of Gas calculation, including gains and losses from approved hedging activities for the month; and (h) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

H. ANNUAL RECONCILIATION REPORT

The Company shall file an Annual Reconciliation Report with the Regulatory Authority which shall include but not necessarily be limited to:

1. A tabulation of volumes of gas purchased and costs incurred listed by account or type of gas, supplier and source by month for the 12 months ending June 30.

2. A tabulation of gas units sold to sales customers and related Cost of Gas Clause revenues.

3. A tabulation of all other costs and refunds made during the year and their effect on the Cost of Gas Clause to date.

4. A description of the hedging activities conducted each month during the 12 months ending June 30, including the types of transaction used, resulting gains and losses, any changes in the hedging program implemented during the period and the rationale for the changes. The report should include the customer impact of hedging activities stated as costs to the average residential and commercial customer during the period.

5. A description of the imbalance payments made to and received from the Company's transportation customers within the service area, including monthly imbalances incurred, the monthly imbalances resolved, and the amount of the cumulative imbalance. The description should reflect the system imbalance and imbalance amount for each supplier using the Company's distribution system during the reconciliation period.

6. A tabulation of Uncollectible Cost of Gas during the period and its effect on the Cost of Gas Clause to date.

This report shall be filed concurrently with the Cost of Gas Statement for October. If the Regulatory Authority determines that an adjustment to the Reconciliation Component is required, such adjustment shall be included in the Reconciliation Component for the next annual Reconciliation Audit following the date of such determination.

TRANSPORTATION SERVICE RATE

APPLICABILITY

Applicable to customers who have elected Transportation Service not otherwise specifically provided for under any other rate schedule.

Service under this rate schedule is available for the transportation of customer-owned natural gas through Texas Gas Service Company, a Division of ONE Gas, Inc.'s (the "Company") distribution system. The customer must arrange with its gas supplier to have the customer's gas delivered to one of the Company's existing receipt points for transportation by the Company to the customer's facilities at the customer's delivery point. The receipt points shall be specified by the Company at its reasonable discretion, taking into consideration available capacity, operational constraints, and integrity of the distribution system.

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's Central-Gulf Service Area distribution system which includes the incorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas. Such service shall be provided at any point on the Company's System where adequate capacity and gas supply exists, or where such capacity and gas supply can be provided in accordance with the applicable rules and regulations and at a reasonable cost as determined by the Company in its sole opinion.

COST OF SERVICE RATE

During each monthly billing period, a customer charge per meter per month listed by customer class as follows:

Commercial	\$297.51 per month
Industrial	\$772.02 per month
Public Authority	\$179.05 per month
Compressed Natural Gas	\$619.88 per month
Electrical Generation	\$175.98 per month

TRANSPORTATION SERVICE RATE
(Continued)

Plus – A delivery charge per monthly billing period listed by customer class as follows:

Commercial	$0.12679 per Ccf
Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf
Compressed Natural Gas	$0.06684 per Ccf
Electrical Generation	
For the First 5,000Ccf/month	$0.07427 per Ccf
For the Next 35,000 Ccf/month	$0.06590 per Ccf
For the Next 60,000 Ccf/month	$0.05314 per Ccf
All Over 100,000 Ccf/month	$0.03864 per Ccf

ADDITIONAL CHARGES

1) A charge will be made each month to recover the cost of taxes paid to the State of Texas pursuant to Texas Utilities Code, Chapter 122 as such may be amended from time to time which are attributable to the transportation service performed hereunder.

2) A charge will be made each month to recover the cost of any applicable local taxes and fees.

3) In the event the Company incurs a demand charge, balancing service rate, or reservation charge from its gas supplier(s) or transportation providers in the incorporated areas of the Central-Gulf Service Area, the customer may be charged its proportionate share of the demand charge, balancing service rate, or reservation charge based on benefit received by the customer.

4) The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

5) The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedules PIT and PIT-Rider.

6) The billing of commercial transportation shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

7) The billing shall reflect adjustments in accordance with the provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

TRANSPORTATION SERVICE RATE
(Continued)

SUBJECT TO

1) Tariff T-TERMS, General Terms and Conditions for Transportation.

2) Transportation of natural gas hereunder may be interrupted or curtailed at the discretion of the Company in case of shortage or threatened shortage of gas supply from any cause whatsoever, to conserve gas for residential and other higher priority customers served. The curtailment priority of any customer served under this schedule shall be the same as the curtailment priority established for other customers served pursuant to the Company's rate schedule which would otherwise be available to such customer.

3) The taking of service under this rate schedule is subject to all valid orders, laws, rules, and regulations of duly constituted State and Federal governmental authorities and agencies having jurisdiction or control over the parties, their facilities or gas supplies, the Agreement, or any provision hereof. The Company reserves the right to seek modification or termination of any of the General Terms and Conditions, the Gas Transportation Agreement, and any of the tariffs to which it applies.

4) The Agreement shall be interpreted under Texas law.

TRANSPORTATION SERVICE RATE

APPLICABILITY

Applicable to customers who have elected Transportation Service not otherwise specifically provided for under any other rate schedule.

Service under this rate schedule is available for the transportation of customer-owned natural gas through Texas Gas Service Company, a Division of ONE Gas, Inc.'s (the "Company") distribution system. The customer must arrange with its gas supplier to have the customer's gas delivered to one of the Company's existing receipt points for transportation by the Company to the customer's facilities at the customer's delivery point. The receipt points shall be specified by the Company at its reasonable discretion, taking into consideration available capacity, operational constraints, and integrity of the distribution system.

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's unincorporated areas of the Central-Gulf Service Area distribution system which includes the environs of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas. Such service shall be provided at any point on the Company's System where adequate capacity and gas supply exists, or where such capacity and gas supply can be provided in accordance with the applicable rules and regulations and at a reasonable cost as determined by the Company in its sole opinion.

COST OF SERVICE RATE

During each monthly billing period, a customer charge per meter per month listed by customer class as follows:

Commercial	$297.51 per month
Industrial	$772.02 per month
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TRANSPORTATION SERVICE RATE
(Continued)

Plus – A delivery charge per monthly billing period listed by customer class as follows:

Commercial	$0.12679 per Ccf
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For the Next 60,000 Ccf/month	$0.05314 per Ccf
All Over 100,000 Ccf/month	$0.03864 per Ccf

ADDITIONAL CHARGES

1) A charge will be made each month to recover the cost of taxes paid to the State of Texas pursuant to Texas Utilities Code, Chapter 122 as such may be amended from time to time which are attributable to the transportation service performed hereunder.

2) A charge will be made each month to recover the cost of any applicable local taxes and fees.

3) In the event the Company incurs a demand or reservation charge from its gas supplier(s) or transportation providers in the unincorporated areas of the Central-Gulf Service Area, the customer may be charged its proportionate share of the demand or reservation charge based on benefit received by the customer.

4) The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

5) The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

6) The billing shall reflect adjustments in accordance with the provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

TRANSPORTATION SERVICE RATE
(Continued)

SUBJECT TO

1) Tariff T-TERMS, General Terms and Conditions for Transportation.

2) Transportation of natural gas hereunder may be interrupted or curtailed at the discretion of the Company in case of shortage or threatened shortage of gas supply from any cause whatsoever, to conserve gas for residential and other higher priority customers served. The curtailment priority of any customer served under this schedule shall be the same as the curtailment priority established for other customers served pursuant to the Company's rate schedule which would otherwise be available to such customer.

3) The taking of service under this rate schedule is subject to all valid orders, laws, rules, and regulations of duly constituted State and Federal governmental authorities and agencies having jurisdiction or control over the parties, their facilities or gas supplies, the Agreement, or any provision hereof. The Company reserves the right to seek modification or termination of any of the General Terms and Conditions, the Gas Transportation Agreement, and any of the tariffs to which it applies.

4) The Agreement shall be interpreted under Texas law.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE

1.1 REQUIREMENTS FOR TRANSPORTATION SERVICE

Nothing shall be deemed to supersede the respective rights and obligations of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") and Customer as provided by Texas statutes, rules, and/or regulations. The Company reserves the right to seek modification or termination of transportation service or any of the tariffs to which it applies and the unilateral right to seek regulatory approval to make any changes to, or to supersede, the rates, charges and terms of transportation service. This rate schedule shall apply to customers who have elected Transportation Service through the Company's Central Gulf distribution system within the Incorporated and Unincorporated Areas of Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas.

1.2 DEFINITIONS

The following definitions shall apply to the indicated words as used in this Tariff:

Adder:	Shall mean the Company's incremental cost to purchase natural gas.
Aggregation Areas:	Shall mean aggregation pools established by the Company within geographic, operational, administrative, and/or other appropriate parameters, for the purposes of nominating and imbalances.
Agreement:	Shall mean any written Gas Transportation Agreement (including any gas transportation orders, forms or other exhibit(s) which are incorporated into and become a part of the same) to which the General Terms and Conditions for Transportation apply.
Btu:	Shall mean British thermal unit(s) and shall be computed on a temperature base of 60° Fahrenheit and at the standard pressure base of the applicable service area and on a gross-real-dry basis and shall not be corrected for real water vapor as obtained by means commonly acceptable to the industry, and "MMBtu" shall mean 1,000,000 Btu.
Commercial Service:	Service to Consumers engaged primarily in the sale or furnishing of goods and services and any usage not otherwise provided for.
Commission or The Commission:	The Railroad Commission of Texas.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Consumption Period:	Shall mean a volumetric billing period.
Cumulative Tolerance Limit:	Shall mean the percent of aggregate historical annual deliveries of a Qualified Supplier's Aggregation Area pool of customers for the most recent year ended on June 30. The Company, at its sole discretion, may make adjustments to the Cumulative Tolerance Limit.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (Central Standard Time) on one calendar day and ending at 9:00 a.m. (Central Standard Time) the following calendar day.
Dekatherm (Dth):	Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.
Electrical Generation Service:	Service to customers operating electric generation assets and that are registered with the applicable balancing authority including bulk power system assets, co- generation facilities, distributed generation, and/or backup power systems. This service may also be provided to those known Customers who use thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.
Electronic Flow Measurement (EFM):	A device that remotely reads a gas meter.
Firm Service:	Services offered to Customers (regardless of service class) under schedules or contracts that anticipate no interruptions. Service may be interrupted or curtailed at the discretion of the Company during Force Majeure events.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

Force Majeure: If either Company or Customer is rendered unable, wholly or in part, by reason of force majeure or any other cause of any kind not reasonably within its control, other than financial, to perform or comply with their obligations hereunder, then such party's obligations or conditions shall be suspended during the continuance of such inability and such party shall be relieved of liability for any damage or loss for failure to perform the same during such period; provided, however, obligations to make payments when due hereunder shall not be suspended. The term "Force Majeure" as used herein means acts of God; strikes, lockouts, or other industrial disturbances; acts of the public enemy; wars; blockades; insurrections; riots; epidemics; pandemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; arrests and restraints of the government, or any agency thereof, either federal or state, civil or military; civil disturbances; explosions; breakage or accident to machinery or lines of pipe; freezing of wells or lines of pipe; shortage of gas supply, whether resulting from inability or failure of a supplier to deliver gas; partial or entire failure of natural gas wells or gas supply; depletion of gas reserves; mandatory testing or maintenance necessary for compliance and safe operation, and any other causes, whether of the kind herein enumerated or otherwise. If due to a Force Majeure the Company curtails or temporarily discontinues the receipt or delivery of Gas hereunder, Customer agrees to hold Company harmless from any loss, claim, damage, or expense that Customer may incur by reason of such curtailment or discontinuance.

Gas or Natural Gas: Shall mean the effluent vapor stream in its natural, gaseous state, including gas-well gas, casing head gas, residue gas resulting from processing both casing head gas and gas-well gas, and all other hydrocarbon and non-hydrocarbon components thereof.

Industrial Service: Service to Consumers engaged primarily in a process which changes raw or unfinished materials into another form of product. This classification shall embrace all Consumers included in Division A (except Major Groups 01 and 02) and Division D of the Standard Industrial Classification Manual.

Mcf: Shall mean 1,000 cubic feet of Gas.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

Month:	Shall mean the period beginning at 9:00 a.m. Central Standard Time on the first Day of each calendar month and ending at 9:00 a.m. Central Standard Time on the first Day of the next succeeding calendar month.
Monthly Tolerance Limit:	Shall mean 5% of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for gas.
PDA:	Shall mean a predetermined allocation method.
Pipeline System:	Shall mean the current existing utility distribution facilities of Company located in the State of Texas.
Point of Delivery:	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.
Point of Receipt:	Shall mean the point or points where Company shall receive Gas into the Pipeline System from Customer.
Point Operator:	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.
Qualified Supplier:	Shall mean an approved supplier of natural gas for transportation to customers through the Company’s pipeline system.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the Central-Gulf Service Area, or the Railroad Commission of Texas, as applicable.
Service Area:	The area receiving gas utility service provided by the Company under the terms of this Tariff.
Tariff:	Shall mean every rate schedule, or provision thereof, and all terms, conditions, rules and regulations for furnishing gas service filed with the regulatory authorities or agencies having jurisdiction over Company or the services provided hereunder.
Transportation Form:	Shall mean the Company approved selection of transportation service document.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Transportation Rate Schedule:	A rate schedule designed for service to any Customer for the transportation of Customer-owned natural gas through the Company's distribution system.
Transportation Service:	The transportation by the Company of natural gas owned by someone other than the Company through the Company's distribution system.
Week:	Shall mean a period of 7 consecutive Days beginning at 9:00 a.m. Central Standard Time on each Monday and ending at the same time on the next succeeding Monday.
Year:	Shall mean a period of 365 consecutive Days, or 366 consecutive Days when such period includes a February 29.

1.3 RESTRICTIONS AND RESERVATIONS

a) It is understood and agreed that Customer has only the right to transportation service in the Pipeline System and all equipment, including (but not in any way limited thereto) all pipe, valves, fittings, and meters comprising the Pipeline System and all other property and capacity rights and interests, shall at all times during the term of the Agreement remain the property of Company. Customer agrees not to cause or permit any liens or encumbrances to be filed with respect to the Pipeline System by reason of Customer's actions. Customer's Gas shall at all times remain the property of Customer, and Company shall have no right or property interest herein.

b) Company reserves the right in its sole discretion to remove, relocate, expand, or rebuild, without approval of Customer, any portion of the Pipeline System. Customer shall make no alterations, additions, or repairs to or on the Pipeline System, nor shall Customer bear any cost of any alterations, additions, repairs, maintenance or replacements made to or on said Pipeline System initiated by and to the benefit of the Company.

c) Customer agrees not to connect or cause the connection of any third party to the Pipeline System for any purpose without the express written approval and consent of Company to be granted in Company's sole discretion. Customer further agrees not to transport or cause to be transported any Gas for any third party. If either of these conditions is breached by Customer, Company shall have the right and option, notwithstanding any other provision of the Agreement, to terminate the Agreement.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

d) Company presently is transporting Gas to third parties on the Pipeline System and shall have the right in the future to transport additional Gas for such purposes and to transport Gas to additional third parties as it may desire, and Company shall have the right to make additional connections to the Pipeline System as may be required to serve presently existing and new customers, all of which is subject to the provisions of the Agreement. Company's transportation Gas hereunder shall not obligate Company in any manner beyond the terms of the Agreement and any Exhibits attached thereto.

e) Company shall own any and all liquids which are recovered from the Pipeline System and may use, sell or transfer all liquids without having to account in any manner, or pay any monies or other consideration to Customer.

f) The Company reserves the unilateral right from time to time to seek Commission approval to make any changes to, or to supersede, the rates, charges and any terms stated in the tariffs, rate schedules, the agreements, and the General Terms and Conditions.

1.4 COMPANY'S RESPONSIBILITY

Company shall deliver to Customer, at the Point of Delivery, volumes of gas, as received from designated Qualified Supplier, for the Customer, at a Company designated Point of Receipt, less Payment in Kind (PIK).

1.5 CUSTOMER'S RESPONSIBILITY

Customer, by selecting service under a transportation service rate schedule by completing a Transportation Form, warrants and agrees that:

a) Customer shall indemnify and hold Company harmless from and against all suits, actions, causes of action, claims and demands, including attorneys' fees and costs, arising from or out of any adverse claims by third parties claiming ownership of, or an interest in said gas caused by the failure to provide clear title to the gas;

b) Customer acknowledges Company shall not be responsible in any way for damages or claims relating to the Customer's gas or the facilities of the Customer or others containing such gas prior to receipt into Company's facilities or after delivery to the Customer;

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

c) Customer must provide Company with a signed Transportation Form identifying its Qualified Supplier. Customer may designate no more than one Qualified Supplier. This authorization shall be in a form agreeable to Company and shall remain in effect until a signed replacement is received by Company;

d) Customer acknowledges the Qualified Supplier's responsibilities under Section 1.6;

e) Transportation Service is not available for a term less than 12-months. Termination of transportation service may, at the Company's sole discretion, delay Customer's request to resume transportation service;

f) Electronic flow measurement (EFM) may be required for Customers under transportation service, at the Company's sole discretion. The Customer may be required to reimburse the Company for any cost related to the installation of the EFM as well as provide for or reimburse the Company for any ongoing maintenance, repair, or communications costs; and

g) In the event Customer's source of gas supply is terminated by Customer's Qualified Supplier due to non-payment or other reasons, or if customer is otherwise unable to continue as a transportation customer, Customer may, upon the first of the month after 30-calendar days advance written notice to Company, obtain service from Company under the general sales tariff applicable to Customer. Prior to commencing such service, Company may, in its sole discretion, require Customer to post a deposit or bond.

1.6 QUALIFIED SUPPLIER'S RESPONSIBILITY

Qualified Supplier shall act on behalf of the Customer to procure gas supplies, deliver gas supplies plus Payment in Kind volume, into Company designated Points of Receipt and shall act as the Customer's agent with respect to nominations, operational notices and resolution of imbalances.

a) Qualified Suppliers shall aggregate their Customers' volumes for balancing purposes, into Aggregation Areas, as determined, in the Company's sole discretion.

b) Qualified Supplier shall submit nominations to the Company's gas scheduling department, in accordance with their currently effective nomination process, which can be provided to the parties upon request. Customer and Qualified Supplier shall exercise commercially reasonable best efforts to deliver to the Pipeline System Dths of gas that Company is to deliver from the Pipeline System to Customer during any particular Hour, Day, Week and Month, including but not limited to volumes needed for peak Day usage for Customer's facilities. Qualified Supplier shall not intentionally nominate more or less gas than is anticipated for consumption by Customer(s), except as may be needed for balancing purposes to the extent Company accepts such nomination.

c) Before the start of the Gas Day, the Point Operator and Company shall establish a predetermined allocation (PDA) method to specify how gas received or delivered by Company shall be allocated in accordance with confirmed nominations at such point. Only one PDA methodology shall be applied per allocation period.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

d) Daily Quantity of Transportation Service Gas: Company shall receive and deliver gas hereunder as nearly as practicable at uniform hourly and daily rates of flow. It is recognized that it may be physically impracticable, because of measurement, gas control limitations and other operating conditions, to stay in zero imbalance each hour and each day; therefore, the daily and hourly quantities received may, due to the aforementioned reasons, vary above or below the daily and hourly quantities delivered. If the quantities received and the quantities delivered hereunder should create an imbalance at the end of any hour, Day, Week, or Month, then Company and Qualified Supplier shall adjust receipts and/or deliveries at any time to the end that the quantities received and delivered shall be kept as near to zero imbalance as practicable.

e) Quality of Transportation Service Gas: The gas procured by a Qualified Supplier, for receipt by Company, shall conform to the standards prescribed in Company's applicable rate schedules, Agreements, and applicable local, state or federal laws, rules and/or regulations.

1.7 IMBALANCES

Qualified Supplier shall, to the extent practicable, not deliver into the Pipeline System more or less Dths of Gas than Company delivers to the Aggregation Area of Customers, at the Points of Delivery, during a Consumption Period. The following imbalance provisions shall be applied to the Qualified Supplier for its Aggregation Area of Customers.

a) If Company receives less Dths of Gas than are delivered to the Aggregate Area Customers at the Points of Delivery in excess of the Monthly Tolerance Limit or Cumulative Tolerance Limit in any particular Consumption Period, then Qualified Supplier shall purchase such under-delivered volumes at 105% of the applicable index, plus the Adder.

b) If Company receives more Dths of Gas than are delivered to the Aggregate Area Customers at the Points of Delivery in excess of the Monthly Tolerance Limit or Cumulative Tolerance Limit in any particular Consumption Period, Qualified Supplier shall sell such excess Gas to Company at 95% of the applicable index.

c) The applicable index and Adder will be defined in the Qualified Supplier Agreement and amended from time to time.

d) A proportional share of any upstream pipeline transportation service charges, additional commodity charges, and penalties incurred by the Company, that in whole or in part, are the result of Qualified Supplier's scheduling and/or managing the upstream transportation of the Customer's gas to Company's interconnection point(s) with the upstream pipeline(s). The proportional share will be calculated using the Qualified Supplier's receipts and deliveries and the upstream pipeline invoices for the applicable period. Proceeds from this charge will be credited to the Reconciliation Account. The Company will bill Qualified Supplier for these charges and penalties manually on a separate bill. Payment shall be required in accordance with applicable Rules of Service.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

e) The Company will provide monthly imbalance statements along with calculations of the charges in accordance with the aforementioned provisions to the Qualified Supplier each month.

f) Payments for imbalance settlements will be due each month within 15 business days of the imbalance statement date. The Company may elect at its sole discretion to accrue the imbalance settlement provisions each month and only require periodic settlement rather than monthly payments.

g) On or about 15 days after the Company receives necessary volumetric information from other parties for each Consumption Period after commencement of Gas receipts and deliveries hereunder, Company shall render to the Qualified Supplier a statement for the preceding Consumption Period showing the total Dths of Gas received and delivered and each Point of Receipt and Point of Delivery. If information necessary for statement purposes is in the possession of Customer, Customer shall furnish such information to Company on or before the 6th Day of the Month in which the statement requiring such data is to be rendered.

h) Both parties hereto shall have the right at any and all reasonable times within 24 months from the time period in question, to examine the books and records of the other to the extent necessary to verify the accuracy of any statement, computation, or demand made hereunder.

1.8 LACK OF LIABILITY

a) Furnishing of Gas. The Company shall not be liable for any loss or damage caused by variation in gas pressure, defects in pipes, connections and appliances, escape or leakage of gas, sticking of valves or regulators, or for any other loss or damage not caused by the Company's negligence arising out of or incident to the furnishing of gas to any Consumer.

b) After Point of Delivery. Company shall not be liable for any damage or injury resulting from gas or its use after such gas leaves the point of delivery other than damage caused by the fault of the Company in the manner of installation of the service lines, in the manner in which such service lines are repaired by the Company, and in the negligence of the Company in maintaining its meter loop. All other risks after the gas left the point of delivery shall be assumed by the Customer or consumer, his agents, servants employees, or other persons.

c) Reasonable Diligence. The Company agrees to use reasonable diligence in rendering continuous gas service to all Customers or Consumers, but the Company does not guarantee such service and shall not be liable for damages resulting from any interruption to such service.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

d) Force Majeure. If either Company or Customer is rendered unable, wholly or in part, by reason of force majeure or any other cause of any kind not reasonably within its control, other than financial, to perform or comply with their obligations hereunder, then such party's obligations or conditions shall be suspended during the continuance of such inability and such party shall be relieved of liability for any damage or loss for failure to perform the same during such period; provided, however, obligations to make payments when due hereunder shall not be suspended.

e) Damage to Pipeline. If a portion of the Pipeline System required to make the transportation service available is partially damaged by fire, line strikes or other casualty, the damage may be repaired by Company, at its option and in its sole discretion, as speedily as practicable, to include the time taken for the settlement of insurance claims. Until such repairs are made, the payments shall be apportioned in proportion to the portion of the capacity of the Pipeline System which is still available for the purposes hereof, such determination to be made in the sole discretion of Company. If the damages are so extensive as to render the Pipeline System wholly unusable, in Company's sole opinion, the payments, if any, shall cease until such time as the Pipeline System is again useable. In case the damage shall, in Company's sole opinion, amount substantially to a destruction of the portion of the Pipeline System available for the transportation of Gas and Company shall elect not to repair the damage, then the Agreement shall terminate at the time of such damage, and Company shall not be liable to Customer for any liability, damage, or claim which arises out of any failure to make repairs.

WEATHER NORMALIZATION ADJUSTMENT CLAUSE

APPLICABILITY

The Weather Normalization Adjustment Clause (WNA) shall apply to the following general service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") in the incorporated and unincorporated areas served in the Central-Gulf Service Area including Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas: Rate Schedules 10, 15, 1Z, 1Y, 20, 25, 2Z, 2Y, 40, and 4Z. The WNA shall be effective during the September through May billing cycles.

PURPOSE

The WNA refunds over-collections or surcharges under-collections of revenue due to colder or warmer than normal weather, as established in the Company's most recent rate filing.

WNA MECHANISM

In order to reflect weather effects in a timely and accurate manner, the WNA adjustment shall be calculated separately for each billing cycle and rate schedule. The weather factor, determined for each rate schedule in the most recent rate case, shows the effect of one heating degree day on consumption for that rate schedule. During each billing cycle, the weather factor is multiplied by the difference between normal and actual heating degree days for the billing period and by the number of customers billed. This WNA volume adjustment is priced at the current cost of service rate per Ccf to determine a WNA revenue adjustment, which is spread to the customers in the billing cycle on a prorata basis. The WNA for each billing cycle and rate schedule shall be based on the following formula:

$$\text{WNA Rate} = \frac{\text{WNAD}}{\text{CV}}, \quad \text{where}$$

CV = Current Volumes for the billing period.

WNAD = Weather Normalization Adjustment Dollars to be collected from each billing cycle and rate schedule. This factor shall be based on the following formula:

WEATHER NORMALIZATION ADJUSTMENT CLAUSE
(Continued)

WNAD = (HDD Diff * CB * WF) * COS rate, where

HDD Diff = (Normal HDD – Actual HDD), the difference between normal and actual heating degree days for the billing period.

CB = Number of customers billed for the billing period.

WF = Weather factor determined for each rate schedule in the most recent rate case.

<u>Austin, Bastrop (environs only), Bee Cave, Buda, Cedar Park, Dripping Springs, Georgetown, Hutto, Kyle, Lakeway, Marble Falls, Mustang Ridge, Pflugerville, Rollingwood, Sunset Valley, and West Lake Hills:</u>
Residential 0.14945; Commercial 0.46174; Public Authority 1.91573
Weather Station: KATT

<u>Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum:</u>
Residential 0.13893; Commercial 0.24380; Public Authority 0.82469
Weather Station: KSAT

<u>Bayou Vista, Galveston, and Jamaica Beach:</u>
Residential 0.19840; Commercial 0.50668; Public Authority 5.12822
Weather Station: KGLS

<u>Beaumont, Groves, Nederland, Port Arthur, and Port Neches:</u>
Residential 0.14683; Commercial 0.21018; Public Authority 1.04076
Weather Station: KBPT

<u>FILING WITH THE CITIES AND THE RAILROAD COMMISSION OF TEXAS (RRC)</u>

The Company will file monthly reports showing the rate adjustments for each applicable rate schedule. Supporting documentation will be made available for review upon request. By each October 1, the Company will file with the Cities and the RRC an annual report verifying the past year's WNA collections or refunds.

The Company shall file the report with the RRC electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Director of Oversight and Safety Division
Gas Services Department
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

PIPELINE INTEGRITY TESTING (PIT) RIDER

PURPOSE

The purpose of this Pipeline Integrity Testing Rider is to promote the public interest in pipeline safety by enabling Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") to recover the reasonable and necessary Pipeline Integrity Safety Testing expenses incurred by the Company during the prior year (including contractor costs but excluding the labor cost of Texas Gas Service Company employees). These legally mandated operating and maintenance expenses shall be recovered through a separate monthly volumetric charge (the Pipeline Integrity Testing or "PIT" Surcharge) that shall be shown as a separate line item on the customer's monthly bill and calculated for each customer class as described below. Capital expenditures associated with the Pipeline Integrity Program shall continue to be recovered through base rates and any interim rate adjustments implemented pursuant to Section 104.301 of the Texas Utilities Code.

APPLICABILITY

This Rider shall be applied to all gas sales and transportation customers within the service territory designated below, except special contract customers.

TERRITORY

This Rider shall apply to the following gas sales and standard transportation rate schedules of the Company's Central-Gulf Service Area ("CGSA") within the incorporated and unincorporated areas of Austin, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Georgetown, Gonzales, Hutto, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nixon, Pflugerville, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas and in the environs area of Bastrop, Texas: 10, 15, 20, 25, 30, 40, C-1, CNG-1, 1Z, 1Y, 2Z, 2Y, 3Z, 4Z, C-1-ENV, CNG-1-ENV, T-1, and T-1-ENV.

QUALIFYING EXPENSES

This Rider applies only to the legally mandated safety testing of the Company's transmission lines in the CGSA under the Pipeline Integrity Safety Testing Program. The operating and maintenance expense items that qualify for recovery under this Rider shall include the contractor costs associated with land and leak survey, permitting, and job order preparation and completion; the clearing of right-of-way; any needed notifications to adjacent businesses and residences; traffic control equipment and personnel; Direct Current Voltage Gradient ("DCVG"), Close Interval ("CI"), and other surveys to ensure the integrity of the pipeline system; any required rigid bypasses; flushing of the lines and testing and disposal of the flush water; hydrostatic testing of the lines and analysis and disposal of the test water; any required "pigging" of the lines in connection with safety testing; any required x-ray welding; metallurgical testing of the pipeline or components thereof; site restoration, painting, and clean-up; expenses associated with providing a supply of compressed natural gas ("CNG") to ensure uninterrupted service to customers during testing; and any other operating and maintenance expenses reasonably necessary to safely and effectively perform required safety testing of the Company's pipelines in the CGSA. Neither capital expenditures by the Company, nor the labor cost of Company employees, shall be recovered under this Rider.

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

CALCULATION OF PIT SURCHARGES

The Pipeline Integrity Testing Surcharges established under this Rider shall be designed so as to recover the Total Testing Expense incurred in the prior year for Pipeline Integrity Safety Testing, and shall be calculated as follows:

The Total Annual Testing Expense shall be divided by the estimated average annual usage to produce the annual PIT Surcharge.

$$\text{PIT Surcharge} = \frac{\text{Total Annual Testing Expense}}{\text{Estimated Annual Usage}}$$

Based upon customer data for the prior calendar year and any other relevant factors, the estimated annual usage may be revised annually to account for customer growth, and the resulting revised PIT Surcharge shall be applied to each class for the ensuing 12-month recovery period.

ANNUAL RECONCILIATION

After completion of each annual recovery period, the total revenues collected under this Rider for that year shall be reconciled against the revenues previously calculated to be collected for that year, and the PIT Surcharge for each class shall be adjusted upward or downward so that the Company recovers any underrecoveries or refunds any overrecoveries that may have accrued under the Rider, plus monthly interest on those underrecoveries or overrecoveries at the cost of long-term debt approved in the Company’s most recent general rate case in which rates were set for application to customers in the CGSA. The reconciliation shall be filed with the regulatory authority on or before February 21st of each year, and the regulatory authority shall complete its review of the reconciliation on or before March 21st of each year, so that the Company can implement the reconciled PIT Surcharges beginning with the first billing cycle for April of each succeeding year.

DEFERRED ACCOUNTING

The Company is authorized and directed to defer, as a regulatory asset, all Pipeline Integrity Safety Testing expenses incurred during the testing cycle starting on January 1, 2016 and all revenues specifically collected under this Rider shall be applied to the deferred expense account. The Company shall not earn a return on any regulatory asset created under this provision, and no such regulatory asset shall be included in the Company’s invested capital (rate base) for ratemaking purposes.

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

ANNUAL REPORT & APPLICABLE PSCC

On or before February 21st after each calendar year, the Company shall file a report with the Commission and the CGSA Cities showing all Pipeline Integrity Safety Testing expenses incurred during the previous calendar year and verifying the prior year's collections and any underrecoveries or overrecoveries accruing to date under this Rider. The report shall separately identify and list such expenses by account number and project number. Prior to the effective date of this Rider and on or before February 21st of each succeeding year while this Rider is in effect, the Company shall also file an Addendum to this Rider with the Commission and the CGSA Cities (a) identifying the PIT Surcharges that will be applied during the ensuing 12-month recovery period from April through March billing cycles, and (b) providing the underlying data and calculations on which each PIT Surcharge for that period is based.

The Company shall file the report with the Commission electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Director of Oversight and Safety Division
Gas Services Department
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

NOTICE TO AFFECTED CUSTOMERS

In addition to the annual report and Addendum to this Rider required above, the Company shall provide, on or before March 31st after each calendar year, written notice to each affected customer of (a) the PIT Surcharge that will be applied during the ensuing 12-month period from April through March billing cycles, and (b) the effect the PIT Surcharge is expected to have on the average monthly bill for each affected customer class. The written notice shall be provided in both English and Spanish, shall be the only information contained on the piece of paper on which it is printed, and may be provided either by separate mailing or by insert included with the Company's monthly billing statements, including electronic billing statements. The Company shall also electronically file an affidavit annually with the Commission and the CGSA Cities certifying that notice has been provided to customers in this manner. The notice shall be presumed to be complete three calendar days after the date the separate mailing or billing statement is deposited in a postage-paid, properly addressed wrapper in a post office or official depository under care of the United States Postal Service. The initial notice shall be filed with, reviewed, and approved by the regulatory authority, and each subsequent notice shall follow the same format as that of the approved initial notice.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area (Select areas) **RATE SCHEDULE PIT-RIDER**

PIPELINE INTEGRITY TESTING (PIT) SURCHARGE RIDER

A. APPLICABILITY

The Pipeline Integrity Testing Surcharge (PIT) rate as set forth in Section (B) below is for the recovery of costs associated with pipeline integrity testing as defined in Rate Schedule PIT. This rate shall apply to the following gas sales and standard transportation rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. currently in force in the Company's Central-Gulf Service Area ("CGSA") within the incorporated and unincorporated areas of Austin, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Georgetown, Gonzales, Hutto, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nixon, Pflugerville, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas and in the environs area of Bastrop, Texas: 10, 15, 20, 25, 30, 40, C-1, CNG-1, T-1, 1Z, 1Y, 2Z, 2Y, 3Z, 4Z, C-1-ENV, CNG-1-ENV and T-1-ENV.

B. PIT RATE

-$0.00010 per Ccf

This rate will be in effect until all approved and expended pipeline integrity testing expenses are recovered under the applicable rate schedules.

C. OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchises fees) related to above.

D. CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE RCE**

RATE CASE EXPENSE SURCHARGE

A. APPLICABILITY

The Rate Case Expense Surcharge (RCE) rate as set forth in Section (B) below is pursuant to City Ordinance. This rate shall apply to the following rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. in the incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas: 10, 15, 20, 25, 30, 40, C-1, CNG-1, and T-1.

B. RCE RATE

All Ccf during each billing period: $0.XXXX per Ccf

This rate will be in effect until all approved and expended rate case expenses are recovered under the applicable rate schedules. Texas Gas Service Company, a Division of ONE Gas, Inc. will recover $XX.XX in actual expense and no more than $XX.XX in estimated expense. The Rate Case Expense Surcharge will be a separate line item on the bill.

C. OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

D. CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area **RATE SCHEDULE RCE - ENV**

RATE CASE EXPENSE SURCHARGE

A. APPLICABILITY

The Rate Case Expense Surcharge (RCE) rate as set forth in Section (B) below is pursuant to Gas Utilities Case No. XXXXX: Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated Areas of the Central-Gulf Service Area, Final Order Finding of Fact No. XX-XX. This rate shall apply to the following rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. in the unincorporated areas of the Central-Gulf Service Area which includes Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas: 1Z, 1Y, 2Z, 2Y, 3Z, 4Z, C-1-ENV, CNG-1-ENV and T-1-ENV.

B. RCE RATE

All Ccf during each billing period: $ 0.XXXX per Ccf

This rate will be in effect until all approved and expended rate case expenses are recovered under the applicable rate schedules. Texas Gas Service Company, a Division of ONE Gas, Inc. will recover $XX.XX in actual expense and up to $XX.XX in estimated expenses. The Rate Case Expense Surcharge will be a separate line item on the bill.

C. OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees related to above.

D. CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

E. COMPLIANCE

The Company shall file an annual rate case expense reconciliation report within ninety (90) days after each calendar year end until and including the calendar year end in which the rate case expenses are fully recovered. The Company shall file the report with the Commission addressed to the Director of Oversight and Safety Division, Gas Services Department and referencing Gas Utilities Case No. XXXXX Rate Case Expense Recovery Report. The report shall detail the monthly collections for RCE surcharge by customer class and show the outstanding balance. Reports for the Commission should be filed electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Compliance Filing
Director of Oversight and Safety Division
Gas Services Dept.
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

RENEWABLE NATURAL GAS ("RNG") CREDITS PROGRAM

APPLICABILITY

The Renewable Natural Gas (RNG) Credits Program option shall apply to all gas sales customers of Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") in the incorporated and unincorporated areas served in the Central-Gulf Service Area including Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas.

DEFINITION

RNG - Renewable Natural Gas is the term used to describe pipeline-quality biogas produced from various biomass sources (such as landfills, wastewater treatment facilities, and anaerobic digesters) through a biochemical process that has been processed to purity standards and is interchangeable with conventional natural gas. The cost of RNG may also include the cost of carbon "Environmental Attributes" purchased and retired in association with the purchase of Renewable Natural Gas.

Environmental Attributes – Environmental Attributes represents any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of Renewable Natural Gas, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions.

SUBSCRIPTION LEVEL

Up to $150,000 at a time of Environmental Attributes related to RNG will be made available to customers in Blocks. Each Block shall represent the Environmental Attributes associated with 0.25 MMBtu of RNG.

Customers may voluntarily opt, at any time, to purchase monthly Blocks of Environmental Attributes associated with RNG for a year.

Once subscribed, customers must remain on this tariff rate for 12 months at the subscription level requested. At the Company's sole discretion, the Company may permit early withdrawal for customers experiencing financial hardship or other extenuating circumstances affecting the customer's ability to complete their 12-month commitment.

RENEWABLE NATURAL GAS ("RNG") CREDITS PROGRAM
(Continued)

RNG RATE

$3.04 per Block.

The RNG rate shall represent the cost of RNG Environmental Attributes separate from and in addition to the cost of conventional natural gas recovered through the Cost of Gas Clause, Rate Schedules 1-INC and 1-ENV.

The RNG charge will show as a separate line item on customer bills and will be in addition to all other applicable service charges, delivery fees, riders, customer fuel cost, fees, and taxes.

The RNG rate may be updated based on the cost of new purchases of Environmental Attributes or changes to the cost to retire Environmental Attributes through a filing with the regulator.

RULES OF SERVICE

CENTRAL-GULF SERVICE AREA

Incorporated and Unincorporated Areas of Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, TX

Effective for Bills Rendered On and After TBD

Communications Regarding this Tariff Should Be Addressed To:
Customer Relations
401 N. Harvey
Oklahoma City, OK 73102
customerrelations@onegas.com
(405) 551-6752

Supersedes and Replaces Rules of Service for Incorporated and Unincorporated Areas of the Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas and the environs area of Buda, Texas dated August 4, 2020, Incorporated and Unincorporated Areas of the Central-Gulf Service Area including Marble Falls and Pflugerville, Texas, Incorporated Areas of Buda, and the environs area of Bastrop, Texas dated September 15, 2022, and Incorporated and Unincorporated Areas of the Central-Gulf Service Area including Mustang Ridge, Texas and the environs area of Hutto, Texas dated January 15, 2024

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SECTION 1 — GENERAL STATEMENT AND DEFINITIONS

1.1 TARIFF APPLICABILITY

Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") operates as a gas utility under Texas Utilities Code § 101.003(7) within the State of Texas. This Tariff applies to all incorporated areas, unincorporated areas and census designated places in the Company's Central-Gulf Service Area comprised of the incorporated and unincorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, and the environs of Bastrop, Texas.

Service under this Tariff is subject to the original jurisdiction of the municipalities in the Central-Gulf Service Area and the Railroad Commission of Texas. The Company will provide service to any person and/or business within its service area in accordance with the rates, terms and conditions provided for in its Tariff and regulations.

1.2 RATE SCHEDULES

All Customers shall be served under rate schedules filed with the municipality or Railroad Commission of Texas. Customers shall be assigned to rate schedules in accordance with the class of the particular Customer, the usage which will be made of the gas and that Customer's volume requirements. The Company shall advise an Applicant or Customer regarding the most economical rate for their usage if more than one rate is applicable. A Customer assigned to a rate schedule shall remain on that schedule for a minimum of one year except that an assignment made in error may be corrected immediately. In the event of a question regarding the Customer's classification, the questions shall be resolved by reference to the coding of the Customer's primary business in the latest edition of the Standard Industrial Classification Manual of the United States Government's Office Management and Budget.

1.3 DEFINITIONS

The following definitions shall apply to the indicated words as used in this Tariff:

Adder:	Shall mean the Company's incremental cost to purchase natural gas.
Aggregation Areas:	Shall mean aggregation pools established by the Company within geographic, operational, administrative, and/or other appropriate parameters, for the purposes of nominating and imbalances.
Agricultural Service:	Service to Consumers engaged in agricultural production.
Applicant:	Any person, organization or group of persons or organizations making a formal request either orally or in writing for gas service from the Company.
Automated Meter Reading (AMR):	The process of remotely reading a gas meter.

Average Day Usage:	The gas demand of a given Customer for gas in any one month divided by 30. Gas demand is considered to be equivalent to consumption during each billing month, provided however, that when service has been curtailed, demand shall be considered to be actual consumption plus estimated curtailment during the period.
Blanket Builder:	A builder or someone acting for a builder who requests the installation of service lines.
Btu:	Shall mean British thermal unit(s) and shall be computed on a temperature base of sixty degrees (60°) Fahrenheit and at the standard pressure base of the applicable service area and on a gross-real-dry basis and shall not be corrected for real water vapor as obtained by means commonly acceptable to the industry, and "MMBtu" shall mean one million (1,000,000) Btu.
Commercial Service:	Service to Consumers engaged primarily in the sale or furnishing of goods and services and any usage not otherwise provided for.
Commission or The Commission:	The Railroad Commission of Texas.
Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Consumer:	Any person or organization receiving gas service from the Company for his or her own appliances or equipment whether or not the gas is billed directly to him or her. (For example, a rental unit where the utilities are part of the rent, the landlord is a Customer and the tenant is a Consumer.)
Consumption Period:	Shall mean a volumetric billing period.
Cumulative Tolerance Limit:	Shall mean the percent of aggregate historical annual deliveries of a Qualified Supplier's Aggregation Area pool of customers for the most recent year ended on June 30. The Company, at its sole discretion, may make adjustments to the Cumulative Tolerance Limit.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (Central Standard Time) on one calendar day and ending at

	9:00 a.m. (Central Standard Time) the following calendar day.
Dekatherm (Dth):	Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.
Domestic Service:	Service to any Consumer which consists of gas service used directly for heating, air conditioning, cooking, water heating and similar purposes whether in a single or multiple dwelling unit.
Electric Generation Service:	Service to customers operating electric generation assets and that are registered with the applicable balancing authority including bulk power system assets, co-generation facilities, distributed generation, and/or backup power systems. This service may also be provided to those known Customers who use thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.
Electronic Document:	Any document sent electronically via email or the internet.
Electronic Flow Measurement (EFM):	An electronic means of obtaining readings on a gas meter.
Electronic Fund Transfer (EFT):	The process to convert a paper check or electronic bill payment request to an electronic transfer. Paper checks received by Company or their agents are destroyed.
Electronic Radio Transponder (ERT):	A device that assists with remotely reading a gas meter.
Excess Flow Valve (EFV):	A safety device installed on a natural gas service line. The EFV is designed to automatically shut off the flow of natural gas in the service line and mitigate the impact of a significant break, puncture or severance in the line. EFVs are not designed to shut off the flow of gas in the line breaks at the connection of a gas appliance in a residence or in the customer's piping system (interior or exterior) on the customer's side of the gas meter.
Expedited Service:	Customer request for same day service or service during non-business hours for connection or reconnection of gas service.
Firm Service:	Services offered to Customers (regardless of service class) under schedules or contracts that anticipate no

interruptions. Service may be interrupted or curtailed at the discretion of the Company during Force Majeure events or at the direction of a regulatory or government agency.

Force Majeure: If either Company or Customer is rendered unable, wholly or in part, by reason of force majeure or any other cause of any kind not reasonably within its control, other than financial, to perform or comply with their obligations hereunder, then such party's obligations or conditions shall be suspended during the continuance of such inability and such party shall be relieved of liability for any damage or loss for failure to perform the same during such period; provided, however, obligations to make payments when due hereunder shall not be suspended. The term "Force Majeure" as used herein means acts of God; strikes, lockouts, or other industrial disturbances; acts of the public enemy; wars; blockades; insurrections; riots; epidemics; pandemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; arrests and restraints of the government, or any agency thereof, either federal or state, civil or military; civil disturbances; explosions; breakage or accident to machinery or lines of pipe; freezing of wells or lines of pipe; shortage of gas supply, whether resulting from inability or failure of a supplier to deliver gas; partial or entire failure of natural gas wells or gas supply; depletion of gas reserves; mandatory testing or maintenance necessary for compliance and safe operation, and any other causes, whether of the kind herein enumerated or otherwise. If due to a Force Majeure the Company curtails or temporarily discontinues the receipt or delivery of Gas hereunder, Customer agrees to hold Company harmless from any loss, claim, damage, or expense that Customer may incur by reason of such curtailment or discontinuance.

Gas or Natural Gas: Shall mean the effluent vapor stream in its natural, gaseous state, including gas-well gas, casing head gas, residue gas resulting from processing both casing head gas and gas-well gas, and all other hydrocarbon and non-hydrocarbon components thereof.

General Rate Schedule: A rate schedule available to all Customers of the appropriate class or classes for usages indicated therein.

Industrial Service: Service to Consumers engaged primarily in a process which changes raw or unfinished materials into another form of product. This classification shall embrace all Consumers included in Division A (except Major Groups 01 and 02) and Division D of the Standard Industrial Classification Manual.

Irrigation or Irrigation Pumping Service:	(SIC Division A - Major Group 01) who use gas for operating engine-driven pumping equipment.
Master Meter:	A single large volume gas measurement device by which gas is metered and sold to a single purchaser who distributes the gas to one or more additional persons downstream from that meter. Master meter operators shall comply with the minimum safety standards in 49 CFR Part 192.
Mcf:	Shall mean one thousand (1,000) cubic feet of Gas.
Month:	Shall mean the period beginning at 9:00 a.m. Central Standard Time on the first Day of each calendar month and ending at 9:00 a.m. Central Standard Time on the first Day of the next succeeding calendar month.
Monthly Tolerance Limit:	Shall mean five percent (5%) of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
Optional Rate Schedule:	A General Rate Schedule which may be selected by a Customer in lieu of another general schedule but which may require installation of special equipment.
Overtime Rate:	The fee charged by the Company to perform work outside its normal business hours or on holidays and includes changes to previously scheduled work that must be performed outside the Company's normal business hours.
Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for gas.
PDA:	Shall mean a predetermined allocation method.
Pipeline System:	Shall mean the current existing utility distribution facilities of the Company located in the State of Texas.
Point of Delivery:	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.

Point of Receipt:	Shall mean the point or points where the Company shall receive Gas into the Pipeline System from Customer.
Point Operator:	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.
Qualified Supplier:	Shall mean an approved supplier of natural gas for transportation to customers through the Company's pipeline system.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the Central-Gulf Service Area, or the Railroad Commission of Texas, as applicable.
Service Area:	The area receiving gas utility service provided by the Company under the terms of this Tariff.
Special Rate Schedule:	A rate schedule designed for a specific Customer.
System:	Any group of interconnected pipelines and appurtenances owned or operated by the Company and independent from any other such group of facilities.
Tariff:	Shall mean every rate schedule, or provision thereof, and all terms, conditions, rules and regulations for furnishing gas service filed with the regulatory authorities or agencies having jurisdiction over the Company or the services provided hereunder.
Temporary Service:	Any service which will not be utilized continuously at the same location for a period of two or more years.
Transportation Form:	Shall mean the Company approved selection of transportation service document.
Transportation Rate Schedule:	A rate schedule designed for service to any Customer for the transportation of Customer-owned natural gas through the Company's distribution system.
Transportation Service:	The transportation by the Company of natural gas owned by someone other than the Company through the Company's distribution system.
Week:	Shall mean a period of seven (7) consecutive Days beginning at 9:00 a.m. Central Standard Time on each

Monday and ending at the same time on the next succeeding Monday.

Year: Shall mean a period of three hundred sixty-five (365) consecutive Days, or three hundred sixty-six (366) consecutive Days when such period includes a February 29.

SECTION 2. [Reserved for future rules]

SECTION 3. RATES AND UTILITY CHARGES

Current Rate Schedules are on file with each applicable Regulatory Authority and available on the Company's website at https://www.texasgasservice.com/rateinformation/home.

SECTION 4 — CONDITIONS OF SERVICE

4.1 PROVISION OF SERVICE

The Company will provide gas service to any person or organization located within the Central-Gulf Service Area from the Company's facilities or in certain cases, the facilities of its supplier, in accordance with the provisions of this Tariff and other applicable Rate Schedules.

The Customer shall make or procure, and hereby agrees to make or procure, conveyance to the Company of perpetual right-of-way across the property owned or controlled by the Customer that is required to install natural gas facilities and is in a location and condition satisfactory to the Company, provides clear access to Company's facilities, and enables the Company to provide service to Customer's property or the premises of the Consumer.

4.2 FEES AND CHARGES

All fees and charges assessed by the Company to provide and maintain utility services are as provided for in this Tariff. If the Customer elects transportation service, the commodity cost of gas shall be determined between the Customer and the Customer's selected supplier.

4.3 RESALE OF GAS

Gas delivered by the Company shall not be redelivered or resold for the use thereof by others unless otherwise expressly agreed to in writing by the Company; provided, however, that those Customers receiving gas for redistribution to the Customer's tenants may separately meter each tenant's distribution point for the purpose of prorating the Customer's actual amount of gas delivered among the various tenants on a per unit basis.

4.4 CONTINUITY OF SERVICE

a) Service interruptions

i) The Company shall make all reasonable efforts to prevent interruptions of Firm Service. When interruptions occur, the Company shall re-establish service within the shortest possible time consistent with prudent operating principles so that the smallest number of Customers are affected.

ii) The Company shall make reasonable provisions to meet emergencies resulting from failure of service and shall issue instructions to its employees covering procedures to be followed in the event of an emergency in order to prevent or mitigate interruption or impairment of service.

iii) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

iv) Curtailment of Firm Service will be done in accordance with Texas Administrative Code Title 16, Part 1, Chapter 7, Subchapter D, Rule §7.455 Curtailment Standards.

b) Record of interruption. Except for momentary interruptions which do not cause a major disruption of service, the Company shall keep a complete record of all interruptions, both emergency and scheduled. This record shall show the cause of interruptions, date, time duration, location, approximate number of Customers affected, and, in cases of emergency interruptions, the remedy and steps taken to prevent recurrence, if applicable.

Report to Railroad Commission of Texas. The Commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four hours. The notice shall also state the Company's belief as to the cause of such interruptions. If any service interruption is reported to the Commission otherwise (for example, as a curtailment report or safety report), such other report is sufficient to comply with the terms of this Section.

c) The Company does not guarantee uninterrupted service to any Customer and shall not be liable for damages resulting from any loss of service to any Customer.

4.5 AVAILABILITY OF TARIFFS

A copy of this Tariff and other Rate Schedules can be requested through TGS's customer service number at 1-800-700-2443 (non-emergency number) or requested under the 'Contact Us' section of www.texasgasservice.com and are available on the Company's website at https://www.texasgasservice.com/rateinformation/home.

4.6 CUSTOMER INFORMATION

The Company shall:

a) Maintain a current set of maps showing the physical locations of its facilities. All distribution facilities shall be labeled to indicate the size or any pertinent information which will accurately describe the Company's facilities. These maps, or such other maps as may be required by the Regulatory Authority, shall be kept by the Company in a central location and will be available for inspection by the Regulatory Authority during normal working hours. Each business office or service center shall have available up-to-date maps, plans or records of its immediate area, with such other information as may be necessary to enable the Company to advise applicants and others entitled to the information as to the facilities available for serving that locality;

b) Assist the Customer or Applicant in selecting the most economical rate schedule;

c) In compliance with applicable law or regulations, notify customers affected by a change in rates or schedule or classification;

d) Post a notice in a conspicuous place in each business office of the utility where applications for service are received informing the public that copies of the rate schedules and rules relating to the service of the utility as filed with the Commission are available for inspection;

e) Upon request inform its customers as to the method of reading meters;

f) Make available, during normal business hours, such additional information on rates and services as any Customer or Applicant may reasonably request; and

g) Provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. The Company may provide this notification to customers electronically. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the Regulatory Authority upon application and a showing of good cause may exempt the Company from the requirement that the information be provided in Spanish:

i) the Customer's right to information concerning rates and services and the Customer's right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

ii) the Customer's right to have their meter checked without charge under Section (7) of the Commission's Rule 7.45, if applicable;

iii) the time allowed to pay outstanding bills;

iv) grounds for termination of service;

v) the steps the Company must take before terminating service;

vi) how the Customer can resolve billing disputes with the Company and how disputes and health emergencies may affect termination of service;

vii) information on alternative payment plans offered by the Company;

viii) the steps necessary to have service reconnected after involuntary termination;

ix) the appropriate Regulatory Authority with whom to register a complaint and how to contact such authority;

x) the hours, addresses and telephone numbers of utility offices where bills may be paid and information may be obtained; and

xi) the Customer's right to be instructed by the Company how to read their meter.

h) At least once each calendar year, the Company shall notify Customers that information is available upon request, at no charge to the Customer, concerning the items listed in subsection (g) above. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself. The Company may provide this notification to Customers electronically.

4.7 CUSTOMER COMPLAINTS

Upon complaint to the Company by residential or small commercial customers either at its office, by letter, by telephone or by email, the Company shall promptly make a suitable investigation and advise the complainant of the results thereof. The Company shall keep a record of all complaints which shall show the name and address of the complainant, the date and nature of the complaint, and the adjustment or disposition thereof for a period of one year subsequent to the final disposition of the complaint.

4.8 COMPANY RESPONSE

Upon receipt of a complaint, either by letter, by telephone or by email from the Regulatory Authority on behalf of a customer, the utility shall make a suitable investigation and advise the Regulatory Authority and complainant of the results thereof. An initial response must be made by the next working day. The Company must make a final and complete response within 15 days from the date of the complaint, unless additional time is granted within the 15-day period. The Commission encourages all customer complaints to be made in writing to assist the regulatory authority in maintaining records of the quality of service of the Company; however, telephone communications will be acceptable.

4.9 LIMITATION OF LIABILITY

THE CUSTOMER ASSUMES ALL RESPONSIBILITY FOR ALL FACILITIES AND THEIR INSTALLATION, MAINTENANCE, OPERATION, FUNCTIONALITY, TESTING AND CONDITION THEREOF ON THE CUSTOMER'S SIDE OF THE POINT OF DELIVERY OF GAS TO THE PROPERTY OF THE CUSTOMER OR TO THE PREMISES OF THE CONSUMER, AS DEFINED IN SECTION 12.11. THE COMPANY IS NOT LIABLE TO A CUSTOMER, AND CUSTOMER SHALL INDEMNIFY, HOLD HARMLESS, AND DEFEND THE COMPANY AND ITS EMPLOYEES OR AGENTS FROM ANY AND ALL CLAIMS OR LIABILITY FOR DAMAGES OF ANY KIND OR NATURE INCLUDING, BUT NOT LIMITED TO, PERSONAL INJURY, DAMAGE TO PROPERTY, ANY INCIDENTAL, CONSEQUENTIAL, BUSINESS INTERRUPTION, OR OTHER ECONOMIC OR OTHER DAMAGES OR LOSSES IN ANY MANNER DIRECTLY, INDIRECTLY OR ARISING FROM, OR CAUSED BY ACTS OR OMISSIONS OF ANY PERSON OR PARTY ON THE CUSTOMER'S SIDE OF SAID POINT OF DELIVERY OF GAS TO THE PROPERTY OF THE CUSTOMER OR TO THE PREMISE OF THE CONSUMER, AS DEFINED IN SECTION 12.11.

The Company shall be liable to the Customer or Consumer only for personal injury or property damages directly caused by the negligent acts or omissions of the Company or its employees occurring on the Company's side of the point of delivery. The Company shall not be liable or responsible for damages of any kind or nature including, but not limited to, personal injury, property damages, or any other loss or damages arising from or caused by the acts or conduct, negligence or intentional act or omission of any person, other than an employee of the Company, who adjusts, repairs, disconnects, changes, alters, or tampers with the Company's meter or facilities in any way.

In no event shall the Company or its employees be liable for any indirect, incidental, consequential, business interruption, or other economic damages or losses of Customer, Consumer, or third parties including, but not limited to, lost time, lost money, lost profits, or out of pocket expenses whether in contract, tort, or otherwise, and whether such damages are seen or unforeseen in any manner, directly or indirectly, arising from, caused by, or growing out of the interruption or termination of gas utility service.

If Company becomes unable to provide gas utility service, either wholly or in part, by an event of Force Majeure, the obligations affected by the event of Force Majeure will be suspended only during the continuance of that inability. The term "Force Majeure" means acts of God, extreme weather events, industrial disturbances, acts of public enemies, wars, blockades, insurrections, riots, epidemics, pandemics, earthquakes, fires, priority allocations of gas services, restraints or prohibitions by any court, board, department, commission or agency of the United States or of any States, any restraints, civil disturbances, explosions, or other occurrence beyond the control and without the fault or negligence of the Company and which the Company is unable to prevent or provide against by the exercise of reasonable diligence. Company will remedy its inability to provide gas utility service as soon as possible.

SECTION 5 — INITIATION OF SERVICE

5.1 REGULAR SERVICE

Application for service can be made by telephone or through the internet. Each Applicant must comply with the appropriate requirements of this Tariff before service shall be instituted. No written agreement shall be required for residential service under the standard provisions of this Tariff; commencement of service by the Company and the use of gas service by the Customer shall be evidence of such agreement. Any Customer requesting service under any special provision of this Tariff must execute a written agreement for service in the form prescribed by the Company designating those provisions which shall apply. Each Applicant may be required to produce two forms of verifiable identification; one being a government-issued identification card bearing a photograph of Applicant; and verifiable proof of their right to occupy a specific service address as of a specific date of occupancy.

5.2 RESPONSE TO REQUEST FOR SERVICE

Every gas utility must serve each qualified applicant for service within its service area as rapidly as practical. As a general policy, those applications not involving line extensions or new facilities should be filled within seven (7) working days. Those applications for individual residential service requiring line extensions should be filled within 90 days unless unavailability of materials or other causes beyond the control of the Company result in unavoidable delays. In the event the residential service is delayed in excess of 90 days after an applicant has met credit requirements and made satisfactory arrangements for payment of any required construction charges, a report must be made to the Regulatory Authority listing the name of the applicant, location and cause for delay. Unless such delays are due to causes which are reasonably beyond the control of the utility, a delay in excess of 90 days may be found to constitute a refusal to serve.

5.3 SPECIAL CONTRACTS

Under certain special conditions, the Company may agree to rates, terms or conditions of service other than those provided in this Tariff. Such service must be established under the terms of a special contract or service agreement. To the extent that the provisions of any special contract are at variance with this Tariff, the provisions of the contract shall apply.

5.4 TEMPORARY SERVICE

Temporary Service shall be furnished under the same rate schedules applicable to regular service of a similar kind.

5.5 FEES AND CHARGES

The Company shall charge a non-refundable fee to each Applicant to compensate for the cost involved in initiation or reconnection of service or when service is transferred from one name to another at any location, or whenever a meter is reset or relocated on the same premises at the request of the Customer, all as specified in Section 15 of this Tariff.

Whenever the Applicant requests expedited service, the Company will accomplish the work as expeditiously as possible and the Customer will be charged at the Company's approved rate for service work. Expedited service and the charges therefore shall be made only on request of the Applicant. Whenever service is furnished from the facilities of a third party and the Company must pay any special fees to that third party, the Company may, at its option, pass that charge plus 20% for handling through to the Applicant requesting service. See Section 15 relating to fees.

SECTION 6 — REFUSAL OF SERVICE

6.1 COMPLIANCE BY APPLICANT

The Company may decline to serve an Applicant for whom service is available from previously installed facilities until such Applicant has complied with the state and municipal regulations and approved rules and regulations of the Company on file with the Commission governing the service applied for or for the following reasons:

a) If the Applicant's installation or equipment is known to be hazardous or of such character that satisfactory and safe service cannot be given. The existence of an unsafe condition, such as a leak in the Applicant's piping system, shall be in the Company's sole opinion of endangerment to life or property;

b) If the Applicant is indebted to the Company for the same kind of service as that applied for; provided, however, that in the event the indebtedness of the Applicant for service is in dispute, the Applicant shall be served upon complying with the applicable deposit requirement;

c) For refusal to make a deposit if Applicant is required to make a deposit under this Tariff;

d) Failure to pay fees, advances or contributions required for service under this Tariff;

e) Delinquency in payment for gas service by another occupant if that person still resides at the premises to be served;

f) To any Applicant who refuses Company or Company's representatives access to or entry for observation or whose facilities do not comply with the applicable provision of this Tariff.

g) Failure of the Applicant to furnish any service or meter location specified for service under this Tariff; or

h) Failure of the Applicant to provide satisfactory identifying information as required by the Federal Trade Commission's Red Flag Rules and the Company's Identity Theft Prevention Program.

The right to refuse service shall terminate when the Applicant has complied with the Company's requirements or corrected the cause for the refusal to serve in a manner satisfactory to the Company.

6.2 APPLICANT'S RECOURSE

In the event that the Company shall refuse to serve an Applicant under this Section, the Company must inform the Applicant of the basis of its refusal and that the Applicant may file a complaint with the municipal regulatory authority or Commission, whichever is appropriate. The right to refuse service shall terminate when the Applicant has complied with the Company's requirements or corrected the cause for the refusal to serve.

6.3 INSUFFICIENT GROUNDS FOR REFUSAL TO SERVE

The following shall not constitute sufficient cause for refusal of service to a present Customer or Applicant:

a) Delinquency in payment for service by a previous occupant of the premises to be served;

b) Failure to pay for merchandise or charges for non-utility service purchased from the utility;

c) Failure to pay a bill to correct previous underbilling due to misapplication of rates more than six months prior to the date of application;

d) Violation of the Company's rules pertaining to operation of nonstandard equipment or unauthorized attachments which interfere with the service of others unless the customer has first been notified and been afforded reasonable opportunity to comply with these rules;

e) Failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the Company as a condition precedent to service; and

f) Failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of the Company's bill.

SECTION 7 — DISCONTINUANCE OF SERVICE

7.1 CUSTOMER REQUESTED DISCONTINUANCE

The Customer shall be responsible for all charges and amounts billed from the time Customer gives notice of their intention to discontinue service until the Company has read the meter, or for 5 working days from the date of such notice, whichever is the shorter period of time.

7.2 DUE DATE OF BILL

The due date of the bill for the Company's service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the Regulatory Authority. A bill for the Company's service is delinquent if unpaid by the due date.

7.3 DELINQUENT ACCOUNT

A Customer's utility service may be disconnected if the bill or other charges authorized by this Tariff or the applicable rate schedules have not been paid or a deferred payment plan pursuant to this Tariff has not been entered into within five (5) working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit in the United States mail, postage prepaid, or hand delivery to the Customer at least five (5) working days prior to the stated date of disconnection, with the words "TERMINATION NOTICE" or similar language prominently displayed on the notice. The notice shall be provided in English and Spanish as necessary to adequately inform the Customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the Company may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency. If a representative of the Company makes an attempt to collect a past due amount, a collection fee per visit shall be assessed to such Customers as specified in Section 15.

7.4 REASONS FOR DISCONNECTION

The Company's service may be disconnected for any of the following reasons:

a) Without notice for the presence of what the Company considers to be an unsafe condition on the Consumer's premises or if an emergency exists or where a known dangerous condition exists for as long as the condition exists;

b) Without notice for willful destruction or damage to or tampering with or bypassing the Company's meter or equipment by the Consumer or by others with knowledge or negligence of the Consumer;

c) Within 5 working days after written notice for violation of the Company's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the Customer and the Customer is provided with a reasonable opportunity to remedy the situation;

d) Without notice if failure to curtail by such Consumer endangers the supply to Consumers in higher priority classes pursuant to applicable Commission rules;

e) 5 working days after written notice from the Company for refusal to grant Company personnel or its designee's access to the Consumer's premises at any reasonable time for any lawful purpose;

f) 5 working days after written notice from the Company for use, sale or delivery of gas in violation of the provisions of this Tariff or violation of any applicable laws, orders or ordinances, provided that disconnection may be made without notice if the violation creates an unsafe condition;

g) For Customers on transportation service, the Company may discontinue service upon request of a Qualified Supplier, provided however, that the Qualified Supplier represents to the Company that notice has been given to the Customer by the Qualified Supplier of delinquency in payment at least 5 working days prior to Qualified Supplier's request for disconnection, and provided that Qualified Supplier agrees to indemnify and hold harmless the Company from any potential resulting liability;

h) Failure to pay a delinquent account or failure to comply with the terms a deferred payment plan for installment payment of a delinquent account;

i) Failure to comply with deposit or guarantee arrangements where required by this Tariff; or

j) Within 5 working days after written or electronic notice, for Consumers enrolled in e-bill, that any payment including paper check, electronic transfer payment, and debit or credit card payment, that has been rejected or returned to the Company by the bank.

7.5 DISCONNECTION NOT ALLOWED

The Company's service may not be disconnected for any of the following reasons:

a) Within a period of 5 working days after mailing of the notice or the day following the date indicated in the notice, whichever is the later time.

b) After full payment of the delinquent bill except when there is not sufficient time to advise Company's service personnel of receipt of the payment.

c) Delinquency in payment for service by a previous occupant of the premises.

d) Failure to pay for merchandise or charges for non-utility service by the Company.

e) Failure to pay for a different type or class of utility service unless fee for such service is included on the same bill.

f) Failure to pay the account of another customer as guarantor thereof, unless the Company has in writing the guarantee as a condition precedent to service.

g) Failure to pay charges arising from an underbilling occurring due to any misapplication of rates more than six months prior to the current billings.

h) Failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due.

i) Failure to pay an estimated bill other than a bill rendered pursuant to an approved meter reading plan, unless the Company is unable to read the meter due to circumstances beyond its control.

j) The Company may not discontinue service to a delinquent residential Customer permanently residing in an individually metered dwelling unit when that Customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill in the service is discontinued. Any Customer seeking to avoid termination of service under this Section must make a written request supported by a written statement from a licensed physician. Both the request and the statement must be received by the Company not more than five (5) working days after the date of delinquency of the bill. The prohibition against service termination provided by this Section shall last twenty (20) days from the date of receipt by the Company of the request and statement or such lesser period as may be agreed upon by the Company and the Customer. The Customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

k) The Company shall not disconnect a delinquent residential customer for a billing period in which the Company receives a written pledge, letter of intent, purchase order, or other written notification from an energy assistance provider that it is forwarding sufficient payment to continue service.

7.6 TIME OF DISCONNECTIONS

Unless a dangerous condition exists, or unless the Customer requests disconnection, service shall not be disconnected before 7:00 AM or after 7:00 PM on any day, or on Friday, Saturday, Sunday, Holiday, or day before a Holiday unless Company personnel are available the following day for the purpose of making collections or reconnecting service.

7.7 SUSPENSION OF DISCONNECTIONS DURING EXTREME WEATHER EMERGENCY

Except where there is a known dangerous condition or a use of natural gas service in a manner that is dangerous or unreasonably interferes with service to others, the Company shall not disconnect natural gas service in the following circumstances:

a) The Company shall not disconnect a delinquent residential customer during an extreme weather emergency. An extreme weather emergency means a day when the previous day’s highest temperature did not exceed 32 degrees Fahrenheit and the temperature is predicted to remain at or below that level for the next 24 hours according to the nearest National Weather Station for the county where the customer takes service. In accordance with Texas Utilities Code §105.023, the Office of the Attorney General of Texas on its own initiative or at the request of the Commission may file suit to recover a civil penalty for a violation of this paragraph. The table in this paragraph contains a classification system to be used by a court when such a suit is filed.

Classification System

Violation Factors	Factor Value (1-4)	Points Tally
Customer is disconnected in violation of 16 TAC Section 7.460, subsection (ab)(1) of this Section for 24 hours or more	4	
Customer is disconnected in violation of 16 TAC Section 7.460, subsection (ab)(1) of this section for less than 24 hours, but more than 12 hours	3	
Customer is disconnected in violation of 16 TAC Section 7.460, subsection (ab)(1) of this section for 12 hours or less	2	
Demand for collection of full payment of bills due is made during an extreme weather emergency	3	
The temperature is 10 degrees or less during the period of disconnection	4	
The temperature is more than 10 degrees but less than or equal to 20 degrees during the period of disconnection	3	
The temperature is more than 20 degrees but less than or equal to 32 degrees during the period of disconnection	2	
Repeat violations based on Company's history of compliance	3	
Good faith effort to remedy violation	-2	
No effort to remedy violation during the extreme weather emergency	4	
		Total
		Penalty maximum per violation
10 points or more = Class A violation		More than $5,000[1]
7-9 points = Class B violation		$5,000.00
4-6 points = Class C violation		$4,000.00
1-3 points = Class D violation		$3,000.00

The Company shall defer collection of the full payment of bills that are due during an extreme weather emergency until after the emergency is over and shall work with customers to establish a payment schedule for deferred bills.

Beginning in the September or October billing periods, the Company shall give notice as follows:

a) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to the social service agencies that distribute funds from the low-income Home Energy Assistance Program within the Company's service areas. The Company may provide a copy electronically.

b) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to any other social service agency of which the Company is aware that provides financial assistance to low-income customers in the Company's service areas. The Company may provide a copy electronically.

[1] Pursuant to Utilities Code §105.023(f), the required classification system shall provide that a penalty in an amount that exceeds $5,000 may be recovered only if the violation is included in the highest class of violations in the classification system.

c) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to all residential customers of the Company and customers who are owners, operators or managers of master metered systems. Owners, operators or managers of master metered systems shall provide a copy of this rule to all their customers. The Company may provide a copy electronically.

7.8 RECONNECTION OF SERVICE

a) When service has been disconnected for non-payment, the Company shall require that the Customer pay the total amount of their account then due plus the prescribed reconnect fee or make satisfactory arrangements for that payment before service is reinstituted. In addition, the Company shall require that the Customer re-establish satisfactory credit in accordance with this Tariff.

b) If disconnection has been made by the Company for reasons other than non-payment, service shall not be reinstated until the condition for which it was terminated has been corrected to the Company's satisfaction. The Customer shall also be required to pay a reconnect fee before service is turned on. When service has been disconnected at the Customer's request for a period of one year or more, the request for service shall be treated as a new application. When service has been disconnected for less than one year, the request shall be treated in the same manner as a disconnection for non-payment.

c) The Company shall restore service as soon as feasible after receipt of a reconnection request and compliance with the requirements of this Tariff. The Company shall charge a non-refundable reconnection fee for all Customers in accordance with Section 15. The restoration of service will be accomplished as expeditiously as scheduling permits. If the Customer requests service after hours or earlier than reconnection would otherwise be scheduled, the Company shall offer expedited service in accordance with Section 15. Customer shall be advised that an additional fee will be charged and must agree to pay such charge. In the event the Company is required to make more than one call because the reason for disconnection has not been properly corrected, the reconnect fee may be charged for each call made. No fee shall be charged for any reconnection made after disconnection due to Company's operation. See Section 15 for fees.

7.9 RIGHT OF ENTRY TO DISCONNECT SERVICE

The Company shall have the right to enter the Consumer's premises at any reasonable time to shut off service in accordance with this Tariff and to remove its meter and any other Company property. If the Company is required to take legal action to enforce its rights hereunder, the Company shall be entitled to recover all of its necessary expenses and fees including, but not limited to attorneys' fees, police escort fees, the cost to discontinue service at the main, and/or the cost to relocate the meter at the Customer's expense.

7.10 ABANDONMENT OF SERVICE

The Company may not abandon a Customer without written approval from the Regulatory Authority. The Company will comply with Commission Rule 7.465.

SECTION 8 — SECURITY DEPOSITS

8.1 ESTABLISHMENT OF CREDIT FOR RESIDENTIAL APPLICANT

The Company may require a residential Applicant for service to satisfactorily establish credit, but such establishment of credit shall not relieve the Customer from complying with the rules and Tariff requirements for prompt payment of bills.

8.2 DEPOSIT REQUIRED

a) The Company shall require a security deposit from any present or prospective Customer in accordance with this Tariff to guarantee payment of bills and

b) From any present Customer who during the last 12 consecutive months has on more than one occasion paid its utility bill after becoming delinquent.

8.3 RESIDENTIAL DEPOSIT NOT REQUIRED

A residential Applicant shall not be required to pay a deposit:

a) if the residential Applicant has been a Customer of any utility for the same kind of service within the last two years and is not delinquent in payment of any such utility service account and during the last 12 consecutive months of service did not have more than one occasion in which a bill for such utility service was paid after becoming delinquent and never had service disconnected for nonpayment;

b) if the residential Applicant furnishes in writing a satisfactory guarantee to secure payment of bills for the service required; or

c) if the residential Applicant furnishes in writing a satisfactory credit rating by appropriate means, including, but not limited to, the production of generally acceptable credit cards, letters of credit references, the names of credit references which may be quickly and inexpensively contacted by the Company, or ownership of substantial equity.

d) All Applicants for residential service who are 65 years of age or older will be considered as having established credit if such Applicant does not have an outstanding balance with the Company or another utility for the same utility service which accrued within the last two years. No cash deposit shall be required of such Applicant under these conditions.

e) Each gas utility shall waive any deposit requirement for residential service for an Applicant who has been determined to be a victim of family violence as defined in Texas Family Code, §71.004, by a family violence center, by treating medical personnel, by law enforcement agency personnel, or by a designee of the Attorney General in the Crime Victim Services Division of the Office of the Attorney General. This determination shall be evidenced by the applicant's submission of a certification letter developed by the Texas Council on Family Violence and made available on its web site.

8.4 OTHER EXEMPTIONS FROM DEPOSIT

The Company may not require a deposit if:

a) The Applicant has been a Customer for the same kind of service within the last two (2) years and does not have more than one (1) occasion in which a bill for service from any such utility service account was delinquent and never had service disconnected for nonpayment;

b) The Applicant furnishes a letter of credit acceptable and satisfactory to the Company; or

c) The application for service is made for or guaranteed by an agency of the federal, state or local government.

8.5 RE-ESTABLISHMENT OF CREDIT

Every Applicant who has previously been a Customer of the Company and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all amounts due to the Company or execute a written deferred payment agreement, if offered, and re-establish credit as provided in Section 8.6.

8.6 AMOUNT OF DEPOSIT

The required deposit shall not exceed an amount equivalent to one-sixth of the estimated annual billings. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two (2) days. If such additional deposit is not made, the Company may disconnect service under the standard disconnection procedure for failure to comply with deposit requirements.

8.7 INTEREST ON DEPOSITS

a) Each utility which requires deposits to be made by its customers shall pay a minimum interest on such deposits according to the rate as established by law. If a refund of deposit is made within 30 days of receipt of deposit, no interest payment is required. If the Company retains the deposit more than 30 days, payment of interest shall be made retroactive to the date of deposit.

b) Payment of interest to the Customer shall be annually or at the time the deposit is returned or credited to the Customer's account.

c) The deposit shall cease to draw interest on the date it is returned or credited to the Customer's account.

8.8 RECORDS OF DEPOSITS

a) The Company shall keep records to show:

i) the name and address of each depositor;

ii) the amount and date of the deposit; and

iii) each transaction concerning the deposit.

b) The Company shall issue a receipt of deposit to each Applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

c) A record of each unclaimed deposit must be maintained for at least four (4) years, during which time the Company shall make a reasonable effort to return the deposit.

8.9 REFUND OF DEPOSITS

Deposits on residential accounts returned to the Customer in accordance with Section 8.6 above shall be applied in the first calendar quarter following the month in which the good payment record is established. Whenever the deposit of any Customer is returned to the Customer, the Company shall pay all previously unpaid interest with the payment.

a) If service is not connected or after disconnection of service, the Company shall promptly and automatically refund the Customer's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. The transfer of service from one premise to another within the service area of the Company shall not be deemed a disconnection within the meaning of these rules and no additional deposit may be demanded unless permitted by these rules.

b) When a residential Customer has paid bills for service for twelve (12) consecutive residential bills without having service disconnected for nonpayment of bill and without having more than two (2) occasions in which a bill was delinquent and when the Customer is not delinquent in the payment of the current bills, the Company shall promptly and automatically refund the deposit plus accrued interest to the Customer in the form of cash, check or credit to a Customer's account.

8.10 ACCEPTABLE FORMS OF DEPOSIT

Any one of the following forms of credit security may be accepted from Customers and Applicants for service:

a) A cash deposit of as much as one-sixth (1/6) the estimated annual billings for service requested; but no less than the minimum deposit set forth in Section 15;

b) For commercial customers only, a nontransferable, irrevocable letter of credit from an established financial institution, payable for as much as one-sixth (1/6) the estimated annual billings for services requested and, which can be drawn on for a minimum of two (2) years; but no less than the minimum deposit set forth in Section 15; or

c) For commercial customers only, a surety bond issued by a reputable insurance company which can be drawn on for a minimum of 2 years.

8.11 DEPOSITS FOR TEMPORARY OR SEASONAL SERVICE

The Company may require a deposit for temporary or seasonal service and for weekend or seasonal residences sufficient to reasonably protect it against the assumed risk, provided such a policy is applied in a uniform and nondiscriminatory manner.

8.12 SALE OR TRANSFER OF COMPANY

Upon the sale or transfer of the Company or operating units thereof, the Company shall file with the Commission under oath, in addition to other information, a list showing the names and addresses of all customers served by the Company or unit who have to their credit a deposit, the date such deposit was made, the amount thereof, and the unpaid interest thereon.

8.13 COMPLAINT

The Company shall direct its personnel engaged in initial contact with an Applicant or Customer for service seeking to establish or re-establish credit under the provisions of these rules to inform the Customer, if dissatisfaction is expressed with the Company's decision, of the Customer's right to file a complaint with the regulatory authority thereon.

8.14 FRANCHISE AGREEMENTS

To the extent the terms of a franchise agreement are inconsistent with this Section, the terms of the franchise agreement control. Applicable to customers inside the corporate limits of an incorporated municipality that imposes a franchise fee to Company for the gas service provided to Customer.

SECTION 9 — BILLING AND PAYMENT OF BILLS

9.1 RENDERING OF BILLS

Bills for gas service shall be rendered monthly, unless otherwise authorized or unless service is rendered for a period less than a month. Bills shall be rendered as promptly as possible following the reading of meters.

Bills shall be due and payable in full on or before the due date, which shall be stated on the face of the bill and shall not be earlier than fifteen (15) days after the bill is mailed (including electronic mail). Bills shall be considered to have been rendered when deposited in the United States Mail with postage prepaid thereon or, when the customer has elected to receive billings via electronic mail, when the electronic document has been sent. Payment shall be considered received when the correct amount has been received through a company authorized payment method. If not paid by the date due, the bill shall be considered delinquent.

9.2 REQUIRED BILL INFORMATION

The Customer's bill must show all the following information. The information must be arranged and displayed in such a manner as to allow the customer to compute their bill with the applicable rate schedule. The applicable rate schedule must be mailed to the Customer on request of the customer.

a) if the meter is read by the utility, the date and reading of the meter at the beginning and end of the period for which rendered;

b) the number and kind of units billed;

c) the applicable rate schedule title or code;

d) the total base bill;

e) the total of any adjustments to the base bill and the amount of adjustments per billing unit;

f) a distinct marking to identify an estimated bill.

9.3 ESTIMATED BILLS

Where there is good reason for doing so, estimated bills may be submitted, provided that an actual meter reading is taken at least every six months. For the second consecutive month in which the meter reader is unable to gain access to the premises to read the meter on regular meter reading trips, or in months where meters are not read otherwise, the utility must provide the customer with a postcard and request that the customer read the meter and return the card to the utility if the meter is of a type that can be read by the customer without significant inconvenience or special tools or equipment. If such a postcard is not received by the utility in time for billing, the utility may estimate the meter reading and render the bill accordingly.

9.4 DISPUTED BILLS

a) In the event of a dispute between the Customer and the Company regarding the bill, the Company must make such investigation as is required by the particular case and report the results to the Customer. If the Customer wishes to obtain the benefits of subsection b) of this Section, notification of the dispute must be given to the Company prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the Company shall inform the Customer of the complaint procedures of the appropriate Regulatory Authority.

b) Notwithstanding any other subsection of this Section, the Customer shall not be required to pay the disputed portion of the bill which exceeds the amount of that Customer's average usage for the billing period at current rates until the earlier of the following: resolution of the dispute or the expiration of the 60-day period beginning on the day the disputed bill is issued. For purposes of this Section only, the Customer's average usage for the billing period shall be the average of the Customer's usage for the same billing period during the preceding two (2) years. Where no previous usage history exists, the average usage shall be estimated on the basis of usage levels of similar customers and under similar conditions.

9.5 PAYMENT RE-PROCESSING FEE

The Company may charge or add to the Customer's account and collect a fee (as provided in Section 15) to recover costs for reprocessing any payment, including paper check, electronic transfer payment, and debit and credit card payment, that has been rejected or returned to the Company by the bank for any reason other than bank error.

9.6 ELECTRONIC BILLING STATEMENTS

The Customer may at their option receive bills via electronic mail. Customers shall provide current, accurate and complete information to the Company and shall update their information as necessary so that it remains current, accurate and complete. The Company may verify Customer information at any time.

9.7 PAYMENT OPTIONS

The Company, at its option and discretion, may contract with payment vendors to provide various payment options and authorize these vendors to accept payments from Customers on the Company's behalf. Payment options may be electronic, telephonic, in person, or by mail and may include automatic bank draft, credit/debit card, check or cash. Contracted payment vendors may charge Customers an additional fee for the use of that payment option and the contracted payment vendor shall be solely responsible for collecting any fee from the Customer.

9.8 DEFERRED PAYMENT PLANS

The Company, at its sole discretion, may offer a deferred payment plan for delinquent Customer accounts. Deferred payment plans shall conform to the following guidelines:

a) Every deferred payment plan entered into due to the Customer's inability to pay the outstanding bill in full must provide that service will not be discontinued if the customer pays current bills and a reasonable amount of the outstanding bill and agrees to pay the balance in reasonable installments until the bill is paid.

b) For purposes of determining reasonableness, the following shall be considered:

i) size of delinquent account;

ii) Customer's ability to pay;

iii) Customer's payment history;

iv) time that the debt has been outstanding;

v) reasons why debt has been outstanding; and

vi) other relevant factors concerning the circumstances of the Customer.

c) A deferred payment plan, if reduced to writing, shall state immediately preceding the space provided for the Customer's signature and in bold-face print at least two sizes larger than any other used that, "If you are not satisfied with this agreement, do not sign. If you are satisfied with this agreement, you give up your right to dispute the amount due under the agreement except for the Company's failure or refusal to comply with the terms of this agreement."

d) A deferred payment plan may include a one-time penalty up to 5.0% for late payment on the original amount of the outstanding bill except in cases where the outstanding bill is unusually high as a result of the Company's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

e) If a Customer for utility service has not fulfilled the terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the utility shall have the right to disconnect pursuant the disconnection rules in this Tariff, and under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.

f) The Company shall not refuse a Customer participation in a deferred payment plan on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

9.9 AVERAGE PAYMENT PLAN

Any residential Customer or non-residential Customer with annual usage less than 500 Ccf may elect to participate in the Company's Average Payment Plan ("APP Plan"). The terms, conditions, and other information regarding the Average Payment Plan are set forth herein by reference.

A. TERMS AND CONDITIONS

1. The Average Payment Plan ("Plan") is available to residential and qualifying nonresidential customers that have a minimum of six (6) months consumption history available at the premise. Residential and Non-residential customers may request participation in the Plan at any time during the year. Request for participation can be made by telephone or in writing.

2. A customer's account should be current at the time the customer elects to participate in the Plan and at all times during Plan enrollment, which means the account does not have a previous balance and the current billing is not past due.

3. Service is not available under this Plan for a term of less than twelve (12) months.

B. AVERAGE PAYMENT AMOUNT

1. Each month under the Plan, a customer's Average Payment Amount will be computed by averaging the amount actually billed to the customer's account during the last 12 months (current + 11), plus or minus one-twelfth (1/12) of the Average Payment Plan Settlement amount and then rounded to the nearest dollar. In the event 12 months history is not available, Company may estimate the missing months in order to determine the appropriate average payment amount.

2. The Average Payment Amount is identified as a separate item on the gas bill so the participating consumer will know the amount to pay.

3. Gas costs and/or rate changes shall be factored into the monthly average payment calculations on a rolling basis.

SECTION 10 — FACILITIES AND EQUIPMENT

10.1 STANDARDS OF CONSTRUCTION

The Company is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards that are generally accepted by the industry as modified by rule or regulation of the Regulatory Authority or otherwise by law, and in such a manner to best accommodate the public and prevent interference with service furnished by other public utilities insofar as practical.

10.2 COMPANY OWNED FACILITIES

The Company shall maintain all facilities owned by it and shall be responsible for the safe conduct and handling of the gas until it passes the point of delivery. The Company's representative shall have the right to enter the Customer's premises at any reasonable time, in the event of an emergency at any time, to read the meter or make any necessary inspection, repair, adjustment, or replacement of any property owned by the Company.

No one other than a Company representative or other person authorized by Company shall be permitted to repair or remove Company's meter or facilities, or any of the property of Company on or about customer's premises. Any seals placed by Company on meters or regulators shall not be broken or disturbed by anyone other than authorized representatives of Company. Any unauthorized tampering with Company's meter or facilities is in violation of this restriction and such tampering shall be considered cause for immediate discontinuance of service by Company.

10.3 CUSTOMER OWNED FACILITIES

a) The Customer shall maintain all facilities owned by them and shall be responsible for the safe conduct and handling of the gas after it passes the point of delivery. Any facilities downstream of the meter installed by the Customer shall remain the property and responsibility of the Customer. Whenever the condition of the facility is such that replacement is required, the work shall be done by the Company pursuant to the provisions of Section 10.8 of this Tariff. New facilities will continue to be installed pursuant to Sections 10.5 and 10.6 of this Tariff.

b) The Customer shall remove, repair or adjust any Customer-owned property which may pose a threat of damage to the property of the Company. The Customer shall take all reasonable means to assure that no one other than an employee of the Company shall adjust, repair, disconnect or change the meter or other Company facilities in any way.

c) Nothing in this Section shall make the Company responsible for the safe upkeep of any Customer or Consumer-owned facilities.

d) In case of loss or damage to the Company's property from the negligence or willful acts of the Customer or Consumer or the Customer's or Consumer's representatives, the Customer will reimburse the Company for all costs of repairing or replacing the damaged property, including any costs of collection such as attorney's fees.

10.4 LEAKS

The Customer or Consumer shall give the Company notice of any leaking or escaping gas as soon as it is detected. Upon receipt of this notice, the Company shall investigate the matter as promptly as feasible under the circumstances. If the Company's test indicates leakage in the Customer's or Consumer's facilities, the Company shall have the right to disconnect service immediately until the Customer or Consumer has had the condition corrected. If leakage is found to be from Company owned facilities, the Company shall have the right to disconnect service for a reasonable period of time until the leakage can be corrected by the Company. The Company shall have the right to disconnect service immediately if any of the Customer's or Consumer's appliances or equipment is, in the Company's opinion, operating in an unsafe manner.

10.5 MATERIALS OR EQUIPMENT FURNISHED BY THE COMPANY

a) The Company shall furnish and install at its expense, the service pipe from the Company's existing main to the property line nearest the meter and the equipment related thereto, including meter valve and service regulator. Although affixed to or buried in the Customer's property, the entire service line and meter set shall become the property of the Company and shall be operated and maintained by the Company.

b) Whenever the meter is located at any point other than the property line, the Company shall determine the estimated cost of that portion of the service between the property line and the meter set. This estimate shall be based on the size and footage to be installed and charged in accordance with Section 11 and other applicable provisions of this Tariff. This estimated amount shall be contributed by the Applicant to the Company before construction, unless the Applicant is a qualified Blanket Builder.

10.6 MATERIALS OR EQUIPMENT FURNISHED BY THE APPLICANT

a) The Applicant shall furnish and install at their expense all piping, equipment and appliances required to conduct and utilize the gas furnished by the Company and conversions of existing equipment and appliances required to conduct and utilize the gas furnished by the Company from the outlet of the meter set to the point(s) of utilization and those portions of the service line and meter set not furnished by the Company as described in Section 10.5.

b) The adequacy, safety and compliance with applicable codes and ordinances of piping, conversion equipment and appliances shall be the responsibility of the Applicant and no action of the Company in accordance with this Tariff shall release the Applicant of the responsibility for the facilities installed or furnished by them. All piping, installations, and conversion equipment owned by the Applicant shall comply with all applicable federal, state, and county requirements and municipal ordinances, or otherwise, and shall be properly designed for the pressures and volumes to be handled. Where there are none, the most current International Fuel Gas Code shall apply.

10.7 RELOCATION OF COMPANY FACILITIES

a) A charge of not more than actual cost may be made for relocating a meter or other Company equipment on the same premises at the request of the Customer or Consumer.

b) If the Company shall for its own convenience and not for the safety or convenience of the Customer, change the point of delivery or change the location of its equipment on private property, the Company shall bear the expense.

10.8 REPLACEMENT OF CUSTOMER-OWNED PIPING

a) When repair or replacement of Customer-owned piping becomes necessary due to deterioration of the Company's line, damage to the Company's line (except when caused by Customer or Customer's agent), relocation of the Company's distribution main, or for other safety reasons determined by the Company, the Company may relocate the Customer's meter to the exterior of the building wall, as close as possible to the existing stub out (where piping exits the structure), and may replace the service piping up to the stub out. The Company will own and be responsible for all service piping from the main line to the meter, and Customer will own and be responsible for all piping from the meter to the building.

b) The Customer may be billed for all costs of the meter relocate and pipeline replacement.

c) In the absence of any provision contained in a deed of dedication authorizing the Company to install the service piping and meter on Customer's premises, the owner of the premises shall execute an agreement establishing the meter location, authorizing the Company to install or replace the line, and granting Company access for such work. If the Customer or owner of the premises refuses to give Company personnel or Company authorized personnel appropriate access to the property for purposes of installation, the Customer will retain responsibility for their facilities and shall bear the expense of any replacement or repairs.

SECTION 11 — EXTENSION OF FACILITIES

11.1 LINE EXTENSION AND CONSTRUCTION CHARGES

a) Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the Regulatory Authority. No contribution in aid of construction may be required of any customer except as provided for in the extension policy.

b) The Company shall install the necessary facilities to provide service to Applicants whose premises are located beyond the Company's existing distribution facilities in accordance with the provisions of this Section. The expenditure for such extensions must either be cost justified or the Applicant(s) and Company must mutually agree to terms that justify the installation.

11.2 DESIGN AND COST OF FACILITIES

As soon as practical after a completed application for service is received, the Company shall determine the extent of the facilities required to serve the new customer and the cost thereof. This cost shall include all amounts to be spent for system improvements necessary to deliver the required gas, in accordance with the Company's current practice. Whenever the Company chooses to install facilities of greater capacity than would be required to serve the new customer for which the application is being made or to permit supply from another source, the estimate of costs shall be based on only the size and capacity normally used to serve requirements similar to that of the Applicant.

11.3 ALLOWANCE FOR NEW BUSINESS

The Company shall also determine the number of existing permanent Customers located along the route of the extension expected to be served therefrom. To be included, the occupant of each premise must request service and demonstrate capability for using such service through a major gas burning appliance. Single or groups of individually owned mobile homes shall be included only if the wheels and hitch have been removed from each mobile home and/or substantial improvements have been made to the property. Mobile home parks may be served either through a master meter or individual meters served by a Company-owned system, provided that required mains can be installed and dedicated streets or rights-of-way have been provided to the Company for installation of facilities as evidenced by agreement executed on the Company's form. An allowance to be determined by the Company may be given for each Customer whose premises exist at the time of application to be served from the proposed main extension. In order to qualify for this allowance, the Customer must file an application and agree to initiate gas service upon completion of the Company's facilities.

11.4 ADVANCES

The mutually agreed upon terms will determine the amount of advance required. The Applicant shall have 30 calendar days after notification of the amount required to execute an extension agreement on the Company's form and pay the required advance. At the end of that time, the Company may revise its estimates to reflect any changes in costs or conditions which will affect the amount of the advance. The Company may waive or reduce collection of any advance based on an economic analysis of the project.

11.5 CONSTRUCTION OF FACILITIES

As soon as practical after the advance has been paid or it has been determined that no advance will be required, the Company shall begin construction of the required facilities and thereafter prosecute the work with reasonable diligence. The Company shall not be responsible for delays in the construction of the facilities occasioned by events or conditions reasonably beyond the Company's control. Whenever the construction of the new facilities requires the acquisition of rights-of-way across the Applicants(s) land(s), these rights-of-way shall be provided by the Applicant(s) in the Company's name and on its form at no cost to the Company (except for fees involved in the recording of documents).

11.6 REVIEW OF ADVANCES

The Company shall review each extension agreement on the first anniversary of the signing of that agreement. Upon the Applicant(s) request if the extension provided for in the agreement has not been installed through no fault of the Company, the agreement shall be considered to be terminated and a complete refund made to the Applicant(s). Once the extension has been installed and service has been initiated, the Company shall thereafter review the extension agreement at its second through fifth execution dates. At each review, the number of Customers then served directly from the extension shall be compared with the number served on the last prior anniversary date. A refund, shall be given for each additional Customer served, based on mutually agreed upon terms provided that the total of the refunds given does not exceed the cost of the extension of facilities.

11.7 REFUND LIMITATIONS

The Company may, at its sole option, make a refund at any time. In no case, however, shall a refund be given unless the number of Customers then served is greater than the number for whom refunds have previously been given. No refund shall be given which shall cause the total refunds to be greater than the total amount of the advance. No interest shall be paid on any advance made under the provisions of this Section. At the end of the five-year period, any remaining amount of the advance shall be retained by the Company as a contribution in aid of construction.

11.8 DELIVERY OF REFUNDS

Upon Applicant(s) request, when a refund is due, a check in the appropriate amount and a letter setting forth the method of calculation of the refund and the balance remaining un-refunded shall be made to the person or business in whose name the extension agreement is made or to their assignee. If that letter is returned undelivered, the check shall be cancelled and the next review made without regard to that refund. All sums described in this Section which are returned undelivered and remain unclaimed in the Company's possession for a period of six months following expiration of the five-year period of the extension agreement shall be retained by the Company and considered a contribution in aid of construction.

SECTION 12 — METERS

12.1 METER REQUIREMENTS

a) All gas sold by the Company must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the Regulatory Authority, or tariff.

b) Unless otherwise authorized by the Regulatory Authority, the Company must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

c) The Company may not furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

12.2 METER READING

Meters shall be read as nearly as may be practical on the same day of each calendar month. Whenever a reading of a general service meter is missed or the meter is not registering, the Company shall estimate the amount of gas used during the period. Such estimates shall be based on either -

a) That Customer's use of gas during the same period(s) in previous years;

b) That Customer's normal use of gas during preceding months; or

c) The use of a similar Customer for the period missed.

If practical, an actual reading shall be made after two consecutive estimated bills. All meters in Special Service shall be read at least once a month. Whenever such a meter fails to register or is misread, the amount of gas used during the preceding period shall be estimated using data applicable to that Special Service Customer only. The Company will make a special reading of any meter upon request and may assess a service charge in accordance with Section 15. The time of the special reading shall be agreed upon with the Customer so that they may be present. If the original reading was in error (subject to consumption between the two readings) the service charge will be refunded to the Customer.

12.3 METER LOCATION

The Company shall have the sole right to determine the location of the meter in accordance with the needs of the service.

Each Applicant shall furnish and subsequently maintain a suitable location on his or her premises for the Company's meter and related facilities at a point selected by the Company. Meters shall be located where they will be safely accessible for reading and service, adequately ventilated, and not subject to damage. Meters shall not be located within any enclosed area unless the enclosure is solely intended as a meter house or in the Company's opinion, conditions prohibit installation outside. It may be necessary for the Company to install bollards or guard posts around the meters for safety.

12.4 METER RECORDS

The Company must keep the following records:

a) The Company must keep a record of all its meters, showing the Customer's address and date of the last test.

b) All meter tests must be properly referenced to the meter record provided for therein. The record of each test made on request of a Customer must show the identifying number and constants of the meter, the standard meter and other measuring devices used, the date and kind of test made, by whom made, the error (or percentage of accuracy) at each load tested, and sufficient data to permit verification of all calculations.

c) In general, each meter must indicate clearly the units of service for which charge is made to the Customer.

12.5 METER ACCURACY

The accuracy limit of all Company meters is established at two percent (2%) fast or slow. Any meter found to be registering outside of the limits of accuracy shall immediately be removed or repaired. As long as the meter is operating within the limits of accuracy, it shall be the conclusive determination as to the quantities of gas delivered to the Customer on whose service it is set.

12.6 PERIODIC TESTS

The Company shall make periodic tests of meters, associated devices and instruments to assure their accuracy. Such tests shall be scheduled within the calendar year or earlier, when the interval is stated in years; or within the calendar month, or earlier when the interval is stated in months. The basic periodic test interval shall be no longer than provided for in the manufacturer’s recommendations, a copy of which is available upon request.

12.7 ACCESS TO THE METER

The Customer shall permit the Company safe access to the meter at all reasonable times for reading thereof and at all reasonable times for reading, maintenance, testing, or replacement of the meter. Upon the Customer’s failure or refusal to grant such access, the Company may issue a written notice to the Customer, advising them the situation must be corrected and access granted within 5 working days and that failure to do so can result in the disconnection of service and removal of the meter. Additional fees may apply and will be assessed to such Customer as specified in Section 15.

12.8 METER TESTING AT CUSTOMER REQUEST

a) The Company must, upon request of a Customer, make a test of the accuracy of the meter serving that Customer. The Company must inform the Customer of the time and place of the test and permit the Customer or his authorized representative to be present if the Customer so desires. If no such test has been performed within the previous four (4) years for the same Customer at the same location, the test is to be performed without charge. If such a test has been performed for the same Customer at the same location within the previous four (4) years, the Company is entitled to charge a fee for the test not to exceed $15 or such other fee for the testing of meters as may be set forth in Section 15 of this Tariff properly on file with the Regulatory Authority. The Customer must be properly informed of the result of any test on a meter that serves him.

b) Notwithstanding subsection (a) of this Section, if the meter is found to be more than nominally defective, to either the Customer's or the Company's disadvantage, any fee charged for a meter test must be refunded to the Customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

12.9 BILLING ADJUSTMENTS DUE TO METER ERROR

a) If any meter test reveals a meter to be more than nominally defective, the Company must correct previous readings consistent with the inaccuracy found in the meter for the period of either:

i) the last six months; or

ii) the last test of the meter, whichever is shorter. Any resulting underbillings or overbillings are to be corrected in subsequent bills, unless service is terminated, in which event a monetary adjustment is to be made. This requirement for a correction may be foregone by the Company if the error is to the Company's disadvantage.

b) If a meter is found not to register for any period of time, the Company may make a charge for units used but not metered for a period not to exceed three months previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated customers, when not available.

12.10 PROVISIONS FOR SPECIAL SERVICE

The following modifications shall apply to the provisions of this Section for all Special Service rate schedules and service under special written agreements:

a) Turbine meters shall be tested at least once each calendar year. Orifice meters shall be tested at a minimum: every 6 months for 0-500 Mcf/d; every 3 months for volumes 500-2000 Mcf/d; and every month for volumes 2000 Mcf/d and greater. Should the Customer so elect, tests shall be made in the presence of his or her representative.

b) Whenever a meter is found to be registering above or below the limits of accuracy, adjustment of the bill (either up or down) shall be limited to the monthly billing subsequent to the last meter test. The adjustment shall be made upon the basis of the best data available, using the first of the following methods, whichever is most appropriate:

i) by using registration of Customer's check meter(s);
ii) by correcting the error, if the percentage of error is ascertainable by calibration test or mathematical calculation; or
iii) by estimating the quantity of gas delivered by comparison with deliveries during the preceding period under similar conditions when accurate registration was obtained.

12.11 POINT OF DELIVERY

The point of delivery of gas sold by the Company to the Customer shall be at the outlet side of the Company's meter, provided that in those cases in which the Customer owns a section of the underground pipe between the Customer's property line and the meter, the point of delivery shall be at the property line. The title of all gas sold by the Company to the Consumer shall pass from the Company at the point of delivery. The point(s) of delivery and point(s) of redelivery for Transportation Service shall be as provided in the contract entered into between the Customer and the Company.

12.12 CONNECTION TO COMPANY FACILITIES

No Consumer shall make any connection or alteration of any kind on any of the Company's facilities upstream of the Company's meter or shall permit any other person to make such connection or alteration.

12.13 MULTIPLE METERS

Each Customer or group of Customers located on the same lot or tract of land may be served from a single meter location. The Company may, at its option, permit additional meter locations to simplify installation of facilities or provide better service. Whenever more than one meter location is permitted for the same Customer, the Company shall bill the usage through each meter separately, provided that any combined billings in effect at the time of adoption of this Tariff may be continued until the affected Customer discontinues service or upon order by the Regulatory Authority.

12.14 INDIVIDUALLY METERED SYSTEMS

The Company shall not render service to any Customer through a meter not connected to a system owned by the Company or one of the Company's suppliers.

12.15 MASTER METERS

The Company shall provide service through a master meter into the piping systems of others to be distributed to more than one Consumer, except when the gas served is resold to those Consumers on either a commodity or separate cost of service basis; provided, however, that those Customers purchasing gas for redistribution to the Customer's own tenants only on the Customer's premises may separately meter each tenant distribution point for the purpose of prorating the Consumer's actual purchase price of gas delivered among the various tenants on a per unit basis, and further provided that the provisions of this Section shall not preclude the Company from supplying natural gas to a third party for resale to the public as fuel for natural gas powered vehicles (NGV's).

SECTION 13 — GAS MEASUREMENT

13.1 PRESSURE

The standard serving and measurement pressure shall be 4 ounces (0.25 psig) or 7" Water Column above the standard atmospheric pressure in the area served. The atmospheric pressure and standard serving pressure determined to be the average in the cities and environs of the Central-Gulf Service Area are listed below.

Cities and their Environs	Atmospheric Pressure PSIA	Standard Serving Pressure PSIA
Austin	14.40	14.65
Bastrop	14.40	14.65
Bayou Vista	14.70	14.95
Beaumont	14.70	14.95
Bee Cave	14.40	14.65
Buda	14.40	14.65
Cedar Park	14.40	14.65
Cuero	14.48	14.73
Dripping Springs	14.40	14.65
Galveston	14.70	14.95
Gonzales	14.48	14.73
Groves	14.70	14.95
Hutto	14.40	14.65
Jamaica Beach	14.70	14.95
Kyle	14.40	14.65
Lakeway	14.40	14.65
Lockhart	14.48	14.73
Luling	14.48	14.73
Marble Falls	14.40	14.65
Mustang Ridge	14.40	14.65
Nederland	14.70	14.95
Nixon	14.48	14.73
Pflugerville	14.40	14.65
Port Arthur	14.70	14.95
Port Neches	14.70	14.95
Rollingwood	14.40	14.65
Shiner	14.48	14.73
Sunset Valley	14.40	14.65
Yoakum	14.48	14.73
West Lake Hills	14.40	14.65

The Consumer and the Company may, at the Company's option, agree to a higher serving pressure. Service regulators shall be set as close as practical to the standard serving pressure under a load condition of approximately 10 percent of meter capacity. Increases in serving pressure because of the inadequacy of the Consumer's facilities shall not be permitted.

13.2 UNIT OF MEASUREMENT

The standard unit of measurement shall be one hundred cubic feet (Ccf). A cubic foot shall be defined as the amount of gas which occupies a volume of one cubic foot at the standard serving pressure and at a temperature of 60 degrees Fahrenheit.

Whenever the Company delivers gas at any pressure other than the standard serving pressure, volumes shall be corrected to the standard serving pressure in the manner provided in this Tariff, provided however, that such correction may be made to any other standard provided in the rate schedules or special agreement under which the Customer is served. The Company may, at its sole option, waive the correction of measurement for temperature deviation.

13.3 BILLING UNIT

Unless otherwise specified on the rate schedules or by special agreement, Customers shall be billed on the basis of Ccf measured at or corrected to the standard serving pressure. The index of the meter shall be the sole determinant of volumes passing through the meter. Whenever the meter reads directly in hundreds or smaller units, a reading of one-half a billing unit or more (500 Ccf or more) shall be considered a whole billing unit. Readings of less than one-half a unit shall be disregarded for billing. In those cases in which heating value is used as the billing unit, the calculation of the heating value in BTU's shall be made in accordance with Section 13.7 of this Tariff.

13.4 PRESSURE CORRECTION - STANDARD METERING

Whenever gas is delivered to any Customer served under a rate schedule which provides for standard metering, the Company shall correct actual volumes measured to volumes which would have been measured if the gas had been delivered at the standard serving pressure. Corrections shall be made by one of the following methods.

a) The Company may install pressure or pressure and temperature compensating measurement equipment whenever the cost of this equipment is justified by the volumes served. Such measurements shall be equipped with devices which mechanically or electronically correct the actual measured volumes in accordance with Boyle's Law. Variations in actual atmospheric pressure shall not be considered.

b) The Company may use factor billing whenever the volumes to be delivered are too small to justify special metering. The factor shall be determined by dividing the actual serving pressure by the standard serving pressure, both expressed in absolute units based on the standard atmospheric pressure in the area as specified in Section 13.1 hereof. This factor shall be applied to the measured volumes to determine the correct number of billing units.

13.5 METERING - SPECIAL POSITIVE DISPLACEMENT

Whenever gas is delivered to any Customer served under a rate schedule which provides for special metering and positive displacement or turbine type metering is used, all volumes shall be determined in accordance with the recommendations of the manufacturer of the meter. Meters may be read in actual volumes which shall then be corrected to the standard billing unit or may be furnished with devices designed to correct the actual volumes to the standard billing units. The following criteria shall be used in the correction of volumes or design and calibration of correcting devices.

a) Pressure correction shall be made in accordance with Boyle's Law. Calculations based on pressure reading on a continuously recording chart shall use the average pressure indicated thereon applied to the measured volumes. Correcting devices shall be set at the specified serving pressure and the service regulators shall be adjusted as close to that pressure as practical. Corrections for deviations from Boyle's Law ("supercompressibility") may be made whenever the volumes delivered justify the cost of making such corrections.

b) The flowing temperature of the gas shall be assumed to be 60 degrees Fahrenheit unless temperature correction is provided. Corrections shall be made in accordance with Charles' Law.

c) Whenever a continuously recording instrument is used, the average temperature indicated thereon shall be applied to the measured volumes. The specific gravity of the gas shall be assumed to be the value last indicated by test or reported by the upstream pipeline supplier prior to the installation of the metering facilities. Whenever subsequent reports or test indicate significant changes in gravity, volume calculations shall be changed prospectively to reflect the new gravity.

13.6 METERING - SPECIAL ORIFICE

Whenever gas is delivered to any Customer served under a rate schedule with provisions for special metering and orifice metering is used, all volumes shall be determined in accordance with the recommendations for measuring gas contained in the American Gas Association's Gas Measurement Committee Report No. 3, Orifice Metering of Natural Gas (1992), and subsequent revisions thereof. Orifice meter charts shall be calculated using a standard integrating device or other method recognized in the industry. The following criteria shall be used in the correction of volumes or design and calibration of orifice metering:

a) Correction for deviation of gas from Boyle's Law shall be made in accordance with Report No. 3.

b) Temperature of gas passing the meter shall be assumed to be 60 degrees Fahrenheit unless suitable equipment has been installed to measure actual flowing temperature. The arithmetical average of the temperature recorded during each meter charge period while the gas is flowing shall be used in the computations of volumes during the period.

c) The standard atmospheric pressure for the area served shall be used for measurement irrespective of any variation in the actual barometric pressure.

d) The specific gravity of the gas shall be assumed to be the value last obtained in a spot test made with a gravity balance, impact type unit or other acceptable method. Tests shall be made as frequently as found necessary to assure accurate measurement.

13.7 BTU MEASUREMENT

The heating value of gas for use in billing shall be defined as the gross thermal value of one cubic foot of gas at a pressure of 14.73 psia and temperature of 60 degrees Fahrenheit on a dry basis. The number of billing units delivered shall be determined by multiplying the heating value determined in accordance with this Section by the volumes delivered during the period, expressed in the same units and measured at, or corrected to 14.73 psia and 60 degrees Fahrenheit, and multiplying by the factor necessary to convert the heating value/measurement units to the billing units provided in the appropriate rate schedule. The heating value of the gas shall be determined using one of the following methods:

a) Processing a continuous sample of the main stream at the meter location through a recording calorimeter of a standard type;

b) Analysis of gas samples accumulated from the main stream at the meter location in a sample bottle of an approved type;

   i) passing the sample through a recording calorimeter of a standard type;

   ii) passing the sample through a flow calorimeter of a standard type; or

   iii) passing the sample through a chromatograph to determine the chemical composition and calculating the total heating value from the sum of the constituents.

13.8 CUSTOMER-INSTALLED AND OPERATED METERS

A Customer may install and operate a meter or any other device to measure gas volumes, pressure, temperature, BTU content or specific gravity downstream of the point of delivery. Unless expressly otherwise agreed to by the Company and Customer, however, the Company's meter and equipment shall be the sole determinant of volumes for Company's billing purposes.

SECTION 14 — QUALITY OF GAS

14.1 HEATING VALUE

Gas delivered to Consumers in all service areas shall have an average gross heating value of at least 900 British Thermal Units per cubic foot measured when saturated with water vapor at a pressure of 14.73 psia and temperature of 60 degrees Fahrenheit. Gas of lesser heating value may be delivered for short periods, provided that the average heating value for the calendar month in which the reduction occurs is equal to or greater than the standard and that the burning characteristics of the gas are not significantly altered.

14.2 CHARACTER OF GAS

All gas furnished to Consumers in the Central-Gulf Service Area shall be of merchantable quality suitable for use in standard gas burning appliances. Merchantable quality shall mean that the gas must be commercially free from dust, resins, water and hydrocarbons in liquid form at the pressure and temperature at which the gas is delivered.

14.3 ODORIZATION

All gas shall be odorized with a chemical odorant at a sufficient rate to make it readily detectable. Gas containing enough natural odorant as prescribed by the Railroad Commission of Texas need not be odorized unless the odorant level drops below the acceptable level.

SECTION 15 — SERVICE FEES AND DEPOSIT AMOUNTS

15.1 ADJUSTMENTS TO FEES AND CHARGES

All fees and charges shall be adjusted by taxes and fees (including franchise fees) where applicable. All fees and charges (excluding advances, contributions in aid of construction and deposits) shall be adjusted by the amount which represents the actual gross receipts, occupation, revenue taxes and franchise fees paid by Texas Gas Service Company, a Division of ONE Gas, Inc.

15.2 LEAKAGE AND PRESSURE INVESTIGATION

When a Customer or Consumer smells or detects natural gas and contacts the Company, the Company shall provide to the Consumer, at no-charge to the Customer or Consumer, leakage and pressure investigations to ensure that unsafe conditions do not exist. Where leakage or unsafe conditions are determined by the Company to be in the Customer's or Consumer's piping or equipment, the Customer or Consumer will be so advised and service will be discontinued until such time that all leakage and other unsafe conditions have been properly corrected by the Customer or Consumer. In addition, when service is initiated, gas air adjustments on a standard domestic and commercial gas range and water heater will be made. Any other work performed on any Consumer's appliances or house piping will be on a charge basis.

15.3 SERVICE WORK ON CHARGE BASIS

The Company may have personnel available for and may undertake other service work on the Consumer's premises on a charge basis, as time permits. Charges shall be made at the Company's standard rate in the Service Area and such service work and any associated revenues and costs shall be considered non-utility.

15.4 EXPEDITED SERVICE REQUEST

A Customer may request an expedited service, upon availability. Charges may apply.

15.5 SPECIFIC SERVICE TIME REQUEST

A no access fee may be charged to a Customer who requests a specific time for service if the Company agrees to the time and sends appropriate personnel to the appointed location and the Customer is not present to allow access to the premises.

15.6 SERVICE FEES

All fees and charges shall be adjusted by taxes and fees (including franchise fees) where applicable.

a)	Connection Fee	A connection fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when a meter is set and/or gas turned on.	$38.00
b)	Read-In Fee	A read-in fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when only a meter reading is required.	$18.00

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – Central-Gulf Service Area

c)	Special Handling & Expedited Service	In addition to initiation of service fee, a fee may be charged to any Applicant whose request to initiate service cannot be worked during normal business hours or requires special handling. Applicant must be advised that an additional fee will be charged and must agree to pay such charge.	
		Special Handling Fee - The Company may, at Applicant or Customer's request, provide special handling in order to meet the Applicant or Customer's requirements. Special handling does not include calling the Applicant/Customer in advance or A.M. or P.M. scheduling.	$18.00
		Expedited Service Fee and Overtime Rate - The Applicant or Customer's request for expedited service may be scheduled at any time to fit the Company's work schedule, and an Expedited Service charge shall be collected. The Company shall not be obligated to provide Expedited Service when the personnel and resources to do so are not reasonably available.	$70.00
d)	Services from Others	Whenever service is furnished from the facilities of others and the Company must pay any special fees to the supplying Company, the Applicant may be requested to reimburse the Company for such charge.	Actual cost plus 20% for handling
e)	Customer Requested Meter Test	Positive Displacement Up to 1500 cubic feet per hour Over 1500 cubic feet per hour -- Orifice Meters All sizes	 $150.00 $225.00 ---------------------------- $200.00
f)	Payment Re-processing Fee		$25.00
g)	Collection Fee	A Collection Fee shall be charged to any Customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative to attempt collection of payment from Customer.	$18.00
h)	Reconnect Fees	A reconnect fee shall be charged to any Customer whose service is terminated and then re-initiated unless terminated in error by the Company. This fee is the same as the Standard Initiation Fee charged for new service. Related, non-routine services including but not limited to high bill investigations and building meter loops may be charged. Regular Labor Rate After Hours Rate	$38.00 $50.00 $70.00
i)	Special Read Fee	A special read fee shall be charged for customer requested reading of a meter of which estimated billing has been made. This is not in connection with Section 12.8.	$20.00

j)	Meter Exchange Fee - Customer Request	A fee will be charged for customer requested meter exchanges when a meter is working properly or done for the Customers convenience.	$180.00
k)	Meter Tampering Fee - Residential	A fee will be charged to Customers who knowingly tamper with Company property (i.e. broken meter locks, broken stop cocks, tampered meter dials, and broken meter blind seals).	$180.00
l)	Unauthorized Consumption Fee	Charges for the replacement of an illegally broken meter seal or locking device to the Customer who could be reasonably expected to benefit from gas service received through said meter.	$30.00 plus expenses
m)	No Access Fee	A fee charged to a Customer who schedules an appointment but fails to appear.	$18.00
n)	Meter Removal Fee		$25.00
o)	Account Research Fee	An hourly fee will be charged for Customer account information requiring research of accounting/billing information.	$20.00
p)	Police Escort Fee	A fee charged when the Company is required to use law enforcement personnel to escort it into locked sites or sites requiring animal control in order for the Company to access a meter or other equipment.	Actual cost
q)	Excess Flow Valve Installation Fee	Pursuant to Code of Federal Regulations, §192.383(d) a fee for installation of an excess flow valve (EFV) will be assessed when a Customer requests such installation on the Customer's service line. The EFV will be installed at a date mutually agreeable to both Company and Customer, but after January 1, 2018. The Company reserves the sole right to conduct any required maintenance that may result from the installation. The customer shall be assessed a one-time installation fee.	$400.00

15.7 DEPOSIT AMOUNTS

a)	Advanced Deposit	Estimated expenditure to serve the premises of new business beyond the existing distribution facilities of the Company.	Actual cost
b)	Residential Customer Deposit		Minimum $75.00
c)	Non-Residential Deposit		Minimum $250.00

Line No. (a)	Description (b)	Bills (c)	Volumes (Ccf) (d)	Recommended Rates Customer Charge (e)	Usage Charges (f)	Recommended Revenue (g)	Assigned Revenue (h)	Rounding Diff. (i)	Test Year As Adjusted Revenue (j)	Revenue Change (k)
1	Residential - Small									
2	Incorporated	2,104,186	33,905,211	$25.50	$0.69448	$77,203,228	$77,203,474	$(246)	$63,340,246	$13,863,228
3	Environs	226,572	5,534,338			$9,621,079	9,621,110	(31)	7,893,472	1,727,638
4		2,330,758	39,439,549			$86,824,307	$86,824,584	$(277)	$71,233,718	$15,590,866
5										
6	Residential - Large									
7	Incorporated	1,270,855	52,557,901	$39.00	$0.23425	$61,875,043	$61,875,240	$(197)	$50,764,463	$11,110,777
8	Environs	136,842	8,579,012			$7,346,462	7,346,486	(23)	6,027,296	1,319,189
9		1,407,697	61,136,913			$69,221,505	$69,221,725	$(221)	$56,791,759	$12,429,966
10										
11	Total Residential									
12	Incorporated	3,375,040	86,463,111			$139,078,271	$139,078,714	$(443)	$114,104,709	$24,974,004
13	Environs	363,414	14,113,350			16,967,541	16,967,595	(54)	13,920,768	3,046,827
14	**Total Residential**	**3,738,454**	**100,576,461**			**$156,045,812**	**$156,046,309**	**$(497)**	**$128,025,477**	**$28,020,832**
15	Commercial - Small									
16	Incorporated	111,471	5,238,297	$85.00	$0.15710	$10,297,937	$10,297,832	$105	$11,075,470	$(777,638)
17	Environs	6,533	2,033,152			$874,748	874,739	9	940,795	(66,056)
18		118,004	7,271,449			$11,172,685	$11,172,571	$114	$12,016,265	$(843,694)
19										
20	Commercial - Large									
21	Incorporated	37,889	27,922,937	$100.00	$0.10765	$6,794,831	$6,794,762	$69	$7,307,867	$(513,105)
22	Environs	2,221	10,837,793			1,388,761	1,388,747	14	1,493,618	(104,871)
23		40,110	38,760,730			$8,183,593	$8,183,509	$83	$8,801,485	$(617,976)
24										
25	Commercial Transportation									
26	Incorporated	3,761	16,770,676	$297.51	$0.12679	$3,245,289	$3,245,256	$33	$3,490,321	$(245,065)
27	Environs	131	409,358			$90,876	90,875	1	97,738	(6,862)
28		3,892	17,180,034			$3,336,165	$3,336,131	$34	$3,588,059	$(251,927)
29										
30	Total Commercial									
31	Incorporated	156,674	59,979,340			$20,338,057	$20,337,850	$207	$21,873,658	$(1,535,807)
32	Environs	5,332	409,358			2,354,385	$2,354,361	24	2,532,150	(177,789)
33	**Total Commercial**	**162,006**	**60,388,698**			**$22,692,443**	**$22,692,212**	**$231**	**$24,405,808**	**$(1,713,596)**
34	Industrial									
35	Incorporated	295	615,043	$572.02	$0.12707	$246,899	$246,902	$(3)	$276,189	$(29,287)
36	Environs	0	0			$0	0	0	0	0
37		295	615,043			$246,899	$246,902	$(3)	$276,189	$(29,287)
38										
39	Industrial Transportation									
40	Incorporated	339	11,965,915	$772.02	$0.12707	$1,782,224	$1,782,244	$(21)	$1,993,649	$(211,405)
41	Environs	108	4,719,790			$683,122	683,130	(8)	764,161	(81,031)
42		447	16,685,705			$2,465,345	$2,465,374	$(29)	$2,757,810	$(292,436)
43										
44	Total Industrial									
45	Incorporated	634	12,580,958			$2,029,123	$2,029,146	$(23)	$2,269,838	$(240,692)
46	Environs	108	4,719,790			683,122	683,130	(8)	764,161	(81,031)
47	**Total Industrial**	**742**	**17,300,748**			**$2,712,245**	**$2,712,276**	**($31)**	**$3,033,999**	**$(321,723)**
48	Public Authority									
49	Incorporated	9,394	4,181,353	$156.05	$0.12549	$1,990,699	$1,990,711	$(11)	$2,069,241	$(78,530)
50	Environs	661	738,752			$195,807	195,808	(1)	203,533	(7,724)
51		10,055	4,920,105			$2,186,507	$2,186,519	$(12)	$2,272,773	$(86,254)
52										
53	Public Authority Transportation									
54	Incorporated	5,850	9,474,589	$179.05	$0.12549	$2,236,409	$2,236,421	$(13)	$2,324,644	$(88,223)
55	Environs	120	150,738			$40,402	40,402	(0)	41,996	(1,594)
56		5,970	9,625,327			$2,276,811	$2,276,824	$(13)	$2,366,640	$(89,817)
57										
58	Electrical Cogeneration Transportation									
59	Incorporated	12	4,050,695	$175.98		$182,658	$182,659	$(1)	$189,864	$(7,206)
60	Environs	0	0	First 5,000	$0.07427	0	0	0	0	0
61		12	4,050,695	Next 35,000	$0.06590	$182,658	$182,659	$(1)	$189,864	$(7,206)
62				Next 60,000	$0.05314					
63				All Over 100,000	$0.03864					
64	Total Public Authority									
65	Incorporated	15,256	17,706,637			$4,409,766	$4,409,791	$(25)	$4,583,749	$(173,958)
66	Environs	781	889,490			236,209	$236,211	(1)	245,529	(9,318)
67	**Total Public Authority**	**16,037**	**18,596,127**			**$4,645,975**	**$4,646,002**	**($26)**	**$4,829,278**	**$(183,276)**
68	Compressed Natural Gas									
69	Incorporated	11	0	$594.88	$0.06684	$6,544	$6,544	$0	$7,293	$(749)
70	Environs	0	0			$0	0	0	0	0
71		11	0			$6,544	$6,544	$0	$7,293	$(749)
72										
73	Compressed Natural Gas Transportation									
74	Incorporated	36	562,834	$619.88	$0.06684	$59,936	$59,935	$0	$66,797	$(6,861)
75	Environs	12	572,239			$45,687	45,687	0	50,917	(5,230)
76		48	1,135,073			$105,623	$105,622	$0	$117,714	$(12,091)
77										
78	Total Compressed Natural Gas									
79	Incorporated	47	562,834			$66,479	$66,479	$0	$74,089	$(7,610)
80	Environs	12	572,239			45,687	$45,687	0	$50,917	(5,230)
81	**Total Compressed Natural Gas**	**59**	**1,135,073**			**$112,166**	**$112,166**	**$0**	**$125,006**	**$(12,840)**

Line	Description	Recommended Revenue	Assigned Revenue	Rounding Diff.	Test Year As Adjusted Revenue	Revenue Change	Service Charges and Other Revenue	Cost of Gas	% Change (Non Gas Revenue)	% Change (Total Revenue)
82	Proposed CGSA Revenue									
83	Incorporated	$165,921,696	$165,921,980	($285)	$142,906,044	$23,015,937	$4,600,505	$86,700,913	15.60 %	9.83 %
84	Environs	$20,286,945	$20,286,984	-$39	$17,513,525	$2,773,459	398,453	10,124,915	15.48 %	9.89 %
85	**Total Revenue**	**$186,208,641**	**$186,208,965**	**($324)**	**$160,419,569**	**$25,789,396**	**$4,998,958**	**$96,825,829**	**15.59 %**	**9.83 %**

Company's overall combined revenue requirement for CGSA:	$191,207,599
The total revenue received during the test year	$165,418,527
revenue deficiency	$25,789,396
rates will increase TGS's revenues in CGSA by	$25.8 Million
which is an increase of including the cost of gas	9.83 %
which is an increase of excluding the cost of gas	15.59 %

Average Bill Impact by Class (Including Cost of Gas)

Customer Class	Current Average Monthly Bill Including Cost of Gas	Current Average Monthly Bill Including Cost of Gas	Proposed Monthly Dollar Change	Proposed Percentage Change with Gas Cost
Sales Service: (1) (2)				
Residential - Small (3)				
Incorporated	$41.76	$48.02	$6.26	14.99%
Environs	$41.76	$48.02	$6.26	14.99%
Residential - Large (3)				
Incorporated	$67.28	$76.81	$9.53	14.16%
Environs	$67.28	$76.81	$9.53	14.16%
Commercial - Small (3)				
Incorporated	$143.11	$133.90	($9.21)	(6.44%)
Environs	$143.11	$133.90	($9.21)	(6.44%)
Commercial - Large (3)				
Incorporated	$833.61	$819.03	($14.58)	(1.75%)
Environs	$833.61	$819.03	($14.58)	(1.75%)
Industrial				
Incorporated	$2,597.27	$2,163.88	($433.39)	(16.69%)
Environs	$2,597.27	$2,163.88	($433.39)	(16.69%)
Public Authority				
Incorporated	$533.27	$528.62	($4.65)	(0.87%)
Environs	$533.27	$528.62	($4.65)	(0.87%)
Public Schools Space Heating (4)				
Incorporated	$1,238.21	$1,215.85	($22.36)	(1.81%)
Environs	$1,238.21	$1,215.85	($22.36)	(1.81%)
Compressed Natural Gas				
Incorporated	$812.71	$594.88	($217.83)	(26.80%)
Environs	$812.71	$594.88	($217.83)	(26.80%)
Unmetered Gas Light				
Incorporated	$993.52	$993.52	$0.00	0.00%
Transportation Service: (5)				
Commercial Transportation				
Incorporated	$3,536.39	$3,525.82	($10.57)	(0.30%)
Environs	$3,536.39	$3,525.82	($10.57)	(0.30%)
Industrial Transportation				
Incorporated	$28,514.60	$28,081.21	($433.39)	(1.52%)
Environs	$28,514.60	$28,081.21	($433.39)	(1.52%)
Public Authority Transportation				
Incorporated	$1,360.59	$1,355.94	($4.65)	(0.34%)
Environs	$1,360.59	$1,355.94	($4.65)	(0.34%)
Public Schools Space Heating Transportation (4)				
Incorporated	$966.26	$855.10	($111.16)	(11.50%)
Environs	$966.26	$855.10	($111.16)	(11.50%)
Electrical Cogeneration Transportation				
Incorporated	$219,905.95	$219,305.49	($600.46)	(0.27%)
Environs	$219,905.95	$219,305.49	($600.46)	(0.27%)
Compressed Natural Gas Transportation				
Incorporated	$16,715.00	$16,497.17	($217.83)	(1.30%)
Environs	$16,715.00	$16,497.17	($217.83)	(1.30%)

(1) Bill impacts are shown for those schedules with customers during the test year. The test year cost of gas is included in the bill calculations. Bills under current and recommended rates do not include revenue-related taxes. These taxes vary across different locations in the service area.

(2) Bills are based on the following average usage levels:

	Year-Round
Residential - Small	17
Residential - Large	43
Commercial - Small	62
Commercial - Large	966
Industrial	2,085
Public Authority	489
Public Schools Space Heat	1,391
Compressed Natural Gas	0

(3) Calculations for residential and commerical are based on usage at the Small and Large amounts shown in Note 2 (Residential: 17 Ccf for Small and 43 Ccf for Large/Commercial: 62 Ccf for Small and 966 Ccf for Large). See the individual rate design tabs for the source of these values.

(4) The gas sales and transportation Public School Space Heating tariffs will be discontinued. Customers will be consolidated into the Public Authority class.

(5) Transportation customers secure their own gas. While the Company has no way of knowing the customer's cost of gas, these bill comparisons assume that customers obtain their gas at a cost that is five percent less than the Company's gas cost. These transportation bill comparisons are only illustrations of the level of total bills and the percentage changes in those bills. Bills are based on the following average usage levels:

	Year-Round
Commercial Transportation	4,414
Industrial Transportation	37,325
Public Authority Transportation	1,612
Transportation	926
Electrical Cogeneration Transportation	337,558
Compressed Natural Gas Transportation	23,647

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JEFFREY J. HUSEN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

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LIST OF EXHIBITS

DIRECT TESTIMONY OF JEFFREY J. HUSEN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey J. Husen. My business address is 15 East 5th Street, Tulsa, Oklahoma, 74103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President, Rates and Regulatory, for ONE Gas, Inc. ("ONE Gas"). I have responsibility for the rates and regulatory functions at ONE Gas. These responsibilities include development of rate and regulatory filing strategies and oversight and administration of rate and regulatory filing processes for ONE Gas and its divisions, including Texas Gas Service Company ("TGS" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science in Accounting from Oklahoma State University. For more than 30 years, I have worked in accounting and financial reporting roles. Prior to my current position, I was Chief Accounting Officer and Controller for ONE Gas responsible for accounting, financial reporting, federal and state income tax and budgeting processes and controls for ONE Gas. I also served as Assistant Controller - Corporate Accounting and Reporting for ONEOK, Inc. ("ONEOK") and ONEOK Partners, L.P. where I was responsible for corporate accounting, Securities and Exchange Commission reporting, Sarbanes Oxley compliance and enterprise risk management processes. During my tenure at ONEOK, I also served as the Director of Accounting for the Gathering and Fractionation portion of

ONEOK Partners' natural gas liquids business, and as Director of Accounting for Oklahoma Natural Gas, which is now a division of ONE Gas. Prior to joining ONEOK, I was a Senior Manager in the audit practice with KPMG, L.L.P. in Tulsa, Oklahoma. In that role, I audited accounting policies and practices for companies in the utility, transportation and manufacturing industries. I am licensed as a Certified Public Accountant in Oklahoma. I also am certified as a Chartered Global Management Accountant by the American Institute of Certified Public Accountants.

Q. WAS THIS TESTIMONY, INCLUDING ITS EXHIBITS, PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony before the Railroad Commission of Texas ("Commission") in Gas Utilities Docket ("GUD") Nos. 10739, 10766, 10928 and Commission Docket Nos. OS-22-00009896 ("Docket No. 9896") and OS-23-00014399 ("Docket No. 14399"). Similarly, I have also filed testimony before the Kansas Corporation Commission in 18-KGSG-560-RTS; and before the Oklahoma Corporation Commission in Cause No. PUD 202100063.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides an overview and explanation of TGS's Statement of Intent ("SOI") filing and of ONE Gas and its operations in Texas. I explain the issues that are driving the timing of the Company's filing for the Central-Gulf Service Area ("CGSA") and the relief TGS seeks through this case. I also identify the witnesses who are providing testimony in support of this SOI. In addition, I address the annual CGSA capital investment reports TGS has filed with the Commission as part of its Interim Rate Adjustment ("IRA" or "GRIP") filings since the last rate case,[1] which supports the Company's request for a determination that the Direct, TGS Division and Corporate capital investment that has been made through December 31, 2023, is used and useful and was prudently incurred.

Q. PLEASE IDENTIFY THE WITNESSES SUBMITTING TESTIMONY IN THIS RATE CASE ON BEHALF OF TGS.

A. In addition to my testimony, the Company's witnesses and the subjects addressed in the testimony are identified in Exhibit JJH-1.

II. <u>OVERVIEW OF THE STATEMENT OF INTENT FILING</u>

Q. PLEASE BRIEFLY DESCRIBE TGS'S PARENT COMPANY, ONE GAS.

A. TGS is one of three divisions operated by ONE Gas, which is an independent natural gas distribution company focusing on delivering natural gas safely and reliably to customers through its divisions in Oklahoma, Kansas and Texas. ONE Gas has approximately 3,900 employees, 940 of which are in Texas. As a 100% regulated company focused solely on delivering natural gas safely and reliably, all costs ONE Gas incurs support providing that service to its customers, including those in the CGSA.

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[1] The Company last filed a rate case with the CGSA cities and Commission on December 20, 2019 (*Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and the Gulf Coast Service Area*, GUD No. 10928, consol.).

Q. WHAT TEST YEAR WAS USED IN THIS STATEMENT OF INTENT?

A. The Company's SOI is based on the financial results for the test year ended December 31, 2023, with adjustments for some known and measurable changes as discussed in the direct testimonies of Company witnesses Marie J. Michels, Stacey R. Borgstadt and Stacey L. McTaggart.

Q. WHY IS TGS FILING A STATEMENT OF INTENT AT THIS TIME?

A. The Company's current base rates within the CGSA cities and environs were established in August 2020. Although the Company has been able to update rates with four annual GRIP filings with the Cities and Commission since that last rate case, the Company's rates are not sufficient to recover the cost of providing service at this time. The filing is intended to support the recovery of investments in the Company's distribution system, explain the changes in expenses (including depreciation expense), address the accumulation of deferred taxes since the last rate case and better align each customer class's contribution to the overall revenue requirement based on the cost of providing service.

The Company's top priority is maintaining a safe and reliable natural gas system, which includes annual investments to improve the natural gas system and expenses incurred in order to operate safely and reliably. Since the last rate case in the CGSA (GUD No. 10928), the Company's net plant has increased over $342 million as the result of investments in its natural gas distribution system. These investments replaced aging infrastructure and support the safe and reliable delivery of natural gas to residential and business customers and include costs of extending service to new customers. This case provides an opportunity to realign rates to support these and future investments, allowing the Company to continue to provide safe and reliable service to our CGSA customers and to update the Company's tariffs accordingly.

Q. WHAT IS DRIVING TGS'S REQUEST FOR AN INCREASE IN RATES IN THIS STATEMENT OF INTENT?

A. In terms of revenue requirement, the Company's cost of service calculations show that TGS is experiencing a revenue deficiency primarily driven by the need to recover costs related to plant investment and related depreciation, ad valorem tax expenses, payroll-related expenses and the Company's ongoing efforts to meet all regulatory and safety requirements. In addition to an increase of over $342 million in net plant since base rates were last changed in the CGSA, TGS must also continue to invest in its employees and has experienced increases in reasonable and necessary personnel-driven expense items, such as wages, salaries and employee benefits. Also, costs associated with meeting regulatory and safety requirements including documenting, testing, surveying, repairing, planning and replacing system assets continue to increase. The increasing costs associated with meeting these requirements include operating expenses for activities such as leak repair, leak survey, line locating and distribution integrity management. TGS also made additional capital investments in its natural gas distribution system for technology that provides critical services supporting all employees in their efforts to provide service safely and reliably to customers. The Company continues to incur these types of costs annually due to aging infrastructure; compliance with natural gas pipeline safety and system integrity regulations; and the need to invest in technology that allows the Company to increase operational capabilities, provide system security and improve customer service. These issues have resulted in a revenue deficiency that does not provide the Company with a reasonable opportunity to earn a reasonable return on its investment in the current economic environment.

Q. ARE THERE OTHER FACTORS INFLUENCING TGS'S REQUEST FOR AN INCREASE IN RATES IN THIS SOI?

A. Yes. As TGS has noted in other recent rate case filings, the Company continues to be impacted by unusually high inflation rates due to several factors including labor shortages coupled with wage increases, supply chain issues across multiple industries, which include the impacts resulting from ongoing global conflicts. The Company observed that, since the previous rate case for the CGSA, prices for equipment, materials, supplies, employee labor and contractor services have increased. Accordingly, these external factors contribute to the need to increase rates to be able to continue to provide safe and reliable service.

Q. PLEASE GENERALLY DESCRIBE THE RELIEF REQUESTED IN THIS SOI.

A. The Company's cost of service demonstrates a total annual gross revenue deficiency of $25,789,395 for the CGSA. The Company proposes to eliminate this annual earnings deficiency and to have its rates set at a level that provides TGS a return on equity of 10.25%. TGS is requesting recovery of necessary operating and maintenance costs it incurred from 2020 through 2022, as a result of COVID-19. The request for recovery of the COVID-19 related expenses is consistent with the

Regulatory Asset Notice the Commission issued in April 2020.[2] TGS is also seeking to recover extraordinary operating and maintenance costs it incurred as a result of Winter Storm Uri in 2021 and related interest costs that exceeded the amount authorized for recovery through securitization. This request is consistent with the Regulatory Asset Determination Order in Commission Docket No. OS-21-00007061 ("Docket No. 7061"), the Regulatory Asset Notice issued on February 13, 2021, Notice to Gas Utilities issued on June 17, 2021 and the Financing Order in Docket No. 7061.[3] In addition, TGS seeks recovery of employee compensation and benefit costs, in accordance with Gas Utility Regulatory Act ("GURA") § 104.060, which is addressed by Company witnesses Megan Z. Gough and Ms. Borgstadt. The Company is also requesting new depreciation rates, as discussed in the direct testimony of Company witness Dr. Ronald E. White.

In addition to the rate relief requested in this SOI, the Company is also proposing a small and large customer rate design for residential and commercial customers based on individual customer usage characteristics, as explained by Company witness Paul H. Raab. TGS recently proposed similar rate designs that were approved by the Commission for residential customers in TGS's West North Service Area in Docket No. 9896 and for residential and commercial customers in the Rio Grande Valley Service Area in Docket No. 14399. The Company is also

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[2] Notice of Authorization for Regulatory Asset Accounting for Gas Utilities Affected by the COVID-19 Outbreak (April 2020), https://portalvhdskzlfb8q9lqr9.blob.core.windows.net/media/57195/nto-state-disaster-waiver-gas-utility-asset-accounting_04-08-2020.pdf.

[3] *Consolidated Applications for Customer Rate Relief and Related Regulatory Asset Determinations in Connection with the February 2021 Winter Storm*, Docket No. OS-21-00007061, consol., Financing Order (Feb. 8, 2022).

requesting a Renewable Natural Gas ("RNG") Credits Program tariff as explained by Ms. McTaggart.

Finally, TGS is requesting a prudence determination finding that the capital investment made since the last CGSA cities and environs rate case is just and reasonable. I have attached a detailed list of witnesses and their testimony topics hereto as Exhibit JJH-1. Also, Exhibit JJH-2 is a copy of the Table of Contents Summary to the CGSA Cost of Service schedules, which lists all the schedules and workpapers in this filing, along with the sponsor(s).

Q. HAS THE COMPANY FOLLOWED PRIOR COMMISSION DECISIONS IN PREPARING THIS STATEMENT OF INTENT?

A. Yes. Throughout my testimony as well as testimony provided by other witnesses, there are numerous references to prior TGS cases, including both litigated and settled proceedings. In each SOI filing, the Company relies on and builds upon prior Commission decisions to inform how the Company prepares its cost of service calculations, calculates rates or seeks other forms of relief. For example, the Commission has repeatedly approved the Company's use of a 13-month average to calculate materials and supplies, the Distrigas cost allocation method for Shared Services and Corporate costs as presented in this filing and the use of the Company's actual capital structure. More recently, the Commission has approved the Company's proposed small and large rate classes for residential and commercial customers as presented in the Company's other service territories here in Texas. As the Commission makes consistent decisions on various issues, regulatory certainty builds. In addition, by relying on prior Commission decisions, the natural result should be a reduction in the number of contested issues and the increase in administrative efficiency.

Q. WHAT ROLE DOES REGULATORY CERTAINTY PLAY IN TGS'S DECISION-MAKING?

A. As a regulated entity, TGS is always mindful of the regulatory environment in which it operates both in terms of providing service to customers and in the regulatory proceedings that are an inherent part of the Company's activities. Regulatory certainty, or the ability to rely on past Commission decisions and methodologies related to the Company's operations, rate calculations or other aspects of the way the business functions, is incredibly important. Regulatory certainty provides utilities such as TGS with a clear understanding of the rules and policies that will be applied to the Company. Being able to rely on consistent regulatory treatment helps TGS to operate more efficiently and to make decisions that align with reasonable regulatory expectations.

Q. WHAT IMPACT WILL THE REQUESTED RATE INCREASE HAVE ON AVERAGE MONTHLY RESIDENTIAL BILLS IN THE CGSA?

A. The proposed rate increase will result in changes to the average monthly bills for the 281,253 residential customers in the incorporated areas of the CGSA and the 30,284 residential customers in the environs areas of the CGSA, as shown in the table below.[4]

[4] The changes in year-round average bills shown in Column (d) and (e) vary due to differences in current rates.

Line No.	Description	Current	Recommended	Change Dollars	Change %
	(a)	(b)	(c)	(d)	(e)
1	**Residential - Small**				
2	Incorporated	$41.76	$48.02	$6.26	14.99%
3	Environs	$41.76	$48.02	$6.26	14.99%
4	**Residential - Large**				
5	Incorporated	$67.28	$76.81	$9.53	14.16%
6	Environs	$67.28	$76.81	$9.53	14.16%

The proposed rates for all rate classes are identified in Mr. Raab's direct testimony and are reflected in the tariffs sponsored by Ms. Michels. In addition to proposed gas sales, transportation and cost of gas tariffs, the Company's filing proposes a new RNG Credits Program tariff. In addition, the Company proposes revised service fees and updated language in its transportation tariffs and rules of service.

Q. HAS TGS TAKEN REASONABLE ACTIONS TO MANAGE COSTS?

A. Yes. The ongoing evolution of the energy markets creates greater competition and, with that, greater customer choice. Therefore, TGS is motivated to reasonably manage its costs so that the Company remains competitive and customers continue to choose natural gas. The Company has taken, and continues to take, steps to ensure that resources are used wisely and that costs are reasonably managed. Additionally, the Company understands that its continued success relies both on its commitment to efficient and cost-conscious management and on its employees operating safely and in a responsible manner. TGS also strives to provide excellent customer service by improving performance through increased productivity and to balance personal interactions and technology to deliver efficient and satisfying experiences to our customers.

Q. PLEASE PROVIDE EXAMPLES OF THE COMPANY'S EFFORTS RELATED TO CUSTOMER SERVICE ACTIVITIES.

A. Examples of improved customer service since the last rate cases are:

1. Electronic Bill Statement Growth - approximately 55% of ONE Gas customers now receive electronic bill statements, which results in savings in postage and materials.

2. Enhanced Customer Communications - established proactive measures to place safety and/or educational related information in customers' hands through social media regarding weather, outages, safety tips, payment assistance and social service agencies.

3. New Payment Options - implemented new customer payment options including Automatic Payments using a credit or debit card and advanced payment options such as PayPal, Amazon Pay and Venmo. We are reviewing the feasibility of adding others such as Apple Pay and Google Pay.

4. Courtesy Collection Calls - added payment reminder calls that are made when a customer is past due on a bill, which gives customers another opportunity to make a payment before being disconnected.

5. Energy Assistance - in late 2020, TGS implemented an Energy Assistance Portal for the Company's Energy Assistance partners, which are agencies that distribute available utility bill assistance to customers in need. Previously, the Energy Assistance partners were required to call TGS to submit pledges or receive copies of bills or notices. With the updated portal, Energy Assistance partners are able to submit pledges online and retrieve the necessary documentation. This portal expedited the processing of Energy Assistance efforts, which has prevented disconnects and increased customer satisfaction with the Energy Assistance experience.

6. Interactive Voice Response ("IVR") Enhancements - upgraded phone and IVR systems with enhanced capabilities and functionality provide more ways for customers to find the answers they need without having to take the time to talk to a customer service agent.

7. Web Site Enhancements - enhanced search functionality for customers to more easily find what they are looking for, including a new blog section that features up-to-date information for customers with answers to recently

asked questions, financial assistance information and community involvement, refreshed and updated content on the TGS website including more accessible and clear navigation regarding how to make payments and added additional "banner" alerts featured on the TGS homepage to share information on payment assistance and payment options for customers impacted by the winter storm and COVID-19 pandemic.

8. Mobile App - highly rated with industry-leading scores from the Verint/Foresee survey when benchmarked against our utility peer set. The TGS Mobile App was released in July 2017 and is installed on approximately 17,500 user devices.

These initiatives are designed to provide customers with greater flexibility and more options other than speaking with a live customer service agent to address customer account matters.

Q. PLEASE PROVIDE EXAMPLES OF THE COMPANY'S EFFORTS RELATED TO COST SAVINGS INITIATIVES.

A. A few examples of cost savings initiatives instituted by the Company are:

1. Implementation of Customer Service System (Banner) and Automated Meter Reading ("AMR") technology to retrieve stored readings captured by our AMR technology and to auto-close service orders that only require a read of a meter. The initiative is estimated to reduce on-site visits to customer locations by approximately 3,700 visits per year with an estimated cost savings of $26,000 per year.

2. The Company has embraced enhancements in technology put in place in response to the COVID-19 pandemic and has recognized the value of employees participating remotely when it is reasonable and meets the needs of the task or activity. During the pandemic, meals, travel and training expenses decreased significantly. Post pandemic, the Company has maintained a level of expense in the current test year 2023 that is approximately 25% less ($300,000) than 2019, pre-pandemic, levels.

III. CAPITAL INVESTMENT DETERMINATION

Q. WHAT CAPITAL INVESTMENT IS THE COMPANY SEEKING RECOVERY OF IN THIS RATE CASE?

A. TGS requests recovery of the reasonable and necessary net capital investment made in the CGSA since the last rate case in the amount of approximately $342 million. All capital investment included in this rate case is for natural gas distribution system assets, facilities or items that are currently used and useful in providing utility service as of the end of the test year, which Company witnesses Alejandro Limón, Ms. Michels and Ms. Borgstadt address in more detail in their direct testimonies. As addressed by Ms. Michels and Ms. Borgstadt, the Company has proposed adjustments to capital investment to remove costs for activities such as miscoded investment, costs for meals greater than $25 per person, exclusive of taxes and tip amount and hotel stays greater than $175 per night, exclusive of taxes.

Q. HOW DOES TGS RECOVER CAPITAL INVESTMENT AMOUNTS?

A. Based on my understanding of applicable statutes and Commission rules, capital investment can be requested for recovery through a statement of intent filing like this proceeding or through an IRA or GRIP filing. GURA § 104.301 establishes the state's Gas Reliability Infrastructure Program and is commonly referred to as the "GRIP statute." The purpose of the statute is to encourage the timely investment in needed system improvements and to reduce the frequency of traditional rate cases by providing a streamlined process for utilities to recover the costs of those investments on an interim basis between rate cases. Capital investment in a GRIP filing is not subject to a prudence review during the GRIP process. Instead, the prudence review, which involves a determination that capital investment is just and reasonable, occurs in the next general rate case for that service area.

Q. IS TGS INCLUDING CAPITAL INVESTMENT FROM GRIP FILINGS IN THIS RATE CASE?

A. Yes. The Company has made annual GRIP filings for the CGSA environs since the last rate case for this service area, which includes investment from January 1, 2020 through December 31, 2023.

Q. IN ADDITION TO YOURS AND MR. LIMÓN'S TESTIMONY, WHAT SUPPORT IS THE COMPANY PROVIDING FOR THE ANNUAL CAPITAL INVESTMENT AMOUNTS?

A. In Exhibit JJH-3, I am providing capital investments reports, including Corporate and TGS Division investment, for the test year and as provided in TGS's GRIP filings since the last base rate case in the CGSA.

These investment reports list projects and contain detailed support of TGS's capital investment request. The investment reports are project activity summaries for plant in service and completed construction not classified. Each report includes the project number, utility account, project in-service date, project description, function description, customers benefited and any adjustments.

Q. WHAT RELIEF IS TGS SEEKING IN THIS RATE CASE WITH REGARD TO CAPITAL INVESTMENT?

A. The Company is requesting a determination that the capital investment included in this rate case is prudent, just and reasonable, including test year and GRIP capital investment amounts.

Q. IS THE CAPITAL INVESTMENT INCLUDED IN THE COMPANY'S RATE CASE REASONABLE AND NECESSARY?

A. Yes. Mr. Limón explains how TGS requires each capital investment expenditure or project to be approved through a thorough decision-making process to include consideration of whether those investments are necessary for TGS to maintain a safe and reliable system, which provides an appropriate level and quality of gas utility service to customers. This is also true for TGS Division and Corporate capital investment amounts that are allocated to the CGSA. Therefore, the ongoing capital investment is a necessary and critical aspect of the Company's ability to provide service.

IV. SMALL AND LARGE RATE DESIGN

Q. PLEASE DESCRIBE THE COMPANY'S SMALL AND LARGE RATE DESIGN PROPOSAL.

A. The Company is excited to propose a rate design that recognizes the differing usage characteristics of customers in the residential and commercial classes. The Company is proposing separate rates for small and large residential and commercial customers. The proposal allows customers who desire it some amount of choice in how they are billed for gas service. As Mr. Raab explains in detail in his direct testimony, the proposed rate design mitigates the potential rate increase for low-usage customers as compared to a traditional rate design that applies the same customer charge and usage charge to all customers within a rate class. The small customer rate benefits customers with lower-than-average usage through a combination of a lower monthly customer charge and a higher volumetric rate as follows:

Small	Residential	Commercial
Customer Charge	$25.50	$85.00
Volumetric Rate (All Ccf)	$0.69448	$0.15710

The large customer rate benefits customers with higher-than-average usage through a higher monthly customer charge and a much lower volumetric rate.

Large	Residential	Commercial
Customer Charge	$39.00	$100.00
Volumetric Rate (All Ccf)	$0.23425	$0.10765

Both lower-use customers and higher-use customers benefit from the Company's proposed rate design as discussed in the testimony of Mr. Raab. Many of the lowest use commercial customers will, in fact, experience an overall rate decrease as shown in Exhibit PHR-6 to Mr. Raab's testimony. Likewise, the lowest-use residential customer rate increases are mitigated with the small and large rate design approach as shown in Exhibit PHR-4.

On the other hand, the proposed rate design ensures that higher-use customers will not experience significantly higher bill impacts during the winter months. For example, the proposed large customer rate, which has a higher customer charge but lower volumetric charge, helps to levelize monthly charges for higher-use customers throughout the year.

If the proposed rate design is approved, the Company will communicate with customers in advance of the new rates going into effect and will place customers on the rate that is most economical based on the customer's usage from the prior year, consistent with the Commission's Quality of Service Rules, which require the Company to "assist the customer or applicant in selecting the most economical rate schedule."[5] The customer will have the option to contact the Company and choose the alternate residential rate based on their own preference, provided that they remain on the rate they choose for a full year.

Q. IN ADDITION TO BEING IMPLEMENTED IN TWO OF THE COMPANY'S TEXAS SERVICE AREAS, HAS A SIMILAR RATE DESIGN BEEN IMPLEMENTED IN OTHER ONE GAS JURISDICTIONS?

A. Yes. A similar rate design (called A/B rate design) was approved for ONE Gas' Oklahoma division, Oklahoma Natural Gas, and has been successfully implemented for 19 years.

Q. DID THE COMMISSION CONSIDER THIS INFORMATION TO BE PERSUASIVE IN DOCKET NO. 9896 REGARDING SMALL AND LARGE RESIDENTIAL RATES?

A. Yes. In recommending approval of Small and Large Residential rates, the Examiners noted:

- that the dual rate design will address impacts associated with revenue increases and benefits customers by applying a rate design that results in lower rates based on their typical usage;[6]
- the new rate structure can be implemented with transparency, and they were persuaded that Oklahoma Natural Gas has operated a similar structure with minimal complaints and confusion since 2005;[7] and

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5 *See* 16 TAC § 7.45(2)(A)(ii).

6 *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, the North Texas Service Area, and the Borger Skellytown Service Area,* Docket No. OS-22-00009896, consol., Amended Proposal for Decision at 61 (Jan. 11, 2023).

7 *Id.* at 62.

- the two-tier rate design will give small usage customers more control over their bill and will give large usage customers more stable bills.[8]

This analysis supports the decision in the Final Order in Docket No. 9896 that the two-tiered rate structure for residential customers is just and reasonable.[9]

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

[8] *Id.*

[9] *See* Docket No. OS-22-00009896, consol., Final Order at Findings of Fact No. 103 (Jan. 18, 2023).

Witness	Title	Testimony Subjects
Jeffrey J. Husen	Vice-President of Rates and Regulatory Affairs for ONE Gas	Provides an overview of the Statement of Intent filing, including an explanation of the relief TGS is requesting and sponsors the Company's annual capital investment reports included with the Company's IRA filings to support the Company's requested prudence determination.
Alejandro Limon	Vice-President of Operations for TGS	Provides an overview of operations within the CGSA; addresses the reasonableness and necessity of capital investment and Operations and Maintenance (O&M) expenses; addresses ONE Gas' response to Winter Storm Uri and COVID-19; and addresses the Company's Pipeline Integrity Testing Program.
Marie J. Michels	Manager of Rates and Regulatory Analysis for TGS	Provides an overview of the cost of service and overall revenue requirement calculation and supports TGS's Direct rate base and Direct expense adjustments; addresses the Company's compliance with certain regulatory and statutory requirements; affiliate cost recovery issues related to Utility Insurance Company ("UIC"); the Company's recovery of pipeline integrity testing costs; the Company's recovery of rate case expenses; and describes the proposed CGSA rate schedules and tariffs as well as rate schedules and tariffs currently in effect for the CGSA.
Stacey L. McTaggart	Rates and Regulatory Director for TGS	Describes the Company's proposed EDIT adjustment to return excess deferred income taxes to customers; TGS's recovery of costs associated with COVID-19, Winter Storm Uri and another regulatory asset, new RNG Credits Program rate schedule , and Rule 8.209 accruals.
Stacey R. Borgstadt	Director of Rates and Regulatory Compliance for ONE Gas	Addresses the cost allocation methodology used to determine TGS's share of allocated costs and certain Corporate expense adjustments; supports certain TGS Division and Corporate capital investment that is included in the CGSA revenue requirement as well as Corporate depreciation and amortization expense; and explains Direct, TGS Division and Corporate expense adjustments related to payroll, employee benefits, and incentive compensation.
Megan Z. Gough	Manager of Compensation for ONE Gas	Addresses the reasonableness of ONE Gas' compensation philosophy and structure, as well as related costs for base pay, incentive plans, benefits, and incentive compensation related to efforts during Winter Storm Uri.
Cyndi L. King	Director of Treasury and Finance for ONE Gas	Supports the recovery of a return on the Company's prepaid pension asset.
Jaime D. Shelton	Director of Risk and Insurance for ONE Gas	Describes ONE Gas' captive insurance company, UIC.
Kenneth E. Eakens	Director of Tax Compliance and Financial Reporting for ONE Gas	Describes the calculation of the Company's EDIT.
Timothy S. Lyons	Partner with ScottMadden, Inc.	Sponsors TGS's lead-lag study that determines TGS's cash working capital requirement to be included in rate base.
Janet M. Simpson	Accountant and Managing Member of Utility Regulatory Consulting, LLC	Presents TGS's Accumulated Deferred Income Tax (ADIT) calculations.
Ronald E. White	Engineer and President of Foster Associates Consultants, LLC	Sponsors a study of the depreciation rates for TGS plant located in the CGSA and for common facilities shared among all TGS service areas, including Corporate assets.
Bruce H. Fairchild	Principal with Financial Concepts and Applications, Inc.	Supports TGS's requested return on equity, cost of debt, capital structure, and overall return on invested capital.
Teresa Serna	Rate Specialist for TGS	Describes the class cost of service study and supports TGS's proposed class revenue allocation.
Zane M. Drummond	Rates Analyst for TGS	Supports TGS's revenue adjustments.
Paul H. Raab	Economic Consultant	Describes and supports TGS's proposed rate design.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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Exhibit JJH-3 is voluminous and is being provided
in electronic format.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF JEFFREY J. HUSEN

BEFORE ME, the undersigned authority, on this day personally appeared Jeffrey J. Husen who having been placed under oath by me did depose as follows:

1. "My name is Jeffrey J. Husen. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Vice-President of Rates and Regulatory Affairs for ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Jeffrey J. Husen

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jeffrey J. Husen on this 22 day of May 2024.

STATE OF OKLAHOMA NOTARY PUBLIC M. FREEMAN #21014828 EXP. 11/12/25

M Freeman
Notary Public in and for the State of Oklahoma

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

ALEJANDRO LIMÓN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

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LIST OF EXHIBITS

DIRECT TESTIMONY OF ALEJANDRO LIMÓN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alejandro Limón. My business address is 9228 Tuscany Way, Austin, Texas 78754.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Vice President of Operations for Texas Gas Service Company ("TGS" or the "Company"), a Division of ONE Gas, Inc. ("ONE Gas").

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As Vice President of Operations, I have primary responsibility for Field Operations for the TGS division. These responsibilities include:

- Construction and maintenance on TGS's distribution systems,
- Field customer service;
- Meter reading;
- Collections;
- Compliance-related activities; and
- Operations and maintenance ("O&M") and capital budgets.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Civil Engineering from the University of Texas at El Paso in 1992. Following graduation, I worked for three years as an engineer for the Texas Department of Transportation ("TxDOT") where I worked in the Bridge Design Section on a series of major bridge projects in the El Paso area. These assignments involved extensive coordination with gas, electric, telecommunications, water and sewer utilities in order to minimize required utility relocation and related expense. As a member of the design team for the Cordova International Bridge, I additionally coordinated design and construction activities with both U.S. and Mexican representatives of the International Boundary and Water Commission.

In 1995, I joined El Paso Water Utilities ("EPWU"), where I initially worked in the New Development Section, dealing with developers on service availability issues and the design of new and expanded water and sanitary sewer facilities. After a year, I became EPWU's in-house Master Water Modeling Subject Matter Expert, a technical position in which I analyzed water distribution system flows. At EPWU, I utilized the Cybernet modeling program and worked with both the EPWU Engineering Department and outside engineering consultants in properly sizing the water distribution and transmission system to meet existing and projected demands for service. I prepared a $201 million budget forecasting water infrastructure master plan improvements from 2000 to 2026. The plan consisted of 12" water mains through 60" water transmission pipelines and 30 million gallons of storage and pump stations.

In 1999, I left EPWU to accept a position with Southern Union Gas, whose Texas assets were purchased by ONEOK, Inc. ("ONEOK") in January 2003 and are now known as Texas Gas Service Company, which became a division of ONE Gas as of January 2014. I have had responsibilities in various roles as the Regional Engineer Manager, Operations Manager, Director of Operations and Director of Compliance with statewide responsibilities for the past 23 years with TGS. I served as the West Texas Regional Engineer Manager from 1999 to 2006 with responsibilities in El Paso, Permian and the Rio Grande Valley service areas and in 2001 managed both Engineering and Construction and Maintenance departments until 2006. As the Manager of Operations, I oversaw engineering design, estimating, project coordination, project management for TxDOT, City of El Paso and Governmental entities in roadway improvement projects. I also managed capital and operation and maintenance (O&M) budgets. I was responsible for state and federal inspection audits, maintenance and operations standards, system replacement projects and pipeline integrity design, estimating, bidding, construction and inspection management. Starting in 2007, I was the Director of Operations for the El Paso and Permian Service Areas (now part of the West North Service Area) with responsibilities for Customer Service, Meter Reading, Construction and Maintenance, Inspections, Leak Survey, Cathodic Protection, Pressure and Measurement, Engineering and Warehouse. In 2022, I became the Director of Compliance for TGS with statewide responsibilities overseeing Line Locating, Compliance, Leak Survey, Cathodic Protection and Pressure and Measurement. I began serving in my current position as Vice President of Operations on January 1, 2023.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony with the Railroad Commission of Texas ("Commission") in Gas Utilities Docket ("GUD") No. 9988 and Docket No. OS-23-00014399 ("Docket No. 14399").

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, it was.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I am sponsoring the exhibits listed in the table of contents.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, they were.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides an overview of the Company's current system and operations in its Central-Gulf Service Area ("CGSA") and explains how the costs TGS incurs are necessary for maintaining a safe and reliable natural gas distribution system. My testimony, along with the direct testimony of other TGS witnesses, supports the reasonableness and necessity of the Company's requested O&M expenses and capital investment that has been made in the CGSA through December 31, 2023. My direct testimony and that of other witnesses also supports a determination that the requested capital investment amounts (Direct, TGS Division and Corporate) for the test year as well as amounts included in the Company's annual Gas Reliability Infrastructure Program ("GRIP") filings, are prudent and used and useful. I also support the reclassification of the former ONE Gas Pipeline Company ("OPC")[1] line costs from transmission to distribution

[1] The Commission has previously approved the acquisition of the OPC line, so that issue is not within the scope of this case. *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change*

accounts on the Company's books and records, as well as the reasonable and necessary costs of the Company's Pipeline Integrity Testing ("PIT"). Finally, I explain how TGS's operations and costs have been affected by the COVID-19 pandemic, Winter Storm Uri, a tight labor market and economic conditions.

II. OVERVIEW OF TGS SYSTEM AND OPERATIONS

Q. PLEASE DESCRIBE TGS'S SYSTEM AND OPERATIONS IN TEXAS.

A. TGS provides safe, clean and reliable natural gas service to approximately 700,000 customers in more than 100 communities within three regulatory service areas in Texas. A map of the areas TGS currently serves is attached to my testimony as Exhibit AL-1. TGS and its predecessor utilities have served these areas for over 100 years. Operational decisions for TGS are made at the statewide level in coordination with management decision-making based in Tulsa, Oklahoma.

Q. PLEASE EXPLAIN HOW THE TGS SYSTEM IS MANAGED.

A. The Company's management uses a functional operating model which is centralized in nature. This approach to decision-making and management of TGS's gas service means that the employees living and working within the regulatory service area boundaries do not represent the full scope of employees responsible for the activities and workload associated with its actual operations in the CGSA. Instead, the centralized approach means that the regulatory service areas are actually operated on a statewide basis.

The functional operating approach has been utilized since 2013 and allows ONE Gas to operate the local distribution companies in each state as one company,

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Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and the Gulf Coast Service Area, GUD No. 10928, consol., Final Order at Findings of Fact ("FoF") No. 62 (Aug. 4, 2020).

rather than three separate companies. Under the functional model, employees across ONE Gas are organized by function, which allows ONE Gas to better align common processes across the enterprise, regardless of the state where that function is completed. Many activities that affect the Company's operations (functions) are centralized at the corporate level in Tulsa, the TGS Division level statewide and within specific regions of Texas. For example, project planning and management is coordinated at the ONE Gas level to ensure that capital projects are evaluated and prioritized based on total system needs. This, in turn, enables the Company to efficiently monitor and maintain its systems and ensure the provision of safe and reliable service in Texas. Examples of functions that are centralized at ONE Gas include Asset Management, Resource Management, Information Technology and Human Resources. Examples of operations-related functions that are centralized at a statewide level include leak survey, pressure control and measurement and cathodic protection. Examples of departments that are centralized at the statewide level include Operations, Engineering, Financial Accounting, Fleet, Customer Information Center, Dispatch and Gas Supply. The Company has operated this way for approximately ten years, so all recent rate cases and related costs have reflected this approach.

In addition to organizing the workload by function, ONE Gas and TGS have also focused on integrating systems and process changes to support the implementation and use of technology relating to construction, maintenance and replacement of assets. This has led to more efficient operations as well as enhanced communication among necessary personnel at all levels of TGS and ONE Gas related to operation of the Texas system.

Q. PLEASE DESCRIBE TGS'S CENTRAL GULF SERVICE AREA.

A. TGS provides natural gas distribution service to approximately 325,000 customers in the CGSA[2] and operates approximately 4,228 miles of distribution mains, approximately 11.64 miles of transmission mains, and approximately 2,755 miles of service lines. These system assets combined represent more than $813 million in net investment. As of the end of 2023, the Company directly employed approximately 210 TGS Division and 340 Direct CGSA personnel with a combined annual payroll of over $42 million. The Company remitted approximately $6.2 million in annual property taxes to local taxing authorities in the CGSA.

Q. DESCRIBE ONE GAS' FOCUS ON SAFETY.

A. ONE Gas continually seeks to improve processes for risk assessment and risk mitigation as part of its integrity management programs, as well as its procedures for ensuring full compliance with all laws and regulations. ONE Gas measures: (1) Preventable Vehicle Incident Rate ("PVIR"), (2) Days Away, Restricted and Transferred ("DART"), (3) Emergency Response Time ("ERT") and (4) Emissions Reduction ("ER"). Exhibit AL-2 shows ONE Gas' progress over the last several years with respect to the first three metrics compared to general industry achievement based on data gathered by the American Gas Association. The data in Exhibit AL-2 confirms that ONE Gas has improved significantly from being in the 4th quartile in 2009 to the 1st quartile in recent years. TGS has also

[2] The CGSA includes the cities of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas and the environs of Bastrop and Buda, Texas.

implemented more stringent standards for leak classification and repairs. ONE Gas regularly reviews its leak classification and repair standards for enhancements to its procedures. The more stringent standards are appropriate for management of the system, and the resulting leak repair or system maintenance is a reasonable and necessary expense.

Q. IS TGS REQUIRED TO COMPLY WITH STATE AND FEDERAL REGULATORY REQUIREMENTS?

A. Yes. The Company is subject to many rules and regulations on both the federal and state levels that are focused on ensuring the safety and reliability of TGS's infrastructure throughout the state and safe operation of its equipment. Examples include integrity testing, leak surveys and replacing facilities that present risks to TGS's system, which I will describe in more detail below. TGS must employ qualified personnel or hire contractors and incur costs that are necessary to meet its regulatory compliance obligations. Those costs include both O&M expenses and capital investment, which are costs TGS proposes to recover through base rates or specific riders as part of this rate case.

III. OPERATION AND MAINTENANCE EXPENSES

Q. PLEASE DESCRIBE THE O&M EXPENSES TGS INCURS.

A. TGS's O&M expenses are the result of normal operating, maintenance and administrative activities necessary to operate the natural gas system in a safe and reliable manner and provide effective and efficient customer service. TGS's O&M expenses include maintenance activities, personnel-driven expenses, such as wages and salaries and employee benefits and safety and regulatory compliance obligations. TGS also incurs O&M expenses for necessary tasks performed by employees in the field for safety and regulatory compliance such as cathodic protection, distribution integrity, leak survey, leak monitoring, leak repair and line locating. Company technicians also perform or oversee tasks such as meter maintenance, pressure regulation, odorant testing, service initiation and right-of-way maintenance. These operational functions are supported by back-office functions such as Gas Supply, Accounting, Rates and Regulatory and Human Resources that are necessary to operate the natural gas distribution system.

Q. DOES TGS UTILIZE A PLANNING PROCESS FOR O&M EXPENSES?

A. Yes. Executive management works closely with local management to establish appropriate O&M budgets to maintain a safe and reliable system and provide effective customer service while also balancing the need to control O&M expenses. To control O&M costs, TGS regularly reviews various metrics. For example, TGS conducts periodic reviews of the personnel, including contractors, utilized in operations to ensure the efficient and effective use of resources. Overtime is reviewed on at least a monthly basis to determine whether adjustments are needed to staffing levels, scheduled work and employee schedules to minimize total labor costs. The ability to share resources across the state also aids the Company in maximizing the productivity of its resources. The Company also regularly reviews its budget forecasts to assess variances between actual expenses and forecasted amounts. By utilizing a centralized purchasing department, the Company can make use of volume discounts through approved vendors. Direct purchases of materials are kept to a minimum.

Q. PLEASE ELABORATE ON THE REGULATORY COMPLIANCE ACTIVITIES THAT ARE A NECESSARY PART OF OPERATING TGS'S SYSTEM.

A. One example is requirements from the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") and Commission that are applicable to natural gas distribution companies.[3] Specifically, the Company must establish a risk-based approach to pipeline maintenance and safety. Commission Rule 8.209 requires the Company to develop and implement a risk-based program for the removal or replacement of distribution facilities, including steel service lines. TGS's distribution integrity management program and its risk-based program use scheduled replacements to manage identified risks associated with the integrity of distribution facilities and comply with the requirements mentioned above.

TGS also conducts leak surveys pursuant to Commission Rule 8.206(g) no less frequently than: (1) annually for all systems within a business district; (2) every five years for non-business district polyethylene ("PE") systems or segments within a system; (3) every three years for all other non-business district, cathodically protected steel systems or segments within a system; and (4) every two years for all other non-business district systems or segments within a system.

Q. ARE THERE OTHER REGULATORY COMPLIANCE ACTIVITIES THAT RESULT IN COSTS FOR TGS?

A. Yes. Pipeline integrity testing is an important activity that is a combined federal and state regulatory initiative designed to ensure the safe transportation of natural

[3] *See generally* 49 C.F.R. § 192.1001-.10015 (2020) (distribution integrity management standards).

gas by pipeline by requiring pipeline operators to regularly test the structural integrity of their gas pipelines. In Texas, the Commission has been delegated responsibility for administering and enforcing pipeline integrity requirements for intrastate pipelines and has adopted state regulations that supplement the applicable federal regulations and requirements of PHMSA. The Company's PIT program is specifically implemented to comply with these state and federal regulations that require TGS to assess its facilities at least once every seven years. Certain higher risk facilities are subject to more frequent testing. TGS assesses risks to its entire pipeline system across the state in order to determine the priority by which pipelines should be tested each year.[4] Once the risk assessment and testing schedule has been established statewide, TGS coordinates and schedules testing in an efficient and cost-effective manner. There can also be capital costs associated with testing, which are recovered in the Company's next GRIP filing or as part of test year costs in a rate case.

Q. ARE THE COSTS RELATED TO REGULATORY COMPLIANCE REASONABLE AND NECESSARY?

A. Yes, the costs are reasonable and necessary. The Company is required to incur these costs pursuant to federal and state regulations that require the Company to maintain the safety of its system.

[4] 16 Tex. Admin. Code ("TAC") §§ 8.101, 8.209 and 49 C.F.R. §§ 192.937, 192.1001.

Q. IS THE O&M EXPENSE REQUESTED FOR RECOVERY IN THIS RATE CASE REASONABLE AND NECESSARY?

A. Yes. TGS is requesting recovery of nearly $68 million of O&M expense that was incurred during the test year. Approximately $34 million of O&M expense was directly incurred within the CGSA, which Company witness Marie J. Michels also addresses in her direct testimony. Company witness Stacey R. Borgstadt also addresses the TGS Division and ONE Gas Corporate allocated O&M costs in the amount of $34 million. The test year O&M expense requested for recovery in this rate case is reasonable and necessary because it reflects costs TGS incurs to continue the safe and reliable operation of the system and to provide effective and efficient service to customers. The O&M costs in this rate case are the annual amount of costs TGS incurs for its employees, as well as TGS Division and Corporate employees, to perform the day-to-day functions necessary to operate the TGS system.

IV. CAPITAL INVESTMENT

Q. WHAT IS CAPITAL INVESTMENT?

A. Capital investment is funds TGS spends to acquire or install equipment or facilities that are used and useful to provide service and expected to be in service for an extended period of time before being replaced or retired. TGS makes ongoing capital investment in its infrastructure and other assets because doing so is necessary for the maintenance and expansion of the utility system and in order to provide safe and reliable service to our customers.

Q. PLEASE DESCRIBE TGS'S CAPITAL INVESTMENT ACTIVITIES.

A. Generally, TGS's capital investments are made to: replace pipeline facilities that have reached the end of their useful service lives; add pipeline for serving new customers; relocate pipeline facilities as required by city, county and state roadway projects; and comply with regulatory requirements.

Examples of capital investment activity include:

- In Southwest Austin, a half-mile 6" polyethylene mainline interconnect was completed along Gorman Springs Road to improve system reliability and deliverability during extreme cold weather conditions.
- In North Austin, 2,800 feet of 12" steel high pressure pipeline was replaced and upsized along Walnut Hills and Northeast Drive to improve system capacity.
- In Groves, Texas, a system reinforcement was completed on 32nd Street, from Hickory Street to Cleveland Avenue to improve the system pressure in order to increase deliverability during extremely cold weather.

Q. WHAT CAPITAL INVESTMENT IS THE COMPANY SEEKING TO RECOVER IN THIS RATE CASE?

A. TGS requests recovery of reasonable and necessary capital investment made in the CGSA since the last rate case in the amount of approximately $342 million.[5] All capital investment included in this rate case is for facilities or items that are currently used and useful in providing utility service as of the end of the test year, December 31, 2023, which Company witnesses Jeffrey J. Husen, Ms. Michels and Ms. Borgstadt address in their direct testimony.

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[5] The Company last filed a rate case with the CGSA cities and the Commission for the CGSA environs on December 20, 2019 (GUD No. 10928).

Q. PLEASE EXPLAIN THE COMPANY'S CAPITAL INVESTMENT PLANNING PROCESS.

A. The process by which TGS identifies, evaluates, prioritizes and approves capital investment projects is done on a systemwide basis for TGS rather than on an individual service area basis. ONE Gas' capital budget and procurement processes, which apply to TGS, along with managerial review and oversight, help control costs to ensure the reasonableness of the capital investment made annually to provide safe and reliable service. In addition, ONE Gas has centralized its capital project closing function to promote timeliness, accuracy and consistency in documentation.

ONE Gas' processes for capital projects are designed to ensure that every capital investment project or activity that affects the TGS system is necessary for providing safe and reliable service and reasonable in cost. Specifically, there is a dedicated ONE Gas work group that coordinates replacement activity and identifies capital projects for the TGS system. This work includes identifying potential projects utilizing a risk-based approach and prioritizing the proposed projects based on the relative risk. Additionally, annual and long-term work plans are developed by analyzing and prioritizing projects throughout the Company to maximize risk reduction under given financial, resource and regulatory constraints. For each proposed project, engineering alternatives are evaluated, the preferred course of action is selected, and average cost metrics are applied to develop and assign a cost estimate to each project. General plant expenditures are reviewed to identify and prioritize investment projects needed to maintain working equipment and structures, ensure safety, enhance efficiencies and meet regulatory requirements. Once a project has been approved, the Company's capital budgeting process includes additional cost controls to ensure that construction projects remain within funded limits. Before the work on a capital project begins, and before payments are made, required managerial approvals are obtained. TGS senior management also meets on a regular basis to review capital spending levels and make adjustments as appropriate.

Q. CAN ALL CAPITAL INVESTMENT BE PLANNED IN ADVANCE?

A. No. Based on experience, some investment needs will arise during the year that are not specifically known in advance. For example, leaks can occur on the system at any time of year, and the Company must revise budgeted amounts and allocate capital accordingly. Likewise, state, county and municipal officials submit relocation requests throughout the year. For example, when we coordinate the timing of capital projects with governmental entities, a government agency may postpone or delay a project until later in the year. The projected level of capital expenditures for these items is developed based on experience and by working with the appropriate planning departments. Growth project budgets are based on known projects and experience. TGS's investments in General Plant, like all other capital investments, are identified through Company work processes and are subject to capital funding evaluation.

Q. DO ANY ADDITIONAL FACTORS AFFECT CAPITAL INVESTMENTS?

A. Yes. Pipeline safety and system integrity requirements imposed by the federal government through statutes and regulations require significant capital investment and lead to increased operating costs. To satisfy these requirements, first and foremost, the Company invests capital to maintain and improve the safety, reliability and efficiencies of operating the system and serving customers. Aging asset replacement is also part of the Company's on-going capital investment. The Company has also implemented new technology to reduce risk, increase operational capabilities and efficiencies and improve customer service.

Q. WHAT AMOUNT OF INVESTMENT HAS BEEN MADE SINCE THE LAST CGSA RATE CASE?

A. Since the last CGSA rate case, the Company has, on a combined basis, increased its net plant in the CGSA by approximately $85 million per year, on average, or 13% per year, which totals approximately $342 million as shown below:

Annual Increases in Net Plant			
Year	**Total CGSA Net Adjusted Plant(Note 1)**	**Dollar Increase in Net Plant**	**Percentage Increase in Net Plant**
2019	$543,921,737		
2020	$633,567,416	$89,645,679	16.48%
2021	$702,344,957	$68,777,541	10.86%
2022	$791,085,271	$88,740,314	12.63%
2023	$885,503,224	$94,417,953	11.94%
	Total Increase from 2019 to 2023	$341,581,487	62.80%
	Average Increase in Net Plant between 2019 to 2023	$85,395,372	12.98%
Note 1: Plant balances include Rule 8.209 regulatory assets through December 2023.			

This investment is related to capital investment TGS has made to provide safe and reliable service by replacing aging infrastructure, responding to relocation requests, complying with regulatory requirements, accommodating growth and responding to other system needs. This amount shows that TGS continues to make necessary investment on an ongoing basis, year over year.

Q. IS THE CAPITAL INVESTMENT INCLUDED IN THE COMPANY'S RATE CASE REASONABLE AND NECESSARY?

A. Yes. Each capital investment expenditure or project must be approved through a thorough decision-making process. Each investment included in this rate case was prudent, reasonable in amount and necessary for TGS to maintain a safe and reliable system and to provide an appropriate level and quality of gas utility service to customers. This is also true for TGS Division and Corporate capital investment amounts that are allocated to the CGSA and contribute to the Company's ability to provide service in the CGSA. These capital costs are necessary for the Company's operations and are reasonable and prudent.

V. RECLASSIFICATION OF THE FORMER ONE GAS PIPELINE COMPANY LINE COSTS

Q. WHAT IS THE OPC LINE?

A. In 2019, ONE Gas acquired a pipeline from ONEOK and created an affiliate, OPC to hold the pipeline assets, which are located in the CGSA. In GUD No. 10928, TGS requested and received a finding from the Commission that the acquisition was consistent with the public interest, which the Commission approved in that case.[6] With Commission approval, at the conclusion of GUD No. 10928, the Company dissolved OPC and recorded the assets on TGS's books.

[6] GUD No. 10928, consol., Final Order at FoF No. 62-65.

Q. HOW ARE COSTS RELATED TO THE FORMER OPC LINE ("OPC ASSETS") CURRENTLY CLASSIFIED ON THE COMPANY'S BOOKS?

A. As Ms. Michels explains in her direct testimony, the costs for the former OPC Assets are currently classified as Transmission costs on TGS's books and are being moved into Distribution accounts on TGS's books.

Q. WHY IS THE COMPANY RECLASSIFYING THE FORMER OPC COSTS FROM TRANSMISSION TO DISTRIBUTION?

A. The Company is reclassifying the former OPC costs from transmission to distribution asset accounts on the books because the former OPC Assets are operated as high-pressure distribution ("HPD") pipe by TGS Operations because this HPD asset is not operated over 20% Specific Minimum Yield Strength and therefore, does not meet any of the PHMSA's definition of a transmission line. TGS accounting simply changed the classification on the Company's books from transmission to distribution to reflect the manner of TGS's actual operation of this asset.

Q. WILL THE RECLASSIFICATION OF THE FORMER OPC COSTS ON THE COMPANY'S BOOKS AND RECORDS AFFECT HOW THE COMPANY OPERATES, MAINTAINS OR TESTS THE LINE?

A. No. Operationally, nothing will change about how the Company operates, maintains or tests the former OPC Assets.

VI. PIPELINE INTEGRITY TESTING PROGRAM

Q. WHAT IS THE PIPELINE INTEGRITY TESTING PROGRAM, AND WHAT AGENCIES ARE RESPONSIBLE FOR ITS ADMINISTRATION?

A. Pipeline integrity testing is a combined federal and state regulatory initiative designed to ensure the safe transportation of natural gas by requiring pipeline operators to regularly test the structural integrity of their gas pipelines. It is part of a broader national regulatory program implemented by the Office of Pipeline Safety ("OPS") within PHMSA to ensure the safe transportation of natural gas, petroleum and other hazardous materials. These regulations are found in 49 CFR Part 192, Subpart O. The OPS works in partnership with the Commission and its counterparts in other states to achieve the program's public safety objectives. In Texas, the Commission has been delegated responsibility for administering and enforcing pipeline integrity requirements for intrastate pipelines and, to that end, has adopted state regulations that supplement the applicable regulations and requirements of PHMSA. The Company's pipeline integrity testing program is specifically implemented to comply with these state and federal regulations.

Q. WHEN DID TGS FIRST IMPLEMENT ITS PIPELINE INTEGRITY TESTING PROGRAM?

A. The initial testing began in 2003. Under the program, TGS tested all transmission facilities subject to the regulations as part of a Baseline Assessment over a ten-year period. Since that Baseline Assessment was conducted, TGS is required to reassess its facilities at least once every seven years, with certain higher risk facilities subjected to more frequent testing. The Company has 11.64 miles of gas transmission mains in the CGSA subject to this integrity testing.

Q. DOES THE COMPANY TEST ROUGHLY THE SAME LENGTH OF PIPELINES EACH YEAR TO MEET THE PROGRAM'S REQUIREMENTS?

A. No, it does not. Pursuant to state and federal regulations, the Company must assess risks to its entire pipeline across the state to determine the priority by which pipelines should be tested each year.[7] Once the risk assessment and testing schedule has been established statewide, TGS coordinates and schedules testing in the most efficient and cost-effective manner possible. Accordingly, the miles of pipe tested and the associated level of expense in each year may vary. Ms. Michels discusses the Company's proposal to account for and recover these necessary expenses through a rider, which the Commission approved in Docket Nos. OS-22-00009896 ("Docket No. 9896") and Docket No. 14399.

Q. ARE PIPELINE INTEGRITY TESTING COSTS REASONABLE AND NECESSARY?

A. Yes, they are reasonable and necessary. The Company is required to incur these costs pursuant to federal and state regulations that require the Company to regularly test its pipelines. The Company only seeks to recover the actual costs it incurs in meeting the requirements of the pipeline integrity testing program. Moreover, given the nature and focus of this important safety initiative, it is important that the Company recover those costs on a timely basis. Ms. Michels explains why it is appropriate to use a PIT rider to recover these reasonable and necessary O&M costs that TGS must incur to comply with applicable regulations.

[7] 16 TAC §§ 8.101, 8.209 and 49 C.F.R. §§ 192.937,192.1001.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE COMPANY'S REQUEST TO RECOVER PIT EXPENSES?

A. Yes. Recently, in Docket No. 14399, the Commission approved TGS's request to recover all of its requested PIT expenses through a separate rider.[8] As Ms. Michels notes in her direct testimony, the Commission also approved PIT Riders in TGS rate cases in GUD Nos. 9988, 10506, 10526, 10656, 10739, 10928 and Docket No. 9896.

VII. ISSUES THAT AFFECT TGS OPERATIONS

Q. ARE THERE ANY RECENT ISSUES THAT HAVE AFFECTED THE COMPANY'S OPERATIONS AND ITS SYSTEM?

A. Yes. The Company provided safe and reliable natural gas throughout 2020 and 2021 under unprecedented conditions, including COVID-19, Winter Storm Uri, changing economic factors and a competitive labor market. Specifically, on March 13, 2020, the Governor of Texas declared a State of Disaster in all Texas counties related to COVID-19, which affected TGS's operations in 2020, 2021 and continues to do so through supply chain and labor market conditions I describe later in my testimony. Likewise, a national emergency was declared on March 13, 2020, due to COVID-19 on a federal level.[9] In addition, on February 12, 2021, the Governor of Texas declared a State of Disaster in Texas for all Texas counties in response to the unprecedented winter weather event known as Winter Storm Uri.

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[8] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order at FoF No. 40 (Jan. 30, 2024).

[9] Declaring a National Emergency Concerning the Novel Coronavirus Disease (COVID-19) Outbreak, Proclamation 9994 of March 13, 2020, 85 Fed. Reg. 15337 (Mar. 18, 2020); Continuation of the National Emergency Concerning the Coronavirus Disease 2019 (COVID-19) Pandemic (Notice of February 18, 2022), 87 Fed. Reg. 10289 (Feb. 23, 2022).

Similarly, on February 14, 2021, a major disaster declaration was issued on a federal level due to Winter Storm Uri.[10] These major events, in addition to economic and labor market issues, affected the Company's operations and required TGS to incur costs that are included in this rate case.

Q. WHAT COSTS DID TGS INCUR RELATED TO COVID-19 THAT ARE INCLUDED IN THIS RATE CASE?

A. TGS incurred COVID-19 costs as a result of the implementation of protocols to ensure that employees, whose work was essential to provide and maintain service, could safely continue their day-to-day tasks in the midst of the pandemic. The protocols included infection prevention measures and modifications across operating areas to reduce employee risk of exposure to COVID-19. These measures aligned with the guidance provided by the Centers for Disease Control and Prevention ("CDC"). More specifically, the COVID-19 related costs in this filing include:

- Increased cleaning and disinfecting services on high-contact touchpoints across all facilities to ensure employees and customers were as safe as possible. The cleaning and disinfecting services included cleaning and disinfecting elevators and elevator buttons, spray down of offices, desks, chairs, equipment, tools and any other items employees touched or used.
- Air purifying systems were installed in each HVAC unit in all populated facilities to maintain air quality and remove bacteria. Additionally, all air filters have been updated and upgraded where applicable and were changed monthly in all facilities where personnel work instead of quarterly which was the practice prior to COVID-19.
- Disinfecting or cleaning supplies and hand sanitizer were provided to all operational employees.

[10] President Joseph R. Biden, Jr. Approves Texas Emergency Declaration | The White House (Feb. 14, 2021).

- Safe work supplies were available at every facility entrance and throughout seating areas including masks, gloves, hand sanitizer and spray disinfectant.

Q. PLEASE EXPLAIN HOW COVID-19 AFFECTED OPERATIONS AND THE MEASURES TGS TOOK TO CONTINUE TO PROVIDE SERVICE TO CUSTOMERS.

A. TGS Operations were significantly affected by COVID-19. More specifically, TGS implemented a safety plan regarding the manner in which its essential employees operate when interacting with each other and customers. In that regard, TGS implemented a Field Operation Activities Per COVID-19 Response Level Chart (provided as Exhibit AL-3) that details which field operational activities can be performed depending on the current COVID-19 environment. TGS implemented these new protocols to better protect its employees and the communities it serves. COVID-19 also caused contract labor shortages, delayed delivery times, lower quantities of necessary materials and supplies and fleet vehicle shortages.

Further, the Company required all employees who were able to work from home to do so in accordance with state and local orders issued in mid-March 2020. TGS also formed an internal COVID-19 task force to address safety measures required for continued operations. The added safety measures include a significant increase in personal protective equipment, which ranges from masks and gloves to sanitizing spray and additional cleaning of facilities and vehicles where necessary. TGS has closely followed the guidelines recommended by the CDC and Occupational Safety and Health Administration.

Q. PLEASE DESCRIBE THE MATERIAL SUPPLY CHAIN CONDITIONS AND HOW THEY AFFECTED TGS OPERATIONS.

A. After the onset of COVID-19, many of our suppliers had to shut down material production lines due to lack of labor, raw materials, or both. However, demand for those materials never subsided. This created immediate backlogs for materials. For example, materials that traditionally had a 10-week lead time (time from order until delivery) now had over a six-month lead time. Despite the challenges we faced, the Company was able to leverage long-term relationships built over decades to keep our orders for materials a priority and identify new suppliers. Additionally, ONE Gas shared materials among its divisions at a higher rate than ever. For example, if TGS was out of a certain material but Kansas Gas Service had it in storage in Topeka, Kansas, we made that transfer to TGS.

Q. WHAT COSTS DID THE COMPANY INCUR RELATED TO COVID THAT ARE INCLUDED IN THIS RATE CASE?

A. The costs included in the COVID-19 regulatory asset, include, among other items, the purchase of safety materials and equipment necessary to increase sanitation and to provide additional separation between employees.

Q. WHAT COSTS DID THE COMPANY INCUR RELATED TO WINTER STORM URI THAT ARE INCLUDED IN THIS RATE CASE?

A. The costs included in the Winter Storm Uri regulatory asset include costs for direct service area overtime labor, supplies and expenses and financing costs, as well as a portion of short-term incentive compensation and amounts for employee recognition awards for extraordinary performance during the winter storm. The Company's extraordinary gas costs related to Winter Storm Uri were previously approved as a regulatory asset in Docket No. OS-21-00007061 and approved for recovery through the Commission's securitization process. Accordingly, those extraordinary gas costs are not included in the regulatory asset for which the Company seeks approval in this case.

Q. PLEASE BRIEFLY EXPLAIN HOW THE COMPANY RESPONDED TO WINTER STORM URI AND THE ACTIONS TGS TOOK TO MAINTAIN SERVICE.

A. In the midst of unprecedented weather conditions, TGS's priority was maintaining service to human needs customers. To do so, employees across ONE Gas and TGS worked tirelessly and collaborated on a daily (and sometimes hourly) basis including ONE Gas management, Operations, Engineering, Gas Supply, Communications, Rates and Regulatory and Legal. During the storm, TGS maintained service to 99.9% of its residential customers throughout the state.

At the local levels, field technicians were deployed to locations throughout Texas to physically monitor critical equipment and address system constraints identified by Engineering. In the CGSA, field technicians were dispatched to assess and evaluate the major upstream supply stations. Fortunately, no major issues were found during the initial evaluations and field technicians continued to monitor pressures remotely during the storm. Expenses for the employees needed to monitor the situation and remedy issues as they arose are included in the regulatory asset as discussed in the direct testimony of Company witness Stacey L. McTaggart.

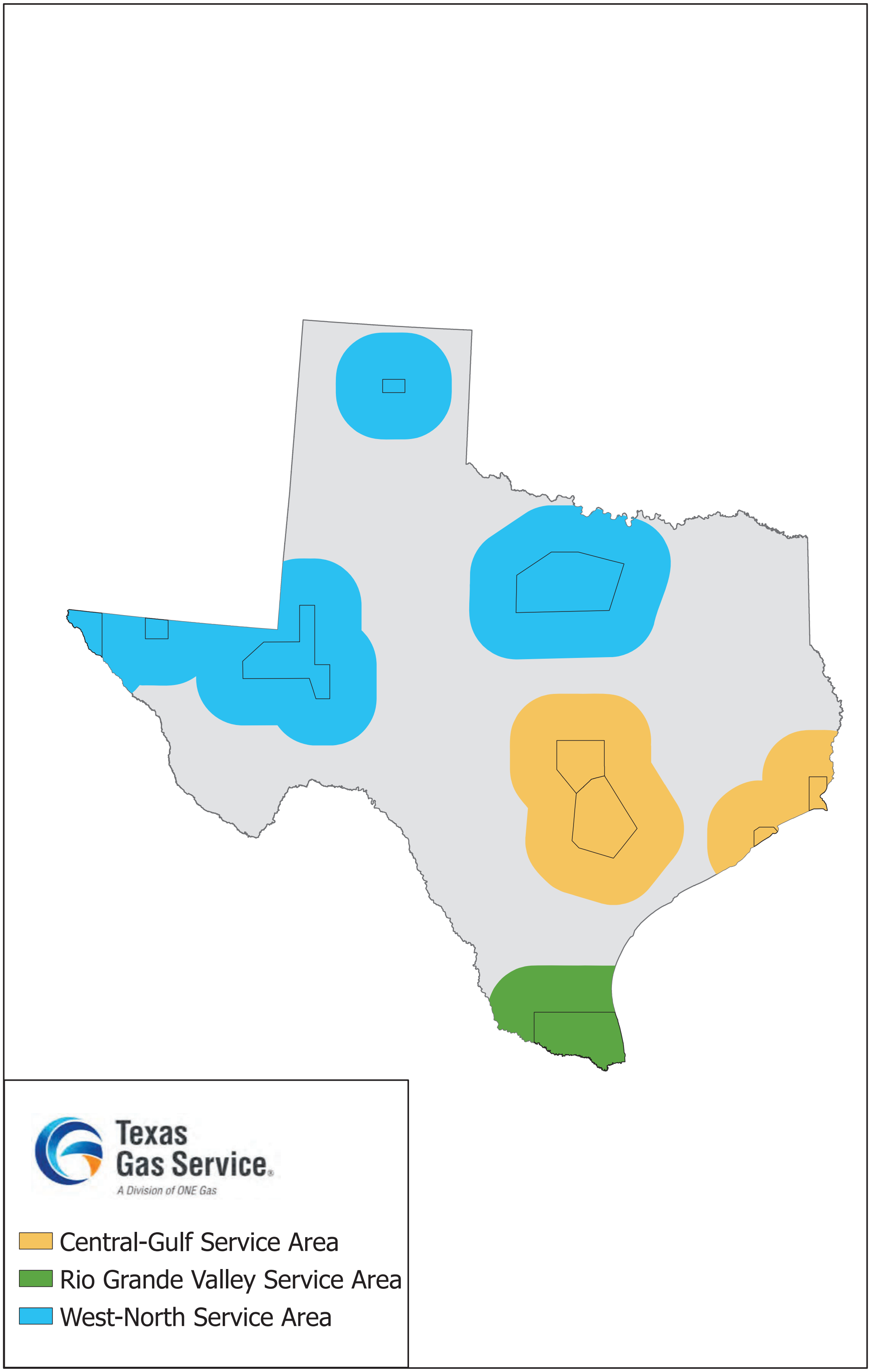
Q. PLEASE DESCRIBE THE LABOR MARKET CONDITIONS THAT HAVE AFFECTED TGS OPERATIONS.

A. TGS employs qualified, experienced and skilled operations employees to ensure that it provides safe and reliable service. As Company witness Megan Z. Gough testifies, due to recent market conditions, a tight labor force and rising labor costs, TGS faces competition for employees from other industries. TGS pays a reasonable salary but cannot always compete with the salaries being offered by other employers. TGS must also invest in necessary training for new employees. For example, it can take six months to train a field technician before they are qualified to actually perform work on the system. There have been instances when TGS loses that newly trained employee to a better job opportunity, and TGS must start the hiring and training process over again. TGS also utilizes contract labor. In recent years, contractor costs have increased as the demand for contract labor has risen. Nevertheless, TGS must continue to directly employ qualified personnel or hire qualified contractors to perform work required to operate and maintain the system in a safe and reliable manner.

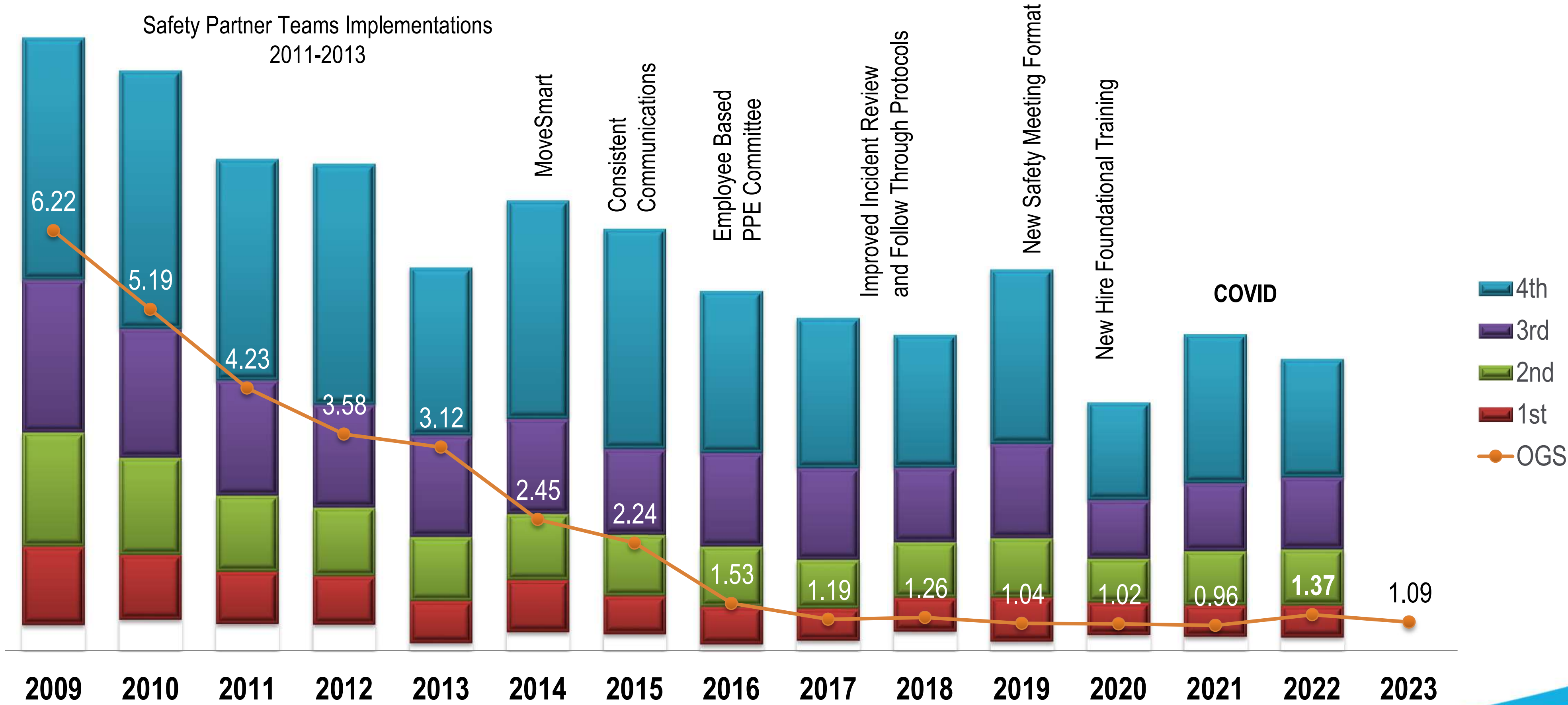
VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

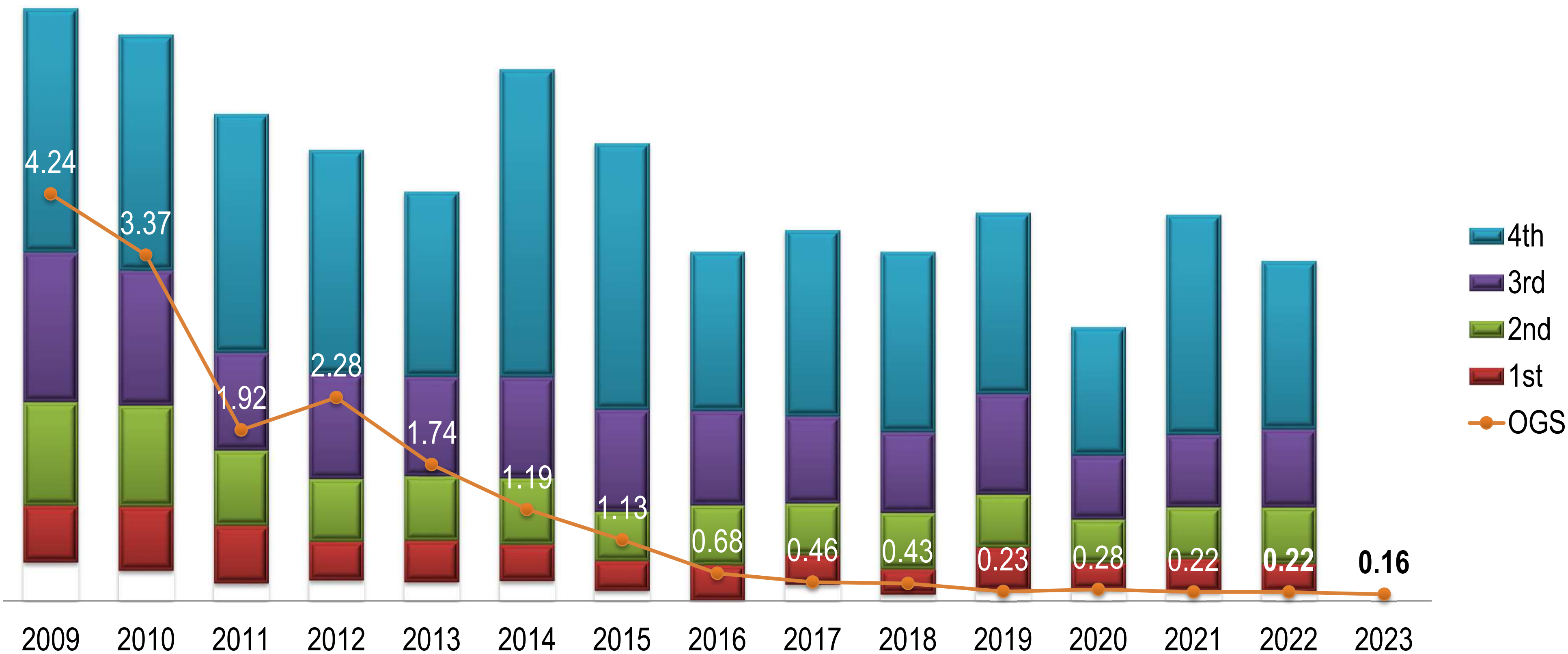
A. Yes, it does.


Texas Gas Service
A Division of ONE Gas
Central-Gulf Service Area
Rio Grande Valley Service Area
West-North Service Area

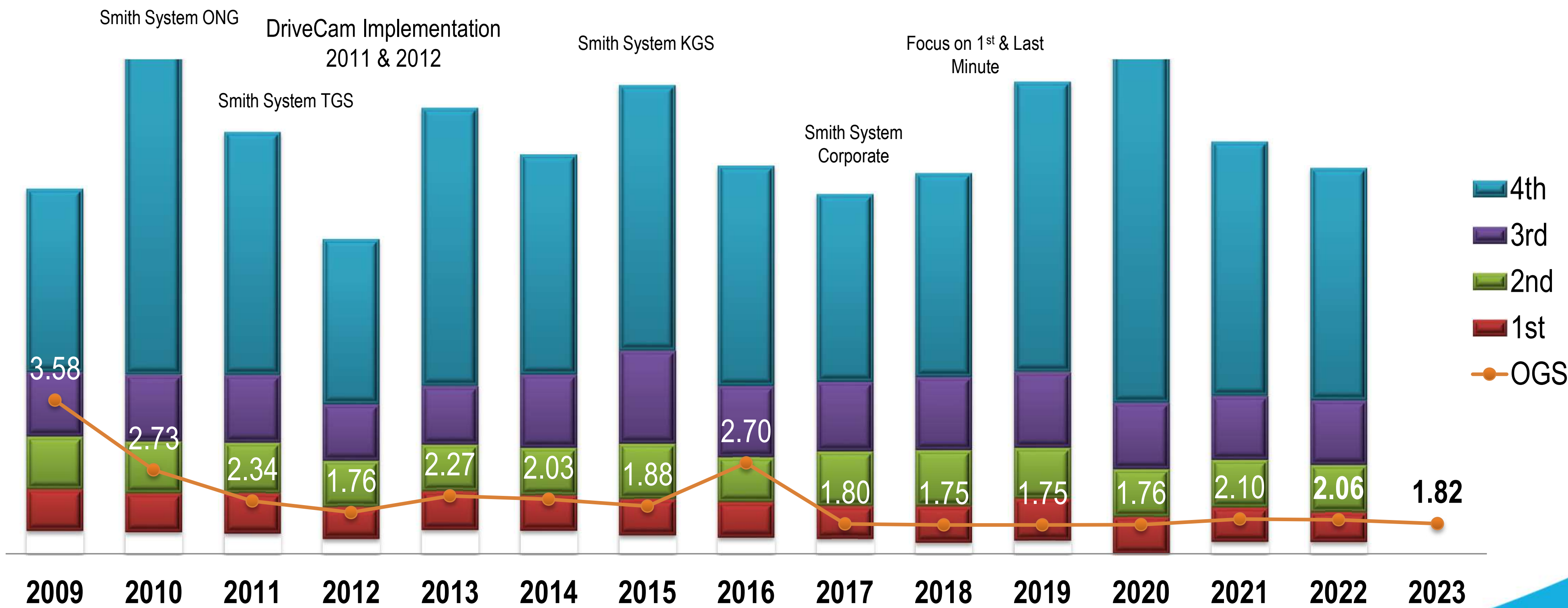
TRIR Historical Performance & Supporting Programs



DART Historical Performance



PVIR Historical Performance & Supporting Programs



ONE Gas

Field Operation Activities Per COVID-19 Response Level

Activities with an X will continue. Items with an X and * are subject to resource constraints.

In Levels 2 and 3, activities without an X **can be done still if**:

- They don't conflict with a higher level (e.g., you can do Rebuilds in Level 3, but we specifically state to do Rebuilds only without service disruption in Level 2).
- The work does not create a discretionary service disruption (service tie-overs from existing main).
- We have adequate resources (e.g., if we have personnel still available, we keep working our government relocation projects, but will stop if we need to dedicate those people to higher priority work).

In Level 1, items without an X cannot be done without VPO approval.

Field Operations Activities	Level 5 (lowest)	Level 4	Level 3	Level 2	Level 1 (highest)
Gas Control	X	X	X	X	X
Gas Supply	X	X	X	X	X
Dispatch	X	X	X	X	X
Emergencies	X	X	X	X	X
Leak Repair (Grade I)	X	X	X	X	X
Compliance	X	X	X	X	X*
Turn-ons /New Sets /Reconnects of critical facilities/outages)	X	X	X	X	X**
Turn-ons	X	X	X	X*	
Reconnects	X	X	X	X*	
New Sets (Builder only non-contact)	X	X	X	X*	
Integrity Management	X	X	X	X*	
Leak Repair (Grade II & III)	X	X	X	X	
Line Extensions	X	X	X	X	
New Services	X	X	X	X	
Reinforcements (w/o service disruption)	X	X	X	X	
Rebuilds (w/o service disruption)	X	X	X	X	
Collections	X	X	X		
Completion of Projects	X	X	X		
Reinforcement Projects	X	X	X		
Rebuilds	X	X	X		
Relocation Projects	X	X	X		
New sets	X	X	X		
Service Kills	X	X*			
Abandonments	X	X*			

X indicates work to be completed at the level.

* As resources allow

** Requires VPO or designee approval

Updated Aug. 11, 2021

STATE OF TEXAS §
§
COUNTY OF BELL §

AFFIDAVIT OF ALEJANDRO LIMÓN

BEFORE ME, the undersigned authority, on this day personally appeared Alejandro Limón who having been placed under oath by me did depose as follows:

1. "My name is Alejandro Limón. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Vice-President of Operations for Texas Gas Service Company, a division of ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

DocuSigned by:
Alejandro Limon
53E52FBABB19462...

Alejandro Limón

SUBSCRIBED AND SWORN TO BEFORE ME by the said Alejandro Limón on this 22nd day of May 2024.

DocuSigned by:
ERLINDA ALVARADO
683FDA66B5FD4C2...

Notary Public in and for the State of Texas

NOTARY PUBLIC STATE OF TEXAS
ERLINDA ALVARADO
Notary ID
13393510-7
My Commission Expires
8/29/2026

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

MARIE J. MICHELS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF MARIE J. MICHELS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Marie J. Michels, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Manager of Rates and Regulatory for Texas Gas Service Company ("TGS" or the "Company"), a Division of ONE Gas, Inc. ("ONE Gas"). My responsibilities include the review and analysis of Company financial data, preparation of and participation in rate cases and other regulatory filings, and related activities for TGS.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration degree in Accounting from Texas State University in 2005 and a Master's in Business Administration from Texas State University in 2010. I joined TGS as a Budget Analyst in 2006, and over the following twelve years, I went on to fulfill various roles of increasing responsibility within the Company including Gas Supply Analyst, Senior Accountant and Financial Planning Analyst. In April 2018, I began my current position as a Manager of Rates and Regulatory.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I have prepared and sponsor the exhibits as detailed in the table of contents.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, they were.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the following issues in this rate case:

a. Compliance with certain Railroad Commission of Texas ("Commission") rules and statutory requirements, including affiliate cost recovery issues related to Utility Insurance Company ("UIC");

b. Support the Direct costs attributed to the Central-Gulf Service Area ("CGSA") in the Company's cost of service calculation that demonstrate the Company's need for a rate change in the CGSA. I also describe the portion of the Company's requested rate base amounts related to CGSA Direct costs;

c. Support the Company's recovery of Pipeline Integrity Testing ("PIT") costs;

d. Support the Company's recovery of rate case expenses; and

e. Describe the rate schedules and tariffs currently in effect for the CGSA and describe the proposed rate schedules and tariffs that TGS is requesting the Commission approve in this case, including discontinuance of the EDIT Rider and an adjustment to include Excess Deferred Income Taxes ("EDIT") in base rates.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following schedules:

RATE BASE:	
Schedule A Revenue Requirement	Sponsoring
Schedule B Rate Base	Co-Sponsor with Stacey R. Borgstadt
Schedule B-1 M&S	Sponsoring
Schedule B-2 Prepayments	Co-Sponsor with Stacey R. Borgstadt

RATE BASE:	
Schedule B-3 8.209 Reg Asset	Co-Sponsor with Stacey L. McTaggart
Schedule B-4 Pens-OPEB Reg Asset	Sponsoring
Schedule B-5 Prepaid Pension Asset	Co-Sponsor with Cyndi L. King
Schedule B-6 CWC	Co-Sponsor with Timothy S. Lyons
Schedule B-7 Deposits	Sponsoring
Schedule B-8 Advances	Sponsoring
Schedule B-9 ADIT	Co-Sponsor with Janet M. Simpson
Schedule B-10 EDIT	Co-Sponsor with Kenneth E. Eakens, & Stacey L. McTaggart
Schedule B-11 Regulatory Assets	Co-Sponsor with Stacey L. McTaggart
Schedule C Plant	Co-Sponsor with Stacey R. Borgstadt
Schedule C-1 CCNC	Co-Sponsor with Stacey R. Borgstadt
Schedule D Reserves	Co-Sponsor with Stacey R. Borgstadt
Schedule F Federal Income Tax	Sponsoring

OPERATING INCOME:	
Schedule G Summary of Operating Revenue & Expense Adj	Co-Sponsor with Zane M. Drummond & Stacey R. Borgstadt
Schedule G-7 Amortization of Pension and Other Post Employment Benefits	Sponsoring
Schedule G-9 Miscellaneous Adjustments	Co-Sponsor with Stacey R. Borgstadt
Schedule G-10 Rents	Co-Sponsor with Stacey R. Borgstadt
Schedule G-11 Interest on Customer Deposits	Sponsoring
Schedule G-12 Uncollectible Expense	Sponsoring
Schedule G-14 Advertising Expense	Co-Sponsor with Stacey R. Borgstadt
Schedule G-15 Depreciation & Amortization	Co-Sponsor with Stacey R Borgstadt
Schedule G-16 Ad Valorem Tax Expense	Sponsoring
Schedule G-17 Texas Franchise Tax Expense	Sponsoring
Schedule G-18 Stores Load	Sponsoring
Schedule G-19 TWE Load	Sponsoring
Schedule G-20 Regulatory Asset Amortization	Co-Sponsor with Stacey L. McTaggart
Schedule G-23 PIT	Sponsoring

RATE BASE:	
Schedule G-24 EDIT	Co-Sponsor with Kenneth E. Eakens, & Stacey L. McTaggart

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q. ARE YOU SPONSORING ALL OF THE SCHEDULES REFERENCED IN YOUR TESTIMONY?

A. No, I am not. There are some schedules that I address below that are adjacent to adjustments in my testimony that are sponsored by other witnesses.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony on behalf of TGS before this Commission in Gas Utilities Docket ("GUD") No. 10928.

II. CURRENT RATE SCHEDULES

Q. WHEN WAS THE LAST STATEMENT OF INTENT TO CHANGE BASE RATES FILED IN THE CGSA?

A. On December 20, 2019, TGS filed a Statement of Intent ("SOI"), docketed as GUD No. 10928, requesting to consolidate the incorporated and unincorporated areas of the then-existing Central Texas Service Area ("CTSA"), Gulf Coast Service Area ("GCSA") and the City of Beaumont, as well as to increase rates with each city within the CTSA and GCSA that have original jurisdiction and with the City of Beaumont. The CTSA and GCSA Cities intervened in the case at the Commission, and a Unanimous Settlement Agreement was entered into by and between TGS, Staff of the Commission, TGS CTSA Cities and TGS GCSA Cities and the GCSA Steering Committees. The Commission approved the settlement agreement on August 4, 2020, and approved the Company's request to combine the then-existing service areas to create the CGSA.

Q. HAS THE COMPANY FILED INTERIM RATE ADJUSTMENTS IN THE CGSA?

A. Yes. Pursuant to the Gas Utility Regulatory Act ("GURA") § 104.301 and Commission Rule 7.7101 (the "GRIP rule"), the Company filed the following Interim Rate Adjustments ("IRAs") within the CGSA incorporated and environs areas:

IRA Filing Date	Case No. for Environs Filing	Plant Investment Period	Environs Interim Order Issue Date
February 11, 2021	00005813	January 1 to December 31, 2020	June 8, 2021
February 10, 2022	00008748	January 1 to December 31, 2021	May 18, 2022
February 9, 2023	00012592	January 1 to December 31, 2022	May 17, 2023
February 9, 2024	00016275	January 1 to December 31, 2023	May 14, 2024

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE CGSA ENVIRONS?

A. As shown in Exhibit MJM-1, the rates in effect for customers in the CGSA environs are the base rates approved in GUD No. 10928 and the IRAs addressed above.

Q. HAS THE COMPANY REQUESTED RATE CHANGES WITH THE CGSA CITIES SINCE THE SOI IN 2019?

A. Yes. The Company has filed the same annual IRAs with the CGSA Cities that were filed with the Commission for environs customers.

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE CGSA INCORPORATED AREAS?

A. As shown in Exhibit MJM-1, the rates in effect for customers in the CGSA incorporated areas are the same rates that are in effect for customers in the environs, which are base rates approved in GUD No. 10928 and the IRAs addressed above.

III. COMPLIANCE WITH COMMISSION RULES AND AFFILIATE STANDARD

A. Commission Rules 7.310 and 7.503

Q. PLEASE SUMMARIZE HOW THE BOOKS AND RECORDS OF TGS ARE MAINTAINED AND UTILIZED IN THE REGULAR COURSE OF BUSINESS.

A. TGS maintains its books and records in accordance with Commission Rule 7.310, which requires that the Company keep its books in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), as supplemented by Commission order or State law.[1] The FERC USOA is prescribed by the FERC for public utilities and licensees subject to the provisions of the Federal Power Act. FERC prescribes accounting classifications and guidance by which public utilities achieve uniform accounting records for use in financial reporting, ratemaking and other regulatory needs. These regulations are found and defined in the Code of Federal Regulations 18 - Conservation of Power and Water Resources, Subchapter F - Accounts, Natural Gas Accounts, Part 201 - Uniform System of Accounts.

[1] *See* 16 Texas Administrative Code ("TAC") § 7.310.

Q. HOW DOES THE COMPANY ENSURE THAT TRANSACTIONS ARE PROPERLY RECORDED?

A. To provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, ONE Gas and TGS maintain a system of internal controls. The internal control process includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and the FERC USOA, as modified, and that our receipts and expenditures are being made only in accordance with authorizations of management and our board of directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Subsequent to the filing of the ONE Gas Form 10-K, ONE Gas reported in its Quarterly reports on Form 10-Q in 2024 that its Chief Executive Officer and Chief Financial Officer have concluded that ONE Gas' disclosure controls and procedures were effective as of the end of the periods covered by these reports based on the evaluation of the controls and procedures required by Rules 13(a)-15(b) of the Securities Exchange Act of 1934, as amended. There have been no changes in ONE Gas' internal controls over financial reporting since then that have materially affected, or are reasonably likely to materially affect, its internal controls over financial reporting.

Q. ARE THE ONE GAS BOOKS AND RECORDS SUBJECT TO AUDIT?

A. Yes, as a publicly traded company, ONE Gas is responsible for the fair presentation of its consolidated financial statements and is required to establish and maintain disclosure controls and procedures and internal controls over financial reporting. In connection with these requirements, ONE Gas must evaluate the effectiveness of its disclosure controls and procedures and internal controls over financial reporting and present a report in its Form 10-K filed with the Securities and Exchange Commission ("SEC") on its conclusions about the effectiveness of these controls, as of the end of the period covered by the financial statements. ONE Gas' evaluation of the effectiveness of our internal control over financial reporting is based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In connection with the evaluation, ONE Gas' Internal Audit Department annually reviews the design and tests the operating effectiveness of the Company's internal controls over financial reporting. The Company's most recent report is included as part of ONE Gas' Annual Report on Form 10-K filed with the SEC on February 22, 2024. The report concluded that our disclosure controls and procedures and our internal control over financial reporting were effective at December 31, 2023.[2] In addition to the evaluation of the Company's internal controls over financial reporting, ONE Gas' Internal Audit Department regularly performs audits of the control systems, processes and procedures utilized by the Company throughout its operations and business processes.

[2] *See* ONE Gas Form 10-K for the fiscal year ended December 31, 2023 at 39 (Item 8) (Feb. 22, 2024).

The independent public accounting firm of PricewaterhouseCoopers L.L.P. ("PWC") performs an integrated audit of the books and records of ONE Gas and ONE Gas' internal controls over financial reporting. The objective of these audits is to express an opinion as to whether the financial statements are free of material misstatements and whether effective internal control over financial reporting was maintained in all material respects. The most recent audit report is included with the ONE Gas financial statements filed with the SEC as part of ONE Gas' Annual Report on Form 10-K on February 22, 2024. In addition, the Company's Distribution Annual Report is reviewed by the Commission annually.

Q. WHAT WERE THE RESULTS OF THE PWC REPORT INCLUDED AS PART OF ONE GAS' ANNUAL REPORT ON FORM 10-K?

A. The report expressed an opinion that the ONE Gas financial statements were fairly presented, "in all material respects . . . in conformity with accounting principles generally accepted in the United States of America. . . . [ONE Gas] maintained, in all material respects, effective internal control over financial reporting at December 31, 2023, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO."[3]

Q. PLEASE EXPLAIN THE PRESUMPTION PROVIDED IN COMMISSION RULE 7.503.

A. Commission Rule 7.503 grants gas utilities in any proceeding before the Commission the presumption of reasonableness when the amounts kept on its books and records are kept in accordance with Commission rules.[4]

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[3] *See id.*
[4] *See* 16 TAC § 7.503.

Q. IN YOUR OPINION, DOES THE INFORMATION CONTAINED WITHIN THE COMPANY'S BOOKS AND RECORDS, AS WELL AS THE SUMMARIES AND EXCERPTS THEREFROM, QUALIFY FOR THE PRESUMPTION SET FORTH IN COMMISSION RULE 7.503?

A. Yes, it does. As I have testified, the Company's system of internal controls and its adherence to the FERC USOA, as modified, fully comply with Commission Rule 7.503. Accordingly, the Company is entitled to the presumption that costs contained within the books and records have been reasonably and necessarily incurred.

B. Commission Rule 7.501

Q. ARE YOU FAMILIAR WITH THE REQUIREMENTS OF COMMISSION RULE 7.501?

A. Yes, I am. Commission Rule 7.501 requires the separation of evidence related to certain types of financial transactions in a rate proceeding, and in some cases, exclusion of these costs from rates. These types of transactions include legislative advocacy expenses, business gifts, entertainment, charitable or civic contributions and certain advertising expenses. They also include any profits or losses resulting from the sale or lease of appliances, fixtures, equipment or other merchandise.

Q. DO THE OPERATING EXPENSES REPORTED IN THE SCHEDULES ATTACHED TO THIS FILING INCLUDE ANY OF THESE EXPENSES?

A. No, they do not. To the extent that expense accounts relate to items that must be excluded from the cost of service, those accounts have been excluded in their entirety from the test year expense shown on Schedule G (Summary of Operating Revenue & Expense Adjustments), column (a). To the extent disallowable items were included in the test year data in other accounts that are included on Schedule G, column (a), an adjustment has been made to Schedule G-9 (Miscellaneous Adjustments) to remove these items from the cost of service.

Q. PLEASE STATE THE AMOUNT OF PROFITS OR LOSSES FROM MERCHANDISING ACTIVITIES, AS REQUIRED BY COMMISSION RULE 7.501(1).

A. The Company has not incurred profits or losses from merchandising activities in the CGSA, and no such profits or losses are included in the Company's cost of service.

Q. PLEASE STATE THE AMOUNT OF INCOME TAX SAVINGS OR DEFERRALS, AS REQUIRED BY COMMISSION RULE 7.501(2).

A. The amount of accumulated deferred income taxes ("ADIT") applicable to the CGSA is $(79,319,324) as shown on Schedule B-9 (ADIT) and discussed in the direct testimony of Company witness Janet M. Simpson.

Q. PLEASE STATE THE AMOUNT OF INVESTMENT TAX CREDIT AMORTIZATION, AS REQUIRED BY COMMISSION RULE 7.501(3).

A. The amount of investment tax credit amortization applicable to the CGSA is $0.

Q. PLEASE STATE THE AMOUNT OF LOBBYING AND LEGISLATIVE ADVOCACY EXPENSE, AS REQUIRED BY COMMISSION RULES 7.501(4) AND 7.501(5).

A. No lobbying, legislative advocacy or related advertising expenses are included in the Company's cost of service.

Q. PLEASE STATE THE AMOUNT OF BUSINESS GIFT, ENTERTAINMENT AND CHARITABLE OR CIVIC CONTRIBUTIONS, AS REQUIRED BY COMMISSION RULE 7.501(6).

A. No business gift, entertainment, charitable or civic contributions are included in the Company's cost of service.

C. Commission Rule 7.5414

Q. PLEASE BRIEFLY EXPLAIN COMMISSION RULE 7.5414.

A. This rule governs what expenses for advertising, contributions and donations are recoverable in the utility's cost of service. Rule 7.5414 states that actual expenditures for advertising will be allowed as a cost of service item for ratemaking purposes, provided that the total sum of such expenditures shall not exceed one-half of 1% of the gross receipts of the utility for utility services rendered to the public.

Q. WHAT LEVEL OF EXPENSE FOR ADVERTISING IS INCLUDED IN THE REQUESTED COST OF SERVICE?

A. The actual advertising expense included in this filing represents only 0.052% of gross receipts. Specifically, Schedule G-14 (Advertising Expense) shows that the Company's cost of service for the CGSA includes $150,493 for advertising expenses during the test year.

Q. DOES THE LEVEL OF ADVERTISING EXPENSE INCLUDED IN THE ATTACHED SCHEDULES COMPLY WITH COMMISSION RULE 7.5414?

A. Yes, it does. The advertising expense included in the Company's cost of service is below the permissible limit and therefore allowable in accordance with the rule.

D. Statutory Affiliate Standard

Q. PLEASE DESCRIBE THE COMMISSION'S AFFILIATE STANDARD.

A. Under GURA § 104.055(b), the Commission "may not allow a gas utility's payment to an affiliate for the cost of a service, property, right or other item or for an interest expense to be included as capital cost or as expense related to gas utility service except to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the regulatory authority." Accordingly, the Commission must make "(1) a specific finding of the reasonableness and necessity of each item or class of items allowed and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person for the same item or class of items."

Q ARE THERE ANY ONE GAS AFFILIATE COSTS IN THIS FILING?

A. Yes. TGS is requesting recovery of affiliate costs from UIC.

Q. PLEASE DESCRIBE THE COMMISSION'S TREATMENT OF THE ALLOCATED ONE GAS AFFILIATE COSTS INCLUDED IN TGS'S FILINGS.

A. The only affiliate costs incurred by ONE Gas, allocated to TGS and approved by the Commission are those related to the captive insurance company, UIC, and have been included in TGS rate cases since 2017. The direct testimony of Company witness Jaime D. Shelton provides a detailed explanation of UIC, and the direct testimony of Company witness Stacey R. Borgstadt supports the schedules that reflect TGS's test year UIC costs.

Q. HAS THE COMPANY MET THE AFFILIATE STANDARD FOR THE COSTS PAID TO UIC?

A. Yes. The costs included in the cost of service for insurance provided to TGS by UIC are reasonable and necessary. As described by Ms. Shelton, it is necessary for TGS and ONE Gas to maintain insurance coverage, and the premiums charged by UIC are developed according to a risk-based methodology common to the insurance industry that results in a reasonable amount of insurance costs. As Ms. Shelton's direct testimony indicates, the rates charged by UIC to the Divisions of ONE Gas are developed according to the same methodology for each Division. Thus, adjusted for risk, the price charged to TGS is not higher than that charged to other affiliates or divisions. UIC does not provide insurance to any non-affiliated parties.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE COMPANY'S REQUESTS FOR RECOVERY OF THIS AFFILIATE COST?

A. Yes. TGS has requested recovery of UIC affiliate costs in GUD No. 10928, and Commission Docket No. OS-23-00014399 ("Docket No. 14399"), which were resolved through settlement agreements and approved by the Commission. The Commission also recently approved TGS's request to recover UIC affiliate costs in Commission Docket No. OS-22-00009896 ("Docket No. 9896"), a case that was fully litigated.[5]

[5] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at Finding of Fact ("FoF") No. 77 (Jan. 18, 2023); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order at FoF No. 42 (Jan. 30, 2024).

IV. OVERVIEW OF COST OF SERVICE CALCULATION

Q. HOW DID THE COMPANY CALCULATE THE REQUESTED RATES FOR THE CGSA?

A. In calculating the requested rates, the Company used the cost of providing service to the entire CGSA so that rates within each customer class in the incorporated and unincorporated areas will be consistent across the entire service area. Exhibit G to the SOI contains the cost of service schedules that, taken together, show the calculation of the Company's revenue requirement in the CGSA. The Company's methodology in this SOI for determining the total cost of service, including the component parts I address below, and resulting rate recovery request is consistent with the methodology the Company has used in prior SOIs.[6]

Q. WHAT TEST YEAR DID TGS USE TO CALCULATE THE REVENUE REQUIREMENT FOR THIS SOI?

A. The Company calculated its revenue requirement based on the twelve-month period ending December 31, 2023, with adjustments for some known and measurable

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[6] *See e.g.*, *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA),* GUD No. 10488, Final Order (May 3, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA),* GUD No. 10506 consol., Final Order (Sept. 27, 2016); *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and the Gulf Coast Service Area*, GUD No. 10928 consol., Final Order (Aug. 4, 2020); Docket No. OS-22-00009896, consol., Final Order; and Docket No. OS-23-00014399, consol., Final Order.

changes as discussed in my testimony, Ms. Borgstadt's direct testimony and the direct testimony of Company witness Stacey L. McTaggart.

Q. ARE THE COSTS REFLECTED IN SCHEDULE A (REVENUE REQUIREMENT) AND INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT REASONABLE AND NECESSARY?

A. Yes, as demonstrated by the schedules included with the SOI, the supporting testimony and workpapers, the proposed revenue requirement reflects costs that are reasonable and necessary to provide safe and reliable service and operate the Company's system within the CGSA.

Q. PLEASE SUMMARIZE THE CALCULATION OF THE COMPANY'S REVENUE REQUIREMENT, AS SET FORTH IN SCHEDULE A.

A. Schedule A summarizes the results of the calculations detailed in other schedules contained within this SOI. For example, adjusted rate base, as calculated in Schedule B (Rate Base), is multiplied by the rate of return, calculated in Schedule E (Cost of Capital), to derive the required return of $64,093,722. Likewise, when federal income taxes from Schedule F (Federal Income Tax) and adjusted expenses from Schedule G are added to the required return, the result is an overall revenue requirement (before gross-up for additional uncollectible expense and Texas franchise tax) of $190,844,628. A comparison of this revenue requirement to adjusted revenues, from Schedule G, demonstrates that the Company's current rates in the CGSA produce a level of revenues that is $25,426,100 lower (before gross-up for additional uncollectible expense and Texas franchise tax) than the Company's cost of providing service in the CGSA. After gross-up for additional uncollectible expense and Texas franchise tax, the revenue deficiency on a system wide basis within the CGSA is $25,789,395 as shown on Schedule A, line 19.

V. RATE BASE

Q. WHAT IS RATE BASE?

A. Rate base represents the Company's invested capital that is used and useful in providing safe and reliable gas utility service to its customers. Rate base is used to calculate the return component of the Company's cost of service. The Company's rate base is summarized on Schedule B and is classified into three components: (1) Net Plant in Service ("PIS"); (2) Other Rate Base Items; and (3) Non-Investor Supplied Funds.

A. Net Plant in Service

Q. WHAT IS NET PLANT IN SERVICE AND HOW IS IT CALCULATED?

A. PIS refers to the Company's investment in the infrastructure necessary to provide safe and reliable service within the CGSA. Gross PIS includes the original cost of any intangible, transmission, distribution and general plant. In addition to Gross PIS, the Company has also included utility plant assets that are functionally in service but the related costs have not yet been transferred on the Company's books to the PIS account (FERC Plant Account 101). Instead, this plant not yet unitized is shown as Completed Construction Not Classified ("CCNC"). Net PIS represents the gross plant amount, plus CCNC, less accumulated depreciation.

Q. PLEASE DESCRIBE CCNC IN GREATER DETAIL.

A. CCNC represents utility plant that has been placed in service and is used and useful but, from an accounting perspective, the dollars associated with CCNC have not yet been transferred on the Company's books from the CCNC account (FERC Plant

Account 106) to the PIS account (FERC Plant Account 101). After a construction project is completed, there is typically an administrative delay in this accounting transfer. The Accounting Department must wait until all charges have been processed in order to transfer a project to FERC Account 101.

Q. PLEASE DESCRIBE THE RELATIONSHIP BETWEEN CONSTRUCTION WORK IN PROGRESS ("CWIP") AND CCNC.

A. CWIP is different from CCNC. Commission Rule 7.115(9) defines CWIP as funds expended by a gas utility which are irrevocably committed to construction projects not yet completed or placed into service. When funds are committed to a project, those funds are recorded in CWIP accounts. Once a project is placed in service, however, those funds will be classified as CCNC. Unlike CWIP dollars, which relate to projects that are not completed and are typically not included in rate base, the dollars in the CCNC account relate to completed construction projects that are used and useful in the provision of utility service.

Q. IS IT APPROPRIATE TO INCLUDE CCNC IN RATE BASE?

A. Yes. As I mentioned, CCNC represents utility plant that has been placed in service. From an accounting perspective, the dollars associated with the utility plant classified as CCNC have not yet been transferred to FERC Plant Account 101, the PIS Account. As CCNC represents plant that is in service, it is appropriate for CCNC to be included in rate base. The Company's proposal for CCNC is consistent with the treatment of CCNC that has been approved in prior proceedings, including Docket Nos. 9896 and 14399.[7]

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[7] *Petition of the De Novo Review of the Denial of the Statements of Intent filed by Texas Gas Service Company by the Cities of El Paso, Anthony, Clint, Horizon City, Socorro, and Village of Vinton, Texas*, GUD No. 9988,

Q. PLEASE EXPLAIN THE CALCULATION OF THE GROSS PIS AND CCNC BALANCES SHOWN ON SCHEDULE B.

A. The adjusted CGSA Gross PIS balance of $1,006,605,719 on Schedule B is the sum of the adjusted plant balances shown on Schedule C (Plant) through the test year ended December 31, 2023, for: (1) Direct CGSA plant; (2) the CGSA's allocated portion of TGS Division plant balances and (3) allocated ONE Gas corporate plant balances. The adjusted CCNC balance of $117,476,238 on Schedule B is the sum of the adjusted CCNC balances shown on Schedule C-1 through the test year ended December 31, 2023, for: (1) Direct CGSA balances; (2) the CGSA's allocated portion of TGS Division balances and (3) allocated ONE Gas Corporate CCNC balances.

Q. PLEASE EXPLAIN HOW THE PER BOOK BALANCE OF PIS WAS CALCULATED.

A. The Per Book PIS balance as of December 31, 2023, of $1,009,354,909 on Schedule C (line 4) results from three component parts: (1) $965,281,002, the per book balance of CGSA Direct PIS; (2) $5,416,589, the CGSA's allocated portion of TGS Division per book PIS and (3) $38,657,318, the CGSA's allocated portion of ONE Gas Corporate per book PIS. Ms. Borgstadt sponsors the TGS Division and ONE Gas Corporate amounts and the reasonableness of these amounts in her direct testimony.

Final Order (Dec. 14, 2010); *Statement of Intent filed by Texas Gas Service Company to Increase Rates in the Unincorporated Areas of the South Texas Service Area*, GUD No. 10217, Final Order (Mar. 26, 2013); GUD No. 10488, Final Order; GUD No. 10506, consol., Final Order; GUD No. 10656, Final Order; Docket No. OS-22-000009896, consol., Final Order; and Docket No. OS-23-00014399, consol., Final Order.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE PER BOOK PIS BALANCES?

A. Yes, adjustments were made on WKP C.a Direct Plant to the per book CGSA Direct PIS balance. The following adjustments were made to:

a) add $6,841 to adjust for miscoded retirements, offset by a matching adjustment to reserves;

b) remove $417,322 to adjust for miscoded additions and transfers;

c) remove $57,905 in plant that will retire once new amortization rates are implemented, offset by a matching adjustment to reserves;

d) remove $48 for meals and hotels adjustments; and

e) a $0 (net-zero) adjustment to reclassify the former ONE Gas Pipeline Company ("OPC") assets, discussed in Company witness Alex Limón's direct testimony, to the correct distribution FERC accounts.

The total amount of adjustments made to the CGSA Direct per book PIS balance equals $(468,433). The Company also adjusted TGS Division and ONE Gas Corporate per book PIS balances as identified and sponsored by Ms. Borgstadt in her direct testimony.

Q. PLEASE EXPLAIN THE IMPACT OF THE RECLASSIFICATION OF THE FORMER OPC ASSETS ON THE PER BOOK PIS BALANCES.

A. The full balance of costs for the former OPC assets were moved from the transmission FERC accounts into distribution FERC accounts on WKP C.a Direct Plant. This reclassification has no impact on the Per Book PIS balance.

Q. PLEASE EXPLAIN THE CALCULATION OF THE ADJUSTED TEST YEAR PIS BALANCE AS SHOWN ON SCHEDULE C.

A. The adjusted CGSA PIS balance of $1,006,605,719 on Schedule C (line 4) results from three components: (1) $964,812,569, the adjusted CGSA Direct PIS balance; (2) $5,175,765, the CGSA's allocated portion of the adjusted TGS Division PIS balance and (3) $36,617,385, the CGSA's allocated portion of the adjusted ONE Gas Corporate PIS balance. Ms. Borgstadt sponsors the TGS Division and ONE Gas Corporate allocated amounts and their reasonableness in her direct testimony.

Q. PLEASE EXPLAIN THE CALCULATION OF THE PER BOOK CCNC BALANCE ON SCHEDULE C-1 (CCNC).

A. Similar to PIS described above, the CCNC per book balance of $117,582,375 on Schedule C-1 (line 4) results from three component parts at December 31, 2023: (1) $113,758,221, the per book balance of CGSA Direct CCNC; (2) $249,787, the CGSA's allocated portion of the adjusted TGS Division PIS balance and (3) $3,574,367, the CGSA's allocated portion of ONE Gas Corporate per book CCNC. Ms. Borgstadt sponsors and supports the reasonableness of the TGS Division and ONE Gas Corporate amounts.

Q. WERE ANY ADJUSTMENTS MADE TO PER BOOK CCNC BALANCES?

A. Yes, adjustments were made on WKP C-1.a Direct CCNC to the per book CGSA Direct CCNC balance. The following adjustments were made to:

a) remove $3,912 for meal & hotel adjustments; and
b) add $40,082 to adjust for miscoded additions and transfers.

The total amount of adjustments to the CGSA Direct per book CCNC balance equals $36,170. Accordingly, the Company also adjusted TGS Division and ONE Gas Corporate per book CCNC balances as identified and sponsored by Ms. Borgstadt in her direct testimony.

Q. PLEASE EXPLAIN THE CALCULATION OF THE TEST YEAR ADJUSTED DEPRECIATION AND AMORTIZATION RESERVE BALANCE SHOWN ON SCHEDULE B.

A. The calculation of the Test Year Adjusted Depreciation and Amortization Reserve balance that appears on Schedule B is summarized on Schedule D. The per book Accumulated Reserve balance as of December 31, 2023, of $(242,592,609) on Schedule D contains: (1) $(220,618,261), the per book CGSA Direct Reserve balance; (2) $(1,623,003), the CGSA allocated portion of the TGS Division reserve balance and (3) $(20,351,344), the CGSA allocated portion of the ONE Gas Corporate reserve balance. Adjustments were made to the per book CGSA Direct Reserve balance to remove plant additions, transfers or retirements mistakenly coded to the CGSA, to reclassify the former OPC assets and to remove plant that will retire once new amortization rates are implemented. Total adjustments to the CGSA Direct per book reserves equal $66,366. Ms. Borgstadt testifies to and sponsors adjustments made to TGS Division and ONE Gas per book reserve balances.

Q. REFERRING TO SCHEDULE B, PLEASE SUMMARIZE THE COMPANY'S REQUEST REGARDING THE TEST YEAR ADJUSTED NET PIS BALANCE.

A. The total adjusted test year net PIS balance shown on Schedule B is $883,654,551. This is the sum of the adjusted test year balances for PIS of $1,006,605,719 plus CCNC of $117,476,238 and Reserves of $(240,427,405).

Q. IS ALL OF THE COMPANY'S ADJUSTED PIS INCLUDED IN THIS SOI USED AND USEFUL IN PROVIDING SERVICE?

A. Yes, all PIS included in this SOI is used and useful in providing service as supported by my testimony and the direct testimonies of Company witnesses Jeffrey J. Husen, Mr. Limón and Ms. Borgstadt.

B. Other Rate Base Items

Q. WHAT ARE OTHER RATE BASE ITEMS?

A. Other Rate Base Items are categories of investor-supplied funds that are necessary to fund the Company's day-to-day business. Because these funds come from the Company's bondholders and shareholders, they are appropriately included in rate base. As reflected on Schedule B, "Other Rate Base Items" include:

- Materials and Supplies Inventory;
- Prepayments, which are addressed by Ms. Borgstadt in her direct testimony;
- Amounts deferred in accordance with Commission Rule 8.209, which are addressed by Ms. McTaggart in her direct testimony;
- Requested Regulatory Assets, which are addressed by Ms. McTaggart in her direct testimony;
- Prepaid Pension Asset, which is addressed by Company Witness Cyndi L. King in her direct testimony; and

- Cash Working Capital ("CWC"), which is addressed by Company witness Timothy S. Lyons in his direct testimony.

Q. REFERRING TO SCHEDULE B-1, PLEASE EXPLAIN THE CALCULATION OF THE MATERIALS AND SUPPLIES INVENTORY BALANCE.

A. The Materials and Supplies Inventory balance consists of the average monthly balances of CGSA Direct Materials and Supplies Inventory and Stores Load as well as ONE Gas Measurement Assets ("OMA"). Included in this balance are investments in Direct Materials such as meters, automatic meter readers, regulators, risers, communication modems, miscellaneous safety equipment and pipeline materials such as polyurethane and steel pipe, various fittings, clamps, valves and epoxy coatings. These inventories are necessary for the provision of utility service to customers in the CGSA. Thus, inventory and storeroom costs are part of the Company's working capital that is included in rate base. Consistent with standard ratemaking practices, the methodology applied by the Company in prior settled rate cases and past Commission decisions,[8] a 13-month average was used and results in a $11,709,937 balance to be included in rate base. An average 13-month balance normalizes the fluctuations during the test year.

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[8] *See e.g.*, *Statement of Intent Filed by Atmos Energy Corp., to Increase Gas Utility Rates Within the Unincorporated Areas Served by the Atmos Energy Corp., Mid-Tex Division*, GUD No. 10170, consol., Final Order at FoF No. 33 (Dec. 4, 2012) (stating that a 13-month average for materials and supplies was approved in GUD Nos. 9670, 9762, 9869, 10000, 10041, 10084, and 10085); GUD No. 10488, Final Order; GUD No. 10506, Final Order; *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016); GUD No. 10656, Final Order; *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019); Docket No. OS-22-00009896, consol., Final Order; Docket No. OS-23-00014399, consol., Final Order.

Q. WHY IS IT APPROPRIATE TO INCLUDE STORES LOAD AS PART OF THE MATERIALS AND SUPPLIES INVENTORY BALANCES INCORPORATED INTO RATE BASE?

A. Overhead costs associated with materials management are accumulated in the Stores Load clearing account. When inventory dollars and Direct purchases are charged to expense accounts or to work orders, a portion of this accumulated materials management cost is charged to the same accounts. This additional cost relating to materials management overhead is referred to as "Stores Load." Because a portion of the Stores Load clearing account relates to the balance in the inventory account, it is appropriate to include an average of these amounts in rate base consistent with the inclusion of the average inventory balance.

Q. WHY IS IT APPROPRIATE TO INCLUDE OMA AS PART OF THE MATERIALS AND SUPPLIES INVENTORY BALANCES INCORPORATED INTO RATE BASE?

A. The OMA inventory balance includes investments such as meters, automatic meter readers, electronic receiver transmitters and regulators, held at a centralized meter shop. These inventories are necessary for the provision of utility service to CGSA customers but are not reflected in the proposed Direct costs; thus, an adjustment is necessary to include these investments in rate base to determine the revenue requirement to support these costs.

The Company calculated a 13-month average for OMA inventory, which normalizes fluctuations in the account during the test year. These assets are allocated to TGS based on the Texas customer count. These assets are further allocated to the CGSA based on the service area customer count. The allocation methodology follows the corporate allocation method, which is discussed further in Ms. Borgstadt's direct testimony.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE ASSOCIATED WITH PREPAYMENTS?

A. The Company has included a 13-month average of prepayments of $4,788,015. This asset is included on Schedule B, line 6 and detailed on Schedule B-2 (Prepayments). Ms. Borgstadt addresses prepayments in her direct testimony.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE ASSOCIATED WITH RULE 8.209?

A. The Company has included Rule 8.209 deferrals of $1,848,673. This asset is included on Schedule B, line 7 and detailed on Schedule B-3 (8.209 Reg Asset). Ms. McTaggart addresses the Rule 8.209 asset in her direct testimony.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE FOR THE PENSION AND OTHER POST EMPLOYMENT BENEFITS ("OPEB") REGULATORY ASSET?

A. The Company has included $(3,315,201) for a Pension and OPEB regulatory asset, as shown on Schedule B-4. GURA § 104.059 states that if a gas utility establishes one or more reserve accounts for the purpose of tracking changes in the costs of pensions and OPEB, the gas utility shall periodically record in a reserve account any differences between the annual amount of pension and OPEB approved and included in the gas utility's then current rates and the annual amount of pension and OPEB costs as determined by actuarial studies. A shortage in a reserve account exists if the amount of pension and OPEB under Subsection (b)(1) is less than the amount determined under Subsection (b)(2). If the gas utility establishes reserve accounts for the costs of pensions and OPEB, the regulatory authority at a subsequent general rate proceeding shall add any shortage to the gas utility's rate base, with the shortage amortized over a reasonable time.

In the most recent rate case for the CGSA (GUD No. 10928), a regulatory asset was approved, and the remaining balance of the regulatory asset that has not been amortized as of the date of this filing is $796,566. In addition, since GUD No. 10928, and consistent with the statute, the Company has recorded in a reserve account the difference between the annual amount of pension and OPEB approved and included in the Company's current rates and annual amount of costs of pension and OPEB as determined by actuarial or other similar studies. As of December 31, 2023, those deferrals total to $(3,315,201), and that amount was included in rate base.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE ASSOCIATED WITH A PREPAID PENSION ASSET?

A. The Company has included a prepaid pension asset of $20,530,077. This asset is included on Schedule B, line 10 and detailed on Schedule B-5. Ms. King addresses the prepaid pension asset in her direct testimony.

Q. WHAT IS CASH WORKING CAPITAL?

A. CWC is the cash flow required to finance the day-to-day operations of a business. Because business operations both generate and expend cash, CWC can be a net inflow or a net outflow to a company. Mr. Lyons calculated the CWC amount of $(3,364,662) shown on Schedule B, line 11 and detailed in Schedule B-6, and he supports the reasonableness of his calculation in his direct testimony.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE FOR ANY OTHER REQUESTED REGULATORY ASSET?

A. The Company has included a requested regulatory asset amount totaling $3,135,695. This amount is included on Schedule B, line 8, and detailed on Schedule B-11, and is comprised of the following:

- Unamortized balance of Regulatory Assets from GUD No. 10526, less the 11 months of amortization that will occur during the preparation and review process of this SOI;
- Deferred regulatory expenses not included in a prior SOI related to GUD No. 10928;
- Deferred Winter Storm Uri operations and maintenance ("O&M") expense at December 31, 2023; and
- COVID-19 related O&M.

C. Non-Investor Supplied Capital

Q. WHAT ARE NON-INVESTOR SUPPLIED FUNDS?

A. Non-investor supplied funds represent capital available to the Company that does not originate from its bondholders and shareholders. A rate of return is applied to the Company's rate base to determine the dollars needed to cover the Company's interest on debt, as well as to provide an opportunity to earn a reasonable return on equity. For this reason, funds supplied to the Company on a cost-free basis by non-investors must be deducted in determining the Company's rate base. These amounts are shown on Schedule B, lines 12 through 15. Lines 12 and 13 are the balances at the test year end for customer deposits and customer advances, respectively. In addition, the ADIT balance shown on line 14 of Schedule B represents funds available to the Company as a result of lower current income tax expenses due to timing differences between book and taxable income. Lastly, the

EDIT balance shown on line 15 of Schedule B represents the remaining EDIT balance resulting from the remeasurement of ADIT due to the federal tax rate decrease from the Tax Cuts and Jobs Act of 2017 ("TCJA"). These funds are also deducted from the rate base calculation. Ms. Simpson explains and sponsors the ADIT balance in her direct testimony. Company witness Kenneth E. Eakens explains and sponsors the EDIT balance in his direct testimony.

Q. PLEASE EXPLAIN THE AMOUNTS SHOWN ON SCHEDULE B FOR THE BALANCES OF CUSTOMER DEPOSITS AND CUSTOMER ADVANCES.

A. The amounts reflected in Rate Base on Schedule B are equal to the CGSA per book balances of customer deposits and customer advances as of December 31, 2023. Customer Deposits (line 12) are $(6,613,930). Customer Advances (line 13) are $(5,170,456).

Q. PLEASE EXPLAIN THE AMOUNTS SHOWN ON SCHEDULE B FOR THE BALANCES OF ADIT AND EDIT.

A. The ADIT balance reflected on Schedule B (line 14) is $(79,319,324), and the EDIT balance (line 15) is $(14,634,668). These balances are treated for ratemaking purposes as offsets to the Company's invested capital (rate base).[9]

Q. PLEASE SUMMARIZE THE COMPANY'S RATE BASE FOR THE CGSA AS CALCULATED ON SCHEDULE B.

A. The total rate base that is included in the cost of service calculation is $813,248,707. This total amount includes all the component parts described above.

[9] For additional support for customer deposits, customer advances, ADIT and EDIT, please see Schedule B-7, Schedule B-8, Schedule B-9 and Schedule B-10, respectively.

Ms. Borgstadt's direct testimony provides details for Corporate and Division rate base items.

Q. ARE THE RATE BASE ADJUSTMENTS DISCUSSED IN YOUR TESTIMONY NECESSARY TO CALCULATE A COST OF SERVICE THAT INCLUDES ONLY THOSE AMOUNTS TO BE COLLECTED THROUGH BASE RATES THAT ARE REASONABLE AND NECESSARY FOR PROVIDING SERVICE TO CUSTOMERS IN THE CGSA?

A. Yes. These adjustments to the historical test year amounts are appropriate and necessary to properly determine the Company's reasonable and necessary costs to provide service to TGS's CGSA customers, which are appropriately recovered through base rates.

Q. HAS THE COMPANY CALCULATED THESE RATE BASE ADJUSTMENTS CONSISTENT WITH PRIOR COMMISSION DECISIONS?

A. Yes. As I have indicated throughout my testimony, the Company has followed applicable Commission decisions regarding the calculations of the adjustments I support in my testimony.

VI. FEDERAL INCOME TAX

Q. PLEASE EXPLAIN THE CALCULATION OF FEDERAL INCOME TAX EXPENSE AS SHOWN ON SCHEDULE F.

A. Federal income tax expense is computed on Schedule F using the method outlined in the Commission's Natural Gas Rate Review Handbook.[10] This method

[10] Railroad Commission of Texas, Oversight and Safety Division - Gas Services, Natural Gas Rate Review Handbook at 38-39 (Sept. 2017).

calculates federal income tax expense by recognizing that the equity component of a total required return is comparable to after-tax net income, as reflected on the financial statements. This method first derives after-tax net income by subtracting the interest expense on the long-term debt portion of return, from the total required return. Because the resulting after-tax net income amount is, by definition, the amount that should result after the deduction of income taxes, it is necessary to "gross it up" by multiplying by a factor of 1/(1-tax rate). The resulting calculated before-tax net income number is then multiplied by the federal income tax rate to derive federal income tax expense.

Before grossing up the "after tax income," however, it is necessary to eliminate the effect of items that represent direct credits to federal income taxes and to eliminate the effect of items that may be appropriate for ratemaking purposes but are not allowable deductions on the Company's income tax return.

As provided in Internal Revenue Service ("IRS") Notice 2018-99,[11] the TCJA added Code § 274(a)(4) precluding employers from deducting for tax purposes qualified transportation fringe benefits such as qualified parking. In December 2020,[12] the IRS issued a final regulation under Internal Revenue Code Section 274 that provided a new exception to the parking disallowance for parking provided in a rural, industrial or remote area in which no commercial parking is available, reducing the number of Company parking lots subject to the

[11] Parking Expenses for Qualified Transportation Fringes Under § 274(a)(4) and § 512(a)(7) of the Internal Revenue Code, Notice 2018-99, https://www.irs.gov/pub/irs-drop/n-18-99.pdf.
[12] Qualified Transportation Fringe, Transportation and Commuting Expenses Under Section 274, 85 Fed. Reg. 81391 (Effective Dec. 16, 2020), https://www.federalregister.gov/documents/2020/12/16/2020-27505/qualified-transportation-fringe-transportation-and-commuting-expenses-under-section-274.

disallowance. The specific mechanics of computing federal income tax expense using the Return Method are shown on Schedule F. The Company used a federal income tax rate of 21% to comply with the TCJA, which lowered the federal corporate tax rate from 35% to 21%. Ms. McTaggart and Mr. Eakens further discuss issues related to the TCJA in their direct testimonies. The adjusted test year federal income tax expense included in the Company's revenue requirement is $13,227,540.

VII. OPERATING REVENUE AND EXPENSES

Q. PLEASE DESCRIBE SCHEDULE G.

A. Schedule G presents a summary of all revenues and expenses, other than federal income tax expense. Page 1 is a summary of the adjustments to revenues and expenses, which are identified in greater detail in Schedules G-1 through G-24. Pages 2 and 3 reflect the same information as Page 1, organized by FERC account number. The total amounts on page 1, line 27 of Schedule G equal the total operating amounts shown on page 3, line 93 of Schedule G. Each page of Schedule G, column (a) identifies the test year amount recorded in the Company's books and records; column (b) shows the net adjustment to each test year amount, which is simply the difference between columns (a) and (c); and column (c) contains the adjusted amount.

The adjustments to revenue and purchased gas expense on Schedules G-1 through G-3 are sponsored by Company witness Zane M. Drummond and attached to his direct testimony. The expense adjustments detailed on Schedules G-4 through G-24 are either discussed in the remainder of my direct testimony or in the direct testimony of Ms. Borgstadt.

Q. DO THE ADJUSTED EXPENSES SHOWN ON SCHEDULE G, COLUMN (C) INCLUDE ALLOCATED EXPENSES?

A. Yes. In addition to expenses that are directly charged to the CGSA, the Company incurs "allocable" expenses for Shared Services provided to customers in the CGSA from various TGS and ONE Gas departments. A portion of these reasonable and necessary expenses must be allocated to the CGSA to determine the total cost TGS incurs to provide service to CGSA customers. For example, during the test year, personnel from various departments provided management, accounting, human resources, customer service and engineering services to the CGSA and generated a variety of expenses that are directly charged or causally allocated to the CGSA. Lastly, there are ONE Gas Corporate level costs allocated through Distrigas for necessary business functions such as treasury, investor relations and executive management that support operations in the CGSA. The CGSA's portion of test year costs charged to the allocable cost centers described above are included in the CGSA's per book costs on Schedule G, column (a). The Company's allocation methodologies are discussed by Ms. Borgstadt in her direct testimony.

Q. DESCRIBE THE PENSION AND OPEB AMORTIZATION AMOUNT SHOWN ON SCHEDULE G-7.

A. Schedule G-7 shows the proforma annual amortization of the Pension and OPEB Regulatory Asset included in rate base in accordance with GURA § 104.059, as discussed in the rate base section of my testimony. The beginning amount of $3,315,201 reflects the deferred annual Pension and OPEB expense that has occurred since the approved rates in GUD No. 10928 were implemented. The proposed annual amortization period is based on a six-year time frame that would include five or six GRIP filings followed by a rate case filing. Schedule G-7 also shows an adjustment made to test-year expense. This adjustment is the difference between the proforma annual amortization amount and actual test-year amortization.

Q. DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE G-9.

A. Schedule G-9 shows adjustments to remove expenses not permitted for regulatory recovery such as civic activities, charitable contributions, out of period accruals and legislative activities. Additionally, meals over $25 per person, exclusive of taxes and tip amounts, and hotel stays over $175 per night, exclusive of taxes, were removed. Ms. Borgstadt in her direct testimony sponsors the adjustments related to Shared Services, which are directly assigned or causally allocated costs, and Distrigas, which are allocated indirect costs.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR INTEREST ON CUSTOMER DEPOSITS SHOWN ON SCHEDULE G-11.

A. The CGSA interest on customer deposits has been calculated by applying the current Commission-required interest rate of 4.86%[13] to the adjusted balance of CGSA customer deposits as shown on Schedule B-7 (Deposits) and as discussed in the rate base section of my testimony. The difference between this amount and test year interest on customer deposits is the adjustment shown on Schedule G-11.

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[13] *See e.g.*, Railroad Commission of Texas, Bulletin No. 1218, Sec. 6(B)(1), December 31, 2023 (citing to Historical PUC Interest Rates, https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/HRates/HistRates.pdf.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO UNCOLLECTIBLE EXPENSE ON SCHEDULE G-12.

A. Uncollectible expense, also known as bad debt, is an amount owed to the Company that is unlikely to be paid. Schedule G-12 presents the calculation of adjusted uncollectible expense relating to the CGSA adjusted base revenues and other revenues. This adjusted expense level is calculated by multiplying the adjusted base revenues and other revenues by a three-year average uncollectible ratio. The uncollectible ratio is non-gas-cost-related. Direct write-offs for the CGSA are divided by total CGSA non-gas-cost revenue. The use of a three-year average is consistent with Commission decisions in prior TGS dockets, as well as in the dockets of other gas utilities in Texas.[14] Test year uncollectible expense is then subtracted from the adjusted uncollectible expense level to obtain the adjustment to the test year amount. In addition, the uncollectible expense ratio is used on Schedule A to gross-up the revenue deficiency for the additional uncollectible expense associated with the requested increase in rates.

The adjusted expense on Schedule G-12 excludes uncollectible expense relating to gas cost revenues because the Company proposes to recover gas-cost-revenue-related bad debt expense through its cost of gas tariffs in the CGSA.

[14] *See e.g.*, GUD No. 10170, Final Order at FoF No. 33 (stating that use of a three-year average for uncollectible expense was approved in GUD Nos. 9762 and 9869). *See also* GUD Nos. 9770, 9988, 10217, 10285, 10488, 10506, 10526, 10656, 10928, Docket Nos. OS-22-00009896 and OS-23-00014399.

Q. PLEASE DESCRIBE THE CALCULATIONS ASSOCIATED WITH ADVERTISING EXPENSE ON SCHEDULE G-14.

A. Commission Rule 7.5414 states that actual expenditures for advertising will be allowed as a cost of service item for rate-making purposes provided that the total sum of such expenditures shall not exceed one-half of 1% of the gross receipts of the utility for utility services rendered to the public. Schedule G-14 demonstrates that total adjusted advertising expense included in the proposed revenue requirement is $150,493, and is less than the allowable amount of $1,441,079.

Q. PLEASE EXPLAIN HOW THE DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENT ON SCHEDULE G-15 IS CALCULATED.

A. Adjusted depreciation expense is calculated by multiplying the Company's depreciation rates by depreciable PIS. In addition, as required by Commission Rule 8.209 (Distribution Replacement Program), depreciation expense on the Company's December 31, 2023, Distribution Integrity Management Program deferral balance is included and is calculated using the CGSA depreciation rates for mains and services.[15]

Test year depreciation expense is subtracted from total adjusted depreciation expense to calculate the adjustment to test year expense reflected on Schedule G-15. Please note, the balances of CGSA transportation and major work equipment ("TWE") are excluded from depreciable plant for purposes of computing adjusted depreciation expense on Schedule G-15. Instead, depreciation relating to these items is charged directly to the TWE clearing account rather than

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[15] *See* 16 TAC § 8.209(j).

to the depreciation expense account on the Company's books. As a result, adjusted depreciation for TWE equipment is included as part of the TWE clearing adjustment on Schedule G-19. Ms. Borgstadt co-sponsors Schedule G-15 and supports the depreciation expense related to the TGS Division and Corporate Plant.

Q. HOW WERE THE DEPRECIATION RATES DETERMINED AS USED IN THIS CASE?

A. The CGSA Direct plant depreciation rates were developed in the 2024 depreciation study conducted by Company witness Ron E. White, Ph. D. for this rate case. Dr. White describes the depreciation study and the resulting rates in his direct testimony.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO AD VALOREM (PROPERTY) TAXES SHOWN ON SCHEDULE G-16.

A. On July 13, 2023, the Texas legislature passed Texas Proposition 4 (Property Tax Changes and State Education Funding Amendment 2023), and Texas voters approved this constitutional amendment on November 7, 2023. As a result, TGS received a property tax savings, which was reflected on the January 2024 property tax bills. TGS's property tax calculation in this case passes on the initial tax savings from the 2023 tax change by using the actual amounts for 2024 property tax bills. TGS first computes the effective tax rate by dividing the property taxes paid in January 2024 by net PIS as of January 1, 2023. TGS uses net PIS as of January 1, 2023, to calculate the effective rate because that is the valuation assessment date used for the 2024 taxes paid. TGS computes adjusted property tax expense by multiplying the December 31, 2023, net PIS included in rate base by the effective property tax rate. TGS's test year property tax expense is subtracted from adjusted property tax expense to calculate the adjustment to test year expense.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR TEXAS FRANCHISE TAX ON SCHEDULE G-17.

A. TGS's Texas franchise tax is recorded as a part of the income tax accrual on the Company's books that is excluded from the per book test year numbers for the CGSA. Instead, the Company includes the franchise tax amount paid by the Company on May 15, 2023. The portion applicable to the CGSA is computed on Schedule G-17 by allocating the company-wide total franchise tax payment to the CGSA based on the CGSA's customer count.

Q. PLEASE EXPLAIN THE STORES LOAD CLEARING ADJUSTMENT ON SCHEDULE G-18.

A. Schedule G-18 shows two categories of adjustments related to stores costs. The first adjustment is for CGSA stores costs that were over-cleared relative to the CGSA costs incurred during the test year. TGS accounts for stores costs through a clearing account. Costs are accumulated in the stores load clearing account on the balance sheet and then cleared to capital and expense accounts based on a percentage load applied to all requisitions for materials and supplies. Because the percentage load is based on estimated usage and costs, the amount cleared may be more or less than the costs incurred during any given twelve-month period. During the test year, the amounts cleared from the CGSA stores clearing account were more than the CGSA actual cost incurred during the test year. Thus, an adjustment to decrease the test year amount cleared is necessary. This adjustment is shown on Schedule G-18, lines 1 through 3.

The second category of adjustments relates to the level of costs that was charged into the CGSA stores clearing account during the test year. As shown on lines 4 through 7, adjustments were made to reflect the difference between CGSA adjusted and test year payroll and payroll-related costs applicable to the stores function. The combination of these two categories of adjustments results in a decrease to overall test year stores clearing as shown on line 8. The two adjustments to stores clearing have been multiplied by the percentage of stores load charged to expense accounts in the CGSA during the test year to determine the adjustment to test year expense and the distribution of that adjustment to specific applicable expense accounts as shown on Schedule G-18, lines 12 through 24.

Q. PLEASE EXPLAIN THE LOAD CLEARING ADJUSTMENT FOR TRANSPORTATION AND WORK EQUIPMENT ON SCHEDULE G-19.

A. Schedule G-19 presents an adjustment similar to the previously discussed stores load adjustment. As with stores load costs, TWE costs are accumulated in a balance sheet account and then cleared to capital and expense accounts based on usage. The amounts cleared for CGSA TWE during the test year were greater than the CGSA actual costs incurred. Thus, an adjustment to decrease the test year amount cleared is necessary to decrease the cleared costs in the Company's cost of service. This adjustment is shown on Schedule G-19, lines 1 through 3. Lines 4 through 9 reflect any necessary adjustments relating to the dollars that were charged into the CGSA TWE clearing account during the year. The primary costs associated with TWE are depreciation, gasoline and maintenance and repair costs. No adjustment was made to the test year level of gasoline or maintenance and repair costs. However, depreciation expense associated with vehicles and major work equipment is also charged to the TWE clearing cost. Line 4 reflects an adjustment to decrease the amount of depreciation that was booked during the test year to reflect the depreciation rates recommended by Dr. White.

The sum of these two categories of TWE adjustments is a decrease to test year CGSA TWE clearing amounts and is shown on line 10. This amount has been multiplied by the percentage of TWE load charged to expense accounts in the CGSA during the test year to determine the adjustment to test year expense and the distribution of that adjustment to specific applicable expense accounts as shown on Schedule G-19, lines 14 through 36.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR AMORTIZATION OF REQUESTED REGULATORY ASSETS REFLECTED ON SCHEDULE G-20.

A. Schedule G-20 reflects the annual amortization expense associated with the requested regulatory asset described in the Rate Base section of my testimony. The total amount of the requested regulatory asset is amortized over six years to calculate proforma amortization expense. Rate case expenses associated with the filing in this case are not included as a requested regulatory asset. The Company requests recovery of rate case expenses associated with this filing through a separate rider, as discussed in the Proposed Rate Schedules section of my testimony.

Q. PLEASE EXPLAIN THE PIT ADJUSTMENT REFLECTED ON SCHEDULE G-23.

A. Schedule G-23 reflects the PIT expense to include in base rates if the Company's request for a rider is not approved. PIT costs incurred during the test year and scheduled to be incurred for the following six years are summed, and an average is included as annual proforma PIT expense. Mr. Limón explains and supports the reasonableness and necessity of the PIT costs, and I address the appropriateness of recovering the PIT expense through a rider in the Proposed Rate Schedules section of my testimony. If the rider is approved, the adjustment shown on Schedule G-23 should be removed from the Company's base revenue requirement.

Q. PLEASE EXPLAIN THE EDIT ADJUSTMENT REFLECTED ON SCHEDULE G-24.

A. Schedule G-24 reflects the annual EDIT amortization credit to include in base rates if the Company's request to discontinue the EDIT rider is approved, which is detailed in Section VIII of my testimony and in the direct testimony of Mr. Eakens.

VIII. PROPOSED RATE SCHEDULES AND TARIFFS

Q. WHAT TARIFFS ARE PROPOSED BY THE COMPANY IN THIS SOI?

A. The proposed CGSA tariffs, attached as Exhibit A to the SOI, are as follows:

- Rate Schedules 10, 15, 20, 25, 30, 40, 70, C-1 and CNG-1 for gas sales service;
- Rate Schedules 1Z, 1Y, 2Z, 2Y, 3Z, 4Z, 7Z, C-1-ENV, CNG-1-ENV for gas sales service;
- Rate Schedules 1-INC and 1-ENV for the cost of gas clause;
- Rate Schedules T-1, T-1-ENV, T-TERMS for transportation service;
- Rate Schedule WNA for weather normalization ("WNA") adjustment;
- Rate Schedules PIT and PIT-Rider for recovery of annually approved PIT expenses;
- Rate Schedules RCE and RCE-ENV for recovery of approved rate case expenses in this filing;

- Rate Schedule RNG for creation of a Renewable Natural Gas ("RNG") Credits Program; and
- Incorporated and environs Rules of Service.

The Company proposes no changes to Rate Schedule PSF, "Pipeline Safety and Regulatory Program Fees," Rate Schedule CRR, "Customer Rate Relief," and the Curtailment Plan Rate Schedule all of which are currently in effect for the CGSA. The proposed rate schedules for the CGSA accurately reflect all the changes requested by the Company in this filing. Exhibit MJM-2 provides the existing rate schedules in redline format to identify the changes the Company proposes for the CGSA.

Q. PLEASE DESCRIBE THE GENERAL APPROACH THE COMPANY TOOK IN DEVELOPING THE PROPOSED RATE SCHEDULES.

A. The Company started with the rate schedules approved in the Company's most recent rate case for the incorporated and the environs of the CGSA, GUD No. 10928. Next, the tariffs and rate schedules approved in recent TGS rate cases (Docket Nos. 9896 and 14399) were reviewed to identify applicable tariff provisions and language to include in the CGSA tariffs.[16]

A. Gas Sales Service Tariffs

Q. PLEASE DESCRIBE THE CGSA GAS SALES RATE SCHEDULES.

A. Rate Schedules 10, 15, 20, 25, 30, 40, 70, C-1, 1Z, 1Y, 2Z, 3Z, 4Z, 7Z, and C-1-ENV are based on the existing CGSA gas sales rate schedules that were approved

[16] GUD No. 10928, consol., Final Order at FoF No. 104; Docket No. OS-22-00009896, consol., Final Order at FoF No. 110; and Docket No. OS-23-00014399, consol., Final Order at FoF No. 27.

in GUD No. 10928 and incorporate approved changes from Docket Nos. 9896 and 14399 with revisions made to:

1. include rate changes as reflected in the direct testimony of Company witness Mr. Paul H. Raab;
2. add language to the residential tariffs, Rate Schedules 10 and 1Z, to designate them for Small Residential Service;
3. add the Large Residential Service, Rate Schedules 15 and 1Y;
4. add language to the commercial tariffs, Rate Schedules 20 and 2Z, to designate them for Small Commercial Service;
5. add the Large Commercial Service, Rate Schedules 25 and 2Y;
6. withdraw the Public School Space Heating Rate Schedules 48 and 4H;
7. revise language on the Electric Generation Service, Rate Schedules C-1 and C-1-ENV;
8. remove references to riders proposed to be withdrawn such as the EDIT Credit, Rate Schedule EDIT-Rider and Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider;
9. add references to proposed new tariffs such as the Rate Case Expense Surcharge Riders, Rate Schedules RCE and RCE-ENV;
10. add references to applicable rate schedules for recovery of the Pipeline Safety Fee, Rate Schedule PSF; and
11. revise implementation dates to read "Bills rendered on and After," which is a later date on the Company's meter reading schedule, to better align with Company processes.

The proposed gas sales rates are consistent with the recommendations of Mr. Raab.

Q. PLEASE EXPLAIN THE TWO PROPOSED RESIDENTIAL TARIFFS BASED ON CUSTOMER USAGE OF NATURAL GAS.

A. As discussed in Mr. Raab's direct testimony, the Company proposes a rate design that includes a Small Residential Rate and a Large Residential Rate to be assigned to residential customers depending upon customer usage. The revisions to Rate

Schedules 10 and 1Z and the addition of Rate Schedules 15 and 1Y reflect the Company's request. This revision is consistent with the tariffs proposed and approved in Docket Nos. 9896 and 14399.

Q. PLEASE EXPLAIN THE TWO PROPOSED COMMERCIAL TARIFFS BASED ON CUSTOMER USAGE OF NATURAL GAS.

A. As discussed by Mr. Raab, the Company proposes a rate design that includes a Small Commercial Rate and a Large Commercial Rate to be assigned to commercial customers depending upon customer usage. The revisions to Rate Schedules 20 and 2Z and the addition of Rate Schedules 25 and 2Y reflect the Company's request. This revision is consistent with the tariffs proposed and approved in Docket No. 14399.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO C-1 AND C-1-ENV GAS SALES RATE SCHEDULES FOR ELECTRIC GENERATION SERVICE.

A. The proposed C-1 and C-1-ENV rate schedules were developed using the electrical cogeneration rate schedules approved in Docket Nos. 9896 and 14399 with revisions to:

1. change the rate schedule name from "Electrical Cogeneration" to "Electric Generation;" and
2. expand the definition in the "Applicability" section to align with Commission Rule 7.455 and include distributed generation and backup power systems that are registered with the applicable balancing authorities.

The proposed language changes on Rate Schedules C-1 and C-1-ENV provide for electric generation service for additional customer applicability, whereas previous language limited availability to Cogeneration customers only. TGS currently has no electric generation customers in the CGSA, and includes these tariff language changes as an option for future customers and for consistency with other TGS service areas.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES TO UNMETERED GAS LIGHT RATE SCHEDULES.

A. Proposed Rate Schedules 70 and 7Z are available for customers on the TGS system who require natural gas service for gas lighting only, without the use of a metering device. Currently, there is one Public Authority customer in the CGSA who will be on this rate schedule.

Q. PLEASE DESCRIBE THE COMPANY'S CGSA COST OF GAS CLAUSE TARIFFS.

A. Proposed Rate Schedules 1-INC and 1-ENV are based on the existing cost of gas clauses in the CGSA while incorporating approved changes from Docket Nos. 9896 and 14399 and GUD No. 10739 with revisions to:

1. add clarifying language to sections B, C, F, and H in the incorporated and environs tariffs to make consistent with recently approved cost of gas clauses in Docket Nos. 9896 and 14399;

2. add clarifying language for the use of financial instruments in sections B.3, B.7 and B.10 to make consistent with the recently approved cost of gas clauses in Docket No. 9896 and 14399; and

3. expand language in section B.3 in the incorporated and environs tariffs to include other renewable sources of natural gas and Environmental Attributes associated with the purchase of RNG Credits to make consistent with the recently approved cost of gas clauses in Docket No. 9896.

In addition to the revisions above, the proposed cost of gas clauses include a number of non-substantive language revisions to make the language of the tariffs consistent with the cost of gas clauses that are in effect in the Company's other service areas.

B. Transportation Service Tariffs

Q. PLEASE DESCRIBE THE CGSA TRANSPORTATION SERVICE TARIFFS.

A. Proposed Rate Schedules T-1 and T-1-ENV are based on the existing CGSA transportation rate schedules, while incorporating approved changes from GUD No. 10928 and Docket Nos. 9896 and 14399.

Additional material differences between the CGSA transportation tariffs and the tariffs currently in effect for the CGSA incorporated and environs areas are revisions made to:

1. include rate changes as reflected in the testimony of Mr. Raab;
2. include Electric Generation service rates;
3. remove rates for Public School Space Heating; and
4. include recovery of any applicable local taxes or fees paid to the cities.

In addition to the revisions above, proposed Rate Schedules T-1 and T-1-ENV include a number of non-substantive language revisions to make the language of the tariffs consistent with the T-1 and T-1-ENV rate schedules that are in effect in the Company's other service areas.

Q. DOES THE COMPANY PROPOSE ANY ADDITIONAL CHANGES TO THE TRANSPORTATION TARIFFS?

A. Yes, the Company also proposes Rate Schedule T-TERMS, which is consistent with the approved Rate Schedule T-TERMS in GUD No. 10928 and Docket Nos. 9896 and 14399 with revisions made to:

1. include definitions for "Agreement," "Firm Service" and "Force Majeure" under "Definitions" to provide clarity for Customer and Company rights and responsibilities during a curtailment event;
2. include definition for "Electric Generation Service" under "Definitions" to align with Commission Rule 7.455 and include distributed generation and backup power systems that are registered with the applicable balancing authorities;
3. include § 1.3 to clarify Restrictions and Reservations for customer use of transportation service on the Company owned pipeline system;
4. revise language in § 1.4 and § 1.6 to clarify Company responsibilities for designating receipt points and Qualified Supplier;
5. add clarifying language to § 1.5 (g) for Customer's responsibility to provide written notice to the Company; and
6. include § 1.8 to clarify Company liability.

In addition to the revisions above, proposed Rate Schedule T-TERMS includes a number of language revisions to make the tariffs consistent with the T-TERMS rate schedules that are in effect in the Company's other service areas.

C. Tariff Riders

Q. HOW HAS THE COMPANY REVISED THE WEATHER NORMALIZATION CLAUSE FOR THE CGSA?

A. Existing Rate Schedule WNA provides a mechanism whereby incorporated and environs customer bills are adjusted up or down each billing cycle to reflect differences in actual weather compared to normal weather, as defined in the rate case and discussed in the direct testimony of Mr. Drummond. Revisions have been made to Rate Schedule WNA to:

1. add Large Residential Service, Rate Schedules 15 and 1Y, and Large Commercial Service, Rate Schedules 25 and 2Y, to the "Applicability" section; and
2. reflect updated weather factors for each class consistent with Mr. Drummond's weather normalization calculation in this case.

In addition to the revisions above, the proposed Rate Schedule WNA includes a few non-substantive revisions to make the language of the tariffs consistent with the WNA clauses that are in effect in the Company's other service areas.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE RECOVERY OF PIT EXPENSES.

A. Proposed Rate Schedules PIT and PIT-Rider provide a mechanism for recovery of costs incurred to comply with the Commission's Pipeline Integrity Assessment and Management Plan Rule, Rule 8.101, and other future Commission rules related to integrity management plans, through a surcharge similar to the PIT-Rider previously approved by the Commission in Docket Nos. 9896 and 14399 and GUD Nos. 9988, 10506, 10526, 10656, 10739 and 10928. To continue the treatment approved by the Commission in previous cases, including the last CGSA rate case, the Company requests approval of revised Rate Schedules PIT and PIT-Rider, applicable to all gas sales and standard transportation customers in the CGSA, to recover PIT costs incurred in a given calendar year through a volumetric rate to be applied to customer bills during the following April through March. Rate Schedule PIT sets forth the calculation and requirements, while Rate Schedule PIT-Rider contains the rate currently in effect.

Q. IS IT REASONABLE TO RECOVER PIT COSTS THROUGH A RIDER?

A. Yes. In Docket Nos. 9896 and 14399, the Commission ordered that PIT expense in the Company's WNSA and RGVSA, respectively, be recovered via a rider rather than in base rates, finding that a rider "based on the amount of prior year PIT costs that fluctuate from year to year, is just and reasonable."[17] It is reasonable and appropriate to recover PIT costs via an annual rider because the annual amount of PIT costs varies greatly from year to year depending upon the testing schedule, making it challenging to determine an appropriate amount of expense to be included in base rates. Finally, a PIT rider has operated successfully and effectively in the CGSA both before and since the last rate case. If the proposed Rate Schedule PIT is not approved, PIT expenses should be included in the calculation of base rates, as discussed in the Direct Operating Expense section of my testimony.

Q. PLEASE DESCRIBE THE PROPOSED REVISIONS TO RATE SCHEDULES PIT AND PIT-RIDER FOR THE RECOVERY OF PIT EXPENSES.

A. Proposed Rate Schedules PIT and PIT-Rider are based on the existing CGSA rate schedules with revisions made to:

1. add Large Residential Service, Rate Schedules 15 and 1Y, and Large Commercial Service, Rate Schedules 25 and 2Y, to the "Territory" and "Applicability" sections; and
2. include electronic transmission of notifications to customers and regulatory authorities in the "Notice to Affected Customers" section of Rate Schedule PIT.

In addition to the revisions above, the proposed Rate Schedules PIT and PIT-Rider include a number of non-substantive revisions to make the language of the tariffs consistent with the PIT and PIT-Rider rate schedules that are in effect in the Company's other service areas.

[17] Docket No. OS-22-00009896, consol., Final Order at FoF No. 88; and Docket No. 14399, Final Order FoF No. 40.

Q. IS THE COMPANY REQUESTING RATE CASE EXPENSE RECOVERY IN THIS CASE?

A. Yes. Pursuant to GURA § 104.051 and Commission Rule 7.5530, the Company seeks reimbursement of all rate case expenses determined by the Commission to be reasonable. These expenses include fees and expenses for outside attorneys and consultants and other reasonable expenses the Company incurs associated with this proceeding. As it has in prior rate cases, TGS has retained outside attorneys and consultants to perform necessary tasks related to the rate case filing. The work of these outside attorneys and consultants is supervised, directed and performed in consultation with the Company's Rates and Regulatory and Legal groups. To ensure that TGS incurs only reasonable and necessary rate case expenses, all outside attorney and consultant invoices are reviewed by Company personnel to ensure they are consistent with the rates and scope of work agreed to by the Company and the outside vendor.

Q. WHAT RATE CASE EXPENSE RECOVERY TARIFFS ARE THE COMPANY REQUESTING?

A. The Company is requesting approval of rate case expense riders, Rate Schedules RCE and RCE-ENV, to enable the Company to recover via surcharge all rate case expenses determined to be reasonable.

Q. PLEASE EXPLAIN THE COMPANY'S WITHDRAWAL OF RATE SCHEDULE EDIT-RIDER FOR THE FLOW BACK OF EDIT.

A. The Company proposes to withdraw Rate Schedule EDIT-Rider, which provided a mechanism for the flow back to customers of the annual amortization of EDIT, via an annual one-time bill credit. As explained in the direct testimony of Mr. Eakens, recent private letter rulings from the IRS necessitate the flow back of EDIT through base rates rather than a rider. This is the same treatment TGS proposed and the Commission approved in Docket Nos. 9896 and 14399.

D. Rules of Service

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RULES OF SERVICE FOR THE CGSA.

A. The Company developed proposed Rules of Service for the CGSA by starting with the RGVSA incorporated and environs Rules of Service, which were updated and approved in 2024. The proposed Rules of Service were revised to reflect revisions approved in GUD No. 10928 and Docket Nos. 9896 and 14399. The proposed Rules of Service have also been extensively updated and reordered in order to more closely conform to the Commission's Quality of Service Rules, which are consistent with the Rules of Service proposed and approved in Docket Nos. 9896 and 14399. Sections impacted by these conforming revisions include:

1. §§ 4.6 and 4.7, Conditions of Service;
2. § 5.2, Initiation of Service (previously § 5.7);
3. § 6, Refusal of Service (previously § 5.6);
4. § 7, Discontinuance of Service (previously §§ 17 and 18);
5. § 8, Security Deposits (previously § 10);
6. § 9, Billing and Payment of Bills (previously §§ 13 and 20);
7. § 10, Facilities and Equipment (previously §§ 7, 15 and 16);
8. § 11, Extension of Facilities (previously § 8);
9. § 12, Meters (previously §§ 6 and 12);
10. § 13, Gas Measurement (previously § 11); and

11. § 15, Service Fees and Deposit Amounts (previously §§ 15 and 21).

Additional material differences between the proposed CGSA Rules of Service and existing CGSA Rules of Service include:

1. Updates to the Company's contact information on page 1 for Customer inquiries;
2. Updating § 1.3, Definitions, to include all definitions of terminology in the Rules of Service consistent with approved Rules of Service in GUD No. 10928 and Docket Nos. 9896 and 14399; add definitions for "Firm Service" and "Force Majeure" to provide clarity for Customer and Company rights and responsibilities during a curtailment event; add definition for "Master Meter;" change the term "Electrical Cogeneration Service" to "Electric Generation Service" and include distributed generation and backup power systems that are registered with the applicable balancing authorities; and expand the definition of "Excess Flow Valve;"
3. Revisions to § 3 and § 4.5 to include language for the availability of rate schedules on the Company's website;
4. Revisions to § 4.4 to remove a reference to the Company's previous filed curtailment plan and § 4.4(iv) to include curtailment language consistent with the new Commission Rule 7.455;
5. Addition of § 4.7 to clarify the process for customer complaints;
6. Revisions to § 4.8 to add language regarding force majeure situations to the limitation of liability provision;
7. Revisions to § 4.6, § 7.4, § 7.7, § 9.1 and § 9.6 to provide for electronic billing and notice;
8. Revisions to § 5 to move Refusal of Service to § 6;
9. Revisions to § 9.9 (previously § 20.1) to update the language to reflect the current plan description for Average Payment Plan;
10. Making an administrative correction to § 12.9;
11. Revisions to § 8 and § 11 (previously § 10 and § 8, respectively) to include language consistent with Commission Rule 7.458 and to clarify security deposits and requirements for customer-owned facilities;
12. Revisions to § 15 (previously § 21), Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas; and

13. Withdraw the rules of service addenda CGSA-Env 7-45 and CGSA-Env 7-46, as these provisions have been included within the proposed CGSA Rules of Service in § 7.7 and § 8.3(e).

The proposed changes provide clarity regarding the Company's current policies and procedures. Creating consistent Rules of Service will lead to more consistent application and more efficient administration of the Company's tariffs, which benefits all the Company's customers.

Q. WHAT REVISIONS HAS THE COMPANY MADE TO ITS SERVICE FEES AND DEPOSITS AS REFLECTED IN SECTION 15 OF THE PROPOSED RULES OF SERVICE?

A. Exhibit MJM-3 identifies the current and proposed service fees. The proposed service fees are similar to those approved for the Company's other service areas in GUD No. 10928 and Docket Nos. 9896 and 14399. As with all service charges, only customers requesting and receiving a particular service will be charged for that service. This addition to revenue has been reflected as a known and measurable change on Schedule G-3, which Mr. Drummond sponsors.

E. Miscellaneous Tariffs

Q. WHAT IS THE RENEWABLE NATURAL GAS CREDITS PROGRAM TARIFF THE COMPANY IS REQUESTING?

A. The Company is requesting approval of a RNG Credits Program tariff, Rate Schedule RNG Credits Program, to enable the Company to provide a RNG Credits Program for customers as discussed in Ms. McTaggart's direct testimony.

Q. ARE THERE ANY ADDITIONAL COMPANY TARIFFS YOU WISH TO ADDRESS?

A. Yes. The Company proposes to withdraw Rate Schedules 48 and 4H "Public School Space Heating." Withdrawal of these tariffs is reasonable because they will no longer be applicable after base rates are implemented, there is not a requirement to maintain the tariff and/or the Company does not have these tariffs in place in other service areas.

IX. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Customer Class		Current Rates: CGSA Incorporated Rates	Current Rates: CGSA Environs Rates	Proposed CGSA Rates
Residential				
No. of Customers Affected		281,253	30,284	
Customer Charge		$25.47	$25.47	
Volumetric Charge (per Ccf)	All Usage	$0.32626	$0.32626	
Rate A Customer Charge				$25.50
Rate A Volumetric	All Usage			$0.69448
Rate B Customer Charge				$39.00
Rate B Volumetric	All Usage			$0.23425
Commercial				
No. of Customers Affected		3,574	433	
Customer Charge (For Commercial Service)		$96.08	$96.08	
Volumetric Charge (per Ccf)	All Usage	$0.12679	$0.12679	
Rate A Customer Charge				$85.00
Rate A Volumetric	All Usage			$0.15710
Rate B Customer Charge				$100.00
Rate B Volumetric	All Usage			$0.10765
Commercial Transportation				
No. of Customers Affected		313	11	
Customer Charge		$308.08	$308.08	$297.51
Volumetric Charge (per Ccf)	All Usage	$0.12679	$0.12679	$0.12679
Industrial				
No. of Customers Affected		25	0	
Customer Charge		$1,005.41	$1,005.41	$572.02
Volumetric Charge (per Ccf)	All Usage	$0.12707	$0.12707	$0.12707
Industrial Transportation				
No. of Customers Affected		28	9	
Customer Charge		$1,205.41	$1,205.41	$772.02
Volumetric Charge (per Ccf)	All Usage	$0.12707	$0.12707	$0.12707
Public Authority				
No. of Customers Affected		777	54	
Customer Charge		$160.70	$160.70	$156.05
Volumetric Charge (per Ccf)	All Usage	$0.12549	$0.12549	$0.12549
Public Authority Transportation				
No. of Customers Affected		412	8	
Customer Charge		$183.70	$183.70	$179.05
Volumetric Charge (per Ccf)	All Usage	$0.12549	$0.12549	$0.12549
Public Authority School Space Heating (Reclassed to Public Authority)				
No. of Customers Affected		6	1	
Customer Charge		$213.70	$213.70	$156.05
Volumetric Charge (per Ccf)	All Usage	$0.10012	$0.10012	$0.12549
Public Authority School Space Heating Transportation (Reclassed to Public Authority)				
No. of Customers Affected		76	2	
Customer Charge		$313.70	$313.70	$179.05
Volumetric Charge (per Ccf)	All Usage	$0.10012	$0.10012	$0.12549
Electric Generation				
No. of Customers Affected		0	0	
Customer Charge		$183.70	$183.70	$175.98
Volumetric Charge (per Ccf)				
First 5,000 Ccf/Month		$0.07720	$0.07720	$0.07427
Next 35,000 Ccf/Month		$0.06850	$0.06850	$0.06590
Next 60,000 Ccf/Month		$0.05524	$0.05524	$0.05314
All Over 100,000 Ccf/Month		$0.04016	$0.04016	$0.03864
Electric Generation Transportation				
No. of Customers Affected		1	0	
Customer Charge		$183.70	$183.70	$175.98
Volumetric Charge (per Ccf)				
First 5,000 Ccf/Month		$0.07720	$0.07720	$0.07427
Next 35,000 Ccf/Month		$0.06850	$0.06850	$0.06590
Next 60,000 Ccf/Month		$0.05524	$0.05524	$0.05314
All Over 100,000 Ccf/Month		$0.04016	$0.04016	$0.03864
Compressed Natural Gas				
No. of Customers Affected		1	0	
Customer Charge		$812.71	$812.71	$594.88
Volumetric Charge (per Ccf)	All Usage	$0.06684	$0.06684	$0.06684
Compressed Natural Gas Transportation				
No. of Customers Affected		3	1	
Customer Charge		$837.71	$837.71	$619.88
Volumetric Charge (per Ccf)	All Usage	$0.06684	$0.06684	$0.06684
Unmetered Gas Light				
No. of Customers Affected		1	0	
Customer Charge		0	0	0
Volumetric Charge (per Ccf)	All Usage	$0.12549	$0.12549	$0.12549

SMALL RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a small residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential ~~consumer~~customer includes an individually-metered residential unit or dwelling that is operated by a public housing agency acting as an administrator of public housing programs under the direction of the U.S. Department of Housing and Urban Development and builders prior to sale or ~~resale~~re-sale of a property for domestic purposes. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	~~$16.00~~ $25.50 plus
~~Interim Rate Adjustments (IRA)~~	~~$ 6.85 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$22.85 per month~~
All Ccf per monthly billing period @	$0.~~3262~~669448 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 352 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 352 Ccf or Greater	Large Residential, Rate Schedule 15

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1INC.~~ 1- INC.

SMALL RESIDENTIAL SERVICE RATE
(Continued)

Conservation Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~ ~~January 15, 2024 (City of Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE 10**~~
~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

~~**RESIDENTIAL SERVICE RATE (Continued)**~~

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $2.37 (Gas Utilities Case No. 00005813); 2021 IRA - $1.99 (Gas Utilities Case No. 00008748); 2022 IRA - $2.49 (Gas Utilities Case No. 00012592)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 10**
Central-Gulf Service Area **Page 3 of 3**

~~Supersedes Rate Schedule Dated~~	~~Meters Read On and After~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~	~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~	~~January 15, 2024 (City of Mustang Ridge)~~

Supersedes Rate Schedule Dated	Bills Rendered On and After
January 15, 2024	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area

RATE SCHEDULE 20
Page 1 of 4

SMALL COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all small commercial customers and to customers not otherwise specifically provided for under any other rate schedule. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of ~~$53.33~~ $85.00 plus
~~Interim Rate Adjustments (IRA) $30.59 per month (Footnote 1)~~
~~Total Customer Charge $83.92 per month~~

All Ccf per monthly billing period @ $0.~~12679~~15710 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 3,640 Ccf	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,640 Ccf or Greater	Large Commercial, Rate Schedule 25

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1INC.~~ 1- INC.

Conservation Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the~~

~~Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

SMALL COMMERCIAL SERVICE RATE
(Continued)

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~ ~~January 15, 2024 (City of Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE 20**~~
~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

~~**COMMERCIAL SERVICE RATE (Continued)**~~

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $10.04 (Gas Utilities Case No. 00005813); 2021 IRA - $9.07 (Gas Utilities Case No. 00008748); 2022 IRA $11.48 (Gas Utilities Case No. 00012592)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 20**
Central-Gulf Service Area **Page 4 of 4**

~~Supersedes Rate Schedule Dated~~	~~Meters Read On and After~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~	~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~	~~January 15, 2024 (City of Mustang Ridge)~~

Supersedes Rate Schedule Dated	Bills Rendered On and After
January 15, 2024	TBD

INDUSTRIAL SERVICE RATE

APPLICABILITY

Applicable to any qualifying industrial customer whose primary business activity at the location served is included in one of the following classifications of the Standard Industrial Classification Manual of the U.S. Government.

Division B - Mining - all Major Groups
Division D - Manufacturing - all Major Groups
Divisions E and J - Utility and Government - facilities generating power for resale only

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	~~$320.96~~ $572.02 plus
~~Interim Rate Adjustments (IRA)~~	~~$469.24 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$790.20 per month~~
All Ccf per monthly billing period @	$0.12707 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1INC.~~ 1- INC.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

~~Supersedes Rate Schedule Dated~~	~~Meters Read On and After~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~	~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~	~~January 15, 2024 (City of Mustang Ridge)~~

~~INDUSTRIAL SERVICE RATE (Continued)~~

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $164.48 (Gas Utilities Case No. 00005813); 2021 IRA - $137.93 (Gas Utilities Case No. 00008748); 2022 IRA - $166.83 (Gas Utilities Case No. 00012592)~~

~~September 15, 2022~~ ~~(Cities of Buda, Marble Falls, and Pflugerville)~~ January 15, 2024 ~~(City of Mustang Ridge)~~ TBD

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to any qualifying public authority, public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	~~$81.70~~$156.05 plus
~~Interim Rate Adjustments (IRA)~~	~~$56.79 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$138.49 per month~~
All Ccf per monthly billing period @	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1INC.~~ 1- INC.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

~~**PUBLIC AUTHORITY SERVICE RATE (Continued)**~~

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

Supersedes Rate Schedule Dated ~~Meters Read~~ Bills Rendered On and After

~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~

~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~ January 15, 2024 ~~(City of Mustang Ridge)~~ TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 70**
Central-Gulf Service Area **Page 1 of 3**

UNMETERED GAS LIGHT SERVICE RATE

APPLICABILITY

Applicable to any Customer on Texas Gas Service Company, a Division of ONE Gas, Inc.'s system requiring natural gas service for gas lighting only, without the use of metering device. Gas service is only available to Customers utilizing standard gas lighting equipment manufactured with an orifice burner assembly or equivalent that is intended for lighting of sidewalks and other walkways. The Company, in its sole discretion, shall determine if Customer's lighting equipment qualifies for this tariff and shall contract with Customer for the appropriate monthly charge based upon Customer's complete installation of gas lighting equipment. Gas service under this rate schedule is available only with the Company as the sole supplier of gas for Customer and is not available for resale to others or for standby or supplemental service. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

-

The total hourly rated consumption of all gas lighting equipment included, expressed in Ccf at the location, shall be multiplied by 730 for gas lighting equipment that runs continuously or 365 for gas lighting equipment with a light sensor, to determine the average monthly consumption of the service. The result, rounded to the next highest Ccf, shall then be billed the rates provided in this rate schedule:

-

~~Residential~~	~~$ 0.32626 per Ccf~~
~~Commercial~~	~~$ 0.12679 per Ccf~~
~~Industrial~~	~~$ 0.12707 per Ccf~~
~~Public Authority~~	~~$ 0.12549 per Ccf~~

-

Residential	$0.69448 per Ccf
Commercial	$0.15710 per Ccf
Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1INC.~~ 1- INC.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

UNMETERED GAS LIGHT SERVICE RATE

~~Initial Rate Schedule~~ ~~Meters Read On and After~~
~~August 4, 2020 (CGSA Cities except Buda, Marble Falls, Mustang Ridge, and Pflugerville)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~
~~January 15, 2024 (City of Mustang Ridge)~~

~~**UNMETERED GAS LIGHT SERVICE RATE**~~ **(Continued)**

CONDITIONS

The Customer shall ensure that the installation of lighting equipment conforms to industry safety standards. The Company reserves the right to review Customer's installation of lighting equipment from time to time to determine if it conforms to terms and conditions as set forth in this tariff and the executed service agreement with the Customer. Customer shall notify Company in writing within 30 days of any change in number of gas lights or other material changes made to the gas lighting installation.

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

UNMETERED GAS LIGHT SERVICE RATE

~~Initial Rate Schedule~~ ~~Meters Read On and After~~
~~August 4, 2020 (CGSA Cities except Buda, Marble Falls, Mustang Ridge, and Pflugerville)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~
~~January 15, 2024 (City of Mustang Ridge)~~

~~ELECTRICAL COGENERATION RATE~~
ELECTRIC GENERATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any ~~customers of~~ customer customer who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc~~., (the "Company") who~~ , to use natural gas for the purpose of ~~cogeneration or the use of fuel cell technology. Cogeneration~~electric generation. Electric generation is defined as ~~the use of thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.~~ facilities registered with the applicable balancing authority including bulk power system assets, co-generation facilities, distributed generation, and or backup power systems.

TERRITORY

This rate shall be available in the incorporated areas of the Central-Gulf Service Area, which includes, Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:
A customer charge per meter per month of ~~$104.70~~ $175.98 plus

~~Interim Rate Adjustments (IRA)~~

~~$56.79~~A

delivery charge per ~~month (Footnote 1)~~ monthly billing period @
~~Total Customer Charge $161.49 per month~~

For the First	5,000 Ccf/Month	$0.~~07720~~07427 per Ccf
For the Next	35,000 Ccf/Month	$0.~~06850~~06590 per Ccf
For the Next	60,000 Ccf/Month	$0.~~05524~~05314 per Ccf
All Over	100,000 Ccf/Month	$0.~~04016~~03864 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of the Cost of Gas Clause, Rate Schedule ~~1INC.~~ 1-INC.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline

Integrity Testing Rider, Rate ~~Schedule~~Schedules PIT~~,~~ and PIT-Rider if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

~~**Supersedes Rate Schedule Dated**~~	~~**Meters Read On and After**~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~	~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~	~~January 15, 2024 (City of Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE NO. C-1**~~

~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

~~**ELECTRICAL COGENERATION RATE (Continued)**~~

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

ELECTRICAL GENERATION SERVICE RATE
(Continued)

CONDITIONS

1. Gas taken under this rate shall be used exclusively for the purpose of ~~cogeneration and fuel cell technology~~electric generation as defined in the Applicability section of this rate schedule and not for other purposes. The gas taken under this rate will be separately metered.

~~This rate will not be available for standby use.~~

~~The curtailment priority of any customer served under this rate schedule shall be the same as the curtailment priority which would pertain if gas were used directly to provide energy for uses as defined and listed in the Company's curtailment plan.~~

2. For the purpose of this rate, the annual load factor must be 60 percent or greater. The annual load factor is defined as the customer's total annual consumption divided by the customer's peak month consumption times twelve. If less than 60 percent load factor occurs for a twelve-month period, the rate charged will revert back to the rate that the customer would have otherwise been served under. A continuous twelve-month period of 60 percent or better load factor must precede a return to the electric generation rate.

Subject to all applicable laws and orders, and the ~~Company's~~Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

~~**Supersedes Rate Schedule Dated**~~	~~**Meters Read On and After**~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~	~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, 2.~~3. ~~and Pflugerville)~~	~~January 15, 2024 (City of Mustang Ridge)~~

TRANSPORTATION SERVICE RATE

APPLICABILITY

Applicable to customers who have elected Transportation Service not otherwise specifically provided for under any other rate schedule.

Service under this rate schedule is available for the transportation of customer-owned natural gas through Texas Gas Service Company, a Division of ONE Gas, Inc.'s (the "Company") distribution system. The customer must arrange with its gas supplier to have the customer's gas delivered to one of the Company's existing ~~delivery~~ receipt points for transportation by the Company to the customer's facilities at the customer's delivery point. The receipt points shall be specified by the Company at its reasonable discretion, taking into consideration available capacity, operational constraints, and integrity of the distribution system.

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's Central-Gulf Service Area distribution system which includes the incorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas. Such service shall be provided at any point on the Company's System where adequate capacity and gas supply exists, or where such capacity and gas supply can be provided in accordance with the applicable rules and regulations and at a reasonable cost as determined by the Company in its sole opinion.

COST OF SERVICE RATE

During each monthly billing period, a customer charge per meter per month listed by customer class as follows:

Commercial $297.51 per month

~~Commercial $265.33 per month~~

~~plus Interim Rate Adjustments $30.59 (Footnote 1) Total Rate $295.92~~

~~Industrial $520.96 per month~~

~~plus Interim Rate Adjustments $469.24 (Footnote 2) Total Rate $990.20~~

~~Public Authority $104.70 per month~~

~~plus Interim Rate Adjustments $56.79 (Footnote 3) Total Rate $161.49~~

~~Public Schools Space Heat $234.70 per month~~

~~plus Interim Rate Adjustments $56.79 (Footnote 4) Total Rate $291.49~~

~~Compressed Natural Gas $217.63 per month~~

~~plus Interim Rate Adjustments $391.17 (Footnote 5) Total Rate $608.80~~

~~Electrical Cogeneration $104.70 per month~~

TRANSPORTATION SERVICE RATE

~~plus Interim Rate Adjustments $56.79 (Footnote 6)~~ ~~Total Rate~~ ~~$161.49~~

~~**(Continued)**~~

Industrial	$772.02 per month
Public Authority	$179.05 per month
Compressed Natural Gas	$619.88 per month
Electrical Generation	$175.98 per month

TRANSPORTATION SERVICE RATE
(Continued)

Plus – ~~All Ccf~~A delivery charge per monthly billing period listed by customer class as

follows: Commercial	$0.12679 per Ccf
Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf ~~Public Schools Space Heat $0.10012 per Ccf~~
Compressed Natural Gas	$0.06684 per Ccf

Electrical ~~Cogeneration~~ Generation

For the First 5,000Ccf/month	$0.~~07720~~07427
per Ccf For the Next 35,000 Ccf/month	$0.~~06850~~06590
per Ccf For the Next 60,000 Ccf/month	$0.~~05524~~05314
per Ccf All Over 100,000 Ccf/month	$0.~~04016~~03864
per Ccf	

ADDITIONAL CHARGES

1) A charge will be made each month to recover the cost of taxes paid to the State of Texas pursuant to Texas Utilities Code, Chapter 122 as such may be amended from time to time which are attributable to the transportation service performed hereunder.

2) A charge will be made each month to recover the cost of any applicable ~~franchise~~local taxes and fees ~~paid to the cities.~~ .

3) In the event the Company incurs a demand charge, balancing service rate, or reservation charge from its gas supplier(s) or transportation providers in the incorporated areas of the Central-Gulf Service Area, the customer may be charged its proportionate share of the demand charge, balancing service rate, or reservation charge based on benefit received by the customer.

4) The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

5) The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate ~~Schedule~~Schedules PIT~~, if applicable.~~ and PIT-Rider.

6) The billing of commercial transportation shall reflect adjustments in accordance with the provisions of the Conservation Adjustment Clause, Rate Schedule CAC and Rate Schedule 1C, if applicable.

~~1)~~ The billing shall reflect adjustments in accordance with the provisions of the ~~Excess Deferred Income Taxes~~Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule ~~EDIT-Rider.~~

7) ~~The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider~~PSF, if applicable.

~~TRANSPORTATION SERVICE RATE~~

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE T-1**
Central-Gulf Service Area **Page 4 of 4**

TRANSPORTATION SERVICE RATE
(Continued)

~~**(Continued)**~~

SUBJECT TO

1) Tariff T-TERMS, General Terms and Conditions for Transportation.

2) Transportation of natural gas hereunder may be interrupted or curtailed at the discretion of the Company in case of shortage or threatened shortage of gas supply from any cause whatsoever, to conserve gas for residential and other higher priority customers served. The curtailment priority of any customer served under this schedule shall be the same as the curtailment priority established for other customers served pursuant to the Company's rate schedule which would otherwise be available to such customer.

~~1) Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.~~

~~Footnote 1: 2020 IRA - $10.04 (Gas Utilities Case No. 00005813); 2021 IRA - $9.07 (Gas Utilities Case No. 00008748); 2022 IRA - $11.48 (Gas Utilities Case No. 00012592)~~

~~Footnote 2: 2020 IRA - $164.48 (Gas Utilities Case No. 00005813); 2021 IRA - $137.93 (Gas Utilities Case No. 00008748); 2022 IRA - $166.83 (Gas Utilities Case No. 00012592)~~

~~Footnote 3: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

~~Footnote 4: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

~~Footnote 5: 2020 IRA - $133.74 (Gas Utilities Case No. 00005813); 2021 IRA - $113.60 (Gas Utilities Case No. 00008748); 2022 IRA - $143.83 (Gas Utilities Case No. 00012592)~~

~~Footnote 6: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

3) The taking of service under this rate schedule is subject to all valid orders, laws, rules, and regulations of duly constituted State and Federal governmental authorities and agencies having jurisdiction or control over the parties, their facilities or gas supplies, the Agreement, or any provision hereof. The Company reserves the right to seek modification or termination of any of the General Terms and Conditions, the Gas Transportation Agreement, and any of the tariffs to which it applies.

~~3)~~4) The Agreement shall be interpreted under Texas law.

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

Applicable to any non-residential customer of Texas Gas Service Company, a Division of ONE Gas, Inc., (the "Company") for usage where customer purchases natural gas which will be compressed and used as a motor fuel. Service will be separately metered. This rate does not include compression by the Company beyond normal meter sales pressure.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of ~~$192.63~~ $594.88 plus
~~Interim Rate Adjustments (IRA) $391.17 per month (Footnote 1)~~
~~Total Customer Charge $583.80 per month~~

All Ccf per monthly billing period @ $0.06684 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1INC.~~ 1- INC.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

~~**Supersedes Rate Schedule Dated**~~ ~~**Meters Read On and After**~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~ ~~January 15, 2024 (City of Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE CNG-1**~~

~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

Subject to all applicable laws and orders and the Company's rules and regulations on file with the regulatory authority.

The Company's Average Payment Plan, also known as the Average ~~Bill Calculation~~Payment Plan (~~ABC/~~APP Plan), is not available to customers served on this rate schedule.

This rate does not include any road use fees, permits, or taxes etc. It provides for the delivery of uncompressed natural gas only.

Customer must provide affidavit to the Company certifying that the gas delivered will be compressed for use as motor fuel.

The Customer's compressor station is subject to inspection by Company engineers.

~~Footnote 1: 2020 IRA - $133.74 (Gas Utilities Case No. 00005813); 2021 IRA - $113.60 (Gas Utilities Case No. 00008748); 2022 IRA - $143.83 (Gas Utilities Case No. 00012592)~~

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area

RATE SCHEDULE CNG-1
Page 3 of 3

~~**Supersedes Rate Schedule Dated**~~	~~**Meters Read On and After**~~
~~May 26, 2022 (CGSA Cities except Buda, Marble Falls and Pflugerville)~~	~~May 25, 2023 (CGSA Cities except Mustang Ridge)~~
~~September 15, 2022 (Cities of Buda, Marble Falls, and Pflugerville)~~	~~January 15, 2024 (City of Mustang Ridge)~~

COST OF GAS CLAUSE

A. ~~A.~~ APPLICABILITY

This Cost of Gas Clause shall apply to all ~~general~~gas sales service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") in all incorporated areas of its Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

B. ~~B.~~ DEFINITIONS

1. Cost of Gas - The rate per billing unit or the total calculation under this clause, consisting of the Commodity Cost, the Customer Rate Relief Component, the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, and the revenue associated fees (including franchise fees) and taxes.

2. Commodity Cost - The Cost of Purchased Gas multiplied by the Purchase/Sales Ratio plus an adjustment ~~for~~to correct any known and quantifiable under or over collection prior to the end of the reconciliation period~~.~~ for the objective of minimizing the impact of under or over collection by the reconciliation factor in the next year.

3. Cost of Purchased Gas - The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average cost for gas purchased by the Company from all sources where applicable. Such cost shall include not only the purchase cost of natural gas, but shall also include all reasonable costs for services such as gathering, treating, processing, transportation, capacity and/or supply reservation, applicable line loss charges, storage, balancing including penalties, ~~and~~ swing services, and any other related costs and expenses necessary for the movement of gas to the Company's city gate delivery points~~.~~ and customers. The Cost of Purchased Gas may also include costs related to the purchase and transportation of Renewable Natural Gas (RNG). ~~Renewable Natural Gas is the term used to describe pipeline-quality biomethane produced from biomass.~~ The Cost of Purchased Gas may also include the cost of "Environmental Attributes" purchased and retired in association with the purchase of RNG. The Cost of Purchased Gas shall also include the value of gas withdrawn from storage and shall include gains and losses from the utilization of natural gas financial instruments that are executed by the Company for the purpose of mitigating price volatility. Companies affiliated with, or sharing services with, the Company shall not be allowed to charge fees for transactions related to natural gas financial instruments utilized for purposes in this Cost of Gas Clause and hence cannot realize a profit in this regard.

4. Customer Rate Relief Component - The rate per billing unit charged in accordance with and specified on Rate Schedule CRR, the Customer Rate Relief Rate Schedule, ~~if applicable,~~ which is a ~~nonbypassable~~non-bypassable charge as defined in Tex. Util. Code § 104.362(7).

5. Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of RNG, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx),

COST OF GAS CLAUSE (Continued)

nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions.

~~5.~~6. Reconciliation Component - The amount to be returned to or recovered from sales customers each month from October through June as a result of the Reconciliation Audit.

~~1.~~ Reconciliation Audit - An annual review of the Company's books and records for each 12-month period ending with the production month of June to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its ~~general service~~sales customers

~~6.~~7. during the period, including ~~prudently incurred~~ gains or losses on the use of natural gas financial instruments; (b) the revenues received from operation of the provisions of this Cost of Gas Clause reduced by the amount of revenue associated fees (including franchise fees) and taxes paid by the Company on those revenues; (c) the total amount of surcharges or refunds made to sales customers during the period and any other revenues or credits received by the Company as a result of relevant gas purchases or operation of this Cost of Gas Clause; (d) the total amount accrued for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

~~7.~~8. Purchase/Sales Ratio - A ratio determined by dividing the total volumes purchased for ~~general service~~sales customers during the 12-month period ending June 30 by the sum of the sales volumes sold to ~~general service~~sales customers. For the purpose of this computation all volumes shall be stated at 14.65 psia. Such ratio as determined shall in no event exceed 1.0526 i.e. 1/(1 - 0.05) unless expressly authorized by the applicable Regulatory Authority.

9. RNG is the term used to describe pipeline-quality biogas produced from various biomass sources through a biochemical process that has been processed to purity standards and is interchangeable with conventional natural gas.

~~8.~~10. Reconciliation Account - The account maintained by the Company to assure that over time it will neither over nor under collect revenues as a result of the operation of the Cost of Gas Clause. Entries shall be made monthly to reflect: (a) the total amounts paid to the Company's supplier(s) for gas applicable to ~~general service~~sales customers as recorded on the Company's books and records (per Section B(3) above), including ~~prudently incurred~~ gains or losses on the use of natural gas financial instruments; (b) the revenues produced by the operation of this Cost of Gas Clause reduced by the amount of fees (including franchise fees) and taxes; (c) refunds, payments, or charges provided for herein or as approved by the Regulatory Authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s), (e) total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

COST OF GAS CLAUSE (Continued)

~~9.~~11. Uncollectible Cost of Gas – The amounts actually written off after the effective date of this rate schedule related to cost of gas will be tracked along with any subsequent recovery/credits related to the Cost of Gas Clause. Annually the charge offs minus recoveries will be included in the annual reconciliation and factored into the resulting Reconciliation Component.

C. ~~C.~~ COST OF GAS

In addition to the cost of service as provided under its ~~general service~~gas sales rate schedules, the Company shall bill each ~~general service~~sales customer for the Cost of Gas incurred during the billing period. The Cost of Gas shall be clearly identified on each customer bill.

D. ~~D.~~ DETERMINATION AND APPLICATION OF THE RECONCILIATION COMPONENT

If the Reconciliation Audit reflects either an over-recovery or under-recovery of revenues, such amount, plus or minus the amount of interest calculated pursuant to Section E below, if any, shall be divided by the ~~general service~~ sales volumes, adjusted for the effects of weather, growth, and conservation for the period

~~**COST OF GAS CLAUSE (Continued)**~~

beginning with the October billing cycle through the June billing cycle preceding the filing of the Reconciliation Audit. The Reconciliation Component so determined to collect any revenue shortfall or to return any excess revenue shall be applied, subject to refund, for a 9 month period beginning with the October billing cycle and continuing through the next June billing cycle at which time it will terminate.

E. ~~E.~~ INTEREST ON FUNDS

Concurrently with the Reconciliation Audit, the Company shall determine the amount by which the Cost of Gas was over or under collected for each month within the period of audit. The Company shall debit or credit to the Reconciliation Account for each month of the reconciliation period: (1) an amount equal to the outstanding over collected balance multiplied by interest of 6 percent per annum compounded monthly; or (2) an amount equal to the outstanding under collected balance multiplied by interest of 6 percent per annum compounded monthly. The Company shall also be allowed to recover a carrying charge calculated based on the arithmetic average of the beginning and ending balance of gas in storage inventory for the prior calendar month times the authorized rate of return.

F. ~~F.~~ SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's supplier are retroactively reduced and a refund of any previous payments is made to the Company, the Company shall make a similar refund to its ~~general service~~sales customers. Similarly, the Company may surcharge its ~~general service~~sales customers for retroactive payments made for gas previously delivered into the system. Any surcharge or refund amount will be included in the Reconciliation Account.

Refunds or charges shall be entered into the Reconciliation Account as they are collected from or returned to the customers. For the purpose of this Section F, the entry shall be made on the same basis used to determine the refund or charge component of the Cost of Gas and shall be subject to the calculation set forth in Section (E) Interest on Funds, above.

COST OF GAS CLAUSE (Continued)

G. ~~G.~~ COST OF GAS STATEMENT

The Company shall file a Cost of Gas Statement with the Regulatory Authority by the beginning of each billing month. The Cost of Gas Statement shall set forth: (a) the estimated Cost of Purchased Gas; (b) that cost multiplied by the Purchase/Sales Ratio; (c) the amount of the Cost of Gas caused by any surcharge or refund; (d) the Customer Rate Relief Component; (e) the Reconciliation Component; (f) the revenue associated fees (including franchise fees) and taxes to be applied to revenues generated by the Cost of Gas; (g) the Cost of Gas calculation, including gains and losses from hedging activities for the month; and (h) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

~~COST OF GAS CLAUSE (Continued)~~

H. ~~H.~~ ANNUAL RECONCILIATION REPORT

The Company shall file an Annual Reconciliation Report with the Regulatory Authority which shall include but not necessarily be limited to:

1. A tabulation of volumes of gas purchased and costs incurred listed by account or type of gas, supplier and source by month for the 12 months ending June 30.

2. A tabulation of gas units sold to ~~general service~~sales customers and related Cost of Gas Clause revenues~~, excluding the Customer Rate Relief Component.~~ .

3. A tabulation of all other costs and refunds made during the year and their effect on the Cost of Gas Clause to date.

4. A description of the hedging activities conducted each month during the 12 months ending June 30, including the types of transaction used, resulting gains and losses, any changes in the hedging program implemented during the period and the rationale for the changes. The report should include the customer impact of hedging activities stated as costs to the average residential and commercial customer during the period.

5. A description of the imbalance payments made to and received from the Company's transportation customers within the service area, including monthly imbalances incurred, the monthly ~~balances~~imbalances resolved, and the amount of the cumulative imbalance. The description should reflect the system imbalance and imbalance amount for each supplier using the Company's distribution system during the reconciliation period.

6. A tabulation of Uncollectible Cost of Gas during the period and its effect on the Cost of Gas Clause to date.

This report shall be filed concurrently with the Cost of Gas Statement for October. If the Regulatory Authority thereafter determines that an adjustment to the Reconciliation Component is required, such adjustment shall be included in the Reconciliation Component for the next annual Reconciliation Audit following the date of such determination.

PUBLIC SCHOOLS SPACE HEATING SERVICE RATE

APPLICABILITY

Applicable to public schools for space heating purposes. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

The incorporated areas of the Central-Gulf Service Area which includes, Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$156.05 plus
All Ccf per monthly billing period @	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-INC.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE.

Taxes: Plus applicable taxes and fees (including franchise fees) related to the above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area

RATE SCHEDULE 1Z
Page 1 of 4

SMALL RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a small residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential ~~consumer~~customer includes an individually-metered residential unit or dwelling that is operated by a public housing agency acting as an administrator of public housing programs under the direction of the U.S. Department of Housing and Urban Development and builders prior to sale or ~~resale~~re-sale of a property for domestic purposes. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of ~~$16.00~~ $25.50 plus
~~Interim Rate Adjustments (IRA) $ 6.85 per month (Footnote 1)~~
~~Total Customer Charge $22.85 per month~~

All Ccf per monthly billing period @ $0.~~3262~~69448 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 352 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 352 Ccf or Greater	Large Residential, Rate Schedule 1Y

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1ENV.~~ 1- ENV.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

Supersedes Rate Schedule Dated
January 15, 2024

Bills Rendered On and After
TBD

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

SMALL RESIDENTIAL SERVICE RATE
(Continued)

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~ ~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

~~**RESIDENTIAL SERVICE RATE (Continued)**~~

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $2.37 (Gas Utilities Case No. 00005813); 2021 IRA - $1.99 (Gas Utilities Case No. 00008748); 2022 IRA - $2.49 (Gas Utilities Case No. 00012592)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1Z**
Central-Gulf Service Area **Page 4 of 4**

~~Supersedes Rate Schedule Dated~~	~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~	~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

SMALL COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to all small commercial customers and to customers not otherwise specifically provided for under any other rate schedule. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of ~~$53.33~~ $85.00 plus
~~Interim Rate Adjustments (IRA) $30.59 per month (Footnote 1)~~
~~Total Customer Charge $83.92 per month~~

All Ccf per monthly billing period @ $0.~~12679~~15710 per Ccf

The Company will initially assign each Customer to the rate schedule that is the most economical based on the annual normalized volume at the Customer's service location for the prior twelve (12)-month period. An anticipated annual normalized usage level assessment will be conducted on each new service and for existing service that has less than twelve (12) months of service. The results of this assessment will decide the initial rate assignment:

Annual Normalized Volume Less than 3,640 Ccf	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,640 Ccf or Greater	Large Commercial, Rate Schedule 2Y

The Company will allow customers to elect service on a different rate schedule, provided that the customer must remain on the alternative rate schedule for a period of no less than twelve (12) months. Rate Schedule changes will be effective with the Customer's next scheduled bill.

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1ENV.~~ 1- ENV.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

SMALL COMMERCIAL SERVICE RATE

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

SMALL COMMERCIAL SERVICE RATE
(Continued)

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Falls and Pflugerville)~~ ~~January 15, 2024 (Unincorporated Hutto Marble and Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE 2Z**~~
~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

~~**COMMERCIAL SERVICE RATE (Continued)**~~

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 2: 2020 IRA - $10.04 (Gas Utilities Case No. 00005813); 2021 IRA - $9.07 (Gas Utilities Case No. 00008748); 2022 IRA - $11.48 (Gas Utilities Case No. 00012592)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Z**
Central-Gulf Service Area **Page 4 of 4**

SMALL COMMERCIAL SERVICE RATE

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Falls and Pflugerville)~~ ~~January 15, 2024 (Unincorporated Hutto Marble and Mustang Ridge)~~

INDUSTRIAL SERVICE RATE

APPLICABILITY

Applicable to any qualifying industrial customer whose primary business activity at the location served is included in one of the following classifications of the Standard Industrial Classification Manual of the U.S. Government.

Division B - Mining - all Major Groups
Division D - Manufacturing - all Major Groups
Divisions E and J - Utility and Government - facilities generating power for resale only

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of ~~$320.96~~ $572.02 plus
~~Interim Rate Adjustments (IRA) $469.24 per month (Footnote 1)~~
~~Total Customer Charge $790.20 per month~~

All Ccf per monthly billing period @ $0.12707 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1ENV.~~ 1- ENV.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

~~Supersedes Rate Schedule Dated~~	~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop,~~	~~January 15, 2024 (Unincorporated Hutto~~

~~Marble Falls and Pflugerville) and Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc. RATE SCHEDULE 3Z**~~
~~**Central-Gulf Service Area Page 2 of 2**~~

~~**INDUSTRIAL SERVICE RATE (Continued)**~~

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $164.48 (Gas Utilities Case No. 00005813); 2021 IRA - $137.93 (Gas Utilities Case No. 00008748); 2022 IRA - $166.83 (Gas Utilities Case No. 00012592)~~

~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~	~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~
~~-~~January 15, 2024	TBD

PUBLIC AUTHORITY SERVICE RATE

APPLICABILITY

Applicable to any qualifying public authority, public and parochial schools and colleges, and to all facilities operated by Governmental agencies not specifically provided for in other rate schedules or special contracts. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	~~$ 81.70~~ $156.05 plus
~~Interim Rate Adjustments (IRA)~~	~~$ 56.79 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$138.49 per month~~
All Ccf per monthly billing period @	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1ENV.~~ 1- ENV.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

~~Supersedes Rate Schedule Dated~~	~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~

~~**PUBLIC AUTHORITY SERVICE RATE (Continued)**~~

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

Supersedes Rate Schedule Dated ~~Meters Read~~	Bills Rendered On and After
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~	January 15, 2024 ~~(Unincorporated Hutto and Mustang Ridge)~~ TBD

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area

RATE SCHEDULE 7Z
Page 1 of 3

UNMETERED GAS LIGHT SERVICE RATE

APPLICABILITY

Applicable to any Customer on Texas Gas Service Company, a Division of ONE Gas, Inc.'s system requiring natural gas service for gas lighting only, without the use of metering device. Gas service is only available to Customers utilizing standard gas lighting equipment manufactured with an orifice burner assembly or equivalent that is intended for lighting of sidewalks and other walkways. The Company, in its sole discretion, shall determine if Customer's lighting equipment qualifies for this tariff and shall contract with Customer for the appropriate monthly charge based upon Customer's complete installation of gas lighting equipment. Gas service under this rate schedule is available only with the Company as the sole supplier of gas for Customer and is not available for resale to others or for standby or supplemental service. ~~This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.~~

TERRITORY

Environs of the Central-Gulf Service Area which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

The total hourly rated consumption of all gas lighting equipment included, expressed in Ccf at the location, shall be multiplied by 730 for gas lighting equipment that runs continuously or 365 for gas lighting equipment with a light sensor, to determine the average monthly consumption of the service. The result, rounded to the next highest Ccf, shall then be billed the rates provided in this rate schedule:

~~Residential~~	-	~~$ 0.32626 per Ccf~~
~~Commercial~~	-	~~$ 0.12679 per Ccf~~
~~Industrial~~	-	~~$ 0.12707 per Ccf~~
~~Public Authority~~	-	~~$ 0.12549 per Ccf~~

Residential	$0.69448 per Ccf
Commercial	$0.15710 per Ccf
Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1ENV.~~ 1-ENV.

Taxes: Plus applicable taxes and fees related to above.

Initial Rate Schedule
January 15, 2024

Bills Rendered On and After
TBD

UNMETERED GAS LIGHT SERVICE RATE

~~Initial Rate Schedule~~ ~~Meters Read On and After~~
~~August 4, 2020 (All Unincorporated Areas except Bastrop,~~
~~Hutto, Marble Falls, Mustang Ridge, and Pflugerville)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble~~
~~Falls and Pflugerville)~~
~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

~~UNMETERED GAS LIGHT SERVICE RATE~~ (Continued)

CONDITIONS

The Customer shall ensure that the installation of lighting equipment conforms to industry safety standards. The Company reserves the right to review Customer's installation of lighting equipment from time to time to determine if it conforms to terms and conditions as set forth in this tariff and the executed service agreement with the Customer. Customer shall notify Company in writing within 30 days of any change in number of gas lights or other material changes made to the gas lighting installation.

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

UNMETERED GAS LIGHT SERVICE RATE

~~Initial Rate Schedule~~ ~~Meters Read On and After~~
~~August 4, 2020 (All Unincorporated Areas except Bastrop,~~
~~Hutto, Marble Falls, Mustang Ridge, and Pflugerville)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble~~
~~Falls and Pflugerville)~~
~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

~~ELECTRICAL COGENERATION RATE~~
ELECTRIC GENERATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any customers who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc. to use natural gas for the purpose of ~~cogeneration or the use of fuel cell technology. Cogeneration~~electric generation. Electric generation is defined as ~~the use of thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.~~ facilities registered with the applicable balancing authority including bulk power system assets, co-generation facilities, distributed generation, and or backup power systems.

TERRITORY

~~Environs~~
This rate shall be available in the unincorporated areas of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:
A customer charge per meter per month of ~~$104.70 plus~~

~~Interim Rate Adjustments (IRA)~~

~~$ 56.79~~

$175.98

A delivery charge per ~~month (Footnote 1)~~ monthly billing period

@
~~Total Customer Charge $161.49 per month~~

For the First	5,000 Ccf/Month	$0.~~07720~~07427 per Ccf
For the Next	35,000 Ccf/Month	$0.~~06850~~06590 per Ccf
For the Next	60,000 Ccf/Month	$0.~~05524~~05314 per Ccf
All Over	100,000 Ccf/Month	$0.~~04016~~03864 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of the Cost of Gas Clause, Rate Schedule ~~1ENV.~~ 1-ENV.

~~Excess Deferred Income Taxes~~
Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the ~~Excess~~

~~Deferred Income Taxes~~Pipeline Integrity Testing Rider, Rate ~~Schedule EDIT~~Schedules PIT and PIT-Rider~~.~~ if applicable.

~~Hurricane Harvey Surcharge Rider~~

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the ~~Hurricane Harvey Surcharge~~Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule ~~HARV Rider, if applicable.~~ PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

~~Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT, if applicable.~~

~~**Supersedes Rate Schedule Dated**~~	~~**Meters Read On and After**~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~	~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.** **RATE SCHEDULE C-1-ENV**~~
~~**Central-Gulf Service Area** **Page 2 of 2**~~

~~**ELECTRICAL COGENERATION RATE (Continued)**~~

Taxes: Plus applicable taxes and fees related to above.

ELECTRIC GENERATION SERVICE RATE
(Continued)

CONDITIONS

1. Gas taken under this rate shall be used exclusively for the purpose of ~~cogeneration and fuel cell technology~~electric generation as defined in the Applicability section of this rate schedule and not for other purposes. The gas taken under this rate will be separately metered.

~~This rate will not be available for standby use.~~

~~The curtailment priority of any customer served under this rate schedule shall be the same as the curtailment priority which would pertain if gas were used directly to provide energy for uses as defined and listed in the Company's curtailment plan.~~

2. For the purpose of this rate, the annual load factor must be 60 percent or greater. The annual load factor is defined as the customer's total annual consumption divided by the customer's peak month consumption times twelve. If less than 60 percent load factor occurs for a twelve-month period, the rate charges will revert back to the rate that the customer would have otherwise been served under. A continuous twelve-month period of 60 percent or better load factor must precede a return to the electric generation rate.

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

~~Footnote 1: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

~~**Supersedes Rate Schedule Dated**~~	~~**Meters Read On and After**~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop,~~ ~~2.~~3. ~~Marble Falls and Pflugerville)~~	~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

TRANSPORTATION SERVICE RATE

APPLICABILITY

Applicable to customers who have elected Transportation Service not otherwise specifically provided for under any other rate schedule.

Service under this rate schedule is available for the transportation of customer-owned natural gas through Texas Gas Service Company, a Division of ONE Gas, Inc.'s (the "Company") distribution system. The customer must arrange with its gas supplier to have the customer's gas delivered to one of the Company's existing ~~delivery~~ receipt points for transportation by the Company to the customer's facilities at the customer's delivery point. The receipt points shall be specified by the Company at its reasonable discretion, taking into consideration available capacity, operational constraints, and integrity of the distribution system.

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's unincorporated areas of the Central-Gulf Service Area distribution system which includes the environs of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas. Such service shall be provided at any point on the Company's System where adequate capacity and gas supply exists, or where such capacity and gas supply can be provided in accordance with the applicable rules and regulations and at a reasonable cost as determined by the Company in its sole opinion.

COST OF SERVICE RATE

During each monthly billing period, a customer charge per meter per month listed by customer class as follows:

Commercial $297.51 per month

~~Commercial $265.33~~ Industrial $772.02 per month
~~plus Interim Rate Adjustments $30.59 (Footnote 1) Total Rate $295.92~~

~~Industrial $520.96 per month~~
~~plus Interim Rate Adjustments $469.24 (Footnote 2) Total Rate $990.20~~

Public Authority ~~$104.70 per month plus Interim Rate Adjustments $56.79 (Footnote 3) Total Rate $161.49~~ ~~**TRANSPORTATION SERVICE RATE (Continued)**~~

~~Public Schools Space Heat $234.70 per month plus Interim Rate Adjustments $56.79 (Footnote 4) Total Rate $291.49~~

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~ ~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

$179.05 per month Compressed Natural Gas ~~$217.63 per month plus Interim Rate Adjustments $391.17 (Footnote 5) Total Rate $608.80~~

$619.88 per month

Electrical ~~Cogeneration $104.70 per month plus Interim Rate Adjustments $56.79 (Footnote 6) Total Rate $161.49~~

Generation $175.98 per month

TRANSPORTATION SERVICE RATE
(Continued)

Plus – ~~All Ccf~~A delivery charge per monthly billing period listed by customer class as

follows: Commercial $0.12679 per Ccf

~~Commercial~~	~~$0.12679 per Ccf~~
~~Industrial~~	~~$0.12707 per Ccf~~
~~Public Authority~~	~~$0.12549 per Ccf~~
~~Public Schools Space Heat~~	~~$0.10012 per Ccf~~
~~Compressed Natural Gas~~	~~$0.06684 per Ccf~~
~~Electrical Cogeneration~~	
~~For the First 5,000Ccf/month~~	~~$0.07720 per Ccf~~
~~For the Next 35,000 Ccf/month~~	~~$0.06850 per Ccf~~
~~For the Next 60,000 Ccf/month~~	~~$0.05524 per Ccf~~
~~All Over 100,000 Ccf/month~~	~~$0.04016 per Ccf~~

Industrial	$0.12707 per Ccf
Public Authority	$0.12549 per Ccf
Compressed Natural Gas	$0.06684 per Ccf
Electrical Generation	
For the First 5,000Ccf/month	$0.07427 per Ccf
For the Next 35,000 Ccf/month	$0.06590 per Ccf
For the Next 60,000 Ccf/month	$0.05314 per Ccf
All Over 100,000 Ccf/month	$0.03864 per Ccf

ADDITIONAL CHARGES

1) A charge will be made each month to recover the cost of taxes paid to the State of Texas pursuant to Texas Utilities Code, Chapter 122 as such may be amended from time to time which are attributable to the transportation service performed hereunder.

2) A charge will be made each month to recover the cost of any applicable local taxes and fees.

~~2)~~3) In the event the Company incurs a demand or reservation charge from its gas supplier(s) or transportation providers in the unincorporated areas of the Central-Gulf Service Area, the customer may be charged its proportionate share of the demand or reservation charge based on benefit received by the customer.

~~3)~~4) The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

~~4)~~5) The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

~~**TRANSPORTATION SERVICE RATE**~~
~~**(Continued)**~~

TRANSPORTATION SERVICE RATE
(Continued)

~~1)~~ The billing shall reflect adjustments in accordance with the provisions of the ~~Excess Deferred Income Taxes~~Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule ~~EDIT-Rider.~~

~~5)~~6) ~~The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider~~PSF, if applicable.

TRANSPORTATION SERVICE RATE
(Continued)

SUBJECT TO

1) Tariff T-TERMS, General Terms and Conditions for Transportation.

2) Transportation of natural gas hereunder may be interrupted or curtailed at the discretion of the Company in case of shortage or threatened shortage of gas supply from any cause whatsoever, to conserve gas for residential and other higher priority customers served. The curtailment priority of any customer served under this schedule shall be the same as the curtailment priority established for other customers served pursuant to the Company's rate schedule which would otherwise be available to such customer.

~~1) Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.~~

~~Footnote 1: 2020 IRA - $10.04 (Gas Utilities Case No. 00005813); 2021 IRA - $9.07 (Gas Utilities Case No. 00008748); 2022 IRA - $11.48 (Gas Utilities Case No. 00012592)~~

~~Footnote 2: 2020 IRA - $164.48 (Gas Utilities Case No. 00005813); 2021 IRA - $137.93 (Gas Utilities Case No. 00008748); 2022 IRA - $166.83 (Gas Utilities Case No. 00012592)~~

~~Footnote 3: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

~~Footnote 4: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

~~Footnote 5: 2020 IRA - $133.74 (Gas Utilities Case No. 00005813); 2021 IRA - $113.60 (Gas Utilities Case No. 00008748); 2022 IRA - $143.83 (Gas Utilities Case No. 00012592)~~

~~Footnote 6: 2020 IRA - $19.58 (Gas Utilities Case No. 00005813); 2021 IRA - $16.47 (Gas Utilities Case No. 00008748); 2022 IRA - $20.74 (Gas Utilities Case No. 00012592)~~

3) The taking of service under this rate schedule is subject to all valid orders, laws, rules, and regulations of duly constituted State and Federal governmental authorities and agencies having jurisdiction or control over the parties, their facilities or gas supplies, the Agreement, or any provision hereof. The Company reserves the right to seek modification or termination of any of the General Terms and Conditions, the Gas Transportation Agreement, and any of the tariffs to which it applies.

~~3)~~4) The Agreement shall be interpreted under Texas law.

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

Applicable to any non-residential customer of Texas Gas Service Company, a Division of ONE Gas, Inc., (the "Company") for usage where customer purchases natural gas which will be compressed and used as a motor fuel. Service will be separately metered. This rate does not include compression by ~~Texas Gas Service Company, a Division of ONE Gas, Inc. (the "~~the Company~~")~~ beyond normal meter sales pressure.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	~~$192.63~~$594.88 plus
~~Interim Rate Adjustments (IRA)~~	~~$391.17 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$583.80 per month~~
All Ccf per monthly billing period @	$0.06684 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule ~~1ENV.~~ 1- ENV.

~~Excess Deferred Income Taxes Rider: The billing shall reflect adjustments in accordance with provisions of the Excess Deferred Income Taxes Rider, Rate Schedule EDIT-Rider.~~

~~Hurricane Harvey Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Hurricane Harvey Surcharge Rider, Rate Schedule HARV-Rider, if applicable.~~

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT and PIT-Rider, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF, if applicable.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

~~**Supersedes Rate Schedule Dated**~~ ~~**Meters Read On and After**~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~ ~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~ ~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE CNG-1-ENV**~~
~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

Subject to all applicable laws and orders and the Company's rules and regulations on file with the regulatory authority.

The Company's Average Payment Plan, also known as the Average ~~Bill Calculation~~Payment Plan (~~ABC/~~APP Plan), is not available to customers served on this rate schedule.

This rate does not include any road use fees, permits, or taxes etc. It provides for the delivery of uncompressed natural gas only.

Customer must provide an affidavit to the Company certifying that the gas delivered will be compressed for use as motor fuel.

The Customer's compressor station is subject to inspection by Company engineers.

~~Footnote 1: 2020 IRA - $133.74 (Gas Utilities Case No. 00005813); 2021 IRA - $113.60 (Gas Utilities Case No. 00008748); 2022 IRA - $143.83 (Gas Utilities Case No. 00012592)~~

~~**Supersedes Rate Schedule Dated**~~	~~**Meters Read On and After**~~
~~May 26, 2022 (All Unincorporated Areas except Bastrop, Marble Falls and Pflugerville)~~	~~May 25, 2023 (All Unincorporated Areas except Hutto and Mustang Ridge)~~
~~September 15, 2022 (Unincorporated Bastrop, Marble Falls and Pflugerville)~~	~~January 15, 2024 (Unincorporated Hutto and Mustang Ridge)~~

COST OF GAS CLAUSE

A. ~~A.~~ APPLICABILITY

This Cost of Gas Clause shall apply to all ~~general~~gas sales service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") in all unincorporated areas of its Central-Gulf Service Area including Austin, Bayou Vista, Beaumont, Bastrop, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

B. ~~B.~~ DEFINITIONS

1. Cost of Gas - The rate per billing unit or the total calculation under this clause, consisting of the Commodity Cost, the Customer Rate Relief Component, the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, and the revenue associated fees and taxes.

2. Commodity Cost - The Cost of Purchased Gas multiplied by the Purchase/Sales Ratio plus an adjustment ~~for~~to correct any known and quantifiable under or over collection prior to the end of the reconciliation period~~.~~ for the objective of minimizing the impact of under or over collection by the reconciliation factor in the next year.

3. Cost of Purchased Gas - The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average cost for gas purchased by the Company from all sources where applicable. Such cost shall include not only the purchase cost of natural gas, but shall also include all reasonable costs for services such as gathering, treating, processing, transportation, capacity and/or supply reservation, applicable line loss charges, storage, balancing including penalties, ~~and~~ swing services, and any other related costs and expenses necessary for the movement of gas to the Company's city gate delivery points~~.~~ and customers. The Cost of Purchased Gas may also include costs related to the purchase and transportation of Renewable Natural Gas (RNG). ~~Renewable Natural Gas is the term used to describe pipeline-quality biomethane produced from biomass.~~ The Cost of Purchased Gas shall also include the cost of "Environmental Attributes" purchased and retired in association with the purchase of RNG. The Cost of Purchased Gas shall not include the cost of financial instruments unless the use of such financial instruments is approved in advance and in writing by the Director of the Oversight and Safety Division of the Railroad Commission of Texas. Such approval would be requested as part of the Company's annual gas purchase plan, which shall be submitted annually to the Commission no later than June 15.

4. Customer Rate Relief Component - The rate per billing unit charged in accordance with and specified on Rate Schedule CRR, the Customer Rate Relief Rate Schedule, ~~if applicable,~~ which is a ~~nonbypassable~~non-bypassable charge as defined in Tex. Util. Code § 104.362(7).

5. Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of RNG, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of

COST OF GAS CLAUSE (Continued)

any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions.

~~5.~~6. Reconciliation Component - The amount to be returned to or recovered from sales customers each month from October through June as a result of the Reconciliation Audit.

~~6.~~7. Reconciliation Audit - An annual review of the Company's books and records for each 12-month period ending with the production month of June to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its ~~general service~~sales customers during the period, including ~~prudently incurred~~ gains or losses on the ~~approved~~ use of natural gas financial instruments; (b) the revenues received from operation of the provisions of this Cost of Gas Clause reduced by the amount of revenue associated fees and taxes paid by the Company on those revenues; (c) the total amount of surcharges or refunds made to sales customers during the period and any other revenues or credits received by the Company as a result of relevant gas purchases or operation of this Cost of Gas Clause; (d) the total amount accrued for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

8. RNG - the term used to describe pipeline-quality biogas produced from various biomass sources through a biochemical process that has been processed to purity standards and is interchangeable with conventional natural gas.

~~7.~~9. Purchase/Sales Ratio - A ratio determined by dividing the total volumes purchased for ~~general service~~sales customers during the 12 month period ending June 30 by the sum of the sales volumes sold to ~~general service~~sales customers. For the purpose of this computation all volumes shall be stated at 14.65 psia. Such ratio as determined shall in no event exceed 1.0526 i.e. 1/(1 - 0.05) unless expressly authorized by the applicable Regulatory Authority.

~~8.~~10. Reconciliation Account - The account maintained by the Company to assure that over time it will neither over nor under collect revenues as a result of the operation of the Cost of Gas Clause. Entries shall be made monthly to reflect: (a) the total amounts paid to the Company's supplier(s) for gas applicable to ~~general service~~sales customers as recorded on the Company's books and records (per Section B(3) above), including ~~prudently incurred~~ gains or losses on the use of approved natural gas financial instruments; (b) the revenues produced by the operation of this Cost of Gas Clause reduced by the amount of fees and taxes; (c) refunds, payments, or charges provided for herein or as approved by the Regulatory Authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s); (e) total amount of Uncollectible Cost of Gas during the period; and (f) an adjustment, if necessary, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

~~9.~~11. Uncollectible Cost of Gas – The amounts actually written off after the effective date of this rate schedule related to cost of gas will be tracked along with any subsequent recovery/credits related to the Cost of Gas Clause. Annually the charge offs minus recoveries will be included in the annual reconciliation and factored into the resulting Reconciliation Component.

COST OF GAS CLAUSE (Continued)

C. ~~C.~~ COST OF GAS

In addition to the cost of service as provided under its ~~general service~~gas sales rate schedules, the Company shall bill each ~~general service~~sales customer for the Cost of Gas incurred during the billing period. The Cost of Gas shall be clearly identified on each customer bill.

D. ~~D.~~ DETERMINATION AND APPLICATION OF THE RECONCILIATION COMPONENT

If the Reconciliation Audit reflects either an over-recovery or under-recovery of revenues, such amount, plus or minus the amount of interest calculated pursuant to Section E below, if any, shall be divided by the ~~general service~~ sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the October billing cycle through the June billing cycle preceding the filing of the Reconciliation Audit. The Reconciliation Component so determined to collect any revenue shortfall or to return any excess revenue shall be applied, subject to refund, for a 9 month period beginning with the October billing cycle and continuing through the next June billing cycle at which time it will terminate.

E. ~~E.~~ INTEREST ON FUNDS

Concurrently with the Reconciliation Audit, the Company shall determine the amount by which the Cost of Gas was over or under collected for each month within the period of audit. The Company shall debit or credit to the Reconciliation Account for each month of the reconciliation period: (1) an amount equal to the outstanding over collected balance multiplied by interest of 6 percent per annum compounded monthly; or (2) an amount equal to the outstanding under collected balance multiplied by interest of 6 percent per annum compounded monthly. The Company shall also be allowed to recover a carrying charge calculated based on the arithmetic average of the beginning and ending balance of gas in storage inventory for the prior calendar month times the authorized rate of return.

F. ~~F.~~ SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's supplier are retroactively reduced and a refund of any previous payments is made to the Company, the Company shall make a similar refund to its ~~general service~~sales customers. Similarly, the Company may surcharge its ~~general service~~sales customers for retroactive payments made for gas previously delivered into the system. Any surcharge or refund amount will be included in the Reconciliation Account.

Refunds or charges shall be entered into the Reconciliation Account as they are collected from or returned to the customers. For the purpose of this Section F, the entry shall be made on the same basis used to determine the refund or charge component of the Cost of Gas and shall be subject to the calculation set forth in Section (E) Interest on Funds, above.

COST OF GAS CLAUSE (Continued)

G. ~~G.~~ COST OF GAS STATEMENT

The Company shall file a Cost of Gas Statement with the Regulatory Authority by the beginning of each billing month. The Cost of Gas Statement shall set forth: (a) the estimated Cost of Purchased Gas; (b) that cost multiplied by the Purchase/Sales Ratio; (c) the amount of the Cost of Gas caused by any surcharge or refund; (d) the Customer Rate Relief Component; (e) the Reconciliation Component; ~~fe~~f) the revenue associated fees and taxes to be applied to revenues generated by the Cost of Gas; (g) the Cost of Gas calculation, including gains and losses from approved hedging activities for the month; and (h) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

H. ~~H.~~ ANNUAL RECONCILIATION REPORT

The Company shall file an Annual Reconciliation Report with the Regulatory Authority which shall include but not necessarily be limited to:

1. A tabulation of volumes of gas purchased and costs incurred listed by account or type of gas, supplier and source by month for the 12 months ending June 30.

2. A tabulation of gas units sold to ~~general service~~sales customers and related Cost of Gas Clause revenues~~, excluding the Customer Rate Relief Component.~~ .

3. A tabulation of all other costs and refunds made during the year and their effect on the Cost of Gas Clause to date.

4. A description of the hedging activities conducted each month during the 12 months ending June 30, including the types of transaction used, resulting gains and losses, any changes in the hedging program implemented during the period and the rationale for the changes. The report should include the customer impact of hedging activities stated as costs to the average residential and commercial customer during the period.

5. A description of the imbalance payments made to and received from the Company's transportation customers within the service area, including monthly imbalances incurred, the monthly ~~balances~~imbalances resolved, and the amount of the cumulative imbalance. The description should reflect the system imbalance and imbalance amount for each supplier using the Company's distribution system during the reconciliation period.

6. A tabulation of Uncollectible Cost of Gas during the period and its effect on the Cost of Gas Clause to date.

This report shall be filed concurrently with the Cost of Gas Statement for October. If the Regulatory Authority ~~thereafter~~ determines that an adjustment to the Reconciliation Component is required, such adjustment shall be included in the Reconciliation Component for the next annual Reconciliation Audit following the date of such determination.

Texas Gas Service Company, a Division of ONE Gas, Inc. — **RATE SCHEDULE 4H**
Central-Gulf Service Area — **Page 1 of 1**

PUBLIC SCHOOLS SPACE HEATING SERVICE RATE

APPLICABILITY

Applicable to public schools for space heating purposes. This rate is only available to full requirements customers of Texas Gas Service Company, a Division of ONE Gas, Inc.

TERRITORY

Environs of the Central-Gulf Service Area, which includes the unincorporated areas of Austin, Bastrop, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$156.05 plus
All Ccf per monthly billing period @	$0.12549 per Ccf

OTHER ADJUSTMENTS

Cost of Gas Component: The basic rates for cost of service set forth above shall be increased by the amount of the Cost of Gas Component for the billing month computed in accordance with the provisions of Rate Schedule 1-ENV.

Pipeline Integrity Testing Rider: The billing shall reflect adjustments in accordance with provisions of the Pipeline Integrity Testing Rider, Rate Schedule PIT, if applicable.

Pipeline Safety and Regulatory Program Fees: The billing shall reflect adjustments in accordance with provisions of the Pipeline Safety and Regulatory Program Fees Rider, Rate Schedule PSF.

Rate Case Expense Rider: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Rider, Rate Schedule RCE-ENV.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with the provisions of the Weather Normalization Adjustment Clause, Rate Schedule WNA.

CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

Supersedes Rate Schedule Dated
January 15, 2024

Bills Rendered On and After
TBD

PIPELINE INTEGRITY TESTING (PIT) RIDER

PURPOSE

The purpose of this Pipeline Integrity Testing Rider is to promote the public interest in pipeline safety by enabling Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") to recover the reasonable and necessary Pipeline Integrity Safety Testing expenses incurred by the Company during the prior year (including contractor costs but excluding the labor cost of Texas Gas Service Company employees). These legally mandated operating and maintenance expenses shall be recovered through a separate monthly volumetric charge (the Pipeline Integrity Testing or "PIT" Surcharge) that shall be shown as a separate line item on the customer's monthly bill and calculated for each customer class as described below. Capital expenditures associated with the Pipeline Integrity Program shall continue to be recovered through base rates and any interim rate adjustments implemented pursuant to Section ~~104.301 of the Gas Utility Regulatory Act.~~
104.301 of the Texas Utilities Code.

APPLICABILITY

This Rider shall be applied to all gas sales and transportation customers within the service territory designated below, except special contract customers.

TERRITORY

This Rider shall apply to the following gas sales and standard transportation rate schedules of the Company's ~~CentralGulf~~Central- Gulf Service Area ("CGSA") within the incorporated and unincorporated areas of Austin, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Georgetown, Gonzales, Hutto, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nixon, Pflugerville, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas and in the environs area of Bastrop ~~and Hutto~~, Texas: 10, 15, 20, 25, 30, 40, ~~48,~~ C-1, CNG-1, 1Z, 1Y, 2Z, 2Y, 3Z, ~~4H,~~ 4Z, C-1-ENV, CNG-1-ENV, T-1, and T-~~1ENV.~~ 1-ENV.

QUALIFYING EXPENSES

This Rider applies only to the legally mandated safety testing of the Company's transmission lines in the CGSA under the Pipeline Integrity Safety Testing Program. The operating and maintenance expense items that qualify for recovery under this Rider shall include the contractor costs associated with land and leak survey, permitting, and job order preparation and completion; the clearing of right-of-way; any needed notifications to adjacent businesses and residences; traffic control equipment and personnel; Direct Current Voltage Gradient ("DCVG"), Close Interval ("CI"), and other surveys to ensure the integrity of the pipeline system; any required rigid bypasses; flushing of the lines and testing and disposal of the flush water; hydrostatic testing of the lines and analysis and disposal of the test water; any required "pigging" of the lines in connection with safety testing; any required x-ray welding; metallurgical testing of the pipeline or components thereof; site restoration, painting, and clean-up; expenses associated with providing a supply of compressed natural gas ("CNG") to ensure uninterrupted service to customers during testing; and any other operating and maintenance expenses reasonably necessary to safely and effectively perform required safety testing of the Company's pipelines in the CGSA. Neither capital expenditures by the Company, nor the labor cost of ~~Texas Gas Service~~ Company employees, shall be recovered under this Rider.

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

CALCULATION OF PIT SURCHARGES

The Pipeline Integrity Testing Surcharges established under this Rider shall be designed so as to recover the Total Testing Expense incurred in the prior year for Pipeline Integrity Safety Testing, ~~except that qualifying expenses incurred in 2019 and 2020 shall be included for recovery in the first filing,~~ and shall be calculated as follows:

The Total Annual Testing Expense shall be divided by the estimated average annual usage to produce the annual PIT Surcharge.

$$\text{PIT Surcharge} \; \cancel{=} \; = \frac{\text{Total Annual Testing Expense}}{\text{Estimated Annual Usage}}$$

Based upon customer data for the prior calendar year and any other relevant factors, the estimated annual usage may be revised annually to account for customer growth, and the resulting revised PIT Surcharge shall be applied to each class for the ensuing 12-month recovery period.

ANNUAL RECONCILIATION

After completion of each annual recovery period, the total revenues collected under this Rider for that year shall be reconciled against the revenues previously calculated to be collected for that year, and the PIT Surcharge for each class shall be adjusted upward or downward so that the Company recovers any underrecoveries or refunds any overrecoveries that may have accrued under the Rider, plus monthly interest on those underrecoveries or overrecoveries at the cost of long-term debt approved in the Company's most recent general rate case in which rates were set for application to customers in the CGSA. The reconciliation shall be filed with the regulatory authority on or before February 21st of each year, and the regulatory authority shall complete its review of the reconciliation on or before March 21st of each year, so that the Company can implement the reconciled PIT Surcharges beginning with the first billing cycle for April of each succeeding year.

DEFERRED ACCOUNTING

The Company is authorized and directed to defer, as a regulatory asset, all Pipeline Integrity Safety Testing expenses incurred during the testing cycle starting on January 1, 2016 and all revenues specifically collected under this Rider shall be applied to the deferred expense account. The Company shall not earn a return on any regulatory asset created under this provision, and no such regulatory asset shall be included in the Company's invested capital (rate base) for ratemaking purposes.

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

ANNUAL REPORT & APPLICABLE PSCC

On or before February 21st after each calendar year, the Company shall file a report with the Commission and the CGSA Cities showing all Pipeline Integrity Safety Testing expenses incurred during the previous calendar year and verifying the prior year's collections and any underrecoveries or overrecoveries accruing to date under this Rider. The report shall separately identify and list such expenses by account number and project number. Prior to the effective date of this Rider and on or before February 21st of each succeeding year while this Rider is in effect, the Company shall also file an Addendum to this Rider with the Commission and the CGSA Cities (a) identifying the PIT Surcharges that will be applied during the ensuing 12-month recovery period from April ~~1st~~ through March ~~31st~~billing cycles, and (b) providing the underlying data and calculations on which each PIT Surcharge for that period is based.

The Company shall file the report with the Commission electronically at GUD_Compliance@rrc.texas.gov or at the following address:

Director of Oversight and Safety Division
Gas Services Department
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

NOTICE TO AFFECTED CUSTOMERS

In addition to the annual report and Addendum to this Rider required above, the Company shall provide, on or before March 31st after each calendar year, written notice to each affected customer of (a) the PIT Surcharge that will be applied during the ensuing 12-month period from April ~~1st~~ through March ~~31st~~billing cycles, and (b) the effect the PIT Surcharge is expected to have on the average monthly bill for each affected customer class. The written notice shall be provided in both English and Spanish, shall be the only information contained on the piece of paper on which it is printed, and may be provided either by separate mailing or by insert included with the Company's monthly billing statements~~.~~, including electronic billing statements. The Company shall also electronically file an affidavit annually with the Commission and the CGSA Cities certifying that notice has been provided to customers in this manner. The notice shall be presumed to be complete three calendar days after the date the separate mailing or billing statement is deposited in a postage-paid, properly addressed wrapper in a post office or official depository under care of the United States Postal Service. The initial notice shall be filed with, reviewed, and approved by the regulatory authority, and each subsequent notice shall follow the same format as that of the approved initial notice.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Central-Gulf Service Area (Select areas) **RATE SCHEDULE PIT-RIDER**

PIPELINE INTEGRITY TESTING (PIT) SURCHARGE RIDER

A. ~~A.~~ APPLICABILITY

The Pipeline Integrity Testing Surcharge (PIT) rate as set forth in Section (B) below is for the recovery of costs associated with pipeline integrity testing as defined in Rate Schedule PIT. This rate shall apply to the following gas sales and standard transportation rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. currently in force in the Company's Central-Gulf Service Area ("CGSA") within the incorporated and unincorporated areas of Austin, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Georgetown, Gonzales, Hutto, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nixon, Pflugerville, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas and in the environs area of Bastrop, Texas: 10, 15, 20, 25, 30, 40, ~~48,~~ C-1, CNG-1, ~~T-1~~T-1, 1Z, 1Y, 2Z, 2Y, 3Z, 4Z, ~~4H,~~ C-1-ENV, CNG-1-ENV and T-1-ENV.

B. ~~B.~~ PIT RATE

-$0.00010 per Ccf ~~(a credit)~~

This rate will be in effect until all approved and expended pipeline integrity testing expenses are recovered under the applicable rate schedules.

C. ~~C.~~ OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees (including franchises fees) related to above.

D. CONDITIONS

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

WEATHER NORMALIZATION ADJUSTMENT CLAUSE

APPLICABILITY

The Weather Normalization Adjustment Clause (WNA) shall apply to the following general service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") in the incorporated and unincorporated areas served in the Central-Gulf Service Area including Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto ~~(environs only),~~, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas: Rate Schedules 10, 15, 1Z, 1Y, 20, 25, 2Z, 2Y, 40, ~~4Z, 48~~ and ~~4H~~4Z. The WNA shall be effective during the September through May billing cycles.

PURPOSE

The WNA refunds over-collections or surcharges under-collections of revenue due to colder or warmer than normal weather, as established in the Company's most recent rate filing.

WNA MECHANISM

In order to reflect weather effects in a timely and accurate manner, the WNA adjustment shall be calculated separately for each billing cycle and rate schedule. The weather factor, determined for each rate schedule in the most recent rate case, shows the effect of one heating degree day on consumption for that rate schedule. During each billing cycle, the weather factor is multiplied by the difference between normal and actual heating degree days for the billing period and by the number of customers billed. This WNA volume adjustment is priced at the current cost of service rate per Ccf to determine a WNA revenue adjustment, which is spread to the customers in the billing cycle on a prorata basis. The WNA for each billing cycle and rate schedule shall be based on the following formula:

WNA Rate = WNAD, where
~~CV~~
-CV

CV = Current Volumes for the billing period.

WNAD = Weather Normalization Adjustment Dollars to be collected from each billing cycle and rate schedule. This factor shall be based on the following formula:

~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)~~ ~~August 4, 2020 (CGSA except Bastrop Env., Buda Inc., Hutto Env., Marble Falls, Mustang Ridge and Pflugerville)~~
~~January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)~~ ~~September 15, 2022 (Bastrop Env., Buda Inc., Marble Falls and Pflugerville)~~
~~November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)~~ ~~January 15, 2024 (Hutto Env. and Mustang Ridge)~~
~~May 9, 2016 (Gulf Coast Service Area)~~
~~May 22, 2019 (City of Beaumont)~~

~~**Texas Gas Service Company, a Division of ONE Gas, Inc.**~~ ~~**RATE SCHEDULE WNA**~~
~~**Central-Gulf Service Area**~~ ~~**Page 2 of 2**~~

WEATHER NORMALIZATION ADJUSTMENT CLAUSE
(Continued)

WNAD = (HDD Diff * CB * WF) * COS rate, where

HDD Diff = (Normal HDD – Actual HDD), the difference between normal and actual heating degree days for the billing period.

CB = Number of customers billed for the billing period.

WF = Weather factor determined for each rate schedule in the most recent rate case.

Austin, Bastrop (environs only), Bee Cave, Buda, Cedar Park, Dripping Springs, Georgetown, Hutto, Kyle, Lakeway, Marble Falls, Mustang Ridge, Pflugerville, Rollingwood, Sunset Valley, and West Lake Hills:
Residential 0.~~15498~~14945; Commercial 0.~~38392~~46174; Public Authority 1.~~94154; Public Schools 3.95052~~ 91573
Weather Station: KATT

Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum:
Residential 0.~~14213~~13893; Commercial 0.~~21988~~24380; Public Authority 0.~~95317~~82469 Weather Station: KSAT

Bayou Vista, Galveston, and Jamaica Beach:
Residential 0.~~18569~~19840; Commercial 0.~~44273~~50668; Public Authority ~~3.44053~~5.12822 Weather Station: KGLS

Beaumont, Groves, Nederland, Port Arthur, and Port Neches:
Residential 0.~~17379~~14683; Commercial 0.~~28946~~21018; Public Authority ~~2.28489~~1.04076 Weather Station: KBPT

~~CV = Current Volumes for the billing period.~~

Supersedes Rate Schedule Dated Bills Rendered On and After
January 15, 2024 TBD

FILING WITH THE CITIES AND THE RAILROAD COMMISSION OF TEXAS (RRC)

The Company will file monthly reports showing the rate adjustments for each applicable rate schedule. Supporting documentation will be made available for review upon request. By each October 1, the Company will file with the Cities and the RRC an annual report verifying the past year's WNA collections or refunds.

The Company shall file the report with the RRC electronically at GUD_Compliance@rrc.texas.gov~~Supersedes Rate Schedule Dated~~ ~~Meters Read On and After~~
~~October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)~~
~~January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)~~
~~November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)~~
~~May 9, 2016 (Gulf Coast Service Area)~~
~~May 22, 2019 (City of Beaumont)~~
~~August 4, 2020 (CGSA except Bastrop Env., Buda Inc., Hutto Env., Marble Falls, Mustang Ridge and Pflugerville)~~
~~September 15, 2022 (Bastrop Env., Buda Inc., Marble Falls and Pflugerville)~~
~~January 15, 2024 (Hutto Env. and Mustang Ridge)~~
or at the following address:

Director of Oversight and Safety Division
Gas Services Department
Railroad Commission of Texas
P.O. Box 12967
Austin, TX 78711-2967

EXCESS DEFERRED INCOME TAX CREDIT

A. APPLICABILITY

This Excess Deferred Income Tax Credit applies to all general service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") currently in force in the Company's Central-Gulf Service Area within the incorporated and unincorporated areas of Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas: 10, 15, 20, 25, 30, 40, 48, C-1, CNG-1, 1Z, 1Y, 2Z, 2Y, 3Z, 4H, 4Z, C-1-ENV, CNG-1-ENV, T-1, and T-1-ENV.

B. CALCULATION OF CREDIT

The annual amortization of the regulatory liability for excess deferred income taxes resulting from the Tax Cuts and Jobs Act of 2017 and in compliance with GUD No. 10695, will be credited to customers annually on a one-time, per bill basis in February of each year and will show as a separate line item on the customer's bill until fully amortized. The initial credit will occur in September 2020.

EDIT CREDIT – The total amount, if any, of the credit in a given year will be determined by:
The average rate assumption method ("ARAM") as required by the Tax Cuts and Jobs Act of 2017 Section 13001(d) for the protected portion of the regulatory liability for excess deferred income taxes; and
A 4-year amortization for nonprotected property.

TRUE-UP ADJUSTMENT – The Excess Deferred Income Tax credit shall be trued-up annually. The True-Up Adjustment will be the difference between the amount of that year's EDIT Credit and the amount actually credited to customers.

EDIT CREDIT PER CUSTOMER – The EDIT credit per customer will be determined by allocating that year's credit, plus/minus any prior year true up adjustment, among the customer classes utilizing the same class revenue allocation as approved in the most recent general rate case, and then by dividing each class's portion by the number of customers in that class.

C. EDIT CREDIT PER CUSTOMER

Residential:	$	3.13
Commercial:	$	14.42
Industrial:	$	211.23
Public Authority:	$	26.05
Public Schools Space Heat:	$	26.05
Electrical Cogeneration:	$	26.05
Compressed Natural Gas:	$	180.63

Taxes: Plus applicable taxes and fees (including franchises fees) related to above.

EXCESS DEFERRED INCOME TAX CREDIT
(Continued)

D. <u>OTHER ADJUSTMENTS</u>

Taxes: Plus applicable taxes and fees (including franchise fees) related to above.

E. <u>ANNUAL FILING</u>

The Company shall make a filing with the Commission each year no later than December 31, including the following information:

the total dollar amount of that year's EDIT Credit;
the total dollar amount actually credited to customers;
true-up amount, if any, due to the difference between items a. and b., above;
the amount of the upcoming year's EDIT Credit; and
the amounts of the upcoming year's EDIT Credit per Customer.

F. <u>CONDITIONS</u>

Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.

GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE

1.1 ~~1.1~~ REQUIREMENTS FOR TRANSPORTATION SERVICE

Nothing shall be deemed to supersede the respective rights and obligations of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") and Customer as provided by Texas statutes, rules, and/or regulations. The Company reserves the right to seek modification or termination of transportation service or any of the tariffs to which it applies and the unilateral right to seek regulatory approval to make any changes to, or to supersede, the rates, charges and terms of transportation service. This rate schedule shall apply to customers who have elected Transportation Service through the Company's Central Gulf distribution system within the Incorporated and Unincorporated Areas of Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, Texas.

1.2 ~~1.2~~ DEFINITIONS

The following definitions shall apply to the indicated words as used in this Tariff:

Adder:	Shall mean the Company's incremental cost to purchase natural gas.
Aggregation Areas:	Shall mean aggregation pools established by the Company within geographic, operational, administrative, and/or other appropriate parameters, for the purposes of nominating and imbalances.
Agreement:	Shall mean any written Gas Transportation Agreement (including any gas transportation orders, forms or other exhibit(s) which are incorporated into and become a part of the same) to which the General Terms and Conditions for Transportation apply.
Btu:	Shall mean British thermal unit(s) and shall be computed on a temperature base of 60° Fahrenheit and at the standard pressure base of the applicable service area and on a gross-real-dry basis and shall not be corrected for real water vapor as obtained by means commonly acceptable to the industry, and "MMBtu" shall mean 1,000,000 Btu.

~~October 26, 2016 (Cities of Austin, Bee Cave, Cedar Park, Dripping Springs, Kyle, Lakeway, Rollingwood, Sunset Valley, and West Lake Hills, TX)~~ ~~August 4, 2020 (CGSA except Bastrop Env., Buda Inc., Hutto Env., Marble Falls, Mustang Ridge and Pflugerville)~~
~~January 6, 2017 (Cities of Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum, TX)~~ ~~September 15, 2022 (Bastrop Env., Buda Inc., Marble Falls and Pflugerville)~~
~~November 23, 2016 (Unincorporated Areas of the Central Texas Service Area)~~ ~~January 15, 2024 (Hutto Env. and Mustang Ridge)~~
~~May 9, 2016 (Incorporated and Unincorporated Areas of the Gulf Coast Service Area)~~ ~~May 22, 2019 (City of Beaumont)~~

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE

Commercial Service:	Service to Consumers engaged primarily in the sale or furnishing of goods and services and any usage not otherwise provided for.
Commission or The Commission:	The Railroad Commission of Texas.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Consumption Period:	Shall mean a volumetric billing period.

~~Supersedes Rate Schedules Dated~~ ~~Meters Read On and After~~

Cumulative Tolerance Limit:	Shall mean the percent of aggregate historical annual deliveries of a Qualified Supplier's Aggregation Area pool of customers for the most recent year ended on June 30. The Company, at its sole discretion, may make adjustments to the Cumulative Tolerance Limit.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (Central Standard Time) on one calendar day and ending at 9:00 a.m. (Central Standard Time) the following calendar day.
Dekatherm (Dth):	Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.
Electrical ~~Cogeneration~~Generation Service:	Service to ~~Consumers who use natural gas for~~customers operating electric generation assets and that are registered with the ~~purpose of generating electricity.~~applicable balancing authority including bulk power system assets, co- generation facilities, distributed generation, and/or backup power systems. This service ~~uses~~may also be provided to those known Customers who use thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.
Electronic Flow Measurement (EFM):	A device that remotely reads a gas meter.
Firm Service:	Services offered to Customers (regardless of service class) under schedules or contracts that anticipate no interruptions. Service may be interrupted or curtailed at the discretion of the Company during Force Majeure events.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Force Majeure: If either Company or Customer is rendered unable, wholly or in part, by reason of force majeure or any other cause of any kind not reasonably within its control, other than financial, to perform or comply with their obligations hereunder, then such party's obligations or conditions shall be suspended during the continuance of such inability and such party shall be relieved of liability for any damage or loss for failure to perform the same during such period; provided, however, obligations to make payments when due hereunder shall not be suspended. The term "Force Majeure" as used herein means acts of God; strikes, lockouts, or other industrial disturbances; acts of the public enemy; wars; blockades; insurrections; riots; epidemics; pandemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; arrests and restraints of the government, or any agency thereof, either federal or state, civil or military; civil disturbances; explosions; breakage or accident to machinery or lines of pipe; freezing of wells or lines of pipe; shortage of gas supply, whether resulting from inability or failure of a supplier to deliver gas; partial or entire failure of natural gas wells or gas supply; depletion of gas reserves; mandatory testing or maintenance necessary for compliance and safe operation, and any other causes, whether of the kind herein enumerated or otherwise. If due to a Force Majeure the Company curtails or temporarily discontinues the receipt or delivery of Gas hereunder, Customer agrees to hold Company harmless from any loss, claim, damage, or expense that Customer may incur by reason of such curtailment or discontinuance.

Gas or Natural Gas: Shall mean the effluent vapor stream in its natural, gaseous state, including gas-well gas, casing head gas, residue gas resulting from processing both casing head gas and gas-well gas, and all other hydrocarbon and non-hydrocarbon components thereof.

Industrial Service: Service to Consumers engaged primarily in a process which changes raw or unfinished materials into another form of product. This classification shall embrace all Consumers included in Division A (except Major Groups 01 and 02) and Division D of the Standard Industrial Classification Manual.

Mcf: Shall mean 1,000 cubic feet of Gas.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

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~~Supersedes Rate Schedules Dated Meters Read On and After~~

-

Month:	Shall mean the period beginning at 9:00 a.m. Central Standard Time on the first Day of each calendar month and ending at 9:00 a.m. Central Standard Time on the first Day of the next succeeding calendar month.
Monthly Tolerance Limit:	Shall mean 5% of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for gas.
PDA:	Shall mean a predetermined allocation method.
Pipeline System:	Shall mean the current existing utility distribution facilities of Company located in the State of Texas.
Point of Delivery:	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.
Point of Receipt:	Shall mean the point or points where Company shall receive Gas into the Pipeline System from Customer.
Point Operator:	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.
Qualified Supplier:	Shall mean an approved supplier of natural gas for transportation to customers through the Company's pipeline system.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the Central-Gulf Service Area, or the Railroad Commission of Texas, as applicable.
Service Area:	The area receiving gas utility service provided by the Company under the terms of this Tariff.

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GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Tariff:	Shall mean every rate schedule, or provision thereof, and all terms, conditions, rules and regulations for furnishing gas service filed with the regulatory authorities or agencies having jurisdiction over Company or the services provided hereunder.
Transportation Form:	Shall mean the Company approved selection of transportation service document.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

Transportation Rate Schedule:	A rate schedule designed for service to any Customer for the transportation of Customer-owned natural gas through the Company's distribution system.
Transportation Service:	The transportation by the Company of natural gas owned by someone other than the Company through the Company's distribution system.
Week:	Shall mean a period of 7 consecutive Days beginning at 9:00 a.m. Central Standard Time on each Monday and ending at the same time on the next succeeding Monday.
Year:	Shall mean a period of 365 consecutive Days, or 366 consecutive Days when such period includes a February 29.

~~**1.3 COMPANY'S RESPONSIBILITY**~~

~~Company shall deliver to Customer, at the Point of Delivery, volumes of gas, as received from designated Qualified Supplier, for the Customer, at a mutually agreed upon Point of Receipt, less Payment in Kind (PIK).~~

~~a) In no event shall Company be required to expand, modify, construct, rearrange, or change the operations of the Pipeline System in order to receive gas from or on behalf of Customer or in order to deliver gas to Customer at any existing Points of Delivery.~~

1.3 RESTRICTIONS AND RESERVATIONS

a) It is understood and agreed that Customer has only the right to transportation service in the Pipeline System and all equipment, including (but not in any way limited thereto) all pipe, valves, fittings, and meters comprising the Pipeline System and all other property and capacity rights and interests, shall at all times during the term of the Agreement remain the property of Company. Customer agrees not to cause or permit any liens or encumbrances to be filed with respect to the Pipeline System by reason of Customer's actions. Customer's Gas shall at all times remain the property of Customer, and Company shall have no right or property interest herein.

~~a)~~b) Company reserves the right in its sole discretion to remove, relocate, expand, or rebuild, without approval of Customer, any portion of the Pipeline System. Customer shall make no alterations, additions, or repairs to or on the Pipeline System~~.~~, nor shall Customer bear any cost of any alterations, additions, repairs, maintenance or replacements made to or on said Pipeline System initiated by and to the benefit of the Company.

~~1.4~~

c) Customer agrees not to connect or cause the connection of any third party to the Pipeline System for any purpose without the express written approval and consent of Company to be granted in Company's sole

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

discretion. Customer further agrees not to transport or cause to be transported any Gas for any third party. If either of these conditions is breached by Customer, Company shall have the right and option, notwithstanding any other provision of the Agreement, to terminate the Agreement.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

d) Company presently is transporting Gas to third parties on the Pipeline System and shall have the right in the future to transport additional Gas for such purposes and to transport Gas to additional third parties as it may desire, and Company shall have the right to make additional connections to the Pipeline System as may be required to serve presently existing and new customers, all of which is subject to the provisions of the Agreement. Company's transportation Gas hereunder shall not obligate Company in any manner beyond the terms of the Agreement and any Exhibits attached thereto.

e) Company shall own any and all liquids which are recovered from the Pipeline System and may use, sell or transfer all liquids without having to account in any manner, or pay any monies or other consideration to Customer.

f) The Company reserves the unilateral right from time to time to seek Commission approval to make any changes to, or to supersede, the rates, charges and any terms stated in the tariffs, rate schedules, the agreements, and the General Terms and Conditions.

1.4 COMPANY'S RESPONSIBILITY

Company shall deliver to Customer, at the Point of Delivery, volumes of gas, as received from designated Qualified Supplier, for the Customer, at a Company designated Point of Receipt, less Payment in Kind (PIK).

~~1.3~~1.5 CUSTOMER'S RESPONSIBILITY

Customer, by selecting service under a transportation service rate schedule by completing a Transportation Form, warrants and agrees that:

~~Supersedes Rate Schedules Dated~~ ~~Meters Read On and After~~

~~a) Gas received by Company for the Customer shall be free from all adverse claims, liens, and encumbrances;~~

a) Customer shall indemnify and hold Company harmless from and against all suits, actions, causes of action, claims and demands, including attorneys' fees and costs, arising from or out of any adverse claims by third parties claiming ownership of, or an interest in said gas caused by the failure to provide clear title to the gas;

b) Customer acknowledges Company shall not be responsible in any way for damages or claims relating to the Customer's gas or the facilities of the Customer or others containing such gas prior to receipt into Company's facilities or after delivery to the Customer;

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

c) Customer must provide Company with a signed Transportation Form identifying its Qualified Supplier. Customer may designate no more than one Qualified Supplier. This authorization shall be in a form agreeable to Company and shall remain in effect until a signed replacement is received by Company;

d) Customer acknowledges the Qualified Supplier's responsibilities under Section 1.~~5;~~ 6;

e) Transportation Service is not available for a term less than 12-months. Termination of transportation service may, at the Company's sole discretion, delay Customer's request to resume transportation service;

f) Electronic flow measurement (EFM) may be required for Customers under transportation service, at the Company's sole discretion. The Customer may be required to reimburse the Company for any cost related to the installation of the EFM as well as provide for or reimburse the Company for any ongoing maintenance, repair, or communications costs; and

g) In the event Customer's source of gas supply is terminated by Customer's Qualified Supplier due to ~~nonpayment~~non- payment or other reasons, or if customer is otherwise unable to continue as a transportation customer, Customer may, upon the first of the month after 30-calendar days advance written notice to Company, obtain service from Company under the general sales tariff applicable to Customer. Prior to commencing such service, Company may, in its sole discretion, require Customer to post a deposit or bond.

~~1.4~~1.6 ~~1.5~~ QUALIFIED SUPPLIER'S RESPONSIBILITY

Qualified Supplier shall act on behalf of the Customer to procure gas supplies, deliver gas supplies plus Payment in Kind volume, into ~~mutually agreed upon~~Company designated Points of Receipt and shall act as the Customer's agent with respect to nominations, operational notices and resolution of imbalances.

a) Qualified Suppliers shall aggregate their Customers' volumes for balancing purposes, into Aggregation Areas, as determined, in the Company's sole discretion.

~~Supersedes Rate Schedules Dated Meters Read On and After~~

b) Qualified Supplier shall submit nominations to the Company's gas scheduling department, in accordance with their currently effective nomination process, which can be provided to the parties upon request. Customer and Qualified Supplier shall exercise commercially reasonable best efforts to deliver to the Pipeline System Dths of gas that Company is to deliver from the Pipeline System to Customer during any particular Hour, Day, Week and Month, including but not limited to volumes needed for peak Day usage for Customer's facilities. Qualified Supplier shall not intentionally nominate more or less gas than is anticipated for consumption by Customer(s), except as may be needed for balancing purposes to the extent Company accepts such nomination.

c) Before the start of the Gas Day, the Point Operator and Company shall establish a predetermined allocation (PDA) method to specify how gas received or delivered by Company shall be allocated in accordance with confirmed nominations at such point. Only one PDA methodology shall be applied per allocation period.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

d) Daily Quantity of Transportation Service Gas: Company shall receive and deliver gas hereunder as nearly as practicable at uniform hourly and daily rates of flow. It is recognized that it may be physically impracticable, because of measurement, gas control limitations and other operating conditions, to stay in zero imbalance each hour and each day; therefore, the daily and hourly quantities received may, due to the aforementioned reasons, vary above or below the daily and hourly quantities delivered. If the quantities received and the quantities delivered hereunder should create an imbalance at the end of any hour, Day, Week, or Month, then Company and ~~Customer~~Qualified Supplier shall adjust receipts and/or deliveries at any time to the end that the quantities received and delivered shall be kept as near to zero imbalance as practicable.

e) Quality of Transportation Service Gas: The gas procured by a Qualified Supplier, for receipt by Company, shall conform to the standards prescribed in Company's applicable rate schedules, Agreements, and applicable local, state or federal laws, rules and/or regulations.

~~1.5~~1.7 ~~1.6~~ IMBALANCES

Qualified Supplier shall, to the extent practicable, not deliver into the Pipeline System more or less Dths of Gas than Company delivers to the Aggregation Area of Customers, at the Points of Delivery, during a Consumption Period. The following imbalance provisions shall be applied to the Qualified Supplier for its Aggregation Area of Customers.

a) If Company receives less Dths of Gas than are delivered to the Aggregate Area Customers at the Points of Delivery in excess of the Monthly Tolerance Limit or Cumulative Tolerance Limit in any particular Consumption Period, then Qualified Supplier shall purchase such under-delivered volumes at 105% of the applicable index, plus the Adder.

~~Supersedes Rate Schedules Dated~~ ~~Meters Read On and After~~

b) If Company receives more Dths of Gas than are delivered to the Aggregate Area Customers at the Points of Delivery in excess of the Monthly Tolerance Limit or Cumulative Tolerance Limit in any particular Consumption Period, Qualified Supplier shall sell such excess Gas to Company at 95% of the applicable index.

c) The applicable index and Adder will be defined in the Qualified Supplier Agreement and amended from time to time.

d) A proportional share of any upstream pipeline transportation service charges, additional commodity charges, and penalties incurred by the Company, that in whole or in part, are the result of Qualified Supplier's scheduling and/or managing the upstream transportation of the Customer's gas to Company's interconnection point(s) with the upstream pipeline(s). The proportional share will be calculated using the Qualified Supplier's receipts and deliveries and the upstream pipeline invoices for the applicable period. Proceeds from this charge will be credited to the Reconciliation Account. The Company will bill Qualified Supplier for these charges and penalties manually on a separate bill. Payment shall be required in accordance with applicable Rules of Service.

**GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)**

e) The Company will provide monthly imbalance statements along with calculations of the charges in accordance with the aforementioned provisions to the Qualified Supplier each month.

f) Payments for imbalance settlements will be due each month within 15 business days of the imbalance statement date. The Company may elect at its sole discretion to accrue the imbalance settlement provisions each month and only require periodic settlement rather than monthly payments.

g) On or about 15 days after the Company receives necessary volumetric information from other parties for each Consumption Period after commencement of Gas receipts and deliveries hereunder, Company shall render to the Qualified Supplier a statement for the preceding Consumption Period showing the total Dths of Gas received and delivered and each Point of Receipt and Point of Delivery. If information necessary for statement purposes is in the possession of Customer, Customer shall furnish such information to Company on or before the 6th Day of the Month in which the statement requiring such data is to be rendered.

h) Both parties hereto shall have the right at any and all reasonable times within 24 months from the time period in question, to examine the books and records of the other to the extent necessary to verify the accuracy of any statement, computation, or demand made hereunder.

1.8 ~~Supersedes Rate Schedules Dated~~ ~~Meters Read On and After~~ LACK OF LIABILITY

a) Furnishing of Gas. The Company shall not be liable for any loss or damage caused by variation in gas pressure, defects in pipes, connections and appliances, escape or leakage of gas, sticking of valves or regulators, or for any other loss or damage not caused by the Company's negligence arising out of or incident to the furnishing of gas to any Consumer.

b) After Point of Delivery. Company shall not be liable for any damage or injury resulting from gas or its use after such gas leaves the point of delivery other than damage caused by the fault of the Company in the manner of installation of the service lines, in the manner in which such service lines are repaired by the Company, and in the negligence of the Company in maintaining its meter loop. All other risks after the gas left the point of delivery shall be assumed by the Customer or consumer, his agents, servants employees, or other persons.

c) Reasonable Diligence. The Company agrees to use reasonable diligence in rendering continuous gas service to all Customers or Consumers, but the Company does not guarantee such service and shall not be liable for damages resulting from any interruption to such service.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

d) Force Majeure. If either Company or Customer is rendered unable, wholly or in part, by reason of force majeure or any other cause of any kind not reasonably within its control, other than financial, to perform or comply with their obligations hereunder, then such party's obligations or conditions shall be suspended during the continuance of such inability and such party shall be relieved of liability for any damage or loss for failure to perform the same during such period; provided, however, obligations to make payments when due hereunder shall not be suspended.

~~i)~~e) Damage to Pipeline. If a portion of the Pipeline System required to make the transportation service available is partially damaged by fire, line strikes or other casualty, the damage may be repaired by Company, at its option and in its sole discretion, as speedily as practicable, to include the time taken for the settlement of insurance claims. Until such repairs are made, the payments shall be apportioned in proportion to the portion of the capacity of the Pipeline System which is still available for the purposes hereof, such determination to be made in the sole discretion of Company. If the damages are so extensive as to render the Pipeline System wholly unusable, in Company's sole opinion, the payments, if any, shall cease until such time as the Pipeline System is again useable. In case the damage shall, in Company's sole opinion, amount substantially to a destruction of the portion of the Pipeline System available for the transportation of Gas and Company shall elect not to repair the damage, then the Agreement shall terminate at the time of such damage, and Company shall not be liable to Customer for any liability, damage, or claim which arises out of any failure to make repairs.

RULES OF SERVICE

CENTRAL-GULF SERVICE AREA

Incorporated and Unincorporated Areas of Austin, Bastrop (environs only), Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto ~~(environs only),~~, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, TX

Effective for ~~Meters Read~~Bills Rendered On and After TBD

Communications Regarding this Tariff Should Be Addressed To:
Customer Relations
401 N. Harvey
Oklahoma City, OK 73102
customerrelations@onegas.com~~August 4, 2020 (~~
(405) 551-6752

Supersedes and Replaces Rules of Service for Incorporated and Unincorporated Areas of the Central-Gulf Service Area ~~except Marble Falls, Mustang Ridge, and Pflugerville, Unincorporated Bastrop and Hutto, and Incorporated Buda)~~
~~September 15, 2022 (Incorporated and Unincorporated Marble Falls and Pflugerville, Unincorporated Bastrop and Incorporated Buda)~~
~~January 15, 2024 (Incorporated and Unincorporated Mustang Ridge and Unincorporated Hutto)~~

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – Central-Gulf Service Area

~~Supersedes and Replaces "Incorporated Central Texas Service Area" (Cities of~~including Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Gonzales, Groves, Jamaica Beach, Kyle, Lakeway, ~~Rollingwood, Sunset Valley, and West Lake Hills, TX) dated October 26, 2016;~~
~~"Incorporated Central Texas Service Area" (Cities of Cuero, Gonzales,~~ Lockhart, Luling, Nederland, Nixon, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, ~~TX)~~Texas and the environs area of Buda, Texas dated ~~January 6, 2017;~~
~~"~~August 4, 2020, Incorporated and Unincorporated Areas of the Central~~-Texas Service Area" dated November 23, 2016;~~
~~"Incorporated and Unincorporated~~- Gulf ~~Coast~~ Service Area~~" dated May 9, 2016;~~
~~"~~ including Marble Falls and Pflugerville, Texas, Incorporated Areas of ~~Beaumont, TX" dated May 22, 2019~~

~~Communications Regarding this Tariff~~
~~Should Be Addressed To:~~

Buda, and the environs area of Bastrop, Texas ~~Gas Service Company, a Division of ONE Gas, Inc.~~
~~5613 Avenue F~~
~~Austin,~~ dated September 15, 2022, and Incorporated and Unincorporated Areas of the Central-Gulf Service Area including Mustang Ridge, Texas ~~78751~~

~~OR~~

and the environs area of Hutto, Texas ~~Gas Service Company, a Division of ONE Gas, Inc.~~dated January 15, 2024

~~4201 39th Street~~
~~Port Arthur, TX 77642~~

~~OR~~

~~Texas Gas Service Company, a Division of ONE Gas, Inc.~~
~~402 33rd Street~~
~~Galveston, TX 77750~~

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – Central-Gulf Service Area

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SECTION 1 — GENERAL STATEMENT AND DEFINITIONS

1.1 ~~1.1~~ TARIFF APPLICABILITY

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~is~~(the "Company") operates as a gas utility ~~operating~~under Texas Utilities Code § 101.003(7) within the State of Texas. This Tariff applies to ~~Texas Gas Service Company, a Division of ONE Gas, Inc.'s~~all incorporated areas, unincorporated areas and census designated places in the Company's Central-Gulf Service Area~~, comprising~~ comprised of the ~~Cities~~incorporated and ~~environs~~unincorporated areas of Austin, Bayou Vista, Beaumont, Bee Cave, Buda, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills, and Yoakum, and the environs of Bastrop~~ and Hutto, Texas. This Tariff supersedes and replaces all tariffs previously approved and applied in the Central Texas, Gulf Coast Service Areas and the City of Beaumont~~, Texas.

Service under this Tariff is subject to the original jurisdiction of the municipalities in the Central-Gulf Service Area and the Railroad Commission of Texas. The Company will provide service to any person and/or business within its service area in accordance with the rates, terms and conditions provided for in its Tariff and regulations.

1.2 ~~1.2~~ RATE SCHEDULES

All Customers shall be served under rate schedules filed with the municipality or Railroad Commission of Texas. Customers shall be assigned to rate schedules in accordance with the class of the particular Customer, the usage which will be made of the gas and that Customer's volume requirements. The Company shall advise an Applicant or Customer regarding the most ~~advantageous~~economical rate for ~~his or her~~their usage if more than one rate is applicable. A Customer assigned to a rate schedule shall remain on that schedule for a minimum of one year except that an assignment made in error may be corrected immediately. In the event of a question regarding the Customer's classification, the questions shall be resolved by reference to the coding of the Customer's primary business in the latest edition of the Standard Industrial Classification Manual of the United States Government's Office Management and Budget.

1.3 ~~1.3~~ DEFINITIONS

The following definitions shall apply to the indicated words as used in this Tariff:

Adder:	Shall mean the Company's incremental cost to purchase natural gas.
Aggregation Areas:	Shall mean aggregation pools established by the Company within geographic, operational, administrative, and/or other appropriate parameters, for the purposes of nominating and imbalances.
Agricultural Service:	Service to Consumers engaged in agricultural production.
Applicant:	Any person, organization or group of persons or organizations making a formal request either orally or in writing for gas service from the Company.
Automated Meter Reading (AMR):	The process of remotely reading a gas meter.

Average Day Usage:	The gas demand of a given Customer for gas in any one month divided by 30. Gas demand is considered to be equivalent to consumption during each billing month, provided however, that when service has been curtailed, demand shall be considered to be actual consumption plus estimated curtailment during the period.
Blanket Builder:	A builder or someone acting for a builder who ~~is invoiced for~~requests the installation of service lines.
Btu:	Shall mean British thermal unit(s) and shall be computed on a temperature base of sixty degrees (60°) Fahrenheit and at the standard pressure base of the applicable service area and on a gross-real-dry basis and shall not be corrected for real water vapor as obtained by means commonly acceptable to the industry, and "MMBtu" shall mean one million (1,000,000) Btu.
Commercial Service:	Service to Consumers engaged primarily in the sale or furnishing of goods and services and any usage not otherwise provided for.
Commission or The Commission:	The Railroad Commission of Texas.
Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Consumer:	Any person or organization receiving gas service from the Company for his or her own appliances or equipment whether or not the gas is billed directly to him or her. (For example, a rental unit where the utilities are part of the rent, the landlord is a Customer and the tenant is a Consumer.)
Consumption Period:	Shall mean a volumetric billing period.
Cumulative Tolerance Limit:	Shall mean the percent of aggregate historical annual deliveries of a Qualified Supplier's Aggregation Area pool of customers for the most recent year ended on June 30. The Company, at its sole discretion, may make adjustments to the Cumulative Tolerance Limit.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (Central ~~clock~~Standard Time) on one calendar day and ending at

9:00 a.m. (Central ~~clock~~Standard Time) the following calendar day.

Dekatherm (Dth): Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.

Domestic Service: Service to any Consumer which consists of gas service used directly for heating, air conditioning, cooking, water heating and similar purposes whether in a single or multiple dwelling unit.

~~Electrical Cogeneration~~Electric Generation Service: Service to ~~Consumers who use natural gas for~~customers operating electric generation assets and that are registered with the ~~purpose of generating electricity.~~applicable balancing authority including bulk power system assets, co- generation facilities, distributed generation, and/or backup power systems. This service ~~uses~~may also be provided to those known Customers who use thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.

Electronic Document: Any document sent electronically via email or the internet.

Electronic Flow Measurement (EFM): An electronic means of obtaining readings on a gas meter.

Electronic Fund Transfer (EFT): The process to convert a paper check or electronic bill payment request to an electronic transfer. Paper checks received by Company or their agents are destroyed.

Electronic Radio Transponder (ERT): A device that assists with remotely reading a gas meter.

Excess Flow Valve (EFV): A safety device installed ~~below ground inside the~~ on a natural gas service line~~between the main and the meter intended to reduce the risk of accidents in limited situations.~~. The EFV is designed to automatically shut off the flow of natural gas in the service line and mitigate the impact of a significant break, puncture or severance in the line. EFVs are not designed to shut off the flow of gas in the line breaks at the connection of a gas appliance in a residence or in the customer's piping system (interior or exterior) on the customer's side of the gas meter.

Expedited Service: Customer request for same day service or service during non-business hours for connection or reconnection of gas service.

Firm Service:	Services offered to Customers (regardless of service class) under schedules or contracts that anticipate no

	interruptions. Service may be interrupted or curtailed at the discretion of the Company during Force Majeure events or at the direction of a regulatory or government agency.
Force Majeure:	If either Company or Customer is rendered unable, wholly or in part, by reason of force majeure or any other cause of any kind not reasonably within its control, other than financial, to perform or comply with their obligations hereunder, then such party's obligations or conditions shall be suspended during the continuance of such inability and such party shall be relieved of liability for any damage or loss for failure to perform the same during such period; provided, however, obligations to make payments when due hereunder shall not be suspended. The term "Force Majeure" as used herein means acts of God; strikes, lockouts, or other industrial disturbances; acts of the public enemy; wars; blockades; insurrections; riots; epidemics; pandemics; landslides; lightning; earthquakes; fires; storms; floods; washouts; arrests and restraints of the government, or any agency thereof, either federal or state, civil or military; civil disturbances; explosions; breakage or accident to machinery or lines of pipe; freezing of wells or lines of pipe; shortage of gas supply, whether resulting from inability or failure of a supplier to deliver gas; partial or entire failure of natural gas wells or gas supply; depletion of gas reserves; mandatory testing or maintenance necessary for compliance and safe operation, and any other causes, whether of the kind herein enumerated or otherwise. If due to a Force Majeure the Company curtails or temporarily discontinues the receipt or delivery of Gas hereunder, Customer agrees to hold Company harmless from any loss, claim, damage, or expense that Customer may incur by reason of such curtailment or discontinuance.
Gas or Natural Gas:	Shall mean the effluent vapor stream in its natural, gaseous state, including gas-well gas, casing head gas, residue gas resulting from processing both casing head gas and gas- well gas, and all other hydrocarbon and non-hydrocarbon components thereof.
General Rate Schedule:	A rate schedule available to all Customers of the appropriate class or classes for usages indicated therein.
Industrial Service:	Service to Consumers engaged primarily in a process which changes raw or unfinished materials into another form of

	product. This classification shall embrace all Consumers included in Division A (except Major Groups 01 and 02) and Division D of the Standard Industrial Classification Manual.
Irrigation or Irrigation Pumping Service:	(SIC Division A - Major Group 01) who use gas for ~~Service:~~ operating engine-driven pumping equipment.
Master Meter:	A single large volume gas measurement device by which gas is metered and sold to a single purchaser who distributes the gas to one or more additional persons downstream from that meter. Master meter operators shall comply with the minimum safety standards in 49 CFR Part 192.
Mcf:	Shall mean one thousand (1,000) cubic feet of Gas.
Month:	Shall mean the period beginning at 9:00 a.m. Central ~~clock~~Standard Time on the first Day of each calendar month and ending at 9:00 a.m. Central ~~clock~~Standard Time on the first Day of the next succeeding calendar month.
Monthly Tolerance Limit:	Shall mean five percent (5%) of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
Optional Rate Schedule:	A General Rate Schedule which may be selected by a Customer in lieu of another general schedule but which may require installation of special equipment.
Overtime Rate:	The fee charged by the Company to perform work outside its normal business hours or on holidays and includes changes to previously scheduled work that must be performed outside the Company's normal business hours.
Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for gas.
PDA:	Shall mean a predetermined allocation method.
Pipeline System:	Shall mean the current existing utility distribution facilities of the Company located in the State of Texas.
Point of Delivery:	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.

Point of Receipt:	Shall mean the point or points where the Company shall receive Gas into the Pipeline System from Customer.
Point Operator:	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.
Qualified Supplier:	Shall mean an approved supplier of natural gas for transportation to customers through the Company's pipeline system.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the Central-Gulf Service Area, or the Railroad Commission of Texas, as applicable.
Service Area:	The area receiving gas utility service provided by the Company under the terms of this Tariff.
Special Rate Schedule:	A rate schedule designed for a specific Customer.
System:	Any group of interconnected pipelines and appurtenances owned or operated by the Company and independent from any other such group of facilities.
Tariff:	Shall mean every rate schedule, or provision thereof, and all terms, conditions, rules and regulations for furnishing gas service filed with the regulatory authorities or agencies having jurisdiction over the Company or the services provided hereunder.
Temporary Service:	Any service which will not be utilized continuously at the same location for a period of two or more years.
Transportation Form:	Shall mean the Company approved selection of transportation service document.
Transportation Rate Schedule:	A rate schedule designed for service to any Customer for the transportation of Customer-owned natural gas through the Company's distribution system.
Transportation Service:	The transportation by the Company of natural gas owned by someone other than the Company through the Company's distribution system.
Week:	Shall mean a period of seven (7) consecutive Days beginning at 9:00 a.m. Central ~~clock~~Standard Time on each

Monday and ending at the same time on the next succeeding Monday.

Year: Shall mean a period of three hundred sixty-five (365) consecutive Days, or three hundred sixty-six (366) consecutive Days when such period includes a February 29.

SECTION 2. [Reserved for future rules]

SECTION 3~~:~~. RATES AND UTILITY CHARGES

~~Please see~~ Current Rate Schedules are on file with each applicable Regulatory Authority~~.~~ and available on the Company's website at https://www.texasgasservice.com/rateinformation/home.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – Central-Gulf Service Area

SECTION 4 — CONDITIONS OF SERVICE

4.1 ~~4.1~~ PROVISION OF SERVICE

The Company will provide gas service to any person or organization located within the Central-Gulf Service Area from the Company's facilities or in certain cases, the facilities of its supplier, in accordance with the provisions of this Tariff ~~including~~and other applicable Rate Schedules~~ and Rules of Service~~.

~~4.2~~ The Customer shall make or procure, and hereby agrees to make or procure, conveyance to the Company of perpetual right-of-way across the property owned or controlled by the Customer that is required to install natural gas facilities and is in a location and condition satisfactory to the Company, provides clear access to Company's facilities, and enables the Company to provide service to Customer's property or the premises of the Consumer.

4.2 FEES AND CHARGES

All fees and charges ~~made~~assessed by the Company to provide and maintain utility services are as provided for in this Tariff. If the Customer elects transportation service, the commodity cost of gas shall be determined between the Customer and the Customer's selected supplier.

4.3 ~~4.3~~ RESALE OF GAS

Gas delivered by the Company shall not be redelivered or resold for the use thereof by others unless otherwise expressly agreed to in writing by the Company~~ – except~~; provided, however, that those Customers receiving gas for redistribution to the Customer's tenants may separately meter each tenant's distribution point for the purpose of prorating the Customer's actual amount of gas delivered among the various tenants on a per unit basis.

4.4 ~~4.4~~ CONTINUITY OF SERVICE

a) Service interruptions

i) ~~i)~~ The Company shall make all reasonable efforts to prevent interruptions of ~~service.~~ Firm Service. When interruptions occur, the Company ~~will reestablish~~shall re-establish service within the shortest possible time consistent with prudent operating principles so that the smallest number of Customers ~~is~~are affected.

ii) ~~ii)~~ The Company shall make reasonable provisions to meet emergencies resulting from failure of service and ~~will~~shall issue instructions to its employees covering procedures to be followed in the event of an emergency in order to prevent or mitigate interruption or impairment of service.

iii) ~~iii)~~ In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

iv) Curtailment of Firm Service will be done in accordance with Texas Administrative Code Title 16, Part 1, Chapter 7, Subchapter D, Rule §7.455 Curtailment Standards.

b) Record of interruption. Except for momentary interruptions which do not cause a major disruption of service, the Company shall keep a complete record of all interruptions, both emergency and scheduled. This record shall show the cause of interruptions, date, time duration, location, approximate number of Customers affected, and, in cases of emergency interruptions, the remedy and steps taken to prevent recurrence, if applicable.

~~CONDITION OF SERVICE (Continued)~~

~~4.4 CONTINUITY OF SERVICE (Continued)~~

~~c)~~ Report to Railroad Commission of Texas. The Commission shall be notified in writing within 48 hours of interruptions in service affecting the entire system or any major division thereof lasting more than four ~~continuous~~ hours. The notice shall also state the Company's belief as to the cause of such interruptions. If any service interruption is reported to the Commission otherwise (for example, as a curtailment report or safety report), such other report is sufficient to comply with the terms of this ~~paragraph~~Section.

~~d) The procedure under which curtailments of service will be made is described in the Curtailment Plan on file with the Railroad Commission of Texas.~~

c) ~~e)~~ The Company does not guarantee uninterrupted service to any Customer and shall not be liable for damages resulting from any loss of service to any Customer.

4.5 ~~4.5~~ AVAILABILITY OF ~~TARIFF~~TARIFFS

A copy of this Tariff ~~including all applicable rates~~and other Rate Schedules can be requested through TGS's customer service number at 1-800-700-2443 (non-emergency number) or requested under the 'Contact Us' section of www.texasgasservice.com~~www.texasgasservice.com. Upon the request of any Customer or Applicant, the Company shall make copies of the Tariff which may be purchased by the Customer or Applicant through TGS's customer service. The Company may charge a fee for each copy not in excess of the Company's reasonable cost to reproduce the material.~~ and are available on the Company's website at https:// www.texasgasservice.com/rateinformation/home.

4.6 ~~4.6~~ CUSTOMER INFORMATION

The Company shall:

a) Maintain a current set of maps showing the physical locations of its facilities. All distribution facilities shall be labeled to indicate the size or any pertinent information which will accurately describe the Company's facilities. These maps, or such other maps as may be required by the Regulatory Authority, shall be kept by the Company in a central location and will be available for inspection by the Regulatory Authority during normal working hours. Each business office or service center shall have available up-to-date maps, plans or records of its immediate area, with such other information as may be necessary to enable the Company to advise applicants and others entitled to the information as to the facilities available for serving that locality;

b) Assist the Customer or Applicant in selecting the most economical rate schedule;

c) In compliance with applicable law or regulations, notify customers affected by a change in rates or schedule or classification;

d) Post a notice in a conspicuous place in each business office of the utility where applications for service are received informing the public that copies of the rate schedules and rules relating to the service of the utility as filed with the Commission are available for inspection;

e) Upon request inform its customers as to the method of reading meters;

~~a)~~f) Make available, during normal business hours, such additional information on rates and services as any Customer or Applicant may reasonably request~~. Upon any Customer's request, the Company shall inform the Customer how to read the Customer's meter. The Company shall annually provide each Customer with notice of the availability of a concise description in English and Spanish of the Customer's rights and the Company's obligations under this Tariff. A new Customer shall be provided with an informational brochure in the mail after requested service initiation or included with the first bill mailed.~~; and

g) ~~4.~~Provide to new customers, at the time service is initiated or as an insert in the first billing, a pamphlet or information packet containing the following information. The Company may provide this notification to customers electronically. This information shall be provided in English and Spanish as necessary to adequately inform the customers; provided, however, the Regulatory Authority upon application and a showing of good cause may exempt the Company from the requirement that the information be provided in Spanish:

i) the Customer's right to information concerning rates and services and the Customer's right to inspect or obtain at reproduction cost a copy of the applicable tariffs and service rules;

ii) the Customer's right to have their meter checked without charge under Section (7) of the Commission's Rule 7.45, if applicable;

iii) the time allowed to pay outstanding bills;

iv) grounds for termination of service;

v) the steps the Company must take before terminating service;

vi) how the Customer can resolve billing disputes with the Company and how disputes and health emergencies may affect termination of service;

vii) information on alternative payment plans offered by the Company;

viii) the steps necessary to have service reconnected after involuntary termination;

ix) the appropriate Regulatory Authority with whom to register a complaint and how to contact such authority;

x) the hours, addresses and telephone numbers of utility offices where bills may be paid and information may be obtained; and

xi) the Customer's right to be instructed by the Company how to read their meter.

h) At least once each calendar year, the Company shall notify Customers that information is available upon request, at no charge to the Customer, concerning the items listed in subsection (g) above. This notice may be accomplished by use of a billing insert or a printed statement upon the bill itself. The Company may provide this notification to Customers electronically.

4.7 CUSTOMER COMPLAINTS

Upon complaint to the Company by residential or small commercial customers either at its office, by letter, by telephone or by email, the Company shall promptly make a suitable investigation and advise the complainant of the results thereof. The Company shall keep a record of all complaints which shall show the name and address of the complainant, the date and nature of the complaint, and the adjustment or disposition thereof for a period of one year subsequent to the final disposition of the complaint.

4.8 COMPANY RESPONSE

Upon receipt of a complaint, either ~~in writing or~~by letter, by telephone~~,~~, or by email from the Regulatory Authority on behalf of a customer, the ~~Company will~~utility shall make a suitable investigation and advise the Regulatory Authority and complainant of the results thereof. An initial response must be made by the next ~~business~~working day. The Company must make a final and complete response within 15 days from the date of the complaint, unless additional time is granted within the 15-day period. ~~Each complainant shall be advised of his or her right~~The Commission encourages all customer complaints to ~~file~~be made in writing to assist the ~~complaint with~~ regulatory authority in maintaining records of the ~~Regulatory Authority if not satisfied by~~quality of service of the Company; however, telephone communications will be acceptable.

~~CONDITION OF SERVICE (Continued)~~

~~4.8~~4.9 ~~4.8~~ LIMITATION OF LIABILITY

~~The Customer assumes all responsibility for all facilities and their installation, maintenance, operation, functionality, testing and condition thereof on the Customer's side of the point of delivery of gas to the property of the Customer or to the premises of the Consumer, as defined in Section 6.2. The Company is not liable to a Customer, and Customer shall indemnify, hold harmless, and defend the Company and its employees or agents from any and all claims or liability for personal injury, damage to property, or any incidental, consequential, business interruption, or other economic damages or losses in any manner directly or indirectly connected to, arising from, or caused by acts or omissions of any person or party on the Customer's side of said point of delivery, as defined in Section 6.2.~~

THE CUSTOMER ASSUMES ALL RESPONSIBILITY FOR ALL FACILITIES AND THEIR INSTALLATION, MAINTENANCE, OPERATION, FUNCTIONALITY, TESTING AND CONDITION THEREOF ON THE CUSTOMER'S SIDE OF THE POINT OF DELIVERY OF GAS TO THE PROPERTY OF THE CUSTOMER OR TO THE PREMISES OF THE CONSUMER, AS DEFINED IN SECTION 12.11. THE COMPANY IS NOT LIABLE TO A CUSTOMER, AND CUSTOMER SHALL INDEMNIFY, HOLD HARMLESS, AND DEFEND THE COMPANY AND ITS EMPLOYEES OR AGENTS FROM ANY AND ALL CLAIMS OR LIABILITY FOR DAMAGES OF ANY KIND OR NATURE INCLUDING, BUT NOT LIMITED TO, PERSONAL INJURY, DAMAGE TO PROPERTY, ANY INCIDENTAL, CONSEQUENTIAL, BUSINESS INTERRUPTION, OR OTHER ECONOMIC OR OTHER DAMAGES OR LOSSES IN ANY MANNER DIRECTLY, INDIRECTLY OR ARISING FROM, OR CAUSED BY ACTS OR OMISSIONS OF ANY PERSON OR PARTY ON THE CUSTOMER'S SIDE OF SAID POINT OF DELIVERY OF GAS TO THE PROPERTY OF THE CUSTOMER OR TO THE PREMISE OF THE CONSUMER, AS DEFINED IN SECTION 12.11.

The Company shall be liable to the Customer or Consumer only for personal injury or property damages ~~from or caused~~ directly caused by the negligent acts or omissions of the Company or its employees occurring on the Company's side of the point of delivery. The Company shall not be liable or responsible for damages of any kind or nature including, but not limited to, personal injury, property damages, or any other loss or damages arising from or caused by the ~~negligent~~acts or conduct, negligence or intentional act or omission of any person, other than an employee of the Company, who adjusts, repairs, disconnects, changes, alters, or tampers with the Company's meter or facilities in any way.

~~The Company shall be liable to third parties only for personal injury or property damage directly arising from the negligence or gross negligence of the Company or its employees when acting within the scope of their employment.~~

In no event shall the Company or its employees be liable for any indirect, incidental, consequential, business interruption, or other economic damages or losses of Customer, Consumer, or third parties including, but not limited to, lost time, lost money, lost profits, or out of pocket expenses whether in contract, tort, or otherwise, and whether such damages are seen or unforeseen in any manner, directly or indirectly, arising from, caused by, or growing out of the interruption or termination of gas utility service.

~~The Customer shall make or procure conveyance to the Company of perpetual right-of-way across the property owned or controlled by the Customer that is satisfactory to the Company, provides clear access to Company's facilities, and enables the Company to provide service to Customer's property or the premises of the Consumer.~~

If Company becomes unable to provide gas utility service, either wholly or in part, by an event of Force Majeure, the obligations affected by the event of Force Majeure will be suspended only during the continuance of that inability. The term "Force Majeure" means acts of God, extreme weather events, industrial disturbances, acts of public enemies, wars, blockades, insurrections, riots, epidemics, pandemics, earthquakes, fires, priority allocations of gas services, restraints or prohibitions by any court, board, department, commission or agency of the United States or of any States, any restraints, civil disturbances, explosions, or other occurrence beyond the control and without the fault or negligence of the Company and which the Company is unable to prevent or provide against by the exercise of reasonable diligence. Company will remedy its inability to provide gas utility service as soon as possible.

SECTION 5 — INITIATION OF SERVICE

5.1 ~~5.1~~ REGULAR SERVICE

Application for service can be made by telephone or through the internet. Each Applicant must comply with the appropriate requirements of this Tariff before service shall be instituted. No written agreement shall be required for residential service under the standard provisions of this Tariff; commencement of service by the Company and the use of gas service by the Customer shall be evidence of such agreement. Any Customer requesting service under any special provision of this Tariff must execute a written agreement for service in the form prescribed by the Company designating those provisions which shall apply. Each Applicant may be required to produce two forms of verifiable identification; one being a government-issued identification card bearing a photograph of Applicant; and verifiable proof of their right to occupy a specific service address as of a specific date of occupancy.

5.2 ~~5.2~~ RESPONSE TO REQUEST FOR SERVICE

Every gas utility must serve each qualified applicant for service within its service area as rapidly as practical. As a general policy, those applications not involving line extensions or new facilities should be filled within seven (7) working days. Those applications for individual residential service requiring line extensions should be filled within 90 days unless unavailability of materials or other causes beyond the control of the Company result in unavoidable delays. In the event the residential service is delayed in excess of 90 days after an applicant has met credit requirements and made satisfactory arrangements for payment of any required construction charges, a report must be made to the Regulatory Authority listing the name of the applicant, location and cause for delay. Unless such delays are due to causes which are reasonably beyond the control of the utility, a delay in excess of 90 days may be found to constitute a refusal to serve.

~~5.2~~5.3 SPECIAL CONTRACTS

Under certain special conditions, the Company may agree to rates, terms or conditions of service other than those provided in this Tariff. Such service must be established under the terms of a special contract or service agreement. To the extent that the provisions of any special contract are at variance with this Tariff, the provisions of the contract shall apply.

~~5.3~~5.4 ~~5.3~~ TEMPORARY SERVICE

Temporary Service shall be furnished under the same rate schedules applicable to regular service of a similar kind.

~~5.4~~5.5 ~~5.4~~ FEES AND CHARGES

The Company shall charge a non-refundable fee to each Applicant to compensate for the cost involved in initiation or reconnection of service or when service is transferred from one name to another at any location, or whenever a meter is reset or relocated on the same premises at the request of the Customer, all as specified in Section ~~21.1~~15 of this Tariff.

Whenever the Applicant requests expedited service, the Company will accomplish the work as expeditiously as possible and the Customer will be charged at the Company's approved rate for service work. Expedited service and the charges therefore shall be made only on request of the Applicant. Whenever service is furnished from the facilities of a third party and the Company must pay any special ~~fees to that third party, the Company may, at its option, pass that charge plus 20 percent for handling through to the Applicant requesting service. See Section 21.1 relating to fees for the above.~~

~~5.5 ESTABLISHMENT OF CREDIT~~

~~Each Applicant for service shall be required to make a security deposit in accordance with Section 10 of this Tariff to establish and maintain satisfactory credit. These deposits shall be computed in the same manner for the same class of service, provided however, that a deposit shall be waived if:~~

~~INITIATION OF SERVICE (Continued)~~

~~5.5 ESTABLISHMENT OF CREDIT (Continued)~~

~~a) The Applicant has been a Customer for the same kind of service within the last two years and did not have more than one occasion in which a bill for service from any such utility service account was delinquent and no disconnection for non-payment was made;~~

~~b) The Applicant furnishes an acceptable letter of credit;~~

~~c) The Applicant demonstrates a satisfactory credit rating by presentation of satisfactory credit references capable of quick, inexpensive verification (applicable to residential Customers only);~~

~~d) The Applicant is 65 years of age or older and has no outstanding balance for natural gas utility service which accrued within the last two years (applicable to residential Customers only);~~

~~e) The application is made for or guaranteed by an agency of the federal, state or local government; or~~

~~f) The Applicant has been determined to be a victim of family violence as defined by TEX. FAM. CODE ANN., §71.004. This determination shall be evidenced by the applicant/s submission of a certification letter developed by the Texas Council on Family Violence (made available on its Web site).~~

~~5.6 GROUNDS FOR REFUSAL TO SERVE~~

~~The~~

fees to that third party, the Company may ~~refuse service to any Applicant for any of~~ , at its option, pass that charge plus 20% for handling through to the Applicant requesting service. See Section 15 relating to fees.

SECTION 6 — REFUSAL OF SERVICE

6.1 COMPLIANCE BY APPLICANT

The Company may decline to serve an Applicant for whom service is available from previously installed facilities until such Applicant has complied with the state and municipal regulations and approved rules and regulations of the Company on file with the Commission governing the service applied for or for the following reasons:

~~a) Failure to pay fees, advances or contributions or to make any deposit required for service under this Tariff;~~

~~b) Failure of the Applicant to furnish any service or meter location specified for service under this Tariff;~~

a) ~~c)~~ If the Applicant's installation or equipment is known to be hazardous or of such character that satisfactory and safe service cannot be given. The existence of an unsafe condition, such as a leak in the ~~Applicant's~~Applicant's piping system~~ which,~~, shall be in ~~Company's~~the Company's sole opinion~~, may endanger~~ of endangerment to life or property;

b) ~~d)~~ If the Applicant is indebted to the Company for the same ~~class~~kind of ~~utility~~ service ~~at~~as that applied for; provided, however, that in the ~~same or another service location within~~event the ~~Company's system; or~~indebtedness of the Applicant for service is in dispute, the Applicant shall be served upon complying with the applicable deposit requirement;

c) ~~e)~~ For refusal to make a deposit if Applicant is required to make a deposit under this Tariff;

d) Failure to pay fees, advances or contributions required for service under this Tariff;

~~e)~~e) Delinquency in payment for gas service by another occupant if that person still resides at the premises to be served~~.~~;

f) To any Applicant who refuses Company or Company's representatives access to or entry for observation or whose facilities do not comply with the applicable provision of this Tariff.

g) Failure of the Applicant to furnish any service or meter location specified for service under this Tariff; or

h) Failure of the Applicant to provide satisfactory identifying information as required by the Federal Trade Commission's Red Flag Rules and the Company's Identity Theft Prevention Program.

The right to refuse service shall terminate when the Applicant has complied with the Company's requirements or corrected the cause for the refusal to serve in a manner satisfactory to the Company.

6.2 APPLICANT'S RECOURSE

In the event that the Company shall refuse to serve an Applicant under this Section, the Company must inform the Applicant of the basis of its refusal and that the Applicant may file a complaint with the municipal regulatory authority or Commission, whichever is appropriate. The right to refuse service shall terminate when the Applicant has complied with the Company's requirements or corrected the cause for the refusal to serve.

~~INITIATION OF SERVICE (Continued)~~

~~5.7 REASONABLE TIME~~

6.3 ~~The Company shall have a reasonable amount of time to institute service~~ INSUFFICIENT GROUNDS FOR REFUSAL TO SERVE

The following ~~application therefore~~shall not constitute sufficient cause for refusal of service to a present Customer or ~~execution of an agreement~~ Applicant:

a) Delinquency in payment for service~~. The time may vary depending on approvals and permits required, the extent of the facilities~~ by a previous occupant of the premises to be ~~built, and~~served;

b) Failure to pay for merchandise or charges for non-utility service purchased from the utility;

c) Failure to pay a bill to correct previous underbilling due to misapplication of rates more than six months prior to the date of application;

d) Violation of the Company's ~~workload~~rules pertaining to operation of nonstandard equipment or unauthorized attachments which interfere with the service of others unless the customer has first been notified and been afforded reasonable opportunity to comply with these rules;

e) Failure to pay a bill of another customer as guarantor thereof unless the guarantee was made in writing to the Company as a condition precedent to service; and

f) Failure to pay the bill of another customer at the same address except where the change of customer identity is made to avoid or evade payment of the Company's bill.

SECTION 7 — DISCONTINUANCE OF SERVICE

7.1 CUSTOMER REQUESTED DISCONTINUANCE

The Customer shall be responsible for all charges and amounts billed from the time Customer gives notice of their intention to discontinue service until the Company has read the meter, or for 5 working days from the date of such notice, whichever is the shorter period of time.

7.2 DUE DATE OF BILL

The due date of the bill for the Company's service shall not be less than 15 days after issuance, or such other period of time as may be provided by order of the Regulatory Authority. A bill for the Company's service is delinquent if unpaid by the due date.

7.3 ~~METERING~~DELINQUENT ACCOUNT

A Customer's utility service may be disconnected if the bill or other charges authorized by this Tariff or the applicable rate schedules have not been paid or a deferred payment plan pursuant to this Tariff has not been entered into within five (5) working days after the bill has become delinquent and proper notice has been given. Proper notice consists of a deposit in the United States mail, postage prepaid, or hand delivery to the Customer at least five (5) working days prior to the stated date of disconnection, with the words "TERMINATION NOTICE" or similar language prominently displayed on the notice. The notice shall be provided in English and Spanish as necessary to adequately inform the Customer, and shall include the date of termination, the hours, address, and telephone number where payment may be made, and a statement that if a health or other emergency exists, the Company may be contacted concerning the nature of the emergency and the relief available, if any, to meet such emergency. If a representative of the Company makes an attempt to collect a past due amount, a collection fee per visit shall be assessed to such Customers as specified in Section 15.

7.4 REASONS FOR DISCONNECTION

The Company's service may be disconnected for any of the following reasons:

a) Without notice for the presence of what the Company considers to be an unsafe condition on the Consumer's premises or if an emergency exists or where a known dangerous condition exists for as long as the condition exists;

b) Without notice for willful destruction or damage to or tampering with or bypassing the Company's meter or equipment by the Consumer or by others with knowledge or negligence of the Consumer;

c) Within 5 working days after written notice for violation of the Company's rules pertaining to the use of service in a manner which interferes with the service of others or the operation of nonstandard equipment, if a reasonable attempt has been made to notify the Customer and the Customer is provided with a reasonable opportunity to remedy the situation;

d) Without notice if failure to curtail by such Consumer endangers the supply to Consumers in higher priority classes pursuant to applicable Commission rules;

e) 5 working days after written notice from the Company for refusal to grant Company personnel or its designee's access to the Consumer's premises at any reasonable time for any lawful purpose;

f) 5 working days after written notice from the Company for use, sale or delivery of gas in violation of the provisions of this Tariff or violation of any applicable laws, orders or ordinances, provided that disconnection may be made without notice if the violation creates an unsafe condition;

g) For Customers on transportation service, the Company may discontinue service upon request of a Qualified Supplier, provided however, that the Qualified Supplier represents to the Company that notice has been given to the Customer by the Qualified Supplier of delinquency in payment at least 5 working days prior to Qualified Supplier's request for disconnection, and provided that Qualified Supplier agrees to indemnify and hold harmless the Company from any potential resulting liability;

h) Failure to pay a delinquent account or failure to comply with the terms a deferred payment plan for installment payment of a delinquent account;

i) Failure to comply with deposit or guarantee arrangements where required by this Tariff; or

j) Within 5 working days after written or electronic notice, for Consumers enrolled in e-bill, that any payment including paper check, electronic transfer payment, and debit or credit card payment, that has been rejected or returned to the Company by the bank.

7.5 DISCONNECTION NOT ALLOWED

The Company's service may not be disconnected for any of the following reasons:

a) Within a period of 5 working days after mailing of the notice or the day following the date indicated in the notice, whichever is the later time.

b) After full payment of the delinquent bill except when there is not sufficient time to advise Company's service personnel of receipt of the payment.

c) Delinquency in payment for service by a previous occupant of the premises.

d) Failure to pay for merchandise or charges for non-utility service by the Company.

e) Failure to pay for a different type or class of utility service unless fee for such service is included on the same bill.

f) Failure to pay the account of another customer as guarantor thereof, unless the Company has in writing the guarantee as a condition precedent to service.

g) Failure to pay charges arising from an underbilling occurring due to any misapplication of rates more than six months prior to the current billings.

h) Failure to pay charges arising from an underbilling due to any faulty metering, unless the meter has been tampered with or unless such underbilling charges are due.

i) Failure to pay an estimated bill other than a bill rendered pursuant to an approved meter reading plan, unless the Company is unable to read the meter due to circumstances beyond its control.

j) The Company may not discontinue service to a delinquent residential Customer permanently residing in an individually metered dwelling unit when that Customer establishes that discontinuance of service will result in some person residing at that residence becoming seriously ill or more seriously ill in the service is discontinued. Any Customer seeking to avoid termination of service under this Section must make a written request supported by a written statement from a licensed physician. Both the request and the statement must be received by the Company not more than five (5) working days after the date of delinquency of the bill. The prohibition against service termination provided by this Section shall last twenty (20) days from the date of receipt by the Company of the request and statement or such lesser period as may be agreed upon by the Company and the Customer. The Customer who makes such request shall sign an installment agreement which provides for payment of such service along with timely payments for subsequent monthly billings.

k) The Company shall not disconnect a delinquent residential customer for a billing period in which the Company receives a written pledge, letter of intent, purchase order, or other written notification from an energy assistance provider that it is forwarding sufficient payment to continue service.

7.6 TIME OF DISCONNECTIONS

Unless a dangerous condition exists, or unless the Customer requests disconnection, service shall not be disconnected before 7:00 AM or after 7:00 PM on any day, or on Friday, Saturday, Sunday, Holiday, or day before a Holiday unless Company personnel are available the following day for the purpose of making collections or reconnecting service.

7.7 SUSPENSION OF DISCONNECTIONS DURING EXTREME WEATHER EMERGENCY

Except where there is a known dangerous condition or a use of natural gas service in a manner that is dangerous or unreasonably interferes with service to others, the Company shall not disconnect natural gas service in the following circumstances:

a) The Company shall not disconnect a delinquent residential customer during an extreme weather emergency. An extreme weather emergency means a day when the previous day's highest temperature did not exceed 32 degrees Fahrenheit and the temperature is predicted to remain at or below that level for the next 24 hours according to the nearest National Weather Station for the county where the customer takes service. In accordance with Texas Utilities Code §105.023, the Office of the Attorney General of Texas on its own initiative or at the request of the Commission may file suit to recover a civil penalty for a violation of this paragraph. The table in this paragraph contains a classification system to be used by a court when such a suit is filed.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – Central-Gulf Service Area

Classification System

Violation Factors	Factor Value (1-4)	Points Tally
Customer is disconnected in violation of 16 TAC Section 7.460, subsection (ab)(1) of this Section for 24 hours or more	4	
Customer is disconnected in violation of 16 TAC Section 7.460, subsection (ab)(1) of this section for less than 24 hours, but more than 12 hours	3	
Customer is disconnected in violation of 16 TAC Section 7.460, subsection (ab)(1) of this section for 12 hours or less	2	
Demand for collection of full payment of bills due is made during an extreme weather emergency	3	
The temperature is 10 degrees or less during the period of disconnection	4	
The temperature is more than 10 degrees but less than or equal to 20 degrees during the period of disconnection	3	
The temperature is more than 20 degrees but less than or equal to 32 degrees during the period of disconnection	2	
Repeat violations based on Company's history of compliance	3	
Good faith effort to remedy violation	-2	
No effort to remedy violation during the extreme weather emergency	4	
		Total
		Penalty maximum per violation
10 points or more = Class A violation		More than $5,000[1]
7-9 points = Class B violation		$5,000.00
4-6 points = Class C violation		$4,000.00
1-3 points = Class D violation		$3,000.00

The Company shall defer collection of the full payment of bills that are due during an extreme weather emergency until after the emergency is over and shall work with customers to establish a payment schedule for deferred bills.

Beginning in the September or October billing periods, the Company shall give notice as follows:

a) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to the social service agencies that distribute funds from the low-income Home Energy Assistance Program within the Company's service areas. The Company may provide a copy electronically.

b) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to any other social service agency of which the Company is aware that provides financial assistance to low-income customers in the Company's service areas. The Company may provide a copy electronically.

[1] Pursuant to Utilities Code §105.023(f), the required classification system shall provide that a penalty in an amount that exceeds $5,000 may be recovered only if the violation is included in the highest class of violations in the classification system.

c) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to all residential customers of the Company and customers who are owners, operators or managers of master metered systems. Owners, operators or managers of master metered systems shall provide a copy of this rule to all their customers. The Company may provide a copy electronically.

7.8 RECONNECTION OF SERVICE

a) When service has been disconnected for non-payment, the Company shall require that the Customer pay the total amount of their account then due plus the prescribed reconnect fee or make satisfactory arrangements for that payment before service is reinstituted. In addition, the Company shall require that the Customer re-establish satisfactory credit in accordance with this Tariff.

b) If disconnection has been made by the Company for reasons other than non-payment, service shall not be reinstated until the condition for which it was terminated has been corrected to the Company's satisfaction. The Customer shall also be required to pay a reconnect fee before service is turned on. When service has been disconnected at the Customer's request for a period of one year or more, the request for service shall be treated as a new application. When service has been disconnected for less than one year, the request shall be treated in the same manner as a disconnection for non-payment.

c) The Company shall restore service as soon as feasible after receipt of a reconnection request and compliance with the requirements of this Tariff. The Company shall charge a non-refundable reconnection fee for all Customers in accordance with Section 15. The restoration of service will be accomplished as expeditiously as scheduling permits. If the Customer requests service after hours or earlier than reconnection would otherwise be scheduled, the Company shall offer expedited service in accordance with Section 15. Customer shall be advised that an additional fee will be charged and must agree to pay such charge. In the event the Company is required to make more than one call because the reason for disconnection has not been properly corrected, the reconnect fee may be charged for each call made. No fee shall be charged for any reconnection made after disconnection due to Company's operation. See Section 15 for fees.

7.9 RIGHT OF ENTRY TO DISCONNECT SERVICE

The Company shall have the right to enter the Consumer's premises at any reasonable time to shut off service in accordance with this Tariff and to remove its meter and any other Company property. If the Company is required to take legal action to enforce its rights hereunder, the Company shall be entitled to recover all of its necessary expenses and fees including, but not limited to attorneys' fees, police escort fees, the cost to discontinue service at the main, and/or the cost to relocate the meter at the Customer's expense.

7.10 ABANDONMENT OF SERVICE

The Company may not abandon a Customer without written approval from the Regulatory Authority. The Company will comply with Commission Rule 7.465.

SECTION 8 — SECURITY DEPOSITS

8.1 ESTABLISHMENT OF CREDIT FOR RESIDENTIAL APPLICANT

The Company may require a residential Applicant for service to satisfactorily establish credit, but such establishment of credit shall not relieve the Customer from complying with the rules and Tariff requirements for prompt payment of bills.

8.2 DEPOSIT REQUIRED

a) The Company shall require a security deposit from any present or prospective Customer in accordance with this Tariff to guarantee payment of bills and

b) From any present Customer who during the last 12 consecutive months has on more than one occasion paid its utility bill after becoming delinquent.

8.3 RESIDENTIAL DEPOSIT NOT REQUIRED

A residential Applicant shall not be required to pay a deposit:

a) if the residential Applicant has been a Customer of any utility for the same kind of service within the last two years and is not delinquent in payment of any such utility service account and during the last 12 consecutive months of service did not have more than one occasion in which a bill for such utility service was paid after becoming delinquent and never had service disconnected for nonpayment;

b) if the residential Applicant furnishes in writing a satisfactory guarantee to secure payment of bills for the service required; or

c) if the residential Applicant furnishes in writing a satisfactory credit rating by appropriate means, including, but not limited to, the production of generally acceptable credit cards, letters of credit references, the names of credit references which may be quickly and inexpensively contacted by the Company, or ownership of substantial equity.

d) All Applicants for residential service who are 65 years of age or older will be considered as having established credit if such Applicant does not have an outstanding balance with the Company or another utility for the same utility service which accrued within the last two years. No cash deposit shall be required of such Applicant under these conditions.

e) Each gas utility shall waive any deposit requirement for residential service for an Applicant who has been determined to be a victim of family violence as defined in Texas Family Code, §71.004, by a family violence center, by treating medical personnel, by law enforcement agency personnel, or by a designee of the Attorney General in the Crime Victim Services Division of the Office of the Attorney General. This determination shall be evidenced by the applicant's submission of a certification letter developed by the Texas Council on Family Violence and made available on its web site.

8.4 OTHER EXEMPTIONS FROM DEPOSIT

The Company may not require a deposit if:

a) The Applicant has been a Customer for the same kind of service within the last two (2) years and does not have more than one (1) occasion in which a bill for service from any such utility service account was delinquent and never had service disconnected for nonpayment;

b) The Applicant furnishes a letter of credit acceptable and satisfactory to the Company; or

c) The application for service is made for or guaranteed by an agency of the federal, state or local government.

8.5 RE-ESTABLISHMENT OF CREDIT

Every Applicant who has previously been a Customer of the Company and whose service has been discontinued for nonpayment of bills shall be required before service is rendered to pay all amounts due to the Company or execute a written deferred payment agreement, if offered, and re-establish credit as provided in Section 8.6.

8.6 AMOUNT OF DEPOSIT

The required deposit shall not exceed an amount equivalent to one-sixth of the estimated annual billings. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two (2) days. If such additional deposit is not made, the Company may disconnect service under the standard disconnection procedure for failure to comply with deposit requirements.

8.7 INTEREST ON DEPOSITS

a) Each utility which requires deposits to be made by its customers shall pay a minimum interest on such deposits according to the rate as established by law. If a refund of deposit is made within 30 days of receipt of deposit, no interest payment is required. If the Company retains the deposit more than 30 days, payment of interest shall be made retroactive to the date of deposit.

b) Payment of interest to the Customer shall be annually or at the time the deposit is returned or credited to the Customer's account.

c) The deposit shall cease to draw interest on the date it is returned or credited to the Customer's account.

8.8 RECORDS OF DEPOSITS

a) The Company shall keep records to show:

i) the name and address of each depositor;

ii) the amount and date of the deposit; and

iii) each transaction concerning the deposit.

b) The Company shall issue a receipt of deposit to each Applicant from whom a deposit is received and shall provide means whereby a depositor may establish claim if the receipt is lost.

c) A record of each unclaimed deposit must be maintained for at least four (4) years, during which time the Company shall make a reasonable effort to return the deposit.

8.9 REFUND OF DEPOSITS

Deposits on residential accounts returned to the Customer in accordance with Section 8.6 above shall be applied in the first calendar quarter following the month in which the good payment record is established. Whenever the deposit of any Customer is returned to the Customer, the Company shall pay all previously unpaid interest with the payment.

a) If service is not connected or after disconnection of service, the Company shall promptly and automatically refund the Customer's deposit plus accrued interest on the balance, if any, in excess of the unpaid bills for service furnished. The transfer of service from one premise to another within the service area of the Company shall not be deemed a disconnection within the meaning of these rules and no additional deposit may be demanded unless permitted by these rules.

b) When a residential Customer has paid bills for service for twelve (12) consecutive residential bills without having service disconnected for nonpayment of bill and without having more than two (2) occasions in which a bill was delinquent and when the Customer is not delinquent in the payment of the current bills, the Company shall promptly and automatically refund the deposit plus accrued interest to the Customer in the form of cash, check or credit to a Customer's account.

8.10 ACCEPTABLE FORMS OF DEPOSIT

Any one of the following forms of credit security may be accepted from Customers and Applicants for service:

a) A cash deposit of as much as one-sixth (1/6) the estimated annual billings for service requested; but no less than the minimum deposit set forth in Section 15;

b) For commercial customers only, a nontransferable, irrevocable letter of credit from an established financial institution, payable for as much as one-sixth (1/6) the estimated annual billings for services requested and, which can be drawn on for a minimum of two (2) years; but no less than the minimum deposit set forth in Section 15; or

c) For commercial customers only, a surety bond issued by a reputable insurance company which can be drawn on for a minimum of 2 years.

8.11 DEPOSITS FOR TEMPORARY OR SEASONAL SERVICE

The Company may require a deposit for temporary or seasonal service and for weekend or seasonal residences sufficient to reasonably protect it against the assumed risk, provided such a policy is applied in a uniform and nondiscriminatory manner.

8.12 SALE OR TRANSFER OF COMPANY

Upon the sale or transfer of the Company or operating units thereof, the Company shall file with the Commission under oath, in addition to other information, a list showing the names and addresses of all customers served by the Company or unit who have to their credit a deposit, the date such deposit was made, the amount thereof, and the unpaid interest thereon.

8.13 COMPLAINT

The Company shall direct its personnel engaged in initial contact with an Applicant or Customer for service seeking to establish or re-establish credit under the provisions of these rules to inform the Customer, if dissatisfaction is expressed with the Company's decision, of the Customer's right to file a complaint with the regulatory authority thereon.

8.14 FRANCHISE AGREEMENTS

To the extent the terms of a franchise agreement are inconsistent with this Section, the terms of the franchise agreement control. Applicable to customers inside the corporate limits of an incorporated municipality that imposes a franchise fee to Company for the gas service provided to Customer.

SECTION 9 — BILLING AND PAYMENT OF BILLS

9.1 RENDERING OF BILLS

Bills for gas service shall be rendered monthly, unless otherwise authorized or unless service is rendered for a period less than a month. Bills shall be rendered as promptly as possible following the reading of meters.

Bills shall be due and payable in full on or before the due date, which shall be stated on the face of the bill and shall not be earlier than fifteen (15) days after the bill is mailed (including electronic mail). Bills shall be considered to have been rendered when deposited in the United States Mail with postage prepaid thereon or, when the customer has elected to receive billings via electronic mail, when the electronic document has been sent. Payment shall be considered received when the correct amount has been received through a company authorized payment method. If not paid by the date due, the bill shall be considered delinquent.

9.2 REQUIRED BILL INFORMATION

The Customer's bill must show all the following information. The information must be arranged and displayed in such a manner as to allow the customer to compute their bill with the applicable rate schedule. The applicable rate schedule must be mailed to the Customer on request of the customer.

a) if the meter is read by the utility, the date and reading of the meter at the beginning and end of the period for which rendered;

b) the number and kind of units billed;

c) the applicable rate schedule title or code;

d) the total base bill;

e) the total of any adjustments to the base bill and the amount of adjustments per billing unit;

f) a distinct marking to identify an estimated bill.

9.3 ESTIMATED BILLS

Where there is good reason for doing so, estimated bills may be submitted, provided that an actual meter reading is taken at least every six months. For the second consecutive month in which the meter reader is unable to gain access to the premises to read the meter on regular meter reading trips, or in months where meters are not read otherwise, the utility must provide the customer with a postcard and request that the customer read the meter and return the card to the utility if the meter is of a type that can be read by the customer without significant inconvenience or special tools or equipment. If such a postcard is not received by the utility in time for billing, the utility may estimate the meter reading and render the bill accordingly.

9.4 DISPUTED BILLS

a) In the event of a dispute between the Customer and the Company regarding the bill, the Company must make such investigation as is required by the particular case and report the results to the Customer. If the Customer wishes to obtain the benefits of subsection b) of this Section, notification of the dispute must be given to the Company prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the Company shall inform the Customer of the complaint procedures of the appropriate Regulatory Authority.

b) Notwithstanding any other subsection of this Section, the Customer shall not be required to pay the disputed portion of the bill which exceeds the amount of that Customer's average usage for the billing period at current rates until the earlier of the following: resolution of the dispute or the expiration of the 60-day period beginning on the day the disputed bill is issued. For purposes of this Section only, the Customer's average usage for the billing period shall be the average of the Customer's usage for the same billing period during the preceding two (2) years. Where no previous usage history exists, the average usage shall be estimated on the basis of usage levels of similar customers and under similar conditions.

9.5 PAYMENT RE-PROCESSING FEE

The Company may charge or add to the Customer's account and collect a fee (as provided in Section 15) to recover costs for reprocessing any payment, including paper check, electronic transfer payment, and debit and credit card payment, that has been rejected or returned to the Company by the bank for any reason other than bank error.

9.6 ELECTRONIC BILLING STATEMENTS

The Customer may at their option receive bills via electronic mail. Customers shall provide current, accurate and complete information to the Company and shall update their information as necessary so that it remains current, accurate and complete. The Company may verify Customer information at any time.

9.7 PAYMENT OPTIONS

The Company, at its option and discretion, may contract with payment vendors to provide various payment options and authorize these vendors to accept payments from Customers on the Company's behalf. Payment options may be electronic, telephonic, in person, or by mail and may include automatic bank draft, credit/debit card, check or cash. Contracted payment vendors may charge Customers an additional fee for the use of that payment option and the contracted payment vendor shall be solely responsible for collecting any fee from the Customer.

9.8 DEFERRED PAYMENT PLANS

The Company, at its sole discretion, may offer a deferred payment plan for delinquent Customer accounts. Deferred payment plans shall conform to the following guidelines:

a) Every deferred payment plan entered into due to the Customer's inability to pay the outstanding bill in full must provide that service will not be discontinued if the customer pays current bills and a reasonable amount of the outstanding bill and agrees to pay the balance in reasonable installments until the bill is paid.

b) For purposes of determining reasonableness, the following shall be considered:

i) size of delinquent account;

ii) Customer's ability to pay;

iii) Customer's payment history;

iv) time that the debt has been outstanding;

v) reasons why debt has been outstanding; and

vi) other relevant factors concerning the circumstances of the Customer.

c) A deferred payment plan, if reduced to writing, shall state immediately preceding the space provided for the Customer's signature and in bold-face print at least two sizes larger than any other used that, "If you are not satisfied with this agreement, do not sign. If you are satisfied with this agreement, you give up your right to dispute the amount due under the agreement except for the Company's failure or refusal to comply with the terms of this agreement."

d) A deferred payment plan may include a one-time penalty up to 5.0% for late payment on the original amount of the outstanding bill except in cases where the outstanding bill is unusually high as a result of the Company's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.

e) If a Customer for utility service has not fulfilled the terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the utility shall have the right to disconnect pursuant the disconnection rules in this Tariff, and under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.

f) The Company shall not refuse a Customer participation in a deferred payment plan on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.

9.9 AVERAGE PAYMENT PLAN

Any residential Customer or non-residential Customer with annual usage less than 500 Ccf may elect to participate in the Company's Average Payment Plan ("APP Plan"). The terms, conditions, and other information regarding the Average Payment Plan are set forth herein by reference.

A. TERMS AND CONDITIONS

1. The Average Payment Plan ("Plan") is available to residential and qualifying nonresidential customers that have a minimum of six (6) months consumption history available at the premise. Residential and Non-residential customers may request participation in the Plan at any time during the year. Request for participation can be made by telephone or in writing.

2. A customer's account should be current at the time the customer elects to participate in the Plan and at all times during Plan enrollment, which means the account does not have a previous balance and the current billing is not past due.

3. Service is not available under this Plan for a term of less than twelve (12) months.

B. AVERAGE PAYMENT AMOUNT

1. Each month under the Plan, a customer's Average Payment Amount will be computed by averaging the amount actually billed to the customer's account during the last 12 months (current + 11), plus or minus one-twelfth (1/12) of the Average Payment Plan Settlement amount and then rounded to the nearest dollar. In the event 12 months history is not available, Company may estimate the missing months in order to determine the appropriate average payment amount.

2. The Average Payment Amount is identified as a separate item on the gas bill so the participating consumer will know the amount to pay.

3. Gas costs and/or rate changes shall be factored into the monthly average payment calculations on a rolling basis.

SECTION 10 — FACILITIES AND EQUIPMENT

10.1 STANDARDS OF CONSTRUCTION

The Company is to construct, install, operate, and maintain its plant, structures, equipment, and lines in accordance with the provisions of such codes and standards that are generally accepted by the industry as modified by rule or regulation of the Regulatory Authority or otherwise by law, and in such a manner to best accommodate the public and prevent interference with service furnished by other public utilities insofar as practical.

10.2 COMPANY OWNED FACILITIES

The Company shall maintain all facilities owned by it and shall be responsible for the safe conduct and handling of the gas until it passes the point of delivery. The Company's representative shall have the right to enter the Customer's premises at any reasonable time, in the event of an emergency at any time, to read the meter or make any necessary inspection, repair, adjustment, or replacement of any property owned by the Company.

No one other than a Company representative or other person authorized by Company shall be permitted to repair or remove Company's meter or facilities, or any of the property of Company on or about customer's premises. Any seals placed by Company on meters or regulators shall not be broken or disturbed by anyone other than authorized representatives of Company. Any unauthorized tampering with Company's meter or facilities is in violation of this restriction and such tampering shall be considered cause for immediate discontinuance of service by Company.

10.3 CUSTOMER OWNED FACILITIES

a) The Customer shall maintain all facilities owned by them and shall be responsible for the safe conduct and handling of the gas after it passes the point of delivery. Any facilities downstream of the meter installed by the Customer shall remain the property and responsibility of the Customer. Whenever the condition of the facility is such that replacement is required, the work shall be done by the Company pursuant to the provisions of Section 10.8 of this Tariff. New facilities will continue to be installed pursuant to Sections 10.5 and 10.6 of this Tariff.

b) The Customer shall remove, repair or adjust any Customer-owned property which may pose a threat of damage to the property of the Company. The Customer shall take all reasonable means to assure that no one other than an employee of the Company shall adjust, repair, disconnect or change the meter or other Company facilities in any way.

c) Nothing in this Section shall make the Company responsible for the safe upkeep of any Customer or Consumer-owned facilities.

d) In case of loss or damage to the Company's property from the negligence or willful acts of the Customer or Consumer or the Customer's or Consumer's representatives, the Customer will reimburse the Company for all costs of repairing or replacing the damaged property, including any costs of collection such as attorney's fees.

10.4 LEAKS

The Customer or Consumer shall give the Company notice of any leaking or escaping gas as soon as it is detected. Upon receipt of this notice, the Company shall investigate the matter as promptly as feasible under the circumstances. If the Company's test indicates leakage in the Customer's or Consumer's facilities, the Company shall have the right to disconnect service immediately until the Customer or Consumer has had the condition corrected. If leakage is found to be from Company owned facilities, the Company shall have the right to disconnect service for a reasonable period of time until the leakage can be corrected by the Company. The Company shall have the right to disconnect service immediately if any of the Customer's or Consumer's appliances or equipment is, in the Company's opinion, operating in an unsafe manner.

10.5 MATERIALS OR EQUIPMENT FURNISHED BY THE COMPANY

a) The Company shall furnish and install at its expense, the service pipe from the Company's existing main to the property line nearest the meter and the equipment related thereto, including meter valve and service regulator. Although affixed to or buried in the Customer's property, the entire service line and meter set shall become the property of the Company and shall be operated and maintained by the Company.

b) Whenever the meter is located at any point other than the property line, the Company shall determine the estimated cost of that portion of the service between the property line and the meter set. This estimate shall be based on the size and footage to be installed and charged in accordance with Section 11 and other applicable provisions of this Tariff. This estimated amount shall be contributed by the Applicant to the Company before construction, unless the Applicant is a qualified Blanket Builder.

10.6 MATERIALS OR EQUIPMENT FURNISHED BY THE APPLICANT

a) The Applicant shall furnish and install at their expense all piping, equipment and appliances required to conduct and utilize the gas furnished by the Company and conversions of existing equipment and appliances required to conduct and utilize the gas furnished by the Company from the outlet of the meter set to the point(s) of utilization and those portions of the service line and meter set not furnished by the Company as described in Section 10.5.

b) The adequacy, safety and compliance with applicable codes and ordinances of piping, conversion equipment and appliances shall be the responsibility of the Applicant and no action of the Company in accordance with this Tariff shall release the Applicant of the responsibility for the facilities installed or furnished by them. All piping, installations, and conversion equipment owned by the Applicant shall comply with all applicable federal, state, and county requirements and municipal ordinances, or otherwise, and shall be properly designed for the pressures and volumes to be handled. Where there are none, the most current International Fuel Gas Code shall apply.

10.7 RELOCATION OF COMPANY FACILITIES

a) A charge of not more than actual cost may be made for relocating a meter or other Company equipment on the same premises at the request of the Customer or Consumer.

b) If the Company shall for its own convenience and not for the safety or convenience of the Customer, change the point of delivery or change the location of its equipment on private property, the Company shall bear the expense.

10.8 REPLACEMENT OF CUSTOMER-OWNED PIPING

a) When repair or replacement of Customer-owned piping becomes necessary due to deterioration of the Company's line, damage to the Company's line (except when caused by Customer or Customer's agent), relocation of the Company's distribution main, or for other safety reasons determined by the Company, the Company may relocate the Customer's meter to the exterior of the building wall, as close as possible to the existing stub out (where piping exits the structure), and may replace the service piping up to the stub out. The Company will own and be responsible for all service piping from the main line to the meter, and Customer will own and be responsible for all piping from the meter to the building.

b) The Customer may be billed for all costs of the meter relocate and pipeline replacement.

c) In the absence of any provision contained in a deed of dedication authorizing the Company to install the service piping and meter on Customer's premises, the owner of the premises shall execute an agreement establishing the meter location, authorizing the Company to install or replace the line, and granting Company access for such work. If the Customer or owner of the premises refuses to give Company personnel or Company authorized personnel appropriate access to the property for purposes of installation, the Customer will retain responsibility for their facilities and shall bear the expense of any replacement or repairs.

SECTION 11 — EXTENSION OF FACILITIES

11.1 LINE EXTENSION AND CONSTRUCTION CHARGES

a) Every utility must file its extension policy. The policy must be consistent, nondiscriminatory, and is subject to the approval of the Regulatory Authority. No contribution in aid of construction may be required of any customer except as provided for in the extension policy.

b) The Company shall install the necessary facilities to provide service to Applicants whose premises are located beyond the Company's existing distribution facilities in accordance with the provisions of this Section. The expenditure for such extensions must either be cost justified or the Applicant(s) and Company must mutually agree to terms that justify the installation.

11.2 DESIGN AND COST OF FACILITIES

As soon as practical after a completed application for service is received, the Company shall determine the extent of the facilities required to serve the new customer and the cost thereof. This cost shall include all amounts to be spent for system improvements necessary to deliver the required gas, in accordance with the Company's current practice. Whenever the Company chooses to install facilities of greater capacity than would be required to serve the new customer for which the application is being made or to permit supply from another source, the estimate of costs shall be based on only the size and capacity normally used to serve requirements similar to that of the Applicant.

11.3 ALLOWANCE FOR NEW BUSINESS

The Company shall also determine the number of existing permanent Customers located along the route of the extension expected to be served therefrom. To be included, the occupant of each premise must request service and demonstrate capability for using such service through a major gas burning appliance. Single or groups of individually owned mobile homes shall be included only if the wheels and hitch have been removed from each mobile home and/or substantial improvements have been made to the property. Mobile home parks may be served either through a master meter or individual meters served by a Company-owned system, provided that required mains can be installed and dedicated streets or rights-of-way have been provided to the Company for installation of facilities as evidenced by agreement executed on the Company's form. An allowance to be determined by the Company may be given for each Customer whose premises exist at the time of application to be served from the proposed main extension. In order to qualify for this allowance, the Customer must file an application and agree to initiate gas service upon completion of the Company's facilities.

11.4 ADVANCES

The mutually agreed upon terms will determine the amount of advance required. The Applicant shall have 30 calendar days after notification of the amount required to execute an extension agreement on the Company's form and pay the required advance. At the end of that time, the Company may revise its estimates to reflect any changes in costs or conditions which will affect the amount of the advance. The Company may waive or reduce collection of any advance based on an economic analysis of the project.

11.5 CONSTRUCTION OF FACILITIES

As soon as practical after the advance has been paid or it has been determined that no advance will be required, the Company shall begin construction of the required facilities and thereafter prosecute the work with reasonable diligence. The Company shall not be responsible for delays in the construction of the facilities occasioned by events or conditions reasonably beyond the Company's control. Whenever the construction of the new facilities requires the acquisition of rights-of-way across the Applicants(s) land(s), these rights-of-way shall be provided by the Applicant(s) in the Company's name and on its form at no cost to the Company (except for fees involved in the recording of documents).

11.6 REVIEW OF ADVANCES

The Company shall review each extension agreement on the first anniversary of the signing of that agreement. Upon the Applicant(s) request if the extension provided for in the agreement has not been installed through no fault of the Company, the agreement shall be considered to be terminated and a complete refund made to the Applicant(s). Once the extension has been installed and service has been initiated, the Company shall thereafter review the extension agreement at its second through fifth execution dates. At each review, the number of Customers then served directly from the extension shall be compared with the number served on the last prior anniversary date. A refund, shall be given for each additional Customer served, based on mutually agreed upon terms provided that the total of the refunds given does not exceed the cost of the extension of facilities.

11.7 REFUND LIMITATIONS

The Company may, at its sole option, make a refund at any time. In no case, however, shall a refund be given unless the number of Customers then served is greater than the number for whom refunds have previously been given. No refund shall be given which shall cause the total refunds to be greater than the total amount of the advance. No interest shall be paid on any advance made under the provisions of this Section. At the end of the five-year period, any remaining amount of the advance shall be retained by the Company as a contribution in aid of construction.

~~11.1~~11.8 DELIVERY OF ~~GAS~~REFUNDS

~~6.1~~ Upon Applicant(s) request, when a refund is due, a check in the appropriate amount and a letter setting forth the method of calculation of the refund and the balance remaining un-refunded shall be made to the person or business in whose name the extension agreement is made or to their assignee. If that letter is returned undelivered, the check shall be cancelled and the next review made without regard to that refund. All sums described in this Section which are returned undelivered and remain unclaimed in the Company's possession for a period of six months following expiration of the five-year period of the extension agreement shall be retained by the Company and considered a contribution in aid of construction.

SECTION 12 — METERS

12.1 METER REQUIREMENTS

a) All gas sold by the Company must be charged for by meter measurements, except where otherwise provided for by applicable law, regulation of the Regulatory Authority, or tariff.

b) Unless otherwise authorized by the Regulatory Authority, the Company must provide and install and will continue to own and maintain all meters necessary for measurement of gas delivered to its customers.

c) The Company may not furnish, set up, or put in use any meter which is not reliable and of a standard type which meets generally accepted industry standards; provided, however, special meters not necessarily conforming to such standard types may be used for investigation, testing, or experimental purposes.

12.2 METER READING

Meters shall be read as nearly as may be practical on the same day of each calendar month. Whenever a reading of a general service meter is missed or the meter is not registering, the Company shall estimate the amount of gas used during the period. Such estimates shall be based on either -

a) That Customer's use of gas during the same period(s) in previous years;

b) That Customer's normal use of gas during preceding months; or

c) The use of a similar Customer for the period missed.

If practical, an actual reading shall be made after two consecutive estimated bills. All meters in Special Service shall be read at least once a month. Whenever such a meter fails to register or is misread, the amount of gas used during the preceding period shall be estimated using data applicable to that Special Service Customer only. The Company will make a special reading of any meter upon request and may assess a service charge in accordance with Section 15. The time of the special reading shall be agreed upon with the Customer so that they may be present. If the original reading was in error (subject to consumption between the two readings) the service charge will be refunded to the Customer.

~~12.1~~12.3 METER LOCATION

The Company shall have the sole right to determine the location of the meter in accordance with the needs of the service.

Each Applicant shall furnish and subsequently maintain a suitable location on his or her premises for the Company's meter and related facilities at a point selected by the Company. Meters shall be located where they will be safely accessible for reading and service, adequately ventilated, and not subject to damage. Meters shall not be located within any enclosed area unless the enclosure is solely intended as a meter house~~.~~ or in the Company's opinion, conditions prohibit installation outside. It may be necessary for the Company to install bollards or guard posts around the meters for safety.

~~6.2~~

12.4 METER RECORDS

The Company must keep the following records:

a) The Company must keep a record of all its meters, showing the Customer's address and date of the last test.

b) All meter tests must be properly referenced to the meter record provided for therein. The record of each test made on request of a Customer must show the identifying number and constants of the meter, the standard meter and other measuring devices used, the date and kind of test made, by whom made, the error (or percentage of accuracy) at each load tested, and sufficient data to permit verification of all calculations.

c) In general, each meter must indicate clearly the units of service for which charge is made to the Customer.

12.5 METER ACCURACY

The accuracy limit of all Company meters is established at two percent (2%) fast or slow. Any meter found to be registering outside of the limits of accuracy shall immediately be removed or repaired. As long as the meter is operating within the limits of accuracy, it shall be the conclusive determination as to the quantities of gas delivered to the Customer on whose service it is set.

12.6 PERIODIC TESTS

The Company shall make periodic tests of meters, associated devices and instruments to assure their accuracy. Such tests shall be scheduled within the calendar year or earlier, when the interval is stated in years; or within the calendar month, or earlier when the interval is stated in months. The basic periodic test interval shall be no longer than provided for in the manufacturer's recommendations, a copy of which is available upon request.

12.7 ACCESS TO THE METER

The Customer shall permit the Company safe access to the meter at all reasonable times for reading thereof and at all reasonable times for reading, maintenance, testing, or replacement of the meter. Upon the Customer's failure or refusal to grant such access, the Company may issue a written notice to the Customer, advising them the situation must be corrected and access granted within 5 working days and that failure to do so can result in the disconnection of service and removal of the meter. Additional fees may apply and will be assessed to such Customer as specified in Section 15.

12.8 METER TESTING AT CUSTOMER REQUEST

a) The Company must, upon request of a Customer, make a test of the accuracy of the meter serving that Customer. The Company must inform the Customer of the time and place of the test and permit the Customer or his authorized representative to be present if the Customer so desires. If no such test has been performed within the previous four (4) years for the same Customer at the same location, the test is to be performed without charge. If such a test has been performed for the same Customer at the same location within the previous four (4) years, the Company is entitled to charge a fee for the test not to exceed $15 or such other fee for the testing of meters as may be set forth in Section 15 of this Tariff properly on file with the Regulatory Authority. The Customer must be properly informed of the result of any test on a meter that serves him.

b) Notwithstanding subsection (a) of this Section, if the meter is found to be more than nominally defective, to either the Customer's or the Company's disadvantage, any fee charged for a meter test must be refunded to the Customer. More than nominally defective means a deviation of more than 2.0% from accurate registration.

12.9 BILLING ADJUSTMENTS DUE TO METER ERROR

a) If any meter test reveals a meter to be more than nominally defective, the Company must correct previous readings consistent with the inaccuracy found in the meter for the period of either:

i) the last six months; or

ii) the last test of the meter, whichever is shorter. Any resulting underbillings or overbillings are to be corrected in subsequent bills, unless service is terminated, in which event a monetary adjustment is to be made. This requirement for a correction may be foregone by the Company if the error is to the Company's disadvantage.

b) If a meter is found not to register for any period of time, the Company may make a charge for units used but not metered for a period not to exceed three months previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated customers, when not available.

12.10 PROVISIONS FOR SPECIAL SERVICE

The following modifications shall apply to the provisions of this Section for all Special Service rate schedules and service under special written agreements:

a) Turbine meters shall be tested at least once each calendar year. Orifice meters shall be tested at a minimum: every 6 months for 0-500 Mcf/d; every 3 months for volumes 500-2000 Mcf/d; and every month for volumes 2000 Mcf/d and greater. Should the Customer so elect, tests shall be made in the presence of his or her representative.

b) Whenever a meter is found to be registering above or below the limits of accuracy, adjustment of the bill (either up or down) shall be limited to the monthly billing subsequent to the last meter test. The adjustment shall be made upon the basis of the best data available, using the first of the following methods, whichever is most appropriate:

i) by using registration of Customer’s check meter(s);
ii) by correcting the error, if the percentage of error is ascertainable by calibration test or mathematical calculation; or
iii) by estimating the quantity of gas delivered by comparison with deliveries during the preceding period under similar conditions when accurate registration was obtained.

~~12.2~~12.11 POINT OF DELIVERY

The point of delivery of gas sold by the Company to the Customer shall be at the outlet side of the Company's meter, provided that in those cases in which the Customer owns a section of the underground pipe between the Customer's property line and the meter, the point of delivery shall be at the property line. The title of all gas sold by the Company to the Consumer shall pass from the Company at the point of delivery. The point(s) of delivery and point(s) of redelivery for Transportation Service shall be as provided in the contract entered into between the Customer and the Company.

12.12 ~~6.3~~ CONNECTION TO COMPANY FACILITIES

No Consumer shall make any connection or alteration of any kind on any of the Company's facilities upstream of the Company's meter or shall permit any other person to make such connection or alteration.

~~12.3~~12.13 MULTIPLE METERS

Each Customer or group of Customers located on the same lot or tract of land may be served from a single meter location. The Company may, at its option, permit additional meter locations to simplify installation of facilities or provide better service. Whenever more than one meter location is permitted for the same Customer, the Company shall bill the usage through each meter separately, provided that any combined billings in effect at the time of adoption of this Tariff may be continued until the affected Customer discontinues service or upon order by the Regulatory Authority.

~~6.4 CONNECTION TO COMPANY FACILITIES~~

~~No Consumer shall make any connection or alteration of any kind on any of the Company's facilities upstream of the Company's meter or shall permit any other person to make such connection or alteration.~~

~~INSTALLATION OF EQUIPMENT~~

~~7.1 EQUIPMENT FURNISHED BY THE COMPANY~~

~~The Company shall furnish and install at its expense, the service pipe from the Company's existing main to the property line nearest the meter and the equipment related thereto, including meter valve and service regulator. Whenever the meter is located at any point other than the property line, the Company shall determine the estimated cost of that portion of the service between the property line and the meter set. This estimate shall be based on the size and footage to be installed and charged in accordance with Section 8 and other applicable provisions of this Tariff. This estimated amount shall be contributed by the Applicant to the Company before construction, unless the Applicant is a qualified Blanket Builder, or unless the cost of the service line was previously included in the main extension calculation under Section 8.1. Although affixed to or buried in the Customer's property, the entire service and meter set shall become the property of the Company and shall be operated and maintained by the Company.~~

~~7.2 EQUIPMENT FURNISHED BY THE APPLICANT~~

~~The Applicant shall furnish and install at his or her expense, all piping and equipment required to conduct and utilize the gas furnished, from the outlet of the meter set to the point(s) of utilization and those portions of the service line and meter set not furnished by the Company as described in Section 7.1 above. The adequacy, safety and compliance with applicable codes and ordinances shall be the responsibility of the Applicant and no action of the Company in accordance with this Tariff shall release the Applicant of the responsibility for the facilities installed by him or her.~~

~~7.3 STATUTES, CODES, AND ORDINANCES~~

~~All piping and installations owned by the Applicant shall comply with all applicable legal requirements, whether federal, state, county, municipal, or otherwise, and shall be properly designed for the pressures and volumes to be handled. In those locations where there are no applicable state or local requirements, the applicable provisions of the National Fuel Gas Code 54; ANSI Z223.1 and any amendments thereto shall apply.~~

~~7.4 CHECKS AND TESTS~~

~~The Company shall have the right to check new installations prior to initiation of service and to make any test of the Applicant's facilities it deems necessary, at no charge to the customer.~~

~~7.5 REFUSAL TO SERVE~~

~~The Company shall refuse service to any Applicant who refuses entry for observation or whose facilities do not comply with the applicable provisions of this Tariff. The right to refuse service shall terminate with the correction of the condition(s) which was cause for refusal. Initiation of service, however, shall not be considered to be acceptance or approval by the Company of such facilities.~~

~~EXTENSION OF FACILITIES~~

~~8.1 EXTENSION OF MAINS~~

~~The Company shall install the necessary facilities to provide service to Applicants whose premises are located beyond the Company's existing distribution facilities in accordance with the provisions of this Section. The expenditure for such extensions must either be cost justified or the Applicant(s) and Company must mutually agree to terms that justify the installation.~~

~~8.2 DESIGN AND COST OF FACILITIES~~

~~As soon as practical after an application for service is received, the Company shall determine the extent of the facilities required to serve the new customer and the cost thereof. This cost shall include all amounts to be spent for system improvements necessary to deliver the required gas, such as mains, regulator and meter stations, upgrading and/or reinforcement, all in accordance with the Company's current practice. Whenever the Company chooses to install facilities of greater capacity than would be required to serve the new customer for which the application is being made or to permit supply from another source, the estimate of costs shall be based on only the size and capacity normally used to serve requirements similar to that of the Applicant.~~

~~8.3 ALLOWANCE FOR NEW BUSINESS~~

~~The Company shall also determine the number of existing permanent Customers located along the route of the extension expected to be served therefrom. To be included, the occupant of each premise must request service and demonstrate capability for using such service through a major gas burning appliance. Single or groups of individually owned mobile homes shall be included only if the wheels and hitch have been removed from each mobile home and/or substantial improvements have been made to the property. Mobile home parks may be served either through a master meter or individual meters served by a Company-owned system, provided that required mains can be installed and dedicated streets or rights-of-way have been provided to the Company for installation of facilities as evidenced by agreement executed on the Company's form. An allowance to be determined by the Company may be given for each Customer whose premises exist at the time of application to be served from the proposed main extension. In order to qualify for this allowance, the Customer must file an application and agree to initiate gas service upon completion of the Company's facilities.~~

~~8.4 ADVANCES~~

~~The mutually agreed upon terms will determine the amount of advance required. The Applicant shall have 30 calendar days after notification of the amount required to execute an extension agreement on the Company's form and pay the required advance. At the end of that time, the Company may revise its estimates to reflect any changes in costs or conditions which will affect the amount of the advance. The Company may waive collection of any advance based on an economic analysis of the project.~~

~~8.5 CONSTRUCTION OF FACILITIES~~

~~As soon as practical after the advance has been paid or it has been determined that no advance will be required, the Company shall begin construction of the required facilities and thereafter prosecute the~~

~~EXTENSION OF FACILITIES (Continued)~~

~~8.5 CONSTRUCTION OF FACILITIES (Continued)~~

~~work with reasonable diligence. The Company shall not be responsible for delays in the construction of the facilities occasioned by events or conditions reasonably beyond the Company's control. Whenever~~
~~the construction of the new facilities requires the acquisition of rights-of-way across the Applicants(s) land(s), these~~

~~rights-of-way shall be provided by the Applicant(s) in the Company's name and on its form at no cost to the Company (except for fees involved in the recording of documents).~~

~~8.6 REVIEW OF ADVANCES~~

~~The Company shall review each extension agreement on the first anniversary of the signing of that agreement. Upon the Applicant(s) request if the extension provided for in the agreement has not been installed through no fault of the Company, the agreement shall be considered to be terminated and a complete refund made to the Applicant(s). Once the extension has been installed and service has been initiated, the Company shall thereafter review the extension agreement at its second through fifth execution date. At each review, the number of Customers then served directly from the extension shall be compared with the number served on the last prior anniversary date. A refund, shall be given for each additional Customer served, based on mutually agreed upon terms provided that the total of the refunds given does not exceed the cost of the extension of facilities.~~

~~8.7 REFUND LIMITATIONS~~

~~The Company may, at its sole option, make a refund at any time. In no case, however, shall a refund be given unless the number of Customers then served is greater than the number for whom refunds have previously been given. No refund shall be given which shall cause the total refunds to be greater than the total amount of the advance. No interest shall be paid on any advance made under the provisions of this Section. At the end of the five year period, any remaining amount of the advance shall be retained by the Company as a contribution in aid of construction.~~

~~8.8 DELIVERY OF REFUNDS~~

~~Upon Applicant(s) request, when a refund is due, a check in the appropriate amount and a letter setting forth the method of calculation of the refund and the balance remaining un-refunded shall be made to the person or business in whose name the extension agreement is made or to his or her assignee. If that letter is returned undelivered, the check shall be cancelled and the next review made without regard to that refund. All sums described in this Section which are returned undelivered and remain unclaimed in the Company's possession for a period of six months following expiration of the five year period of the extension agreement shall be retained by the Company and considered a contribution in aid of construction.~~

~~CUSTOMER-OWNED SYSTEMS~~

~~12.4~~12.14 ~~9.1~~ INDIVIDUALLY METERED SYSTEMS

The Company shall not render service to any Customer through a meter not connected to a system owned by the Company or one of the Company's suppliers.

~~12.5~~12.15 ~~9.2~~ MASTER METERS

The Company shall provide service through a master meter into the piping systems of others to be distributed to more than one Consumer, except when the gas served is resold to those Consumers on either a commodity or separate cost of service basis; provided, however, that those Customers purchasing gas for redistribution to the Customer's own tenants only on the Customer's premises may separately meter each tenant distribution point for the purpose of prorating the Consumer's actual purchase price of gas delivered among the various tenants on a per unit basis, and further provided that the provisions of this Section ~~9~~ shall not preclude the Company from supplying natural gas to a third party for resale to the public as fuel for natural gas powered vehicles (NGV's).

~~SECURITY DEPOSITS~~

~~10.1 REQUIREMENTS~~

~~The Company shall require a security deposit from any present or prospective Customer in accordance with Sections 5.5 and 18.1 of this Tariff to guarantee payment of bills, and from any present Customer who during the last 12 consecutive months has on more than one occasion paid their utility bill after becoming delinquent. However, the deposit requirement may, at the option of the Company be based on annual usage experienced at the particular address with application of one-sixth of the annual amount as determined as the required deposit. If actual use is at least twice the amount of the estimated billings, a new deposit requirement may be calculated and an additional deposit may be required within two days. The deposit shall be refunded to residential Customers in the form of cash or credit to a customer's account when the Customer has paid 12 consecutive bills without having service disconnected for non-payment, and without having one or more occasion in which a bill was delinquent or a payment was returned, and the Customer is not currently delinquent.~~

~~10.2 RECEIPTS~~

~~The Company shall maintain such records as may be necessary to permit any Customer to receive any deposit return to which he or she is entitled without presentation of the receipt. A record of any unclaimed deposits shall be maintained by the Company for at least 4 years.~~

~~10.3 INTEREST~~

~~The Company shall pay interest on all security deposits for the time held at the rate as set by the Public Utility Commission annually except when~~

~~a) The deposit is held 30 days or less;~~
~~b) Notice is sent to the Customer's last known address that the deposit is no longer required;~~
~~c) The service to which the deposit relates has been discontinued; or~~
~~d) All or any part of the deposit has been applied to a delinquent account.~~

~~Interest on deposits earned during the preceding year shall be paid to the Customer annually. Payment shall be made either by check or as a credit on the monthly bill at the Company's option.~~

~~10.4 RETURN OF DEPOSITS~~

~~Deposits on residential accounts returned to the Customer in accordance with Section 10.1 above shall be applied in the first calendar quarter following the month in which the good payment record is established. Whenever the deposit of any Customer is returned to the Customer, the Company shall pay all previously unpaid interest with the payment.~~

~~10.5 ACCEPTABLE FORMS OF DEPOSIT~~

~~Any one of the following forms of credit security may be accepted from Customers and Applicants for service:~~

~~SECURITY DEPOSITS (Continued)~~

~~10.5 ACCEPTABLE FORMS OF DEPOSIT (Continued)~~

~~a) A cash deposit of as much as one-sixth (1/6) the estimated annual billings for service requested; but no less than the minimum deposit set forth in Section 21.2;~~

~~b) For commercial customers only, a nontransferable, irrevocable letter of credit from an established financial institution, payable for as much as one-sixth (1/6) the estimated annual billings for services requested and,~~

~~which can be drawn on for a minimum of two (2) years; but no less than the minimum deposit set forth in Section 21.2; or~~

~~c) For commercial customers only, a surety bond issued by a reputable insurance company which can be drawn on for a minimum of 2 years .~~

~~10.6 FRANCHISE AGREEMENTS~~

~~To the extent the terms of a franchise agreement are inconsistent with this Section, the terms of the franchise agreement controls. Applicable to customers inside the corporate limits of an incorporated municipality that imposes a municipal franchise fee to Company for the gas service provided to Customer.~~

SECTION 13 — GAS MEASUREMENT

13.1 ~~11.1~~ PRESSURE

The standard serving and measurement pressure shall be 4 ounces (0.25 psig) or 7" Water Column above the standard atmospheric pressure in the area served. The atmospheric pressure and standard serving pressure determined to be the average in the cities and environs of the Central-Gulf Service Area are listed below.

Cities and their Environs	Atmospheric Pressure PSIA	Standard Serving Pressure PSIA
Austin	14.40	14.65
Bastrop	14.40	14.65
Bayou Vista	14.70	14.95
Beaumont	14.70	14.95
Bee Cave	14.40	14.65
Buda	14.40	14.65
Cedar Park	14.40	14.65
Cuero	14.48	14.73
Dripping Springs	14.40	14.65
Galveston	14.70	14.95
Gonzales	14.48	14.73
Groves	14.70	14.95
Hutto	14.40	14.65
Jamaica Beach	14.70	14.95
Kyle	14.40	14.65
Lakeway	14.40	14.65
Lockhart	14.48	14.73
Luling	14.48	14.73
Marble Falls	14.40	14.65
Mustang Ridge	14.40	14.65
Nederland	14.70	14.95
Nixon	14.48	14.73
Pflugerville	14.40	14.65
Port Arthur	14.70	14.95
Port Neches	14.70	14.95
Rollingwood	14.40	14.65
Shiner	14.48	14.73
Sunset Valley	14.40	14.65
Yoakum	14.48	14.73
West Lake Hills	14.40	14.65

The Consumer and the Company may, at the Company's option, agree to a higher serving pressure. Service regulators shall be set as close as practical to the standard serving pressure under a load condition of approximately 10 percent of meter capacity. Increases in serving pressure because of the inadequacy of the Consumer's facilities shall not be permitted.

~~GAS MEASUREMENT (Continued)~~

13.2 ~~11.2~~ UNIT OF MEASUREMENT

The standard unit of measurement shall be one hundred cubic feet (Ccf). A cubic foot shall be defined as the amount of gas which occupies a volume of one cubic foot at the standard serving pressure and at a temperature of 60 degrees Fahrenheit.

Whenever the Company delivers gas at any pressure other than the standard serving pressure, volumes shall be corrected to the standard serving pressure in the manner provided in this Tariff, provided however, that such correction may be made to any other standard provided in the rate schedules or special agreement under which the Customer is served. The Company may, at its sole option, waive the correction of measurement for temperature deviation.

13.3 ~~11.3~~ BILLING UNIT

Unless otherwise specified on the rate schedules or by special agreement, Customers shall be billed on the basis of Ccf measured at or corrected to the standard serving pressure. The index of the meter shall be the sole determinant of volumes passing through the meter. Whenever the meter reads directly in hundreds or smaller units, a reading of one-half a billing unit or more (500 Ccf or more) shall be considered a whole billing unit. Readings of less than one-half a unit shall be disregarded for billing. In those cases in which heating value is used as the billing unit, the calculation of the heating value in BTU's shall be made in accordance with Section ~~11~~13.7 of this Tariff.

13.4 ~~11.4~~ PRESSURE CORRECTION - STANDARD METERING

Whenever gas is delivered to any Customer served under a rate schedule which provides for standard metering, the Company shall correct actual volumes measured to volumes which would have been measured if the gas had been delivered at the standard serving pressure. Corrections shall be made by one of the following methods.

a) ~~a)~~ The Company may install pressure or pressure and temperature compensating measurement equipment whenever the cost of this equipment is justified by the volumes served. Such measurements shall be equipped with devices which mechanically or electronically correct the actual measured volumes in accordance with Boyle's Law. Variations in actual atmospheric pressure shall not be considered.

b) The Company may use factor billing whenever the volumes to be delivered are too small to justify special metering. The factor shall be determined by dividing the actual serving pressure by the standard serving pressure, both expressed in absolute units based on the standard atmospheric pressure in the area as specified in Section ~~11~~13.1 hereof. This factor shall be applied to the measured volumes to determine the correct number of billing units.

~~GAS MEASUREMENT (Continued)~~

13.5 ~~11.5~~ METERING - SPECIAL POSITIVE DISPLACEMENT

Whenever gas is delivered to any Customer served under a rate schedule which provides for special metering and positive displacement or turbine type metering is used, all volumes shall be determined in accordance with the recommendations of the manufacturer of the meter. Meters may be read in actual volumes which shall then be corrected to the standard billing unit or may be furnished with devices designed to correct the actual volumes to the standard billing units. The following criteria shall be used in the correction of volumes or design and calibration of correcting devices~~:~~.

a) ~~a)~~ Pressure correction shall be made in accordance with Boyle's Law. Calculations based on pressure reading on a continuously recording chart shall use the average pressure indicated thereon applied to the measured volumes. Correcting devices shall be set at the specified serving pressure and the service regulators shall be adjusted as close to that pressure as practical. Corrections for deviations from Boyle's Law ("~~supercompressability~~supercompressibility") may be made whenever the volumes delivered justify the cost of making such corrections.

b) The flowing temperature of the gas shall be assumed to be 60 degrees Fahrenheit unless temperature correction is provided. Corrections shall be made in accordance with Charles' Law.

c) ~~c)~~ Whenever a continuously recording instrument is used, the average temperature indicated thereon shall be applied to the measured volumes. The specific gravity of the gas shall be assumed to be the value last indicated by test or reported by the upstream pipeline supplier prior to the installation of the metering facilities. Whenever subsequent reports or ~~tests~~test indicate significant changes in gravity, volume calculations shall be changed prospectively to reflect the new gravity.

13.6 ~~11.6~~ METERING - SPECIAL ORIFICE

Whenever gas is delivered to any Customer served under a rate schedule with provisions for special metering and orifice metering is used, all volumes shall be determined in accordance with the recommendations for measuring gas contained in the American Gas Association's Gas Measurement Committee Report No. 3, Orifice Metering of Natural Gas (1992), and subsequent revisions thereof. Orifice meter charts shall be calculated using a standard integrating device or other method recognized in the industry. The following criteria shall be used in the correction of volumes or design and calibration of orifice metering:

a) ~~a)~~ Correction for deviation of gas from Boyle's Law shall be made in accordance with Report No. 3.

b) ~~b)~~ Temperature of gas passing the meter shall be assumed to be 60 degrees Fahrenheit unless suitable equipment has been installed to measure actual flowing temperature. The arithmetical average of the temperature recorded during each meter charge period while the gas is flowing shall be used in the computations of volumes during the period.

c) ~~c)~~ The standard atmospheric pressure for the area served shall be used for measurement irrespective of any variation in the actual barometric pressure.

~~GAS MEASUREMENT (Continued)~~

~~11.6 METERING - SPECIAL ORIFICE (Continued)~~

d) ~~d)~~ The specific gravity of the gas shall be assumed to be the value last obtained in a spot test made with a gravity balance, impact type unit or other acceptable method. Tests shall be made as frequently as found necessary to assure accurate measurement.

13.7 ~~11.7~~ BTU MEASUREMENT

The heating value of gas for use in billing shall be defined as the gross thermal value of one cubic foot of gas at a pressure of 14.73 psia and temperature of 60 degrees Fahrenheit on a dry basis. The number of billing units delivered shall be determined by multiplying the heating value determined in accordance with this Section by the volumes delivered during the period, expressed in the same units and measured at, or corrected to 14.73 psia and 60 degrees Fahrenheit, and multiplying by the factor necessary to convert the heating value/measurement units to the billing units provided in the appropriate rate schedule. The heating value of the gas shall be determined using one of the following methods:

a) ~~a)~~ Processing a continuous sample of the main stream at the meter location through a recording calorimeter of a standard type;

b) ~~b)~~ Analysis of gas samples accumulated from the main stream at the meter location in a sample bottle of an approved type;

i) ~~i)~~ passing the sample through a recording calorimeter of a standard type;

ii) ~~ii)~~ passing the sample through a flow calorimeter of a standard type; or

iii) ~~iii)~~ passing the sample through a chromatograph to determine the chemical composition and calculating the total heating value from the sum of the constituents.

13.8 ~~11.8~~ CUSTOMER-~~OWNED~~INSTALLED AND OPERATED METERS

A Customer may install and operate a meter or any other device to measure gas volumes, pressure, temperature, BTU content or specific gravity downstream of the point of delivery. Unless expressly otherwise agreed to by the Company and Customer, however, the Company's meter and equipment shall be the sole determinant of volumes for Company's billing purposes.

~~METER READING AND ACCURACY~~

~~12.1 METER READING~~

~~Meters shall be read as nearly as may be practical on the same day of each calendar month. Whenever a reading of a general service meter is missed or the meter is not registering, the Company shall estimate the amount of gas used during the period. Such estimates shall be based on either –~~

~~a) That Customer's use of gas during the same period(s) in previous years;~~
~~b) That Customer's normal use of gas during preceding months; or~~
~~c) The use of a similar Customer for the period missed.~~

~~If practical, an actual reading shall be made after two consecutive estimated bills. All meters in Special Service shall be read at least once a month. Whenever such a meter fails to register or is misread, the amount of gas used during the preceding period shall be estimated using data applicable to that Special Service Customer only. The Company will make a special reading of any meter upon request and payment of a service charge will be made in accordance with Section 21.1. The time of the special reading shall be agreed upon with the Customer so that he or she may be present. If the original reading was in error (subject to consumption between the two readings) the service charge will be refunded to the Customer.~~

~~12.2 ACCESS TO THE METER~~

~~The Customer shall permit the Company safe access to the meter at all reasonable times for reading thereof and at all reasonable times for reading, maintenance, testing, or replacement of the meter. Upon the Customer's failure or refusal to grant such access, the Company may issue a written notice to the Customer, advising them the situation must be corrected and access granted within 5 working days and that failure to do so can result in the disconnection of service and removal of the meter. Additional fees may apply and will be assessed to such Customer as specified in Section 21.1.~~

~~12.3 METER ACCURACY~~

~~The accuracy limit of all Company meters is established at two percent (2%) fast or slow. Any meter found to be registering outside of the limits of accuracy shall immediately be removed or repaired. As long as the meter is operating within the limits of accuracy, it shall be the conclusive determination as to the quantities of gas delivered to the Customer on whose service it is set.~~

~~12.4 METER TESTING AT CUSTOMER REQUESTS~~

~~The Company shall have the right to remove and/or test the meter used to determine the quantity of gas delivered. The Customer may request that the Company make a special test of the meter through which he or she is served. Requests for such tests shall be made in writing and the Company shall have 10 days after receipt of the request to remove the meter for testing or to test the meter in place. Tests on removed meters shall be conducted within a reasonable time. If the test is to be performed after the period of presumed accuracy listed by the manufacturer or if the test is to be performed for a residential or small commercial Customer for whom no such test has been performed within the previous four (4) years for the same Customer at the same location, no service charge will be assessed. Otherwise, the Customer shall pay a service charge for such test as specified in Section 21.1.~~

~~METER READING AND ACCURACY (Continued)~~

~~12.5 BILLING ADJUSTMENTS - GENERAL SERVICE~~

~~Whenever it has been determined that a meter reading and the subsequent billing has been in error, the Company shall recalculate the affected bill(s). If the date and amount of the error can be definitely fixed,~~

~~the Company shall refund or may bill the affected Customer for the entire difference between the actual bills rendered and the amount which should have been billed. If a meter is found to have registered inaccurately (such as a meter found to be registering fast or slow), the Company shall refund or bill an amount equal to the difference between the actual bills rendered and the amount which would have been billed if the meter was 100 percent accurate during the time since the last previous test or six months, whichever is less. If the meter is found not to have registered, then the rebilling shall be limited to a three-month period previous to the time the meter is found not to be registering. The determination of amounts used but not metered is to be based on consumption during other like periods by the same Customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated Customers, when not available. Undercharges billed to the Customer may be repaid in a series of equal installments over a reasonable period of time. This Section shall not apply to meter errors found as a result of routine testing in the Company's or its designee's meter shop.~~

~~12.6 PROVISIONS FOR SPECIAL SERVICE~~

~~The following modifications shall apply to the provisions of this Section for all Special Service rate schedules and service under special written agreements:~~

~~a) Orifice and turbine meters shall be tested at least four times per year at intervals not to exceed 120 days. Should the Customer so elect, tests shall be made in the presence of his or her representative.~~

~~b) Whenever a meter is found to be registering above or below the limits of accuracy, adjustment of the bill (either up or down) shall be limited to the monthly billing subsequent to the last meter test. The adjustment shall be made upon the basis of the best data available, using the first of the following methods, whichever is most appropriate:~~

~~i) by using registration of Customer's check meter(s);~~

~~ii) by correcting the error, if the percentage of error is ascertainable by calibration test or mathematical calculation; or~~

~~iii) by estimating the quantity of gas delivered by comparison with deliveries during the preceding period under similar conditions when accurate registration was obtained.~~

~~12.7 PERIODIC TESTS~~

~~The Company shall make periodic tests of meters, associated devices and instruments to assure their accuracy. Such tests shall be scheduled within the calendar year or earlier, when the interval is stated in years; or within the calendar month, or earlier when the interval is stated in months. The basic periodic test interval shall be no longer than provided for in the manufacturer's recommendations, a copy of which is available upon request.~~

~~BILLING AND PAYMENT OF BILLS~~

~~13.1 RENDERING OF BILLS~~

~~Bills for all service shall be rendered monthly as promptly as feasible after the meter has been read. Bills shall be due and payable in full on or before the due date, which shall be stated on the face of the bill and shall not be earlier than fifteen (15) days after the bill is mailed (including electronic mail). Bills shall be considered to have been rendered when deposited in the United States Mail with postage prepaid thereon or, when the customer has elected to receive billings via electronic mail, when the electronic document has been sent. Payment shall be considered received when the correct amount has been received through a company authorized payment method. If not paid by the date due, the bill shall be considered delinquent.~~

~~13.2 BILLING PERIOD~~

~~Bills shall be rendered at regular monthly intervals unless otherwise authorized or unless service is rendered for a period of less than a month.~~

~~13.3 ESTIMATED BILLS~~

~~In the event any meter cannot be read at the end of the billing period, the Company shall bill the Customer on the basis of an estimated consumption determined in accordance with Section 12.1 of this Tariff. The next bill based on actual reading after an estimated bill shall make any corrections necessary to bring the Customer's account to a current status for the actual consumption.~~

~~13.4 DISPUTED BILLS~~

~~a) In the event of a dispute between the Customer and the Company regarding the bill, the Company will make such investigation as is required by the particular case and report the results to the Customer. If the Customer wishes to obtain the benefits of subsection b) of this Section, notification of the dispute must be given to the Company prior to the date the bill becomes delinquent. In the event the dispute is not resolved, the Company shall inform the Customer of the complaint procedures of the appropriate regulatory authority.~~

~~b) Notwithstanding any other subsection of this section, the Customer shall not be required to pay the disputed portion of the bill which exceeds the amount of that Customer's average usage for the billing period at current rates until the earlier of the following: resolution of the dispute or the expiration of the 60-day period beginning on the day the disputed bill is issued. For purposes of this section only, the Customer's average usage for the billing period shall be the average of the Customer's usage for the same billing period during the preceding two years. Where no previous usage history exists, the average usage shall be estimated on the basis of usage levels of similar Customers and under similar conditions.~~

~~13.5 PAYMENT RE-PROCESSING FEE~~

~~The Company may charge or add to the Customer's account and collect a fee (as provided in Section 21.1 d) to recover costs for reprocessing any payment, including paper check, electronic transfer payment, and debit and credit card payment, that has been rejected or returned to the Company by the bank for any reason other than bank error.~~

~~BILLING AND PAYMENT OF BILLS (Continued)~~

~~13.6 E-STATEMENTS~~

~~The Customer may at its option receive bills and notices via electronic mail, thereby eliminating paper bills and notices.~~

~~13.7 PAYMENT OPTIONS~~

~~The Company, at its option and discretion, may contract with payment vendors to provide various payment options and authorize these vendors to accept payments from Customers on the Company's behalf. Payment options may be electronic, telephonic, in person, or by mail and may include automatic bank draft, credit/debit card, check or cash. Contracted payment vendors may charge Customers an additional fee of the use of that payment option and shall be solely responsible for collecting that fee from the Customer.~~

~~13.8 DEFERRED PAYMENT PLANS~~

~~The Company, at its sole discretion, may offer a deferred payment plan for delinquent Customer accounts. Deferred payment plans shall conform to the following guidelines:~~

~~a) Every deferred payment plan entered into due to the Customer's inability to pay the outstanding bill in full must provide that service will not be discontinued if the customer pays current bills and a reasonable amount of the outstanding bill and agrees to pay the balance in reasonable installments until the bill is paid.~~

~~b) For purposes of determining reasonableness, the following shall be considered:~~

~~i) size of delinquent account;~~

~~ii) Customer's ability to pay;~~

~~iii) Customer's payment history;~~

~~iv) time that the debt has been outstanding;~~

~~v) reasons why debt has been outstanding; and~~

~~vi) other relevant factors concerning the circumstances of the Customer.~~

~~c) A deferred payment plan, if reduced to writing shall state immediately preceding the space provided for the Customer's signature and in bold-face print at least two sizes larger than any other used that, "If you are not satisfied with this agreement, do not sign. If you are satisfied with this agreement, you give up your right to dispute the amount due under the agreement except for the Company's failure or refusal to comply with the terms of this agreement."~~

~~d) A deferred payment plan may include a one-time late payment penalty up to but no more than 5% of the original amount of the outstanding bill with no prompt payment discount allowed except in cases where the outstanding bill is unusually high as a result of the Company's error (such as an inaccurately estimated bill or an incorrectly read meter). A deferred payment plan shall not include a finance charge.~~

~~e) If a Customer has not fulfilled terms of a deferred payment agreement or refuses to sign the same if it is reduced to writing, the Company shall have the right to disconnect pursuant to disconnection rules in Section 17.2 of this Tariff and, under such circumstances, it shall not be required to offer a subsequent negotiation of a deferred payment agreement prior to disconnection.~~

~~f) The Company shall not refuse a Customer participation in a deferred payment plan on the basis of race, color, creed, sex, marital status, age, or any other form of discrimination prohibited by law.~~

SECTION 14 — QUALITY OF GAS

14.1 ~~14.1~~ HEATING VALUE

Gas delivered to Consumers in all service areas shall have an average gross heating value of at least 900 British Thermal Units per cubic foot measured when saturated with water vapor at a pressure of 14.73 psia and temperature of 60 degrees Fahrenheit. Gas of lesser heating value may be delivered for short periods, ~~providing~~provided that the average heating value for the calendar month in which the reduction occurs is equal to or greater than the standard and that the burning characteristics of the gas are not significantly altered.

14.2 ~~14.2~~ CHARACTER OF GAS

All gas furnished to Consumers in the Central-Gulf Service Area shall be of merchantable quality suitable for use in standard gas burning appliances. Merchantable quality shall mean that the gas must be commercially free from dust, resins, water and hydrocarbons in liquid form at the pressure and temperature at which the gas is delivered.

14.3 ~~14.3~~ ODORIZATION

All gas shall be odorized with a chemical odorant at a sufficient rate to make it readily detectable. Gas containing enough natural odorant as prescribed by the Railroad Commission of Texas need not be odorized unless the odorant level drops below the acceptable level.

SECTION 15 — SERVICE ~~WORK~~FEES AND DEPOSIT AMOUNTS

~~15.1 CERTAIN SERVICES PROVIDED AT NO CHARGE~~

15.1 ADJUSTMENTS TO FEES AND CHARGES

All fees and charges shall be adjusted by taxes and fees (including franchise fees) where applicable. All fees and charges (excluding advances, contributions in aid of construction and deposits) shall be adjusted by the amount which represents the actual gross receipts, occupation, revenue taxes and franchise fees paid by Texas Gas Service Company, a Division of ONE Gas, Inc.

15.2 LEAKAGE AND PRESSURE INVESTIGATION

When a Customer or Consumer smells or detects natural gas and contacts the Company, the Company shall provide to the Consumer, at no-charge to the Customer or Consumer, leakage and pressure investigations to ensure that unsafe conditions do not exist. Where leakage or unsafe conditions are determined by the Company to be in the Customer's or Consumer's piping or equipment, the Customer or Consumer will be so advised and service will be discontinued until such time that all leakage and other unsafe conditions have been properly corrected by the Customer or Consumer. In addition, when service is initiated, gas air adjustments on a standard domestic and commercial gas range and water heater will be made. Any other work performed on any Consumer's appliances or house piping will be on a charge basis.

~~Any other work performed on any Consumer's appliances or housepiping will be on a charge basis.~~

~~15.1~~15.3 ~~15.2 OTHER~~ SERVICE WORK ON CHARGE BASIS

The Company may have personnel available for and may undertake other service work on the Consumer's premises on a charge basis, as time permits. Charges shall be made at the Company's standard rate in the Service Area and such service work and ~~the~~any associated revenues and costs shall be considered non-utility.

~~15.2~~15.4 ~~15.3~~ EXPEDITED SERVICE REQUEST

A Customer may request an expedited service~~.~~, upon availability. Charges may apply. ~~(See Section 21 – Fees and Deposits)~~

~~15.4 NO ACCESS~~

15.5 SPECIFIC SERVICE TIME REQUEST

A no access fee may be charged to a Customer who requests a specific time for service~~,~~ if the Company agrees to the time~~,~~ and sends appropriate personnel to the appointed location and the Customer is not present to allow access to the premises. ~~(See Section 21 – Fees and Deposits)~~

~~15.5 MATERIALS OR EQUIPMENT FURNISHED BY THE COMPANY~~

~~The Company shall furnish and install the service pipe, and equipment related thereto, including meter valve and service regulator, from the Company's main to the Customer's meter. Although affixed to or buried in the Customer's property, the entire service line and meter set shall become the property of the Company and shall be operated and maintained by the Company.~~

~~15.6 MATERIALS OR EQUIPMENT FURNISHED BY THE APPLICANT~~

~~The Applicant shall furnish and install at his or her expense all piping, conversions of existing equipment, and appliances required to conduct and utilize the gas furnished by the Company. The adequacy, safety, and compliance with applicable codes and ordinances of piping, conversion equipment and appliances shall remain the responsibility of the Applicant and no action of the Company in accordance with this Tariff shall release the Applicant of the responsibility to furnish and install the facilities required by this Section.~~

SERVICE ~~WORK (Continued)~~

~~15.7 CODES AND ORDINANCES~~

~~All piping, installations, and conversion equipment owned by the Applicant shall comply with all applicable federal, state, and city ordinances and shall be properly designed for the pressures and volumes to be handled. Where there are no appropriate ordinances, the applicable provisions of the National Fuels Gas Code 54; ANSI Z223.1, and any amendments thereto shall apply.~~

~~15.8 INSPECTIONS AND TESTS~~

~~The Company shall have the right to inspect new installations and/or conversions of appliances and equipment prior to initiation of service and to require any test or repair of the Applicant's facilities it deems necessary, at no charge to the customer.~~

~~15.9 REFUSAL TO SERVE~~

~~The Company shall refuse service to any Applicant who refuses Company or Company's representatives access to or entry for observation or whose facilities do not comply with the applicable provision of this Tariff. The right to refuse service shall terminate upon satisfactory correction of the condition that was the cause for refusal. Initiation of service, however, shall not be considered acceptance or approval by the Company of such facilities.~~

~~MAINTENANCE OF EQUIPMENT~~

~~16.1 MAINTENANCE BY COMPANY~~

~~The Company shall maintain all facilities owned by it and shall be responsible for the safe conduct and handling of the gas until it passes the point of delivery. The Company's representative shall have the right to enter the Customer's premises at any reasonable time, in the event of an emergency at any time, to read the meter or make any necessary inspection, repair, adjustment, or replacement of any property owned by the Company.~~

~~16.2 MAINTENANCE BY THE CUSTOMER~~

~~The Customer shall maintain all facilities owned by him or her and shall be responsible for the safe conduct and handling of the gas after it passes the point of delivery. The Customer shall remove, repair or adjust any Customer-owned property which may pose a threat of damage to the property of the Company. The Customer shall take all reasonable means to assure that no one other than an employee of the Company shall adjust, repair, disconnect or change the meter or other Company facilities in any way. In case of loss or damage to the Company's property from the negligence or willful acts of the Customer or Consumer or the Customer's or Consumer's representatives, the Customer will reimburse the Company for all costs of repairing or replacing the damaged property, including any costs of collection such as attorney's fees.~~

~~16.3 LEAKS - RIGHT TO DISCONNECT FOR~~

~~The Customer or Consumer shall give the Company notice of any leaking or escaping gas as soon as it is detected. Upon receipt of this notice, the Company shall investigate the matter as promptly as feasible under the circumstances. If the Company's test indicates leakage in the Customer's or Consumer's facilities, the Company shall have the right to disconnect service immediately until the Customer or Consumer has had the condition corrected. If leakage is found to be from Company owned facilities, the Company shall have the right to disconnect service for a reasonable period of time until it can be corrected by the Company. The Company shall have the right to disconnect service immediately if any of the Customer's or Consumer's appliances or equipment is, in the Company's opinion, operating in an unsafe manner.~~

~~16.4 FACILITIES CURRENTLY OWNED BY THE CUSTOMER~~

~~Any facilities downstream of the meter installed by the Customer shall remain the property and responsibility of the Customer. Whenever the condition of the facility is such that replacement is required, the work shall be done by the Company pursuant to the provisions of Section 16.7 of this Tariff. New facilities will continue to be installed pursuant to Sections 7.1 and 7.2 of this Tariff.~~

~~16.5 RESPONSIBILITY~~

~~Nothing in this Section shall make the Company responsible for the safe upkeep of any Customer or Consumer-owned facilities.~~

~~MAINTENANCE OF EQUIPMENT (Continued)~~

~~16.6 RELOCATION OF COMPANY FACILITIES~~

~~a) A charge of not more than actual cost may be made for relocating a meter or other Company equipment on the same premises at the request of the Customer or Consumer.~~

~~b) If the Company shall for its own convenience and not for the safety or convenience of the Customer, change the point of delivery or change the location of its equipment on private property, the Company shall bear the expense.~~

~~16.7 REPLACEMENT OF CUSTOMER-OWNED PIPING~~

~~a) When repair or replacement of Customer-owned piping becomes necessary due to deterioration of the line, damage to the line (except when caused by Customer or Customer's agent), relocation of the Company's distribution main, or for other safety reasons, the Company will relocate Customer's meter to the exterior of the building wall, as close as possible to the existing stub out (where piping exits the structure), and will replace the service piping up to the stub out. The Company will own and be responsible for all service piping from the main line to the meter, and Customer will own and be responsible for all piping from the meter to the building.~~

~~b) The Customer may be billed for all costs of the meter relocate and pipeline replacement.~~

~~c) In the absence of any provision contained in a deed of dedication authorizing the Company to install the service piping and meter on Customer's premises, the owner of the premises shall execute an agreement establishing the meter location, authorizing the Company to install or replace the line, and granting Company access for such work. If the Customer or owner of the premises refuses to give Company personnel or Company authorized personnel appropriate access to the property for purposes of installation, the Customer will retain responsibility for his/her facilities and shall bear the expense of any replacement or repairs.~~

~~DISCONTINUANCE OF SERVICE~~

~~17.1 BY CUSTOMER~~

~~The Customer shall be responsible for all charges for gas service from the time Customer gives notice of the intention to discontinue service until the Company has read the meter, or for five working days from the date of such notice, whichever is the shorter period of time.~~

~~17.2 FOR NON-PAYMENT~~

~~The Company shall have the right to discontinue service to any Customer for non-payment of bills or other charges authorized by this Tariff or the applicable rate schedules, following the due date specified in Section 13.1 hereof. Before discontinuing service for non-payment, the Company shall mail a separate written notice to the Customer in English and Spanish with the words "TERMINATION NOTICE" or similar language prominently displayed. This notice shall include a telephone number to contact the Company, the amount of the delinquent bill and the date by which the bill must be paid to avoid disconnection, and a statement of how to contact the Company in case of illness or other emergency. If a representative of the Company makes an attempt to collect a past due amount, a collection fee per visit shall be assessed to such Customers as specified in Section 21.1.~~

~~No Customer shall be disconnected for non-payment:~~

~~a) Within a period of 5 working days after mailing of the notice or the day following the date indicated in the notice, whichever is the later time.~~

~~b) After full payment of the delinquent bill except when there is not sufficient time to advise Company's service personnel of receipt of the payment.~~

~~c) Before 7:00 AM or after 7:00 PM on any day or on Friday, Saturday, Sunday, Holiday, or day before a holiday unless Company personnel are available the following day for the purpose of making collections or reconnecting service.~~

~~d) If within 5 working days after the date of delinquency of the bill the Company receives a written request from the Customer not to discontinue service for health reasons and the request is accompanied by a written statement from a licensed physician. Upon receipt of such request, the Company will suspend termination of service for a period up to 20 days. The Customer shall sign a deferred payment plan agreement which provides for payment of such service along with timely payments for subsequent monthly billings.~~

~~17.3 EXTREME WEATHER EMERGENCY~~

~~Except where there is a known dangerous condition or a use of natural gas service in a manner that is dangerous or unreasonably interferes with service to others, the Company shall not disconnect natural gas service to:~~

~~a) A delinquent residential customer during an extreme weather emergency. An extreme weather emergency means a day when the previous day's highest temperature did not exceed 32 degrees Fahrenheit and the temperature is predicted to remain at or below that level for the next 24 hours according to the nearest National Weather Station for the county where the customer takes service.~~

~~DISCONTINUANCE OF SERVICE (Continued)~~

~~17.3 EXTREME WEATHER EMERGENCY (Continued)~~

~~b) A delinquent residential customer for a billing period in which the Company receives a written pledge, letter of intent, purchase order, or other written notification from an energy assistance provider that it is forwarding sufficient payment to continue service.~~

~~c) A delinquent residential customer on a weekend day, unless personnel or agents of the Company are available~~

~~for the purpose of receiving payment or making connections and reconnecting service.~~

~~The Company shall defer collection of the full payment of bills that are due during an extreme weather emergency until after the emergency is over and shall work with customers to establish a payment schedule for deferred bills.~~

~~Beginning in the September or October billing periods, the Company shall give notice as follows:~~

~~a) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to the social service agencies that distribute funds from the Low Income Home Energy Assistance Program within the Company's service areas.~~

~~b) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to any other social service agency of which the Company is aware that provides financial assistance to low income customers in the Company's service areas.~~

~~c) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of Gas Utility Service Disconnection During an Extreme Weather Emergency, to all residential customers of the Company and customers who are owners, operators or managers of master metered systems. Owners, operators or managers of master metered systems shall provide a copy of this rule to all their customers.~~

~~17.4 SPECIAL CONDITIONS~~

~~The Company shall have the right to discontinue service to any Consumer for any of the following reasons:~~

~~a) Without notice for the presence of what the Company considers to be an unsafe condition on the Consumer's premises or if an emergency exists;~~

~~b) Without notice for willful destruction or damage to or tampering with the Company's property by the Consumer or by others with knowledge or negligence of the Consumer;~~

~~c) Within 5 working days after written notice if the Consumer uses his or her equipment in any way which causes or creates a potential for adverse affect on the Company's service to others;~~

~~d) Without notice if failure to curtail by such Consumer endangers the supply to Consumers in Priority Class A or B;~~

~~DISCONTINUANCE OF SERVICE (Continued)~~

~~17.4 SPECIAL CONDITIONS (Continued)~~

~~e) 5 working days after written notice from the Company for refusal to grant Company personnel or its designee's access to the Consumer's premises at any reasonable time for any lawful purpose;~~

~~f) 5 working days after written notice from the Company for use, sale or delivery of gas in violation of the provisions of this Tariff or violation of any applicable laws, orders or ordinances, provided that disconnection may be made without notice if the violation creates an unsafe condition;~~

~~g) For Customers acquiring their own supplies of gas, the Company may discontinue service upon request of a Supplier, provided however, that the Supplier represents to the Company that notice has been given to the Customer by the Supplier of delinquency in payment at least five working days prior to Supplier's request for disconnection, and provided that Supplier agrees to indemnify and hold harmless the Company from any potential resulting liability;~~

~~h) If a Customer fails to uphold the terms of a deferred payment plan; or~~

~~i) Within 5 working days after written or electronic notice, for Consumers enrolled in e-bill, that any payment including paper check, electronic transfer payment, and debit or credit card payment, that has been rejected or returned to the Company by the bank.~~

~~17.5 RIGHT OF ENTRY~~

~~The Company shall have the right to enter the Consumer's premises at any reasonable time to shut off service in accordance with this Tariff and to remove its meter and any other Company property. If the Company is required to take legal action to enforce its rights hereunder, the Company shall be entitled to recover all of its necessary expenses and fees including, but not limited to attorneys' fees, police escort fees and/or the cost to relocate the meter at the Customer's expense.~~

~~17.6 ABANDONMENT OF SERVICE~~

~~Unless requested by the Customer, service shall not be abandoned (permanent disconnection of any Customer other than a temporary Customer) without permission of the Regulatory Authority. Failure of the Customer to request reinstitution of service within a reasonable period of time after disconnection shall be considered a request for permanent discontinuance of service.~~

~~RE-ESTABLISHMENT OF SERVICE~~

~~18.1 FOR NON-PAYMENT~~

~~When service has been disconnected for non-payment, the Company shall require that the Customer pay the total amount of his or her account then due plus the prescribed reconnect fee or make satisfactory arrangements for that payment before service is reinstituted. In addition, the Company shall require that the Customer re-establish satisfactory credit in accordance with Section 5 of this Tariff.~~

~~18.2 FOR OTHER REASONS~~

~~If disconnection has been made by the Company for reasons other than non-payment, service shall not be reinstated until the condition for which it was terminated has been corrected to the Company's satisfaction. The Customer shall also be required to pay a reconnect fee before service is turned on. When service has been disconnected at the Customer's request for a period of one year or more, the request for service shall be treated as a new application. When service has been disconnected for less than one year, the request shall be treated in the same manner as a disconnection for non-payment.~~

~~18.3 RECONNECTION~~

~~The Company shall restore service as soon as feasible after receipt of a reconnection request and compliance with the requirements of this Section. The Company shall charge a non-refundable reconnection fee for all Customers in accordance with Section 21.1. The restoration of service will be accomplished as expeditiously as scheduling permits. If the Customer requests service after hours or earlier than reconnection would otherwise be scheduled, the Company shall offer expedited service in accordance with Section 21.1. Customer shall be advised that an additional fee will be charged and must agree to pay such charge. In the event the Company is required to make more than one call because the reason for disconnection has not been properly corrected, the reconnect fee may be charged for each call made. No fee shall be charged for any reconnection made after disconnection due to Company's operation. See Section 21.1 for fees.~~

~~NOTICE~~

~~19.1 GENERAL~~

~~Notice is required for all matters in this Tariff other than billing and payment of bills, which shall be deemed to have been given by the Customer when a letter with postage prepaid has been deposited in the United States Mail addressed to the Company at the office specified on the front sheet of this Tariff, and to the Customer when addressed to Customer at his or her last known service address, or to either party when directly communicated to the other party in person or by telephone.~~

~~AVERAGE BILL CALCULATION PLAN or AVERAGE PAYMENT PLAN~~

~~20.1 DESCRIPTION-RESIDENTIAL~~

~~Any residential Customer may elect to participate in the Company's Average Payment Plan, also known as the Average Bill Calculation Plan ("ABC/APP Plan"), or as such ABC/APP Plan may be modified from time to time for payment of charges for gas service. In the event the Company modifies the ABC/APP Plan, the Company shall notify individual Customers of those changes when the Customer requests enrollment. In general, the conditions under which a Customer may participate in the ABC/APP Plan are set forth below:~~

~~a) The Company reserves the right to adjust the monthly ABC/APP Plan payments of any Customer at any time for changes in conditions or rates;~~

~~b) The Company shall advise each Customer in the ABC/APP Plan of the monthly ABC/APP Plan payment to be paid by the Customer. Each participating Customer will receive a regular monthly gas bill which will reflect actual consumption and charges for that billing month and the amount of any debit or credit balance before the payment of that month's ABC/APP Plan payment. The Customer shall continue to pay the monthly ABC/APP Plan payment amount each month for gas service, notwithstanding the current gas service charge shown on the bill;~~

~~c) In addition to the monthly ABC/APP Plan amount, any other charges incurred by the Customer shall be paid monthly when due;~~

~~d) Interest shall neither be charged to the Customer on accrued ABC/APP Plan debit balances nor paid by the Company on accrued ABC/APP Plan credit balances;~~

~~e) Any amount due the Customer or the Company will be settled and paid at the time a Customer, for any reason, ceases to be a participant in the ABC/APP Plan;~~

~~f) Any Customer's participation in the ABC/APP Plan may be discontinued by the Company if the monthly plan payment has not been paid on or before the due date of the monthly plan payment;~~

~~g) If any Customer in the ABC/APP Plan shall cease, for any reason, to participate in the ABC/APP Plan, then the Company may deny that Customer's reentry into the ABC/APP Plan until the following year.~~

~~15.3~~15.6 FEES~~ AND DEPOSITS~~

~~21.1 FEES~~

All fees and charges shall be adjusted by taxes and fees (including franchise fees) where applicable.~~ In the incorporated areas of Bayou Vista, Cuero, Galveston, Gonzales, Groves, Jamaica Beach, Lockhart, Luling, Nederland, Nixon, Port Arthur, Shiner and Yoakum only, all fees and charges (excluding advances, contributions in aid of construction and deposits) shall be adjusted by the amount which represents the actual gross receipts, occupation, revenue taxes and franchise fees paid by Texas Gas Service Company, a Division of ONE Gas, Inc.~~

~~a) Initiation of Service:~~

~~i) Connect: (Section 5.4) $35.00~~

~~A connection fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when a meter is set and/or gas turned on.~~

~~ii) Read-In: (Section 5.4) $15.00~~

~~A read-in fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when only a meter reading is required.~~

~~iii) Special Handling & Expedited Service: (Sections 5.4 and 15.3)~~

~~In addition to initiation of service fee above, a fee may be charged to any Applicant whose request to initiate service cannot be worked during normal business hours or requires special handling. Applicant must be advised that an additional fee will be charged and must agree to pay such charge. These charges include:~~

~~1) Special Handling $15.00~~

~~The Company may, at Applicant or Customer's request, provide special handling in order to meet the Applicant or Customer's requirements. Special handling does not include calling the Applicant/Customer in advance or A.M. or P.M. scheduling~~

~~2) Expedited Service and Overtime Rate $60.00~~

~~The Applicant or Customer's request for expedited service may be scheduled at any time to fit the Company's work schedule, and an Expedited Service charge shall be collected. The Company shall not be obligated to provide Expedited Service when the personnel and resources to do so are not reasonably available.~~

~~b) Services - Others As stated below~~

~~Whenever service is furnished from the facilities of others and the Company must pay any special fees to the supplying Company, the Applicant may be requested to reimburse the Company for such charge.~~

~~FEES AND DEPOSITS (Continued)~~

~~21.1 FEES (Continued)~~

~~c) Customer Requested Meter Test: (Section 12.4)~~

~~Positive Displacement — Charge~~

~~Up to 1500 cubic feet per hour — $150.00~~
~~Over 1500 cubic feet per hour — $200.00~~

~~Orifice Meters~~

~~All sizes — $200.00~~

~~d) Payment Re-processing Fee: (Section 13.5) — $25.00~~

~~e) Collection Fee: (Section 17.2) — $15.00~~

~~A Collection Fee shall be charged to any Customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative to attempt collection of payment from Customer.~~

~~f) Reconnect Fees: (Section 18.3) — $35.00~~

~~A reconnect fee shall be charged to any Customer whose service is terminated and then re-initiated unless terminated in error by the Company. This fee is the same as the Standard Initiation Fee charged for new service.~~

~~(i) Regular Labor and After Hours Rates — $45.00 (Regular)~~
~~$60.00 (After Hours)~~

~~Charge for non-routine services including but not limited to repeat high bill investigations and building meter loops.~~

~~g) Special Read: (Section 12.1) — $15.00~~

~~A special read fee shall be charged for customer requested reading of a meter of which estimated billing has been made. This is not in connection with Section 12.4.~~

~~h) Meter Exchange (Customer Request): (Section 16.6) — $150.00~~

~~A fee will be charged for customers requested meter exchanges when a meter is working properly or is done for the customer's convenience.~~

~~FEES AND DEPOSITS (Continued)~~

~~21.1 FEES (Continued)~~

~~i) Meter Tampering – Residential: (Section 16.2) — $150.00~~

~~A fee will be charged to repeat customers who knowingly tamper with Company property (i.e. broken meter locks, broken stop cocks, tampered meter dials, and broken meter blind seals).~~

~~j) Unauthorized Consumption: (Section 16.2) — $30 plus expenses~~

~~Charges for the replacement of an illegally broken meter seal or locking device to the Customer who could be reasonably expected to benefit from gas service received through said meter.~~

~~k) No Access Fee: (Section 15.4) $15.00~~

~~A fee charged to a Customer who schedules an appointment but fails to appear.~~

~~l) Meter Removal Fee: (Section 12.2) $25.00~~

~~m) Account Research Fee: $20.00/hr~~

~~A fee will be charged for Customer account information requiring research of accounting/billing information.~~

~~n) Police Escort Fee: (Section 17.4) As stated below~~

~~A fee charged when the Company is required to use law enforcement personnel to escort it into locked sites or sites requiring animal control in order for the Company to access a meter. Company will charge the stated amounts or current rate charged by the entity providing the police escort for this service.~~

~~o) Excess Flow Valve Installation Fee: $400.00~~

~~Pursuant to Code of Federal Regulations, §192.383(d) a fee for installation of an excess flow valve (EFV) will be assessed when a Customer requests such installation on the Customer's service line. The EFV will be installed at a date mutually agreeable to both Company and Customer, but after January 1, 2018. The Company reserves the sole right to conduct any required maintenance that may result from the installation. The customer shall be assessed a one-time installation fee.~~

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – Central-Gulf Service Area

~~FEES AND DEPOSITS (Continued)~~

~~21.2 DEPOSITS~~

~~a) Advances: (Section 8.4) As stated below~~

~~Estimated expenditure to serve the premises of new business beyond the existing distribution facilities of the Company.~~

~~b) Customer Deposits: (Section 10.1) As stated below~~

~~Minimum deposit residential: $75.00~~
~~Minimum non residential deposit: $250.00~~

a)	Connection Fee	A connection fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when a meter is set and/or gas turned on.	$38.00
b)	Read-In Fee	A read-in fee shall be charged to any Applicant for the cost involved in initiation of service. This fee shall be charged when only a meter reading is required.	$18.00

c)	Special Handling & Expedited Service	In addition to initiation of service fee, a fee may be charged to any Applicant whose request to initiate service cannot be worked during normal business hours or requires special handling. Applicant must be advised that an additional fee will be charged and must agree to pay such charge.	
		Special Handling Fee - The Company may, at Applicant or Customer's request, provide special handling in order to meet the Applicant or Customer's requirements. Special handling does not include calling the Applicant/Customer in advance or A.M. or P.M. scheduling.	$18.00
		Expedited Service Fee and Overtime Rate - The Applicant or Customer's request for expedited service may be scheduled at any time to fit the Company's work schedule, and an Expedited Service charge shall be collected. The Company shall not be obligated to provide Expedited Service when the personnel and resources to do so are not reasonably available.	$70.00
d)	Services from Others	Whenever service is furnished from the facilities of others and the Company must pay any special fees to the supplying Company, the Applicant may be requested to reimburse the Company for such charge.	Actual cost plus 20% for handling
e)	Customer Requested Meter Test	Positive Displacement Up to 1500 cubic feet per hour Over 1500 cubic feet per hour -- Orifice Meters All sizes	 $150.00 $225.00 ---------------------------- $200.00
f)	Payment Re-processing Fee		$25.00
g)	Collection Fee	A Collection Fee shall be charged to any Customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative to attempt collection of payment from Customer.	$18.00
h)	Reconnect Fees	A reconnect fee shall be charged to any Customer whose service is terminated and then re-initiated unless terminated in error by the Company. This fee is the same as the Standard Initiation Fee charged for new service. Related, non-routine services including but not limited to high bill investigations and building meter loops may be charged. Regular Labor Rate After Hours Rate	$38.00 $50.00 $70.00
i)	Special Read Fee	A special read fee shall be charged for customer requested reading of a meter of which estimated billing has been made. This is not in connection with Section 12.8.	$20.00

j)	Meter Exchange Fee - Customer Request	A fee will be charged for customer requested meter exchanges when a meter is working properly or done for the Customers convenience.	$180.00
k)	Meter Tampering Fee - Residential	A fee will be charged to Customers who knowingly tamper with Company property (i.e. broken meter locks, broken stop cocks, tampered meter dials, and broken meter blind seals).	$180.00
l)	Unauthorized Consumption Fee	Charges for the replacement of an illegally broken meter seal or locking device to the Customer who could be reasonably expected to benefit from gas service received through said meter.	$30.00 plus expenses
m)	No Access Fee	A fee charged to a Customer who schedules an appointment but fails to appear.	$18.00
n)	Meter Removal Fee		$25.00
o)	Account Research Fee	An hourly fee will be charged for Customer account information requiring research of accounting/billing information.	$20.00
p)	Police Escort Fee	A fee charged when the Company is required to use law enforcement personnel to escort it into locked sites or sites requiring animal control in order for the Company to access a meter or other equipment.	Actual cost
q)	Excess Flow Valve Installation Fee	Pursuant to Code of Federal Regulations, §192.383(d) a fee for installation of an excess flow valve (EFV) will be assessed when a Customer requests such installation on the Customer's service line. The EFV will be installed at a date mutually agreeable to both Company and Customer, but after January 1, 2018. The Company reserves the sole right to conduct any required maintenance that may result from the installation. The customer shall be assessed a one- time installation fee.	$400.00

15.7 DEPOSIT AMOUNTS

a)	Advanced Deposit	Estimated expenditure to serve the premises of new business beyond the existing distribution facilities of the Company.	Actual cost
b)	Residential Customer Deposit		Minimum $75.00
c)	Non-Residential Deposit		Minimum $250.00

	CGSA Incorporated and Environs	
Fee or Deposit	**Current Fee**	**Proposed Fee**
Connect	$35.00	$38.00
Reconnect	$35.00	$38.00
Connect Fee - Read Only	$15.00	$18.00
Special Handling	$15.00	$18.00
Expedited Service/Overtime/After Hours	$60.00	$70.00
Regular Labor Rate	$45.00	$50.00
No Access Fee (Door Tag)	$15.00	$18.00
Meter Test Up to 1500 CFH	$150.00	$150.00
Meter Test Over 1500 CFH	$200.00	$225.00
Orifice Meters	$200.00	$200.00
Payment Re-processing Fee (Returned Check Fee)	$25.00	$25.00
Collection Fee (All Classes)	$15.00	$18.00
Special Read	$15.00	$20.00
Meter Exchange without ERT (Customer Request)	$150.00	Discontinue
Meter Exchange (Customer Request)	$150.00	$180.00
Unauthorized Consumption (Plus Expenses)	$30.00	$30.00
Meter Removal Fee	$25.00	$25.00
Account Research per hour Fee	$20.00	$20.00
Excess Flow Valve Installation Fee	$400.00	$400.00
Minimum Deposit Residential	$75.00	$75.00
Minimum Non Residential Deposit	$250.00	$250.00
Meter Tampering (Residential)	$150.00	$180.00

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF MARIE J. MICHELS

BEFORE ME, the undersigned authority, on this day personally appeared Marie J. Michels who having been placed under oath by me did depose as follows:

1. "My name is Marie J. Michels. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Manager of Rates and Regulatory Analysis for Texas Gas Service Company, a division of ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Marie J. Michels

SUBSCRIBED AND SWORN TO BEFORE ME by the said Marie J. Michels on this 21st day of May 2024.

ERLINDA ALVARADO
NOTARY PUBLIC
ID# 133935107
State of Texas
Comm. Exp. 08-29-2026

Notary Public in and for the State of Texas

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

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LIST OF EXHIBITS

DIRECT TESTIMONY OF STACEY L. MCTAGGART

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stacey L. McTaggart, and my business address is 1301 South MoPac Expressway, Suite 400, Austin, Texas 78746.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Rates and Regulatory Director for Texas Gas Service Company ("TGS" or the "Company"), a Division of ONE Gas, Inc. ("ONE Gas"). I am responsible for managing the regulatory matters for TGS.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration degree in finance and accounting from St. Edward's University in August 1988. From 1983 to 1990, I worked for NCNB Texas, now Bank of America. In April 1990, I joined Southern Union Company as a Rate Analyst. In that capacity, I was responsible for the preparation of rate schedules and testimony in connection with rate requests in the various regulatory jurisdictions in which Southern Union Company operated. From April 1993 to January 1997, I served as a Utility Specialist at the Railroad Commission of Texas ("Commission"). At the Commission, I participated in numerous cases as either a Staff witness or a technical examiner. In January 1997, I returned to Southern Union Company as Manager of Pricing and Economic Analysis, managing rate cases primarily for the company's Southern Union Gas ("SUG") division. In September 2001, I became SUG's Director of Financial and Regulatory Analysis. Upon the sale of Southern Union's Texas assets to ONEOK, Inc.

("ONEOK") in January 2003, I joined ONEOK's TGS division and maintained my position. Upon the separation of ONE Gas from ONEOK in January 2014, I continued as Rates and Regulatory Director.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the following issues in this rate case:

1. Inclusion of Excess Deferred Income Taxes ("EDIT") in base rates to return EDIT to customers;
2. The Company's request for a Renewable Natural Gas ("RNG") Credits Program tariff;
3. The Company's request for regulatory asset treatment of deferred costs related to prior regulatory proceedings, COVID-19 and Winter Storm Uri; and
4. Rule 8.209 costs.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following schedules: B-3, Rule 8.209 Regulatory Asset; B-10, Unamortized Accumulated Excess Deferred Income Taxes; B-11, Regulatory Assets; G-20, Regulatory Expense Amortization and G-24, Excess Deferred Income Tax Amortization.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have filed testimony on behalf of TGS in numerous proceedings before this Commission including: Gas Utilities Docket ("GUD") Nos. 9770, 9790, 9839, 9988, 10094, 10453, 10488, 10506, 10526, 10656, 10739, 10766, 10928; and Commission Docket Nos. OS-21-00007061 ("Docket No. 7061"), OS-22-00009896 ("Docket No. 9896") and OS-23-00014399 ("Docket No. 14399").

II. EFFECTS OF THE FEDERAL TAX CUTS AND JOBS ACT ON RATES

Q. PLEASE EXPLAIN THE CHANGES TO THE FEDERAL CORPORATE INCOME TAX RATE THAT BECAME EFFECTIVE IN 2018.

A. Effective January 1, 2018, the Tax Cuts and Jobs Act lowered the federal corporate income tax rate to 21% from 35%. In response, the Commission issued an Accounting Order in GUD No. 10695 on February 27, 2018, that reflects the Commission's directives regarding changes to utility rates to account for the change in the federal corporate income tax rate.[1]

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMMISSION'S DIRECTIVES IN THE ACCOUNTING ORDER.

A. I understand the Commission's Accounting Order to require gas utilities to: reduce base rates and existing Gas Reliability Infrastructure Program ("GRIP") rates to reflect rates that would be set using a 21% federal tax rate; to refund amounts collected from customers through base rates and GRIP rates that were set using the

[1] On March 20, 2018, the Commission issued an Order Nunc Pro Tunc in *Regulatory Accounting Related to Federal Income Tax Changes*, GUD No. 10695, correcting a clerical error in the original Accounting Order.

35% tax rate; and to present the issue of EDIT for consideration in a Statement of Intent ("SOI") or other proceeding.

Q. HAS THE COMPANY COMPLIED WITH THE DIRECTIVE TO REFLECT THE LOWER FEDERAL CORPORATE INCOME TAX RATE IN BASE RATES AND GRIP RATES FOR THE CENTRAL-GULF SERVICE AREA ("CGSA")?

A. Yes. In GUD No. 10928, the Commission found that the Company has complied with the requirements of the Accounting Order in both the incorporated and environs areas of the CGSA.

Q. PLEASE DESCRIBE MORE SPECIFICALLY THE REQUIREMENTS IN THE ACCOUNTING ORDER REGARDING EDIT.

A. According to the Order, utilities subject to the Commission's original jurisdiction must accrue regulatory liabilities on their books as of the date of the Commission's Accounting Order to reflect the excess deferred tax reserve, including any associated gross up in taxes, caused by the reduction to 21% for the federal corporate income tax rate.[2]

As it relates to EDIT, the utility shall present that issue "for consideration in setting the cost of service rates of the gas utility during the next statement of intent or other rate proceeding." In addition, the amortization of the entire regulatory liability for EDIT shall be consistently calculated using a methodology set forth under the Act.[3]

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[2] *See* GUD No. 10695, Gas Utilities Accounting Order at Ordering Paragraph 1(C) (Feb. 27, 2018).
[3] *Id*. at Ordering Paragraph 7.

Q. PLEASE DESCRIBE HOW EDIT WAS TREATED IN GUD NO. 10928.

A. GUD No. 10928 was TGS's first opportunity to address the issue in a rate case. The final order in GUD No. 10928 reflected the impact of the change in the corporate tax rate on Accumulated Deferred Income Tax ("ADIT"), reducing the balance of ADIT and giving rise to EDIT. Both the new balance of ADIT and the balance of EDIT were deducted from rate base as sources of cost-free capital. For the flow-back of the EDIT to customers, the Commission approved a separate tariff rider, Rate Schedule EDIT-Rider, calculated according to the Average Rate Assumption Method ("ARAM").

Q. PLEASE DESCRIBE HOW EDIT IS INCLUDED IN THIS SOI, INCLUDING HOW TGS IS PRESENTING EDIT FOR CONSIDERATION IN SETTING NEW RATES.

A. This SOI continues to reflect the impact of the change in the corporate tax rate by reflecting the balance of ADIT based on a 21% federal tax rate and separately reflecting the unamortized balance of EDIT. Both the balance of ADIT and the balance of EDIT are deducted from rate base as sources of cost-free capital. Company witness Janet M. Simpson also addresses the ADIT calculations in her direct testimony, while Company witness Kenneth W. Eakens addresses the EDIT calculations.

The Company proposes to withdraw Rate Schedule EDIT-Rider, and instead flow the EDIT back to environs and incorporated customers through base rates, as discussed further in Mr. Eakens' direct testimony. The Commission approved a similar TGS request to return EDIT to customers through base rates in Docket No. 9896 and Docket No. 14399.[4]

Q. WHAT IS THE AMOUNT OF THE EDIT AMORTIZATION TO BE FLOWED BACK ANNUALLY THROUGH THE BASE RATES?

A. The test year EDIT amortization of $(500,677) is shown on Schedule G-24.

III. RENEWABLE NATURAL GAS CREDITS PROGRAM

Q. PLEASE DESCRIBE THE COMPANY'S REQUESTS REGARDING RENEWABLE NATURAL GAS CREDITS.

A. TGS is requesting that the Commission approve a Renewable Natural Gas Program (hereafter referred to as the "RNG Credits Program") to authorize the inclusion of up to $150,000 at a time, of environmental attributes associated with RNG ("RNG Credits") in its gas purchases under the CGSA cost of gas clauses, Rate Schedules 1-INC and 1-ENV, along with a RNG Credits Program tariff through which interested customers can opt to offset a portion of their usage with RNG Credits.

Q. WHAT IS RNG?

A. RNG is pipeline quality renewable gas that is derived from a source of energy ("biogas"), that is equivalent in composition to geological methane or natural gas that is currently utilized in TGS's distribution system. This biogas is produced from the decomposition of organic matter that undergoes processing to meet pipeline quality standards. It is typically derived from landfills, wastewater

[4] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at Findings of Fact ("FoF") No. 115 (Jan. 18, 2023); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order at FoF No. 62 (Jan. 30, 2024).

treatment facilities and/or from manure produced at livestock operations; but it can also be derived from organic waste produced at industrial, commercial and institutional entities. The cost of RNG may also include the cost of carbon environmental attributes purchased and retired in association with the purchase of RNG.

Q. WHAT ARE ENVIRONMENTAL ATTRIBUTES?

A. Environmental attributes represent any and all credits, benefits, emissions reductions or offsets attributable to the production and delivery of RNG, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions.

Q. ARE THE ENVIRONMENTAL ATTRIBUTES AND THE PHYSICAL RNG ALWAYS CONNECTED?

A. No. Physical RNG supply can be purchased with the credits for the attached environmental attributes, or the credits may be sold separately. In other words, if a physical RNG supply is not connected to an entity's system or cannot physically be delivered to the Company's system, credits for the environmental attributes may be purchased for RNG that is being produced in another area and bundled with local gas supply.

Q. ARE THERE BENEFITS RELATED TO GREENHOUSE GAS EMISSIONS REDUCTIONS?

A. The usage of RNG reduces greenhouse gas emissions that would otherwise be emitted from using the same amount of conventional natural gas. In other words, gases such as methane from landfills or water treatment plants that would otherwise be released into the atmosphere are captured and used in place of conventional natural gas. The carbon intensity of each source varies, but the result of using RNG can be net zero or even negative carbon emissions.

Q. HAS THE COMPANY SURVEYED CUSTOMERS TO SEE IF THERE IS INTEREST IN PAYING FOR RNG?

A. Yes, when surveyed during 2022 and 2023, approximately 35% of CGSA participating customers said they would be willing to pay up to 10% more per month for RNG.

Q. HAVE ANY TGS REGULATORS EXPRESSED AN INTEREST IN THE USE OF RNG?

A. Yes. In February 2020, the City of Austin passed a resolution requesting that the Company conduct a feasibility analysis of RNG aiming for aggressive sustainability goals while maintaining affordable energy rates for Austin residents. Exhibit SLM-1 contains a copy of the resolution, and Exhibit SLM-2 contains a copy of the study TGS provided to the City of Austin in response.

Q. HAS THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS ("NARUC") APPROVED ANY RESOLUTIONS RELATED TO RNG?

A. Yes. In 2010, NARUC approved a resolution, sponsored by the NARUC Committee on Gas, supporting pipeline quality biomethane development as a renewable gas resource. Specifically, it was resolved that:

> **RESOLVED,** That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2010 Winter Committee Meetings in Washington, D.C., supports the role and development of biogas, and in particular, pipeline quality biomethane, as a feasible renewable fuel in an effort to capture methane greenhouse gas emissions and simultaneously provide an alternative source of renewable energy; *and be it further*
>
> **RESOLVED,** That the Board of Directors of the National Association of Regulatory Utility Commissioners supports federal incentives for the development of pipeline quality biomethane that are *en par* with incentives currently afforded to other resources for the production of renewable electricity; *and be it further*
>
> **RESOLVED**, That the Board of Directors of the National Association of Regulatory Utility Commissioners urges the U.S. Senate and the U.S. House of Representatives to approve legislation as a means to provide unequivocal support for pipeline quality biomethane development in order to achieve significant greenhouse gas reductions in the transition to a clean energy economy.

Exhibit SLM-3 contains a copy of the full resolution.

Q. HAS TGS INVESTIGATED THE OPTION OF PHYSICAL RNG SUPPLY?

A. Yes, the Company monitors local RNG development activity and works with a national network of RNG developers and producers to assess regional feedstock viability and technological innovations in the industry. Although the Company is aware of projects under consideration, currently there is no physical RNG available for purchase by TGS.

Q. HAS ONE GAS OR THE COMPANY PURCHASED RNG CREDITS?

A. Yes, because a physical supply of RNG is not available, ONE Gas has purchased Renewable Thermal Certificates (a specific type of RNG Credits representing specified environmental attributes).[5] This purchase was completed through a competitive request for proposal and live auction process completed in June 2023. Ultimately, ONE Gas procured 198,734 MMBtu of Renewable Thermal Certificates at $12.10 per MMBtu for a total cost of approximately $2.4 million. Currently, TGS's sister division Oklahoma Natural Gas offers a similar RNG program, like the one TGS is proposing that utilizes RNG Credits.

Q. PLEASE DESCRIBE THE PROPOSED RNG PROGRAM.

A. Under the program, the Company would include $150,000 of RNG environmental attributes (or RNG Credits) in its CGSA gas purchases under the Cost of Gas Clauses, Rate Schedules I-INC and I-ENV. Simultaneously, the Company would offer to interested customers who wish to opt into the program for a year, the opportunity to purchase monthly RNG blocks, equal to one-quarter of a MMBtu. As monthly payments toward the program are received from customers who choose to participate, those amounts will be credited against the cost of gas. If all the available blocks are purchased by interested customers, the net impact to the cost of gas will be zero, and those customers who did not elect to participate will be unaffected.

Q. WHAT IF ALL AVAILABLE BLOCKS ARE NOT PURCHASED BY INTERESTED CUSTOMERS?

A. If only a portion of the available blocks are purchased by interested customers, then the payments from those customers that are credited against the Cost of Gas Clauses will fall short of the $150,000 cost of RNG Credits. The remaining balance will be

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[5] One Renewable Thermal Certificate (RTC) is equivalent to one dekatherm (Dth) of Renewable Thermal generation. *See* https://www.mrets.org/m-rets-renewable-thermal-tracking-system/.

recovered through the cost of gas from all customers. If no blocks at all were purchased and the entire $150,000 were recovered through the cost of gas from all customers, the impact would be an increase to the CGSA cost of gas by approximately $0.01 per Mcf. The initial tranche of RNG Credits is proposed at the relatively low level of $150,000 in order to increase the likelihood that all available blocks are purchased, and to limit any potential increase to the CGSA cost of gas as a result of non-purchased blocks to a maximum of $0.01 per Mcf.

Q. HOW MANY BLOCKS WOULD BE AVAILABLE, AND HOW WOULD THEY BE PRICED?

A. The existing RNG Credits purchased by the Company have a cost of $12.10 per MMBtu. Thus, $150,000 would account for 12,397 RNG Credits or 49,587 blocks. Each block is one-quarter of an MMBtu, so each block would cost $3.025. In addition, there is a $0.075 per MMBtu cost to retire the credits through the Midwest Renewable Energy Tracking System (MRETS).[6] Each block would also include one-quarter of the retirement cost, or $0.01875 per block. The combined price shown on the RNG Credits Program tariff would be $3.04 per block per month.

Q. HOW WOULD POTENTIAL PARTICIPANTS BE MADE AWARE OF THIS PROGRAM?

A. Like any other Company program, TGS will communicate with customers through social media forums and posts on the Company's website. TGS may also decide to communicate with customers about this program through bill inserts.

[6] https://www.mrets.org/m-rets-renewable-thermal-tracking-system/.

Q. WOULD INTERESTED CUSTOMERS SUBSCRIBE FOR A PERIOD OF TIME?

A. Yes. Once subscribed, customers must remain subscribed for 12 months, absent a financial or other hardship.

Q. WHY DOES THE COMPANY PROPOSE TO REQUIRE THAT A CUSTOMER REMAIN ON THE TARIFF FOR 12 MONTHS AT THE REQUESTED AMOUNT AFTER AN ELECTION IS MADE?

A. A 12-month commitment will enable the Company to determine when a $150,000 tranche of RNG Credits has been fully subscribed for the year. It will be important for the Company to be able to quantify and forecast the amount of RNG Credits subscribed on an annual basis.

Q. HOW MANY CUSTOMERS WOULD HAVE TO BUY BLOCKS TO FULLY SUBSCRIBE THE $150,000 OF RNG CREDITS?

A. Assuming that participants purchased one block per month for a year, approximately 4,132 customers, representing a little over 1% of CGSA sales customers, would need to participate in order to fully subscribe the $150,000 of RNG Credits.

Q. WHAT IF INTEREST IN THE PROGRAM IS GREATER THAN THE INITIAL TRANCHE OF $150,000?

A. Under the program, if the initial tranche of $150,000 in RNG Credits becomes fully subscribed, the Company would include in its gas purchases an additional tranche of $150,000 in RNG credits. As each tranche becomes fully subscribed, an additional tranche is added. In this way, the program can scale up based on demand, while ensuring that the cost of gas for all non-participating customers would not be impacted by more than $0.01 per Mcf.

Q. WHAT WILL HAPPEN WHEN THE EXISTING $2.4 MILLION IN RNG CREDITS, ACQUIRED BY ONE GAS AT $12.10 PER MMBTU, ARE FULLY RETIRED?

A. It is likely to take up to several years to fully subscribe and retire the existing $2.4 million in RNG Credits acquired by ONE Gas. When these credits are fully retired, the Company will make a filing with its regulators proposing a new plan.

Q. WILL TGS PROFIT DIRECTLY FROM THE RNG CREDITS PROGRAM?

A. No. Similar to the treatment of natural gas commodity purchased by the Company to serve its customers, under the proposed tariff, TGS will only recover the actual costs of the RNG Credits.

IV. REGULATORY ASSETS

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE FOR A REQUESTED REGULATORY ASSET?

A. The Company has included a requested regulatory asset amount totaling $3,135,695. This amount is reflected on Schedule B, line 8, and detailed on Schedule B-11 and is comprised of the following:

- Unamortized balance of Regulatory Assets from GUD No. 10526;
- Under-collection of rate case expense from GUD No. 10928;
- Deferred Winter Storm Uri operations and maintenance ("O&M") expense at December 31, 2023;
- Deferred Winter Storm Uri-related short-term incentive ("STI") amounts; and
- COVID-19 related O&M.

Q. WHAT IS THE PURPOSE OF A REGULATORY ASSET?

A. The establishment of a regulatory asset provides a means of recovery of costs associated with a specific project, event, or activity that have been accumulated and deferred for later regulatory review to determine whether recovery is appropriate. If approved for recovery, the Commission can establish a regulatory asset which is amortized over the approved recovery period.

Q. PLEASE EXPLAIN THE UNAMORTIZED BALANCE OF REGULATORY ASSETS FROM GUD NO. 10526.

A. At the conclusion of GUD No. 10526, the Commission authorized TGS to recover reasonably incurred regulatory expenses over a six-year period in base rates. The Company began amortizing the regulatory asset in 2016. In 2019, the remaining unamortized balance was included in GUD No. 10928. The Commission authorized TGS to recover the remaining balance over a six-year period. The remaining unamortized balance has been included in the cost of service for this case.

Q. PLEASE EXPLAIN THE UNDER-COLLECTION OF RATE CASE EXPENSE FROM GUD NO. 10928.

A. At the conclusion of GUD No. 10928, the Commission authorized TGS to recover rate case expenses from customers via a volumetric rate. When the rate case expense collection was nearing completion, TGS monitored dollars collected on a daily basis in order to determine which day to discontinue the rate. Because it is impossible to predict in advance exactly how many volumes will be billed at the end of each day, predicting the right day to discontinue the rate can be challenging.

In this case, TGS ended up under-collecting on the final day. TGS maintained the under-collected balance and is seeking recovery in this proceeding.

Q. PLEASE EXPLAIN THE WINTER STORM URI O&M REGULATORY ASSET.

A. The Commission issued a Notice to Local Distribution Companies ("LDCs") on February 13, 2021 ("February Notice") related to Winter Storm Uri.[7] In the February Notice, the Commission authorized LDCs to create a regulatory asset to record "extraordinary expenses associated with the weather event including but not being limited to gas cost and other costs related to the procurement and transportation of gas supply" costs incurred during Winter Storm Uri. Based on the Commission's February Notice, TGS created a regulatory asset for extraordinary storm costs, excluding costs recovered as a part of securitization in Docket No. 7061, for review and recovery during a future rate proceeding.

Q. DESCRIBE COSTS INCLUDED IN THE WINTER STORM URI REGULATORY ASSET.

A. The costs included in the Winter Storm Uri regulatory asset fall into three main categories. First, they include extraordinary O&M expenses TGS incurred in the CGSA related to the winter storm and efforts TGS made to continue to operate its system and provide service during the storm. The costs include direct service area overtime labor, lodging, meals, gasoline and supplies and expenses totaling $458,594.

[7] Notice of Authorization for Regulatory Asset Accounting for Local Distribution Companies Affected by the February 2021 Winter Weather Event (Feb. 13, 2021), https://www.rrc.texas.gov/media/4u1fpycl/2021_nto_gas-services_state-disaster-waiver_gasutilityassetaccountingwinter-2021_2-13-2021.pdf.

Second, a portion of the 2021 STI in the amount of $153,278 is included in the proposed Winter Storm Uri regulatory asset as well as $220,123 in recognition awards, given to certain employees at the supervisor level and below that were directly involved in maintaining and providing service during Winter Storm Uri. Both of those items are discussed in detail in the direct testimony of Company witness Megan Z. Gough.

Third, the costs include carrying costs incurred from September 2022 through March 2023, at TGS's actual financing rate, which ranged from 1% to 1.25%, totaling $1,048,153, of which $833,150 is allocable to the CGSA. This regulatory asset does not include any of the costs the Commission approved for TGS in Docket No. 7061 in February 2022. The costs approved in Docket No. 7061 specifically excluded O&M expenses and included carrying costs calculated through August 2022. TGS requests to amortize the balance in the Winter Storm Uri regulatory asset over a period of six years.

Q. PLEASE ELABORATE ON THE AMOUNTS FOR 2021 STI AND RECOGNITION AWARDS INCLUDED IN THE WINTER STORM URI REGULATORY ASSET.

A. The Company included a portion of the 2021 STI compensation and recognition awards given to certain employees at the supervisor level and below that were directly involved in maintaining and providing service during Winter Storm Uri in the proposed Winter Storm Uri regulatory asset. As explained in Ms. Gough's direct testimony, the achievement level for the Emergency Response Time ("ERT") metric in 2021, was 62.7%, which fell below the threshold of 64%, resulting in an ERT payout of zero percent. However, ONE Gas recognized that its employees were impacted in their response time to emergencies due to the hazardous conditions of Winter Storm Uri, and ONE Gas leadership decided to exclude the data related to the 10-day period during Winter Storm Uri from its 2021 ERT calculation as Ms. Gough discusses in her direct testimony. This adjustment resulted in an ERT payout of 4.69% of STI. Employees at the officer level (vice president) and above did not receive an ERT payout. TGS proposes recovery of the Non Officers' ERT payout of 4.69% and the recognition award amount through the Winter Storm Uri regulatory asset, contained on Schedules B-11 and G-20.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED TGS'S REQUEST TO RECOVER COSTS BOOKED TO A REGULATORY ASSET FOR WINTER STORM URI?

A. Yes. In Docket Nos. 9896 and 14399, TGS requested recovery of similar O&M expenses related to Winter Storm Uri that were booked to a regulatory asset, and the Commission approved TGS's request.[8]

Q. PLEASE EXPLAIN THE INCLUSION OF COVID-19 O&M AS A REGULATORY ASSET.

A. The Company has included a COVID-19 regulatory asset pursuant to the April 2020, Commission notice authorizing each gas utility to record in a regulatory asset account the expenses associated with the COVID-19 State of Disaster. TGS seeks to amortize the balance over a period of six years.

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[8] Docket No. OS-22-00009896, consol., Final Order at FoF No. 45-46; and Docket No. OS-23-00014399, consol., Final Order at FoF No. 53-54.

Q. DESCRIBE THE COSTS INCLUDED IN THE COVID-19 REGULATORY ASSET.

A. The COVID-19 regulatory asset includes test year costs for items such as sanitizing spray services, changing air filters monthly, personal protective equipment such as masks, hand-sanitizing stations and social distancing signage totaling $1,431,855. Company witness Alejandro Limón describes the nature of these costs in more detail in his direct testimony.

Q. IS IT REASONABLE FOR THE COMPANY TO RECOVER THESE COSTS IN THIS RATE CASE?

A. Yes, these costs were incurred to follow recommended Centers for Disease Control and Prevention and Occupational Safety and Health Administration guidelines to ensure the safety of both employees and customers as TGS personnel performed their jobs to allow the Company to continue to provide service to customers. The costs are also the types of costs mentioned in the Commission's notice authorizing recovery through a regulatory asset.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED TGS'S REQUEST TO RECOVER COVID-19 COSTS BOOKED TO A REGULATORY ASSET?

A. Yes. In Docket Nos. 9896 and 14399, TGS requested recovery of similar costs related to COVID-19 that were booked to a regulatory asset and the Commission approved TGS's request.[9]

[9] Docket No. OS-22-0009896, consol., Final Order at FoF No. 44; and Docket No. OS-23-00014399, consol., Final Order at FoF No. 52.

V. <u>RULE 8.209 ACCRUALS</u>

Q. WHAT AMOUNTS HAVE BEEN DEFERRED AND REFLECTED WITHIN RATE BASE IN ACCORDANCE WITH COMMISSION RULE 8.209?

A. Schedule B-3, reflects the Company's deferred costs associated with its Distribution Integrity Management Program ("DIMP") as of December 31, 2023. These amounts have been deferred in accordance with Commission Rule 8.209. Rule 8.209(j) allows the operator of a gas distribution system to ". . . establish one or more designated regulatory asset accounts in which to record any expenses incurred by the operator in connection with the acquisition, installation or operation (including related depreciation) of facilities that are subject to the requirements of this section." Rule 8.209 sets out minimum requirements for development and implementation of a risk-based program for removal and replacement of distribution facilities. Rule 8.209(j) also allows each regulatory asset to include the "interest on the balance in the designated distribution facility replacement accounts based on pretax cost of capital last approved for the utility by the Commission."

Pursuant to Rule 8.209, the Company began deferring these DIMP-related expenses on January 1, 2012. The amount associated with the Company's deferral for the CGSA is $1,848,673 and includes monthly deferred DIMP costs for the CGSA from January 2023 through December 2023. Mr. Limón also addresses the Company's DIMP-related activities in his direct testimony.

Q. HAVE THE COMPANY'S REGULATORS PREVIOUSLY AUTHORIZED TGS TO RECOVER DEFERRED AMOUNTS RELATED TO COMMISSION RULE 8.209?

A. Yes, the Commission has previously authorized TGS to recover deferred amounts related to Rule 8.209 in multiple proceedings. In addition, the CGSA cities, among other cities in other TGS service areas, have also approved the Company's request to recover deferred amounts related to Rule 8.209.

Q. DID TGS FOLLOW THE SAME METHODOLOGY FOR CALCULATING THE DEFERRED AMOUNTS ASSOCIATED WITH COMMISSION RULE 8.209 IN THIS SOI AS IT HAS IN PRIOR FILINGS?

A. Yes, the Company has followed the same methodology.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

RESOLUTION NO. 20200220-047

WHEREAS, the City of Austin has established a goal of achieving community-wide net-zero greenhouse gas emissions by 2050; and

WHEREAS, Resolution 20190808-078 directed the city manager to provide options for more aggressive interim targets to accelerate the reduction pathway to achieve net-zero by 2050, and to consider a range of innovative and aggressive strategies; and

WHEREAS, the City is currently in the process of updating the Austin Community Climate Plan, which outlines the City's goals and methods of reducing community-wide greenhouse gas emissions; and

WHEREAS, according to the 2018 Austin Community Greenhouse Gas Emissions Inventory, natural gas contributes an estimated seven percent of Austin's inventory of greenhouse gas emissions based on currently available data; and

WHEREAS, more complete data is needed to more accurately estimate natural gas contributions to Austin's inventory of greenhouse gas emissions, and natural gas emissions sources include end use as well as system leakage; and

WHEREAS, the City has committed to a goal of Zero Waste by 2040; and

WHEREAS, Austin Energy plans for at least 65 percent of the power supplied to customers to be from renewable sources by 2027; and

WHEREAS, renewable natural gas, also known as biomethane, is gas produced by the decomposition of organic matter under anaerobic (oxygen-free) conditions; and

WHEREAS, once biomethane has been purified to a quality similar to geologic natural gas, it becomes possible to distribute the gas to customers via the existing gas distribution system for use within existing appliances and for transportation; and

WHEREAS, policymakers around the nation have implemented policies to promote the development of renewable natural gas such as federal Renewable Fuel Standards or state and local Low-Carbon Fuel Standards; and

WHEREAS, the U.S. Environmental Protection Agency has found that the integration of captured methane as renewable natural gas has the potential to offset other greenhouse gas emission, particularly in transportation; and

WHEREAS, the Austin Water Hornsby Bend Biosolids Management Plant (HBBMP) uses biomethane from its sludge treatment process to generate clean electricity to power facility operations; and

WHEREAS, Austin Water offsets one hundred percent of facility power consumption at HBBMP using its generated biomethane and is actively studying options for the best use of biomethane, in order to reduce disposal of excess gas by flaring and sustain an economically beneficial program for the City; and

WHEREAS, biomethane can be derived from a variety of sources, including landfills and wastewater treatment plants, and such opportunities exist in Austin and the surrounding area; and

WHEREAS, various utilities in the U.S. purchase carbon offsets including programs for tree planting, forest preservation, renewable energy, and elimination of ozone depleting chemicals; and

WHEREAS, Austin Energy offers a GreenChoice program to allow subscribers to opt in to purchasing one hundred percent renewable Texas wind energy at a low cost; and

WHEREAS, similar opt in programs from Austin local distribution companies do not currently exist; and

WHEREAS, according to currently available data, in 2018, Texas Gas Service gas system leaks were responsible for an estimated 125,045 in metric tons of CO2e in Texas; and

WHEREAS, greater communication and coordination between the Office of Sustainability and local distribution companies is necessary to achieve more accurate reporting; and

WHEREAS, the 2015 Austin Community Climate Plan contains action item RT-4, to "evaluate technology and cost options for increasing natural gas system leak detection and reduction programs"; and

WHEREAS, development and integration of technology for renewable natural gas helps achieve the City's goal of reducing and ultimately eliminating community-wide greenhouse gas emissions; and

WHEREAS, the City desires to keep energy rates affordable while pursuing environmental leadership and goals; **NOW, THEREFORE,**

BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF AUSTIN:

The City encourages the capture of renewable energy within city facilities where appropriate (as successfully implemented at the Hornsby Bend Biosolids Management Plant), and to do so with a goal of retaining the economic value of such projects for the City and its residents.

BE IT FURTHER RESOLVED:

The City requests that Texas Gas Service Company, a division of ONE Gas, Inc., conduct and provide to the city manager by late Spring of 2020 a feasibility analysis of renewable natural gas that addresses:

- Opportunities for methane capture from any and all sources in the Austin area and in the surrounding region;
- The economic benefits of such opportunities for the City, gas providers, and ratepayers; and
- Opportunities and benefits of the use of renewable credits and offsets to support sustainability goals.

The feasibility analysis should include findings identifying:

- A target percentage of biomethane (and potentially, hydrogen) to be incorporated into the throughput of Texas Gas Service or other local distribution companies;
- A target date by which such percentage will be reached, to include interim goals for adoption;
- Options for a potential opt-in consumer renewable energy program modeled on the Austin Energy GreenChoice program;
- Local opportunities that retain revenue for the City;
- Options for opportunities throughout the local economy, and how distribution companies can support local efforts; and
- Options for offsets and renewable credits as another strategy for carbon emissions reduction.

All options and recommendations should aim for aggressive sustainability goals while maintaining affordable energy rates for Austin residents.

The City Council requests that Texas Gas Service present the completed feasibility analysis to the Resource Management Commission and to City Council by late spring 2020.

BE IT FURTHER RESOLVED:

The city manager is directed to facilitate conversations between Texas Gas Service, other local distribution companies, and City departments and to provide input on the completed feasibility analysis

BE IT FURTHER RESOLVED:

The city manager is directed to evaluate the findings of Texas Gas Service's feasibility study and its recommendations for possible incorporation into the 2020 update to the Austin Community Climate Plan, in addition to any related ideas in consideration for inclusion into the plan.

BE IT FURTHER RESOLVED:

Texas Gas Service is requested to evaluate technology and cost options for increasing natural gas system leak detection and reduction programs and to regularly report to the City's Resource Management Commission, at least quarterly, and to City Council, at least annually, an update on leakage rates and efforts to reduce leakage rates. Efforts can include pipeline modernization, third party damage prevention programs, City permitting processes to repair leaks, and coordination with the capture of methane as indicated above.

ADOPTED: February 20, 2020 **ATTEST:** Jannette S. Goodall

Jannette S. Goodall
City Clerk

Renewable Natural Gas Feasibility for the City of Austin

Final Report

July 2020

Submitted to:
ONE Gas
1301 S Mopac Expwy, Ste 400
Austin, TX 78746

Submitted by:
ICF Resources, L.L.C.
9300 Lee Highway
Fairfax, VA 22031

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Executive Summary

The City of Austin has made long-term climate and clean energy commitments, including net-zero community-wide greenhouse gas (GHG) emissions by 2050, that will directly impact the natural gas system. As set out in the City of Austin resolution 202200220-047,[1] ONE Gas was directed by the City to conduct a Renewable Natural Gas (RNG) Feasibility Assessment that reviews the following:

- Opportunities for methane capture from and all sources in the Austin Area and in the surrounding region.
- The economic benefits of such opportunities for the City, gas providers, and ratepayers.
- Opportunities and benefits of the use of renewable credits and offsets to support sustainability goals.
- A target percentage of biomethane (and potentially, hydrogen) to be incorporated into the throughput of Texas Gas Service or other local distribution companies.
- A target date by which such percentage will be reached, to include interim goals for adoption.
- Options for a potential opt-in consumer renewable energy program modeled on the Austin Energy GreenChoice program.
- Local opportunities that retain revenue for the City.
- Options for Opportunities throughout the local economy, and how distribution companies can support local efforts.
- Options for offsets and renewable credits as another strategy for carbon emissions reductions.

Methodology

ICF was engaged by ONE Gas to conduct this feasibility assessment regarding the potential of RNG to contribute to meeting the City of Austin's clean energy objectives and address the issues raised in the resolution. To achieve the assessment objectives, ICF sought to address several questions, including:

- How much RNG can be produced in and around Austin, Texas and delivered to Austin, Texas from various feedstocks and via different production technologies?
- How much will it cost to produce RNG in and around Austin, Texas, with estimates out to 2050?
- What are the corresponding GHG emission reductions that might be achieved, and the associated costs, under different feedstock utilization scenarios?
- What are the potential economic and environmental impacts of deploying RNG to help meet the City of Austin's climate and clean energy objectives?

[1] City of Austin, 2020. Resolution no. 20200220-047, https://www.austintexas.gov/edims/document.cfm?id=336351

RNG is derived from biomass or other renewable resources and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As RNG is a “drop-in” replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, industrial applications, and transportation. Today, about 50,000,000 million Btu per year (MMBtu/y) of RNG from landfills, dairy digesters, and water resource recovery facilities (WRRFs) is injected into pipelines, with production growing year-on-year.

ICF developed three resource potential scenarios by considering RNG production from eight feedstocks and two production technologies. The feedstocks include animal manure, food waste, landfill gas, WRRFs, agricultural residues, energy crops, forestry and forest product residues, and the nonbiogenic fraction of municipal solid waste (MSW). These feedstocks were assumed to be processed using one of two technologies to produce RNG: anaerobic digesters, and thermal gasification systems.

RNG Potential and Costs

ICF developed three RNG production scenarios: Limited Adoption, Achievable Deployment, and Optimistic Growth, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented. ICF estimates that the resource potential scenarios will yield between 8,500,000 MMBtu/y and 33,400,000 MMBtu/y of RNG production by 2050, shown in the table below. For reference, total throughput in ONE Gas’s Central Texas natural gas system at roughly 23,300,000 MMBtu in 2019.

Summary of Estimated Annual RNG Production Potential by Scenario (MMBtu/y)

RNG Feedstock		Scenario		
		Limited Adoption	Achievable Deployment	Optimistic Growth
Anaerobic Digestion	Animal Manure	2,173,000	3,259,000	4,344,000
	Food Waste	156,000	453,000	577,000
	LFG	3,453,000	6,660,000	9,092,000
	WRRFs	159,000	320,000	441,000
Thermal Gasification	Agricultural Residue	578,000	1,283,000	1,633,000
	Energy Crops	811,000	8,107,000	11,653,000
	Forestry and Forest Product Residue	242,000	407,000	547,000
	Municipal Solid Waste	934,000	3,525,000	5,094,000
Total		**8,506,000**	**24,014,000**	**33,381,000**

In other words, using ICF's balanced assumptions regarding feedstock utilization and technology deployment in the three scenarios, there is enough RNG production potential to displace between 33% and 100% of ONE Gas's Central Texas natural gas system today. In addition, RNG resources in Travis County and the surrounding area could displace up to 75% of natural gas consumption in the Achievable Deployment scenario without accessing any potential RNG resources from outside the immediate region.

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings examined. ICF characterizes costs based on a series of assumptions regarding production facility size, gas conditioning and upgrading costs, compression, and interconnect for pipeline injection. The table below summarizes the estimated cost ranges for each RNG feedstock and technology.

Summary of Estimated Cost Ranges by Feedstock Type

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Landfill Gas	$9.90 – $15.31
	Animal Manure	$22.00 – $45.16
	Water Resource Recovery Facilities	$10.87 – $33.26
	Food Waste	$20.40 – $29.60
Thermal Gasification	Agricultural Residues	$18.50 – $51.60
	Forestry and Forest Residues	$17.30 – $31.00
	Energy Crops	$18.30 – $56.10
	Municipal Solid Waste	$17.30 – $36.10

GHG Emission Reductions from RNG

RNG represents a valuable renewable energy source with a low or net negative carbon intensity depending on the feedstock. The GHG emission accounting methodology has a significant impact on how carbon intensities for RNG are estimated, with two methodologies used in this analysis to estimate GHG emission reductions relative to conventional natural gas consumption: a combustion accounting framework and a lifecycle accounting framework approach.

Using a combustion approach, ICF estimates that in the City of Austin region, 0.23 to 1.12 million metric tons (MMT) of GHG emissions could be reduced per year by 2050 through the deployment of RNG based on the Limited Adoption to Optimistic Growth scenarios. Expanding the geographic footprint to include RNG feedstocks from outside the immediate region, this increases to 0.45 to 1.78 MMT of GHG emissions that could be reduced per year by 2050. For comparison, the City of Austin's total direct GHG emissions in were 12.9 MMT in 2018.[2]

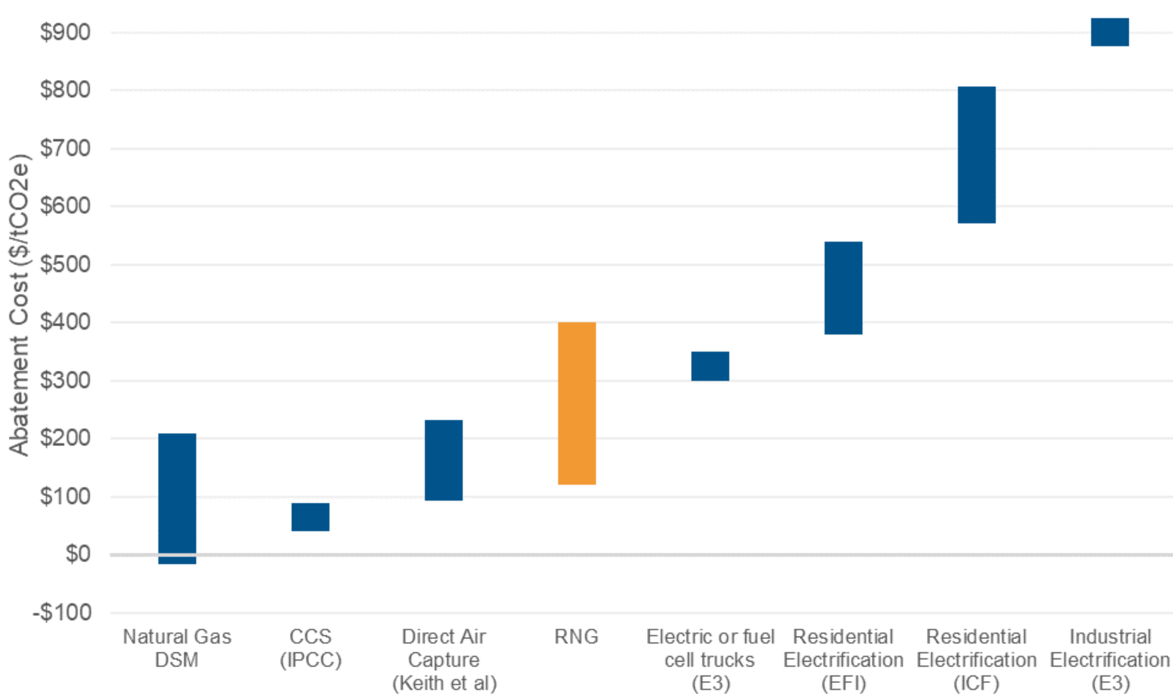
The GHG emission reduction estimates do not vary significantly with the use of a lifecycle accounting framework, with the total reductions ranging from 0.56 to 1.60 MMT of GHG emissions across the three scenarios in 2050.

[2] City of Austin, 2020. Austin Community Climate Plan, https://public.tableau.com/profile/cavan.merski#!/vizhome/CommunityInventoryMetricSprintDashboard/trend

RNG can play an important and cost-effective role to achieve aggressive decarbonization objectives over the long-term future, with ICF estimating GHG emission reductions at a cost of $120 to $400 per metric ton of carbon dioxide equivalent (tCO_2e). RNG is more expensive than its fossil counterpart, but in a decarbonization framework the proper comparison for RNG is to other abatement measures that are viewed as long-term strategies to reduce GHG emissions.

In this context, RNG is a cost-competitive option. The figure below shows a comparison of selected measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization by the 2050 timeframe, including natural gas demand side management (DSM), carbon capture and storage (CCS), RNG (from this study), direct air capture (whereby CO2 is captured directly from the air and a concentrated stream is sequestered or used for beneficial purposes), battery electric trucks (including fuel cell drivetrains), and electrification of certain end uses (including buildings and in the industrial sectors).

GHG Abatement Costs, Selected Measures ($/$tCO_2e$)



Economic Impacts

ICF employed IMPLAN, an input-output economic model, to quantify the economic impacts of producing RNG in Travis County, ONE Gas's Central Texas Service Area, and Texas. ICF accounted for multiple expenditures associated with RNG production from a variety of feedstocks relevant to Travis County and the surrounding region, including digester equipment, biogas conditioning equipment, miscellaneous support equipment, and construction/engineering costs; as well as pipeline for utility interconnection.

- Anaerobic digestion RNG production facilities on average will produce a total of 80—300 cumulative jobs per facility.

- These jobs have an expected average labor income of between $77,000 and $86,000 per job created, greater than the median household income in Travis County and Texas today. These jobs are created in sectors such as construction, engineering services, waste management, commercial and industrial machinery rental, and service industries (e.g., restaurants).
- For every job created through investment in anerobic digestion RNG production facilities, more than 2.2 jobs are created in supporting industries (indirect) and via spending by employees that are directly or indirectly supported by these industries (induced).
- Anerobic digestion RNG production facilities will also generate an average of $11-36 million of value-added economic output per facility, with an output multiplier of roughly 2, representing the total industry activity (including direct, indirect, and induced) divided by the direct industry activity.
- Thermal gasification facilities are likely to produce higher economic and employment impacts per facility relative to anaerobic digestion facilities, driven by larger-scale facilities and higher costs, although there remains uncertainty related to the development of the thermal gasification technology over time.

ICF's economic modeling results provide quantitative insights into the potential for renewable natural gas production in Travis County and the surrounding region, and presents a compelling economic opportunity for Travis County and the region.

Recommendations

ICF developed a series of recommendations that are presented across three areas:

- **Strategic direction** for policymakers and industry stakeholders,
- **Market approaches** that will help to advance RNG deployment, and
- **Regulatory actions** that will help to bring near- and long-term certainty needed to realize the potential for RNG as a cost-effective strategy for decarbonization.

Together, these three areas encompass the suite of actions that will help to realize the opportunities and overcome the challenges for RNG deployment in the City of Austin and surrounding region.

Strategic Direction

ICF recommends developing a strategic roadmap for regional policymakers and stakeholders based on a set of clear principles:

Principles:

- Produce and deliver RNG safely and cost-effectively to participants and end-use customers.
- Contribute to broader regional GHG emission reduction objectives.
- Implement a flexible regulatory and legislative structure that values RNG deployment.
- Engage proactively with key stakeholders through the implementation of the RNG strategy.

RNG Deployment

The potential for RNG in the City of Austin and surrounding region's natural gas system is clear, with aggressive but attainable RNG throughput targets feasible over the medium-term and beyond. ICF's analysis of RNG potential at the local, regional, and national level supports the RNG volumes required to help decarbonize the region's natural gas system. However, ICF notes that for these broader RNG throughput targets to be cost-effective and successful, they would need to cover all natural gas distributors and suppliers in the region, and be supported by a broad and stable regulatory framework that provides a consistent RNG requirement across all suppliers and end users.

ONE Gas is well-positioned to take a leading role to facilitate the necessary development of RNG consumption in the natural gas system in the region, implemented through near-term voluntary throughput targets. Producing RNG from a local facility, such as from a landfill gas or wastewater facility in Travis County, could meet a near-term throughput target of 1–3%.

Market Approaches

- **Develop interconnection standards for RNG projects.** A consistent approach to evaluate RNG quality and constituent composition will facilitate the broader acceptance of different RNG feedstocks and encourage the development of RNG as a source for pipeline throughput and larger sources of demand (e.g., thermal use applications). ONE Gas has already developed these interconnection standards, and is ready to work with potential RNG project developers on interconnection.
- **Deploy RNG into the transportation market.** The transportation sector is a natural fit for the near-term focus of RNG deployment in the region: the combination of higher conventional energy costs and existing incentives makes for a clear opportunity. The market for RNG as a transportation fuel in the City of Austin and surrounding region should take advantage of other market forces, notably that California's market for natural gas as a transportation fuel is nearly saturated with RNG.
- **Establish common tracking across RNG markets**. A system to track and verify RNG in thermal use applications (i.e., outside of transportation and electricity sectors that currently have tracking systems in place) will become increasingly important as multiple sectors and regions seek to deploy RNG across various end uses.

Regulatory Approaches

ICF recommends a regulatory approach that stages potential RNG programs over the near-, mid-, and long-term horizons in an effort to reconcile conflicting requirements.

- **Develop pilot or voluntary RNG procurement programs.** ICF recommends a near-term regulatory approach that supports voluntary purchase of RNG through gas utility service providers to help foster market growth, improve customer awareness, and satisfy nascent demand.
- **Expand RNG in the transportation sector through infrastructure investments.** ICF recommends an innovative regulatory structure whereby utilities are able to invest in NGV fueling infrastructure, offer beneficial and attractive tariffs to CNG users, and partner with key stakeholders to deploy CNG in key vehicle market segments.

- **Support the development of a broad and stable policy framework such as a Renewable Gas Standard.** ICF recommends that ONE Gas support a Renewable Gas Standard (RGS). This is the most robust policy structure, and it will help drive consistent demand in a diverse set of end uses, and assist the market to transition from a near-term focus on the transportation sector to a mid- to long-term focus on stationary uses in thermal applications. The RGS will act as a utility procurement mechanism, thereby providing supply and price certainty without disrupting the success and market participation in existing programs driving existing RNG deployment.

1. Introduction

ICF was engaged by ONE Gas to assess the potential of renewable natural gas (RNG) to contribute to meeting the City of Austin's clean energy objectives. The analysis is intended to help answer the following questions:

- How much RNG can be produced in and around Austin, Texas and delivered to Austin, Texas from various feedstocks?
- How much will it cost to produce RNG in and around Austin, Texas, with estimates out to 2050?
- What are the corresponding GHG emission reductions that might be achieved, and the associated costs, under different feedstock utilization scenarios?

The primary objective of the project is to characterize the technical and economic potential for RNG as a greenhouse gas (GHG) emission reduction strategy, with particular focus on local or regional resources in and around Austin, Texas. Further, the project will yield a series of deliverables that will support the City's and ONE Gas's efforts to improve the region's understanding and external stakeholders' understanding of the extent to which delivering RNG to all sectors of Austin's economy can contribute to broader GHG emission reduction initiatives.

The project is broken into eight tasks, outlined in the table below.

Table 1. Project Tasks

Task	Task Description
1	Develop Inventory of Potential RNG Sources
2	RNG Supply Assessment
3	Evaluate the Technical and Economic Potential of RNG for Austin, TX
4	Evaluation of GHG Reduction Potential of RNG in Austin, TX
5	Conduct RNG Policy Assessment
6	Assess Local and Regional Economic Impacts of RNG Deployment
7	Develop RNG Strategic Roadmap
8	Final Report

.

These tasks will cover the elements included in the City's Resolution No. 20200220-047, as outlined in the table below.[3]

Table 2. City of Austin Resolution Requirements

Task(s)	Feasibility Analysis Elements
Tasks 1 & 2	Opportunities for methane capture from and all sources in the Austin Area and in the surrounding region.
Tasks 3 & 6	The economic benefits of such opportunities for the City, gas providers, and ratepayers.
Tasks 4 & 5	Opportunities and benefits of the use of renewable credits and offsets to support sustainability goals.
Tasks 5 & 7	A target percentage of biomethane (and potentially, hydrogen) to be incorporated into the throughput of Texas Gas Service or other local distribution companies.
Tasks 5 & 6	A target date by which such percentage will be reached, to include interim goals for adoption.
Task 5	Options for a potential opt-in consumer renewable energy program modeled on the Austin Energy GreenChoice program.
Task 6	Local opportunities that retain revenue for the City.
Tasks 5-7	Options for Opportunities throughout the local economy, and how distribution companies can support local efforts.
Tasks 4-7	Options for offsets and renewable credits as another strategy for carbon emissions reductions.

Renewable Natural Gas

RNG is derived from biomass or other renewable resources, and is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As a point of reference, the American Gas Association (AGA) uses the following definition for RNG:[4]

> *Pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower life cycle carbon dioxide equivalent (CO_2e) emissions than geological natural gas.* [5]

RNG is produced over a series of steps (see Figure 1): collection of a feedstock, delivery to a processing facility for biomass-to-gas conversion, gas conditioning, compression, and injection into the pipeline. In this project ICF considers two production technologies: anaerobic digestion and thermal gasification.

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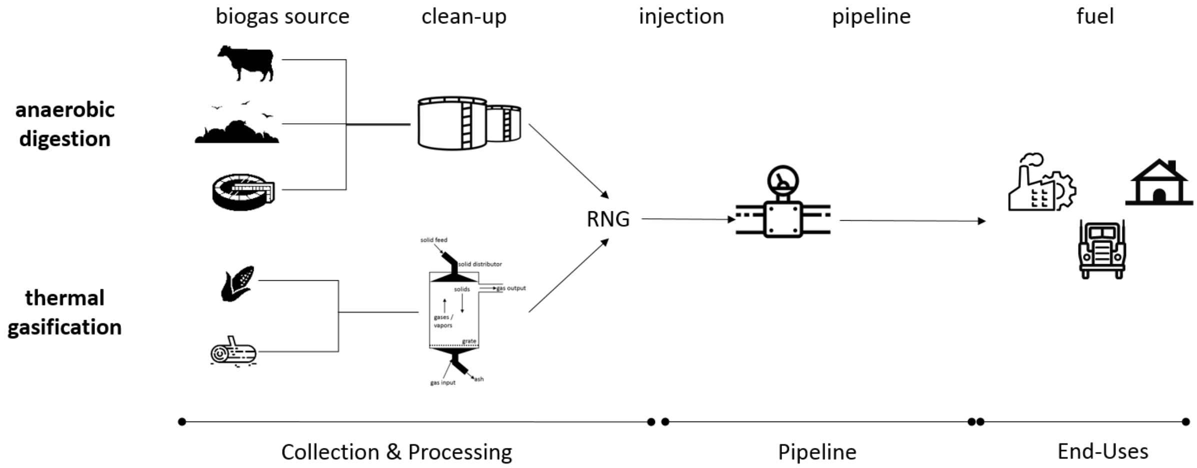
[3] City of Austin, 2020. Resolution No. 20200220-047, https://www.austintexas.gov/edims/document.cfm?id=336351

[4] AGA, 2019. RNG: Opportunity for Innovation at Natural Gas Utilities, https://pubs.naruc.org/pub/73453B6B-A25A-6AC4-BDFC-C709B202C819

[5] ICF notes that this is a useful definition, but excludes RNG produced from the thermal gasification of the non-biogenic fraction of municipal solid waste (MSW). In most cases, however, the thermal gasification of the non-biogenic fraction of MSW yields lower CO_2e emissions than geological natural gas. As a result, MSW is included as an RNG resource in this study.

Figure 1. RNG Production Process via Anaerobic Digestion and Thermal Gasification



Anaerobic Digestion

The most common way to produce RNG today is via anaerobic digestion, whereby microorganisms break down organic material in an environment without oxygen. The four key processes in anaerobic digestion are:

- Hydrolysis
- Acidogenesis
- Acetogenesis
- Methanogenesis

Hydrolysis is the process whereby longer-chain organic polymers are broken down into shorter-chain molecules like sugars, amino acids, and fatty acids that are available to other bacteria. Acidogenesis is the biological fermentation of the remaining components by bacteria, yielding volatile fatty acids, ammonia, carbon dioxide, hydrogen sulfide, and other byproducts. Acetogenesis of the remaining simple molecules yields acetic acid, carbon dioxide, and hydrogen. Lastly, methanogens use the intermediate products from hydrolysis, acidogenesis, and acetogenesis to produce methane, carbon dioxide, and water, where the majority of the biogas is emitted from anaerobic digestion systems.

The process for RNG production generally takes place in a controlled environment, referred to as a digester or reactor. When organic waste, biosolids, or livestock manure is introduced to the digester, the material is broken down over time (e.g., days) by microorganisms, and the gaseous products of that process contain a large fraction of methane and carbon dioxide. The biogas requires capture and then subsequent conditioning and upgrade before pipeline injection. The conditioning and upgrading helps to remove any contaminants and other trace constituents, including siloxanes, sulfides and nitrogen, that cannot be injected into common carrier pipelines, and increases the heating value of the gas for injection.

Thermal Gasification

Biomass-like agricultural residues, forestry and forest produce residues, and energy crops have high energy content and are ideal candidates for thermal gasification. The thermal gasification of biomass to produce RNG occurs over a series of steps:

- Feedstock pre-processing in preparation for thermal gasification (not in all cases).
- Gasification, which generates synthetic gas (syngas), consisting of hydrogen and carbon monoxide (CO).
- Filtration and purification, where the syngas is further upgraded by filtration to remove remaining excess dust generated during gasification, and other purification processes to remove potential contaminants like hydrogen sulfide, and carbon dioxide.
- Methanation, where the upgraded syngas is converted to methane and dried prior to pipeline injection.

While biomass gasification technology is at an early stage of commercialization, the gasification and purification steps remain challenging. The gasification process typically yields a residual tar, which can foul downstream equipment. Furthermore, the presence of tar effectively precludes the use of a commercialized methanation unit. The high cost of conditioning the syngas in the presence of these tars has limited the potential for thermal gasification of biomass. For instance, in 1998, Tom Reed[6] concluded that after “two decades” of experience in biomass gasification, “‘tars’ can be considered the Achilles heel of biomass gasification.” Over the last several years, however, a few commercialized technologies have been deployed to increase syngas quantity and prevent the fouling of other equipment by removing the residual tar before methanation. There are a handful of technology providers in this space, including Haldor Topsoe’s tar-reforming catalyst. Frontline Bioenergy takes a slightly different approach and has patented a process producing tar-free syngas (referred to as TarFreeGas™).

ICF notes that biomass, particularly agricultural residues, are often added to anaerobic digesters to increase gas production (by improving carbon-to-nitrogen ratios, especially in animal manure digesters). It is conceivable that some of the feedstocks considered here could be used in anaerobic digesters. For simplicity, ICF did not consider any multi-feedstock applications in our assessment; however, it is important to recognize that the RNG production market will continue to include mixed feedstock processing in a manner that is cost-effective.

[6] NREL, Biomass Gasifier “Tars”: Their Nature, Formation, and Conversion, November 1998, NREL/TP-570-25357. Available online at https://www.nrel.gov/docs/fy99osti/25357.pdf.

2. RNG Feedstock Inventory

Summary

The following table summarizes the maximum RNG potential for each feedstock and production technology by geography of interest, in million Btu (MMBtu). The RNG potential includes different variables for each feedstock, but ultimately reflects the most aggressive options available, such as the highest biomass price and the utilization of all feedstocks at all facilities.

ICF emphasizes that the estimates included in the table below are based on the maximum RNG production potential from all feedstocks, and does not apply any economic or technical constraints on feedstock availability. An assessment of resource availability is presented in Section 3 of this report.

Table 3. RNG Production by Feedstock and Region (MMBtu/y)

RNG Feedstock	Travis County	ONE Gas Counties[7]	Rest of Texas	Texas
Animal Manure	452,000	14,239,000	251,967,000	266,659,000
Food Waste	334,000	234,000	7,378,000	7,946,000
Landfill Gas	5,803,000	892,000	98,461,000	105,156,000
Water Resource Recovery Facilities	257,000	80,000	4,395,000	4,731,000
Anaerobic Digestion Sub-Total	*6,846,000*	*15,445,000*	*362,201,000*	*384,492,000*
Agricultural Residue	83,000	941,000	43,282,000	44,307,000
Energy Crops	3,006,000	34,032,000	1,564,771,000	1,601,809,000
Forestry & Forest Product Residue	0	0	16,702,000	16,702,000
Municipal Solid Waste	3,079,000	2,360,000	64,635,000	70,074,000
Thermal Gasification Sub-Total	*6,168,000*	*37,334,000*	*1,689,391,000*	*1,732,892,000*
Total	**13,014,000**	**52,779,000**	**2,051,591,000**	**2,117,384,000**

[7] Discussed in further detail below, but includes other counties in ONE Gas's Central Texas Service Area: Caldwell, DeWitt, Gonzales, Hays, Lavaca, Williamson and Wilson.

RNG Feedstocks

RNG can be produced from a variety of renewable feedstocks, as described in the table below.

Table 4. RNG Feedstock Types

Feedstock for RNG		Description
Anaerobic Digestion	Animal manure	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
	Food waste	Commercial food waste, including from food processors, grocery stores, cafeterias, and restaurants, as well as residential food waste, typically collected as part of waste diversion programs.
	Landfill gas (LFG)	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
	Water resource recovery facilities (WRRF)	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.
Thermal Gasification	Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
	Energy crops	Inclusive of perennial grasses, trees, and annual crops that can be grown to supply large volumes of uniform and consistent feedstocks for energy production.
	Forestry and forest product residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
	Municipal solid waste (MSW)	Refers to the non-biogenic fraction of waste that would be landfilled after diversion of other waste products (e.g., food waste or other organics), including construction and demolition debris, plastics, etc.

Inventory Methodology

The RNG feedstock inventory methodology is based on the objective of Task 1: identify the waste stream sources and feedstocks, and the corresponding technologies that can be used to produce RNG for a variety of end uses.

ICF used a mix of existing studies, government data, and industry resources to estimate the current and future supply of the feedstocks. The table below summarizes some of the resources that ICF drew from to complete our resource assessment, broken down by RNG feedstock:

Table 5. List of Data Sources for RNG Feedstock Inventory

Feedstock for RNG	Potential Resources for Assessment
Animal manure	▪ U.S. Environmental Protection Agency (EPA) AgStar Project Database ▪ U.S. Department of Agriculture (USDA) Census of Agriculture
Food waste	▪ U.S. Department of Energy (DOE) 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework (KDF)
LFG	▪ U.S. EPA Landfill Methane Outreach Program ▪ Environmental Research & Education Foundation (EREF)
WRRFs	▪ U.S. EPA Clean Watersheds Needs Survey (CWNS) ▪ Water Environment Federation
Agricultural residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Energy crops	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
Forestry and forest product residue	▪ U.S. DOE 2016 Billion Ton Report ▪ Bioenergy Knowledge Discovery Framework
MSW	▪ U.S. DOE 2016 Billion Ton Report ▪ Waste Business Journal

This RNG feedstock inventory does not take into account resource availability—in a competitive market, resource availability is a function of factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized given the necessary market considerations (without explicitly defining what those are), outlined in Section 3.

Geography

Consistent across all feedstocks, we present RNG potential at the local, regional and state levels. The local level is defined as Travis County, and regional encompasses the surrounding counties that broadly reflect ONE Gas's Central Texas Service Area (CTX) – Caldwell, DeWitt, Gonzales, Hays, Lavaca, Williamson and Wilson. We also provide RNG feedstock information for the rest of Texas, and the Texas total.

RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Animal Manure

Animal manure as an RNG feedstock is produced from the manure generated by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses. The U.S. EPA lists a variety of benefits associated with the anaerobic digestion of animal manure at farms as an alternative to traditional manure management systems, including but not limited to:[8]

- Diversifying farm revenue: the biogas produced from the digesters has the highest potential value. But digesters can also provide revenue streams via "tipping fees" from non-farm organic waste streams that are diverted to the digesters, organic nutrients from the digestion of animal manure, and displacement of animal bedding or peat moss by using digested solids.
- Conservation of agricultural land: digesters can help to improve soil health by converting the nutrients in manure to a more accessible form for plants to use and help protect the local water resources by reducing nutrient run-off and destroying pathogens.
- Promoting energy independence: the RNG produced can reduce on-farm energy needs or provide energy via pipeline injection for use in other applications, thereby displacing fossil or geological natural gas.
- Bolstering farm-community relationships: digesters help to reduce odors from livestock manure, improve growth prospects by minimizing potential negative impacts of farm operations on local communities, and help forge connections between farmers and the local community through environmental and energy stewardship.

The main components of anaerobic digestion of manure include manure collection, the digester, effluent storage (e.g., a tank or lagoon), and gas handling equipment. There are a variety of livestock manure processing systems that are employed at farms today, including plug-flow or mixed plug-flow digesters, complete-mixed digesters, covered lagoons, fixed-film digesters, sequencing-batch reactors, and induced-blanked digesters. Most dairy manure projects today use the plug-flow or mixed plug-flow digesters.

ICF considered animal manure from a variety of animal populations, including beef and dairy cows, broiler chickens, layer chickens, turkeys, and swine. Animal populations were derived from the United States Department of Agriculture's (USDA) National Agricultural Statistics Service. ICF used information provided from the most recent census year (2017) and extracted total animal populations on a county and state level.[9] Based on this information, ICF identified animal populations at the local level by county, and for the rest of Texas.

ICF developed the maximum RNG potential using animal manure production and the energy content of dried manure taken from a California Energy Commission report prepared by the California Biomass Collaborative.[10] These inputs are summarized in the table below.

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[8] More information available online at https://www.epa.gov/agstar/benefits-anaerobic-digestion.
[9] USDA, 2017. 2017 Census of Agriculture, https://www.nass.usda.gov/AgCensus/index.php
[10] Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. An Assessment of Biomass Resources in California, 2013 – DRAFT. Contractor Report to the California Energy Commission. PIER Contract 500-11-020. Available online here.

Table 6. Key Parameters for Animal Manure Resource RNG Potential

Animal Type	Volatile Solids (kg/head/year)	Higher Heating Value (HHV) (Btu/kg, dry basis)
Dairy	3,020	16,111
Beef: - Cattle - Other	 1,674 750	 16,345 16,345
Swine	149	15,077
Poultry: - Layer Chickens - Broiler Chickens - Turkeys	 8.3 9.1 25.0	 14,689 15,077 14,830
Sheep & Goats	242	9,362

The U.S. EPA AgStar database indicates that there are 2 operational anaerobic digesters at farms in Texas, both in Dallam County. These two digesters use the biogas for on-site boiler or furnace fuel use.

The animal manure inventory does not identify specific facilities or locations where RNG will likely be produced. However, concentrated animal feeding operations (CAFOs) provide an indication of where RNG from animal manure could be produced. For example, of the 30 existing anaerobic digesters at farms in New York State, 29 are also licensed CAFOs.

The existing accumulation of animal manure at CAFOs located near pipeline infrastructure could conceivably increase the productive potential of animal manure as an RNG feedstock. The U.S. EPA reports that there are over 1,000 CAFOs in Texas, indicating that the infrastructure for the concentration of animal manure may not be a barrier to growth in RNG production from animal manure.

The table below shows the volume of animal feedstock available and maximum RNG potential in Travis County, surrounding CTX counties, and the rest of Texas. Note that the maximum RNG potential does not take into account the numerous limiting factors that would constrain the volume of RNG that could be produced from animal manure.

Table 7. Animal Manure Resource RNG Potential

Region	Animal Head Count (millions)	Maximum RNG Potential (MMBtu)
Travis County	0.25	452,000
Other CTX	21.26	14,239,000
Rest of Texas	137.56	251,967,000
Texas	159.07	266,659,000

Food Waste

Food waste is a major component of MSW—accounting for about 15% of MSW streams. More than 75% of food waste is landfilled. Food waste can be diverted from landfills to a composting or processing facility where it can be treated in an anaerobic digester. ICF limited our consideration to the potential for utilizing the food waste that is currently landfilled as a feedstock for RNG production via AD, thereby excluding the 25% of food waste that is recycled or directed to waste-to-energy facilities.

ICF extracted county and state level information from the U.S. DOE's Bioenergy Knowledge Discovery Framework (KDF), which includes information collected as part of U.S. DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes food waste at tipping fee price points ranging from $70/ton to $100/ton. ICF assumed a high heating value of 12.04 MMBtu/ton (dry). Note that the values from the Bioenergy KDF are reported in dry tons, so the moisture content of the food waste has already been accounted for in the DOE's resource assessment.

As food waste is generated from population centers and typically diverted at waste transfer stations rather than delivered to landfills, it is challenging to identify specific facilities or projects that will generate RNG from food waste. However, food waste can potentially utilize existing or future AD systems at LFG and WRRF facilities. The table below shows the maximum volume of food waste available, and the maximum RNG potential in Travis County, surrounding CTX counties, and the rest of Texas, noting that no limiting factors were applied to the RNG potential.

Table 8. Maximum Food Waste Potential by Region in 2050

Region	Maximum Production (dry tons)	Maximum RNG Potential (MMBtu)
Travis County	27,756	334,000
Other CTX	19,442	234,000
Rest of Texas	612,985	7,378,000
Texas	660,183	7,946,000

Landfill Gas

The Resource Conservation and Recovery Act of 1976 (RCRA, 1976) sets criteria under which landfills can accept municipal solid waste and nonhazardous industrial solid waste. Furthermore, the RCRA prohibits open dumping of waste, and hazardous waste is managed from the time of its creation to the time of its disposal. Landfill gas (LFG) is captured from the anaerobic digestion of biogenic waste in landfills and produces a mix of gases, including methane, with a methane content generally ranging 45%–60%. The landfill itself acts as the digester tank—a closed volume that becomes devoid of oxygen over time, leading to favorable conditions for certain micro-organisms to break down biogenic materials.

The composition of the LFG is dependent on the materials in the landfill, and other factors, but is typically made up of methane, carbon dioxide (CO_2), nitrogen (N_2), hydrogen, CO, oxygen (O_2), sulfides (e.g., hydrogen sulfide or H_2S), ammonia, and trace elements like amines, sulfurous compounds, and siloxanes. RNG production from LFG requires advanced treatment and upgrading of the biogas via removal of CO_2, H_2S, siloxanes, N_2, and O_2 to achieve a high-energy (Btu) content gas for pipeline injection. The table below summarizes landfill gas constituents, the typical concentration ranges in LFG, and commonly deployed upgrading technologies in use today.

Table 9. Landfill Gas Constituents and Corresponding Upgrading Technologies

LFG Constituent	Typical Concentration Range	Upgrading Technology for Removal
Carbon dioxide, CO_2	40% – 60%	▪ High-selectivity membrane separation ▪ Pressure swing adsorption (PSA) systems ▪ Water scrubbing systems ▪ Amine scrubbing systems
Hydrogen sulfide, H_2S	0 – 1%	▪ Solid chemical scavenging ▪ Liquid chemical scavenging ▪ Solvent adsorption ▪ Chemical oxidation-reduction
Siloxanes	<0.1%	▪ Non-regenerative adsorption ▪ Regenerative adsorption
Nitrogen, N_2 Oxygen, O_2	2% – 5% 0.1% – 1%	▪ PSA systems ▪ Catalytic removal (O_2 only)

To estimate the feedstock potential of LFG, ICF used outputs from the LandGEM model, which is an automated tool with a Microsoft Excel interface developed by the U.S. EPA to estimate the emissions rates for landfill gas and methane based on user inputs including waste-in-place (WIP), facility location and climate conditions, and waste received per year. The estimated LFG output was estimated on a facility-by-facility basis. About 1,150 facilities report methane content; for the facilities for which no data were reported, ICF assumed the median methane content of 49.6%.

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills, with 128 in Texas and included in the inventory.

The U.S. EPA's LMOP database shows that there are 30 operational, under construction or planned LFG-to-energy projects in Texas. 15 of the projects capture LFG and combust it in reciprocating engines to make electricity, 14 produce RNG, and one landfill has direct use for the energy (e.g., thermal use on-site).

The U.S. EPA currently estimates that there are 53 candidate landfills in Texas that could capture LFG for use as energy—the U.S. EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of WIP, and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

Table 10. Texas Landfills by Region[11]

Region	Landfills	Landfill-to-Energy Projects	EPA Candidate Landfills
Travis County	4	2	-
Other CTX	2	1	1
Rest of Texas	122	27	52
Texas	128	30	53

There are four large landfills in Travis County that have more than one million tons of WIP, as well as one in neighboring Williamson County, outlined in the table below. Due to the minimal and declining methane production of waste after 25 years in landfills, ICF typically only considers RNG potential from landfills that are either open or were closed post-2000.

Table 11. Landfills in CTX Service Area

Landfill	County	Status	Landfill-to-Energy	RNG Potential (MMBtu/year)
Austin Community RDF	Travis	Open	Electricity	2,115,000
Texas Disposal Systems LF	Travis	Open	Planned	1,549,000
Sunset Farms Landfill	Travis	Closed (2016)	Shutdown	2,138,000
FM 812 Landfill	Travis	Closed (1999)	Shutdown	N/A
Williamson County LF	Williamson	Open	Construction	892,000

The table below shows overall maximum RNG potential from LFG facilities in Travis County, surrounding CTX counties, and the rest of Texas.

Table 12. RNG Potential from Texas Landfills by Region

Region	Landfills	RNG Potential (MMBtu/y)
Travis County	3	5,803,000
Other CTX	1	892,000
Rest of Texas	94	98,461,000
Texas	98	105,156,000

Water Resource Recovery Facilities

Wastewater is created from residences and commercial or industrial facilities, and it consists primarily of waste liquids and solids from household water usage, from commercial water usage, or from industrial processes. Depending on the architecture of the sewer system and local regulation, it may also contain storm water from roofs, streets, or other runoff areas. The contents of the wastewater may include anything which is expelled (legally or not) from a

[11] Based on data from the LMOP at the U.S. EPA (updated December 2019).

household and enters the drains. If storm water is included in the wastewater sewer flow, it may also contain components collected during runoff: soil, metals, organic compounds, animal waste, oils, and solid debris such as leaves and branches.

Processing of the influent to a large water resource recovery facility (WRRF) is comprised typically of four stages: pre-treatment, primary, secondary, and tertiary treatments. These stages consist of mechanical, biological, and sometimes chemical processing.

- Pre-treatment removes all the materials that can be easily collected from the raw wastewater that may otherwise damage or clog pumps or piping used in treatment processes.
- In the primary treatment stage, the wastewater flows into large tanks or settling bins, thereby allowing sludge to settle while fats, oils, or greases rise to the surface.
- The secondary treatment stage is designed to degrade the biological content of the wastewater and sludge, and is typically done using water-borne micro-organisms in a managed system.
- The tertiary treatment stage prepares the treated effluent for discharge into another ecosystem, and often uses chemical or physical processes to disinfect the water.

The treated sludge from the WRRF can be landfilled, and during processing it can be treated via anaerobic digestion, thereby producing methane which can be used for beneficial use with the appropriate capture and conditioning systems put in place.

To determine the WRRFs in Texas, ICF used the Clean Watersheds Needs Survey (CWNS) conducted in 2012 by the U.S. EPA, an assessment of capital investment needed for wastewater collection and treatment facilities to meet the water quality goals of the Clean Water Act, and includes more than 14,500 WRRFs. ICF distinguishes between facilities based on location and facility size as a measure of average flow (in units of million gallons per day, MGD). ICF also reviewed more than 1,200 facilities that are reported to have anaerobic digesters in place, as reported by the Water Environment Federation.

To estimate the amount of RNG produced from wastewater at WRRFs, ICF used data reported by the U.S. EPA,[12] a study of WRRFs in New York State,[13] and previous work published by AGF.[14] ICF used an average energy yield of 7.003 MMBtu/MG of wastewater.

There are 551 WRRFs in Texas, with a total flow of over 1,850 MGD. There are 13 WRRFs in Travis County, representing flow of 100 MGD, with a further 16 WRRFs in the surrounding CTX counties, but 15 of these are small WRRFs with a combined flow of 15 MGD.

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[12] US EPA, Opportunities for Combined Heat and Power at Wastewater Treatment Facilities, October 2011. Available online here.

[13] Wightman, J and Woodbury, P., Current and Potential Methane Production for Electricity and Heat from New York State Wastewater Treatment Plants, New York State Water Resources Institute at Cornell University. Available online here.

[14] AGF, The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, September 2011.

Of the 551 WRRFs, 35 have anaerobic digestion systems with a total flow of 680 MGD, or 38% of Texas's total flow. None of these WRRFs with anaerobic digestion systems are in Travis County or the surrounding CTX counties. The table summarizes WRRFs by flow and RNG potential.

Table 13. Texas WRRFs by Existing Flow [15]

Region	Large WRRFs (>7.25 MGD)	Small WRRFs (<7.25 MGD)	Total Flow (MGD)	RNG Potential (MMBtu/y)
Travis County	3	10	100.6	257,000
Other CTX	1	15	31.2	80,000
Rest of Texas	41	481	1,719.2	4,395,000
Texas	45	506	1,850.9	4,731,000

RNG: Thermal Gasification of Biogenic or Renewable Resources

The biomass feedstocks for RNG production potential via thermal gasification include agricultural residues, energy crops, forestry and forest product residues, and the non-biogenic fraction of MSW. Given that biomass gasification technology is at an early stage of commercialization, RNG production potential for these feedstocks cannot be determined to a facility-specific level, in contrast to other feedstocks such as LFG and WRRFs. However, sources of thermal gasification feedstocks can be approximated at a regional level based on existing land use patterns and population levels. The specific approach for each feedstock is outlined below.

To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems. This factor is based in part on the 2011 AGF Report on RNG, indicating a range of thermal gasification efficiencies in the range of 60% to 70%, depending upon the configuration and process conditions. The report authors also used a conversion efficiency of 65% in their assessment. More recently, GTI estimated the potential for RNG from the thermal gasification of wood waste in California, and assumed a conversion efficiency of 60%.[16]

Agricultural Residues

Agricultural residues include the material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. More specifically, this resource is inclusive of the unusable portion of crop, stalks, stems, leaves, branches, and seed pods. Agricultural residues (and sometimes crops) are often added to anaerobic digesters.

ICF extracted information from the U.S. DOE Bioenergy KDF, including the following agricultural residues relevant to Texas: corn stover, sorghum stubble and wheat straw. These estimates are based on modeling undertaken as part of the 2016 Billion Ton Study, and utilizes the Policy

[15] Based on data from the LMOP at the U.S. EPA (updated December 2019).
[16] GTI, Low-Carbon Renewable Natural Gas from Wood Wastes, February 2019, available online at https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf

Analysis System (POLYSYS), a policy simulation model of the U.S. agricultural sector. The POLYSYS modeling framework simulates how commodity markets balance supply and demand via price adjustments based on known economic relationships, and is intended to reflect how agricultural producers respond to new and different agricultural market opportunities, such as for biomass. Available biomass is constrained to not exceed the tolerable soil loss limit of the USDA Natural Resources Conservation Service and to not allow long-term reduction of soil organic carbon

POLYSYS simulates exogenous price changes introduced as a farmgate price, which then solves for biomass supplies that may be brought to market in response to these prices. The farmgate price is held constant nationwide in all counties over all years of the simulation to allow farmers to respond by changing crops and practices gradually over time. [17]

Agricultural residue volumes are then derived from these estimates at a county level, and reflect total aboveground biomass produced as byproducts of conventional crops, and then limited by sustainability and economic constraints. Not all agricultural residues are made available, as crop residues often provide important environmental benefits, such as protection from wind and water erosion, maintenance of soil organic carbon, and soil nutrient recycling.

In the simulations no land use change is assumed to occur, except within the agricultural sector (i.e. forested land is not converted to agricultural land for agricultural residue or energy crop purposes).

ICF extracted data from the Bioenergy KDF at $10 price point increments, from $30/ton to $100/ton, that showed variation in production potential for agricultural residue biomass from 2025 out to 2040.

The table below lists the energy content on a higher heating value (HHV) basis for the various agricultural residues included in the analysis. The energy content is based on values reported by the California Biomass Collaborative.

Table 14. Heating Values for Agricultural Residues

Agricultural Component	Btu/lb, dry	MMBtu/ton, dry
Corn stover	7,587	15.174
Sorghum stubble	6,620	13.240
Wheat straw	7,527	15.054

Agricultural residue is distributed proportionally by county based on state share of farmland, with total acreage of agricultural land in Texas taken from the USDA 2017 Census of Agriculture. Travis County accounts for 0.2% of farmland in Texas, while the surrounding CTX counties make up an another 2.1%. The table below shows an annotated summary of the maximum agricultural residue potential at different biomass prices in 2050, broken down by region.

[17] DOE, 2016. 2016 Billion Ton Report, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.

Table 15. Agricultural Residue Production Potential in 2050 by Region (dry tons)

Region	Biomass Price $30	Biomass Price $50	Biomass Price $100
Travis County	6,336	7,959	8,556
Other CTX	71,742	90,108	96,868
Rest of Texas	3,298,633	4,143,086	4,453,926
Texas	3,376,711	4,241,152	4,559,350

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from agricultural residue feedstocks at the different biomass prices in 2050, broken down by region.

Table 16. Agricultural Residue RNG Production Potential in 2050 by Region (MMBtu/y)

Region	Biomass Price $30	Biomass Price $50	Biomass Price $100
Travis County	61,446	77,395	83,142
Other CTX	695,696	876,273	941,343
Rest of Texas	31,987,531	40,290,312	43,282,144
Texas	32,744,674	41,243,981	44,306,629

Energy Crops

Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. Energy crop estimates are based on the same modeling framework used to derive the agricultural residue estimates, outlined in the previous section. With respect to land use, rather than shifting existing agricultural production (e.g. corn and soy) to energy crop production, DOE's modeling also shows that energy crops are largely grown on idle or available pasture lands, particularly at lower farmgate prices. ICF extracted data from the Bioenergy KDF at $10 price point increments, from $30/ton to $100/ton that showed variation in production potential for energy crops from 2025 out to 2040.

The table below lists the energy content on an HHV basis for the various energy crops relevant to Texas.

Table 17. Heating Values for Energy Crops

Energy Crop	Btu/lb, dry	MMBtu/ton, dry
Biomass sorghum	7,240	14.48
Miscanthus	7,900	15.80
Poplar	7,775	15.55
Switchgrass	7,929	15.86
Willow	8,550	17.10

Similar to the approach taken above for agricultural residue, energy crop production is distributed proportionally by county based on state share of farmland, with total acreage of agricultural land in Texas taken from the USDA 2017 Census of Agriculture. Travis County accounts for 0.2% of farmland in Texas, while the surrounding CTX counties make up an another 2.1%. The table below shows the maximum energy crop production potential broken down by region.

Table 18. Energy Crop Production Potential in 2050 by Region (dry tons)

Region	Biomass Price $30	Biomass Price $40	Biomass Price $60	Biomass Price $100
Travis County	6,805	120,818	275,675	293,480
Other CTX	77,046	1,367,913	3,121,209	3,322,804
Rest of Texas	3,542,527	62,895,492	143,510,579	152,779,739
Texas	3,626,378	64,384,223	146,907,462	156,396,023

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from energy crop feedstocks at the different biomass prices in 2050, broken down by region.

Table 19. Energy Crop RNG Production Potential in 2050 by Region (MMBtu/y)

Region	Biomass Price $30	Biomass Price $40	Biomass Price $60	Biomass Price $100
Travis County	70,097	1,242,015	2,829,669	3,005,823
Other CTX	793,641	14,062,192	32,037,735	34,032,171
Rest of Texas	36,490,936	64,567,850	1,473,068,324	1,564,770,826
Texas	37,354,674	661,872,057	1,507,935,728	1,601,808,820

Forestry and Forest Product Residues

Forestry and forest product residues includes biomass generated from logging, forest and fire management activities, and milling. Logging residues (e.g., bark, stems, leaves, branches), forest thinnings (e.g., removal of small trees to reduce fire danger), and mill residues (e.g., slabs, edgings, trimmings, sawdust) are also considered in the analysis. This includes materials from public forestlands (e.g., state, federal), but not specially designated forests (e.g., roadless areas, national parks, wilderness areas) and includes sustainable harvesting criteria as described in the U.S. DOE Billion Ton Update. The updated DOE Billion Ton study was altered to include additional sustainability criteria. Some of the changes included: [18]

- Alterations to the biomass retention levels by slope class (e.g., slopes with between 40% and 80% grade included 40% biomass left on-site, compared to the standard 30%).

[18] DOE, 2011. *2011 Billion Ton Update – Assumptions and Implications Involving Forest Resources*, http://web.ornl.gov/sci/ees/cbes/workshops/Stokes_B.pdf

- Removal of reserved (e.g., wild and scenic rivers, wilderness areas, USFS special interest areas, national parks) and roadless designated forestlands, forests on steep slopes and in wet land areas (e.g., stream management zones), and sites requiring cable systems.
- The assumptions only include thinnings for over-stocked stands and didn't include removals greater than the anticipated forest growth in a state.
- No road building greater than 0.5 miles.

These additional sustainability criteria provide a more realistic assessment of available forestland than other studies.

ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). The Bioenergy KDF estimates are based on ForSEAM, a linear programming model constructed to estimate forestland production over time, including for both traditional forest products but also products that meet biomass feedstock demands. The model assumes that projected traditional timber demands will be met and estimates costs, land use, and competition between lands. The forestry and forest product residue estimates also reflect a cost minimization framework that minimizes the total costs (harvest costs and other costs) under a production target goal in addition to land, growth, and other constraints. The cost minimization framework includes the POLYSYS model as well as IMPLAN, an input-output model that estimates impacts to the economy.

ICF extracted data from the Bioenergy KDF at three price points, $30/ton, $50/ton and $60/ton, that showed variation in production potential for forest and forest product residue biomass from 2025 out to 2040.

The table below lists the energy content on an HHV basis for the various forest and forest product residue elements considered in the analysis. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 20. Heating Values for Forestry and Forest Product Residues

Forestry and Forest Product	Btu/lb, dry	MMBtu/ton, dry
Other forest residue	8,597	17.19
Other forest thinnings	9,027	18.05
Primary mill residue	8,597	17.19
Secondary mill residue	8,597	17.19
Mixedwood, residue	6,500	13.00
Hardwood, lowland, residue		
Hardwood, upland, residue		
Softwood, natural, residue		
Softwood, planted, residue		

The table below shows the maximum forestry and forest product residue potential broken down by region at different biomass price points. Based on data extracted from Bioenergy KDF, there are no forestry operations or forestry residues available for RNG production in Travis County, or surrounding CTX counties, although there are potential production volumes elsewhere in Texas.

Table 21. Forestry and Forest Product Residue Production Potential in 2050 by Region (dry tons)

Region	Biomass Price $30	Biomass Price $50	Biomass Price $60
Travis County	-	-	-
Other CTX	-	-	-
Rest of Texas	913,597	1,323,754	1,918,261
Texas	913,597	1,323,754	1,918,261

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from forestry and forest product residue feedstocks at the different biomass prices in 2050, broken down by region.

Table 22. Forestry and Forest Product Residue RNG Production Potential in 2050 by Region (MMBtu/y)

Region	Biomass Price $30	Biomass Price $50	Biomass Price $100
Travis County	-	-	-
Other CTX	-	-	-
Rest of Texas	7,719,895	11,387,059	16,702,475
Texas	7,719,895	11,387,059	16,702,475

Municipal Solid Waste

MSW represents the trash and various items that household, commercial, and industrial consumers throw away—including materials such as glass, construction and demolition (C&D) debris, food waste, paper and paperboard, plastics, rubber and leather, textiles, wood, and yard trimmings. About 25% of MSW is currently recycled, 9% is composted, and 13% is combusted for energy recovery, with the roughly 50% balance landfilled.

ICF limited our consideration to the potential for utilizing MSW that is currently landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities.

ICF extracted information from the U.S. DOE's Bioenergy KDF, which includes information collected as part of U.S. DOE's Billion Ton Report (updated in 2016). The Bioenergy KDF includes the following waste residues: construction and demolition (C&D) debris, paper and paperboard, plastics, rubber and leather, textiles, wood, yard trimmings, and other. ICF extracted data from the Bioenergy KDF at price points between $30/ton and $70/ton.

The table below lists the energy content on an HHV basis for the various components of MSW relevant to Texas. To estimate the RNG production potential, ICF assumed a 65% efficiency for thermal gasification systems.

Table 23. Heating Values for MSW Components

MSW Component	Btu/lb, dry	MMBtu/ton, dry
Paper and paperboard	7,642	15.28
Plastics	19,200	38.40
Rubber and leather	11,300	22.60
Textiles	8,000	16.00
Yard trimmings	6,448	12.90

The table below shows the maximum MSW potential broken down by region at a price of $70/ton. Regional proportions are based on population weighting by region in Texas, as MSW generation is typically tied to population levels. Travis County accounts for 4.4% of Texas's population, with the surrounding CTX counties making up another 3.4%.

Table 24. MSW Production Potential at $70 by Region (dry tons)

Region	Paper & Paperboard	Plastics	Rubber & Leather	Textiles	Yard Trimmings	Total
Travis County	58,813	72,995	16,084	29,991	14,846	192,729
Other CTX	42,728	53,031	11,685	21,789	10,786	140,019
Rest of Texas	1,237,076	1,535,380	338,304	630,827	312,281	4,053,868
Texas	1,338,617	1,661,407	366,073	682,606	337,913	4,386,616

Using the heating values outlined above and assuming a 65% efficiency for thermal gasification systems, ICF estimated the RNG production potential from MSW at a price of $70/ton, broken down by region.

Table 25. RNG Production Potential from MSW at $70 by Region (MMBtu/y)

Region	Paper & Paperboard	Plastics	Rubber & Leather	Textiles	Yard Trimmings	Total
Travis County	584,131	1,821,957	236,269	311,904	124,487	3,078,748
Other CTX	447,792	1,396,703	181,123	239,104	95,431	2,360,154
Rest of Texas	12,263,220	38,250,059	4,960,221	6,548,094	2,613,482	64,635,076
Texas	13,295,144	41,468,719	5,377,612	7,099,102	2,833,401	70,073,978

3. RNG Supply Curves

Supply Curve Methodology

ICF developed economic supply curves for three separate scenarios for each feedstock included in the RNG inventory in Section 2.

The RNG potential included in the supply curves are based on an assessment of resource availability. In a competitive market, that resource availability is a function of multiple factors, including but not limited to demand, feedstock costs, technological development, and the policies in place that might support RNG project development. ICF assessed the RNG resource potential of the different feedstocks that could be realized, given the necessary market considerations (without explicitly defining what those are).

For the RNG market more broadly, ICF assumed that the market would grow at a compound annual growth rate slightly higher than we have seen over the last five years—a rate of about 35%.[19] ICF applied a logistic function to model the growth potential of the RNG production, whereby the initial stage of growth is approximated as an exponential, and thereafter growth slows to a linear rate and then approaches a plateau (or limited to no growth) at maturity.

Scenarios

ICF developed three scenarios for each feedstock—with variations among conservative, balanced, and aggressive assumptions regarding utilization of the feedstock.

- **Limited Adoption** represents a low level of feedstock utilization, with utilization levels depending on feedstock, with a range from 15% to 40% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 20% to 30%, at lower biomass prices. Overall, the Limited Adoption scenario captures 7% of the RNG feedstock resource in the CTX Service Area, based on the inventory developed in Section 2.
- **Achievable Deployment** represents balanced assumptions regarding feedstock utilization, with a range from 25% to 65% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranges from 20% to 50% at low to medium biomass prices. Overall, the Achievable Deployment scenario captures 25% of the RNG feedstock resource available in the CTX Service Area.

[19] ICF estimates that there were about 17,500,000 MMBtu of RNG produced for pipeline injection in 2016 and that there will be about 50,000,000 MMBtu of RNG produced for pipeline injection be the end of 2020—this yields a compound annual growth rate of about 30%.

- **Optimistic Growth** represents higher levels of utilization, and delivers 31% of the technical potential of RNG feedstocks in the CTX Service Area. Utilization levels vary by feedstock, with a range from 30% to 80% for feedstocks that were converted to RNG using anaerobic digestion technologies. The utilization rates of feedstocks for thermal gasification in this scenario ranged from 20% to 70% at higher biomass prices. It is worth reiterating that the Optimistic Growth scenario does not represent a maximum achievable or technical potential scenario.

In the following sub-sections, ICF outlines the potential for RNG for pipeline injection, broken down by the feedstocks presented previously and considering the potential for RNG growth over time, with 2050 being the final year in the analysis. ICF presents the Limited Adoption, Achievable Deployment and Optimistic Growth RNG production scenarios, varying both the assumed utilization of existing resources as well as the rate of project development required to deploy RNG at the volumes presented.

Geography

Consistent with Section 2, we present RNG potential at the local, regional and state levels. The local level is defined as Travis County, and regional encompasses the surrounding counties that broadly reflect ONE Gas's Central Texas Service Area (CTX) – Caldwell, DeWitt, Gonzales, Hays, Lavaca, Williamson and Wilson.

ICF also includes separate estimates for the rest of Texas and nationally. These estimates are weighted by the share of natural gas consumption of ONE Gas's CTX Service Area (including Travis County) relative to the applicable geography. Natural gas consumption estimates are sourced from the EIA and include residential, commercial, industrial and transportation consumption.

Summary of RNG Potential by Geography

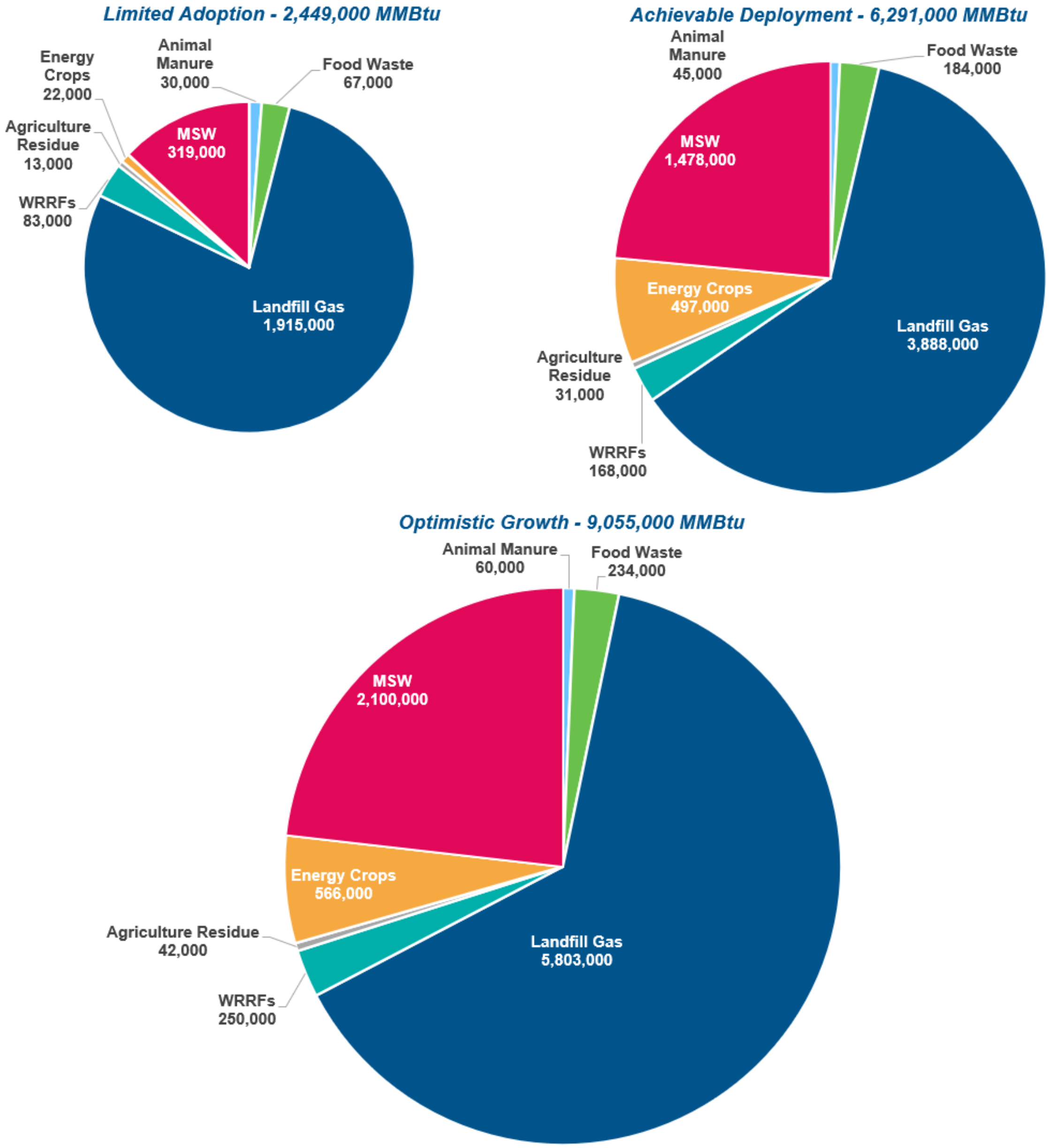
The following subsections summarize the RNG potential for each feedstock and production technology by scenario and geography of interest.

Travis County

The figure below includes estimates for Travis County for the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios, and shows the development potential of each feedstock in 2050, reported in units of million Btu per year (MMBtu/y).

Travis County's RNG resources are focused on waste in an urbanized region, including landfills, WRRFs, food waste, and MSW. Conversely, the local area is resource-limited for specific feedstocks—such as animal manure, agricultural residues, forestry and forest product residues, and energy crops—because it is a predominantly urbanized area. Despite the lack of these resources locally, the local area's access to waste from landfills, wastewater, the potential for diverted food waste, and MSW streams can still provide a significant amount of RNG as part of a broader decarbonization focus.

Figure 2. Estimated Annual RNG Production in Travis County by 2050 (MMBtu/y)



The Limited Adoption scenario captures less than 20% of the total resource available, as outlined in the inventory as part of Task 1. This proportions increases to nearly 50% in the Achievable Deployment scenario, and rising again to 70% in the Optimistic Growth scenario.

ONE Gas Central Texas Service Area

The table below includes estimates for ONE Gas's CTX Service Area, including Travis County, for the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios. The table shows the development potential of each feedstock in 2050, reported in units of MMBtu/y. For reference, with total throughput in ONE Gas's Central Texas natural gas system at roughly 23,300,000 MMBtu in 2019, local RNG resources could displace up to 75% of natural gas consumption in the Achievable Deployment scenario without accessing any potential RNG resources from outside the immediate region.

Expanding the geography to the CTX Service Area delivers greater volumes of RNG feedstocks in all scenarios, with the Achievable Deployment and Optimistic Growth scenarios more than doubling the potential RNG available relative to the same scenarios limited to Travis County. With the inclusion of the surrounding less urbanized counties, animal manure and energy crops become important potential sources of RNG.

Table 26. Estimated Annual RNG Production in CTX Service Area by 2050 (MMBtu/y)

RNG Feedstock		Scenario		
		Limited Adoption	Achievable Deployment	Optimistic Growth
Anaerobic Digestion	Animal Manure	1,190,000	1,785,000	2,379,000
	Food Waste	95,000	312,000	398,000
	LFG	1,915,000	4,780,000	6,695,000
	WRRFs	82,000	209,000	307,000
Thermal Gasification	Agricultural Residue	151,000	381,000	512,000
	Energy Crops	259,000	6,122,000	6,973,000
	Forestry and Forest Product Residue	-	-	-
	Municipal Solid Waste	563,000	2,609,000	3,709,000
Total		**4,255,000**	**16,198,000**	**20,973,000**
Percentage of Total Available Feedstock[20]		**6.5%**	**24.6%**	**31.9%**

[20] Total feedstock reflects the maximum volume of RNG feedstocks available in the CTX Service Area, including all facilities and all biomass.

Rest of Texas

Table 27 below includes estimates for the rest of Texas for the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios, and excludes the above RNG estimates for the CTX Service Area. The estimates are weighted by the share of natural gas consumption of ONE Gas's CTX Service Area (including Travis County) relative to Texas's total, a share of roughly 1% based on Texas's natural gas consumption of approximately 2,250 bcf in 2018.[21] Table 27 also shows the development potential of each feedstock in 2050, reported in units of MMBtu/y.

Table 27. Estimated Annual RNG Production in the Rest of Texas by 2050 (MMBtu/y)

RNG Feedstock		Scenario		
		Limited Adoption	Achievable Deployment	Optimistic Growth
Anaerobic Digestion	Animal Manure	188,000	282,000	376,000
	Food Waste	10,000	40,000	51,000
	LFG	244,000	488,000	650,000
	WRRFs	13,000	19,000	23,000
Thermal Gasification	Agricultural Residue	63,000	160,000	215,000
	Energy Crops	72,000	1,282,000	2,921,000
	Forestry and Forest Product Residue	23,000	56,000	99,000
	Municipal Solid Waste	66,000	307,000	437,000
Total		**680,000**	**2,635,000**	**4,772,000**
Percentage of Total Available Feedstock[22]		**0.03%**	**0.13%**	**0.23%**

[21] EIA, 2020. https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm
[22] Total feedstock reflects the maximum volume of RNG feedstocks available in Texas, including all facilities and all biomass.

National

Table 28 below includes estimates for the U.S., excluding Texas, for the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios. The estimates are weighted by the share of natural gas consumption of ONE Gas's CTX Service Area relative to the U.S. total, equivalent to a share of roughly 0.1%. The table also shows the development potential of each feedstock in 2050, reported in units of MMBtu/y.

Table 28. Estimated Annual RNG Production in the U.S. (excl Texas) by 2050 (MMBtu/y)

RNG Feedstock		Scenario		
		Limited Adoption	Achievable Deployment	Optimistic Growth
Anaerobic Digestion	Animal Manure	795,000	1,192,000	1,589,000
	Food Waste	51,000	100,000	128,000
	LFG	1,294,000	1,392,000	1,746,000
	WRRFs	63,000	92,000	112,000
Thermal Gasification	Agricultural Residue	363,000	741,000	906,000
	Energy Crops	479,000	703,000	1,759,000
	Forestry and Forest Product Residue	219,000	350,000	447,000
	Municipal Solid Waste	306,000	608,000	949,000
Total		**3,571,000**	**5,180,000**	**7,635,000**
Percentage of Total Available Feedstock[23]		**0.03%**	**0.04%**	**0.06%**

[23] Total feedstock reflects the maximum volume of RNG feedstocks available in the U.S. excluding Texas, including all facilities and all biomass.

Summary of RNG Potential by Scenario

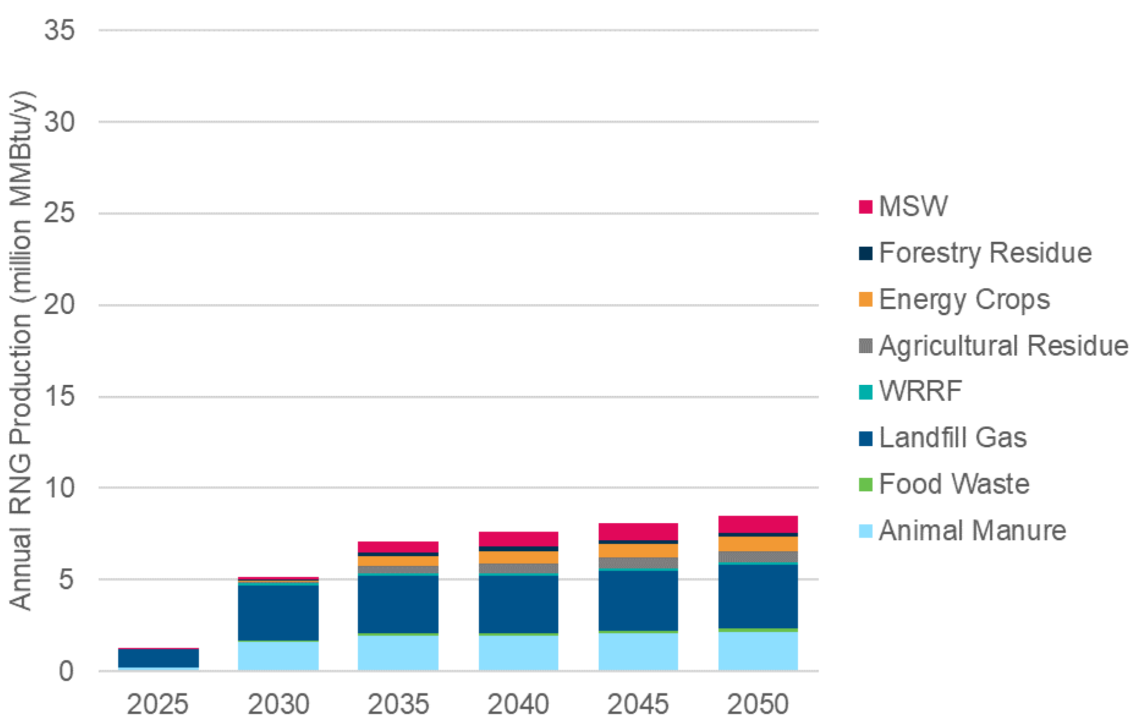
The following subsections show the total RNG potential for each feedstock and production technology by geography for each scenario.

Limited Adoption Scenario

Table 29. Limited Adoption Scenario Annual RNG Production (MMBtu/y)

RNG Feedstock		Geography				
		Travis County	Other CTX	Rest of Texas	Rest of US	Total
Anaerobic Digestion	Animal Manure	30,000	1,160,000	188,000	795,000	**2,173,000**
	Food Waste	67,000	28,000	10,000	51,000	**156,000**
	LFG	1,915,000	0	244,000	1,294,000	**3,453,000**
	WRRFs	82,000	0	13,000	63,000	**159,000**
Thermal Gasification	Agricultural Residue	12,000	139,000	63,000	363,000	**578,000**
	Energy Crops	21,000	238,000	72,000	479,000	**811,000**
	Forestry Residue	0	0	23,000	219,000	**242,000**
	MSW	318,000	244,000	66,000	306,000	**934,000**
Total		**2,446,000**	**1,809,000**	**680,000**	**3,571,000**	**8,506,000**

Figure 3. Estimated Annual RNG Production, Limited Adoption Scenario (million MMBtu/y)

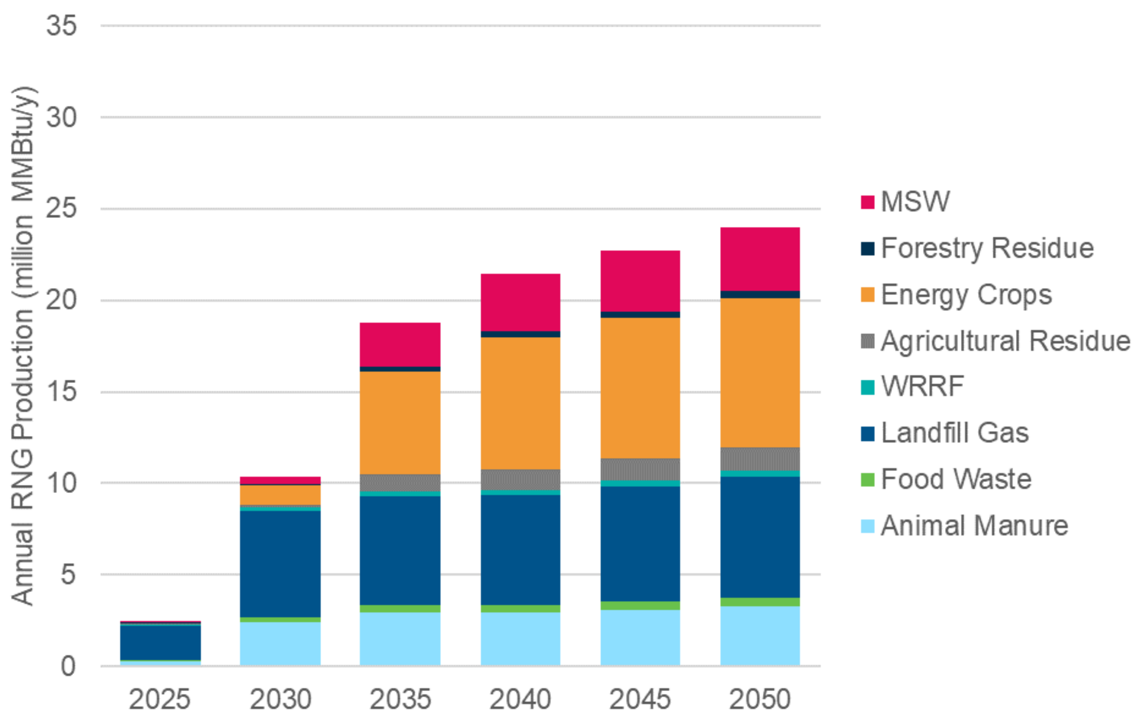


Achievable Deployment Scenario

Table 30. Achievable Deployment Scenario Annual RNG Production (MMBtu/y)

RNG Feedstock		Geography				
		Travis County	Other CTX	Rest of Texas	Rest of US	Total
Anaerobic Digestion	Animal Manure	45,000	1,740,000	282,000	1,192,000	**3,259,000**
	Food Waste	184,000	129,000	40,000	100,000	**453,000**
	LFG	3,888,000	892,000	488,000	1,392,000	**6,660,000**
	WRRFs	167,000	41,000	19,000	92,000	**320,000**
Thermal Gasification	Agricultural Residue	31,000	351,000	160,000	741,000	**1,283,000**
	Energy Crops	497,000	5,625,000	1,282,000	703,000	**8,107,000**
	Forestry Residue	0	0	56,000	350,000	**407,000**
	MSW	1,477,000	1,132,000	307,000	608,000	**3,525,000**
Total		**6,289,000**	**9,910,000**	**2,635,000**	**5,180,000**	**24,014,000**

Figure 4. Estimated Annual RNG Production, Achievable Deployment Scenario (million MMBtu/y)

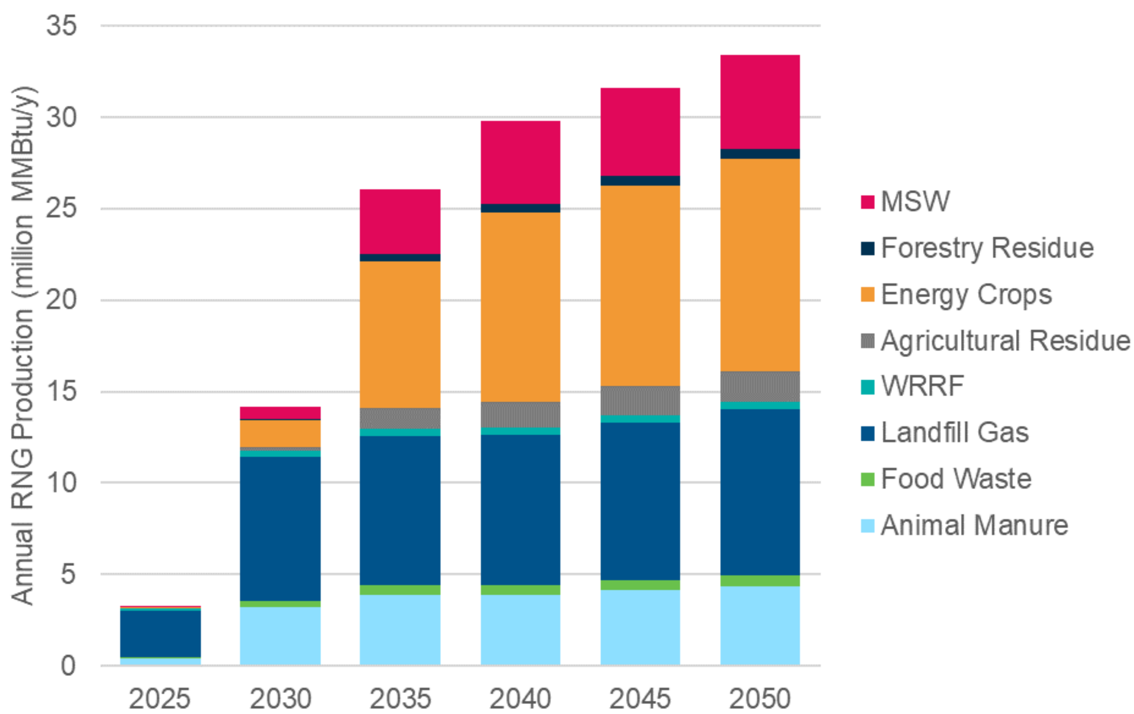


Optimistic Growth Scenario

Table 31. Optimistic Growth Scenario Annual RNG Production (MMBtu/y)

RNG Feedstock		Geography				
		Travis County	Other CTX	Rest of Texas	Rest of US	Total
Anaerobic Digestion	Animal Manure	60,000	2,320,000	376,000	1,589,000	**4,344,000**
	Food Waste	234,000	164,000	51,000	128,000	**577,000**
	LFG	5,803,000	892,000	650,000	1,746,000	**9,092,000**
	WRRFs	250,000	57,000	23,000	112,000	**441,000**
Thermal Gasification	Agricultural Residue	42,000	471,000	215,000	906,000	**1,633,000**
	Energy Crops	566,000	6,408,000	2,921,000	1,759,000	**11,653,000**
	Forestry Residue	0	0	99,000	447,000	**547,000**
	MSW	2,099,000	1,609,000	437,000	949,000	**5,094,000**
Total		**9,053,000**	**11,920,000**	**4,772,000**	**7,635,000**	**33,381,000**

Figure 5. Estimated Annual RNG Production, Optimistic Growth Scenario (million MMBtu/y)



RNG: Anaerobic Digestion of Biogenic or Renewable Resources

Animal Manure

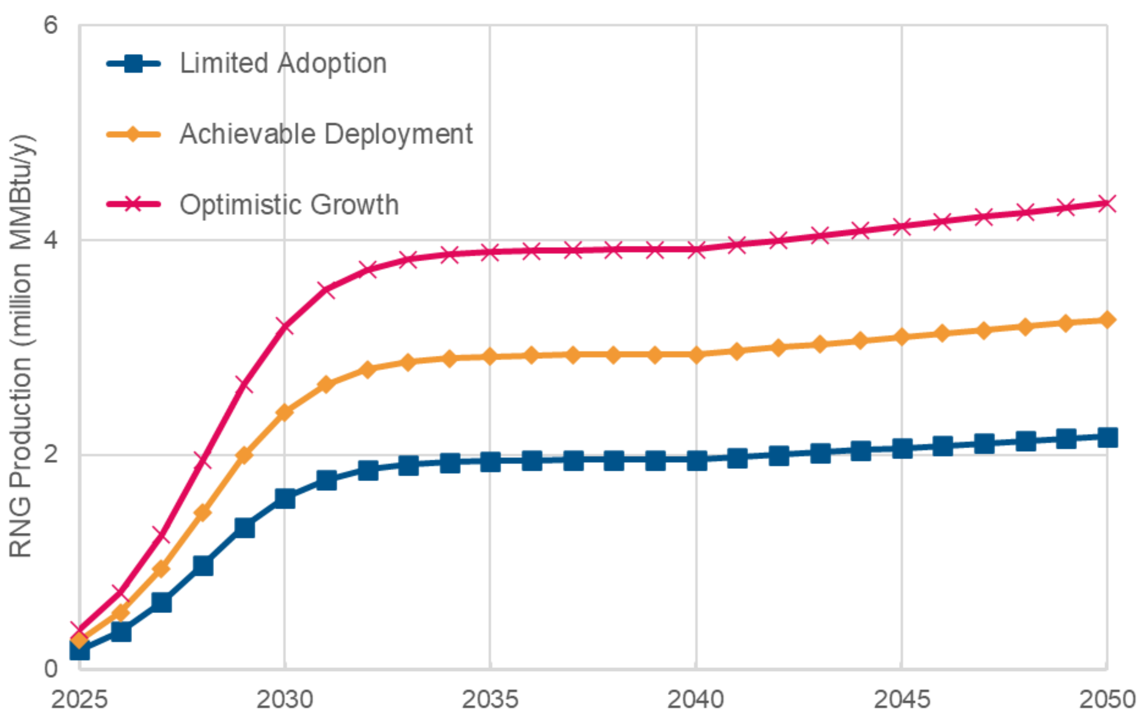
Prior to the application of economic and market constraints for animal manure as an RNG feedstock, ICF applied technical availability factors to each manure type to reflect that not all animal manure can be collected, due to practical considerations such as small farming operations and the inability to collect manure from grazing animals. After applying these technical availability factors for each animal manure type, the total available animal manure potential is reduced by over half.

ICF developed the following assumptions for resource potentials for RNG production from the anaerobic digestion of animal manure in the three scenarios.

- In the Limited Adoption scenario, ICF assumed that RNG could be produced from 30% of the animal manure, after accounting for the technical availability factor.
- In the Achievable Deployment scenario, ICF assumed that RNG could be produced from 45% of the animal manure, after accounting for the technical availability factor.
- In the Optimistic Growth scenario, ICF assumed that RNG could be produced from 60% of the animal manure, after accounting for the technical availability factor.

The figure below shows the Limited Adoption, Achievable Deployment and Optimistic Growth resource potential from animal manure between 2025 and 2050.

Figure 6. Annual RNG Production Potential from Animal Manure (million MMBtu/y)



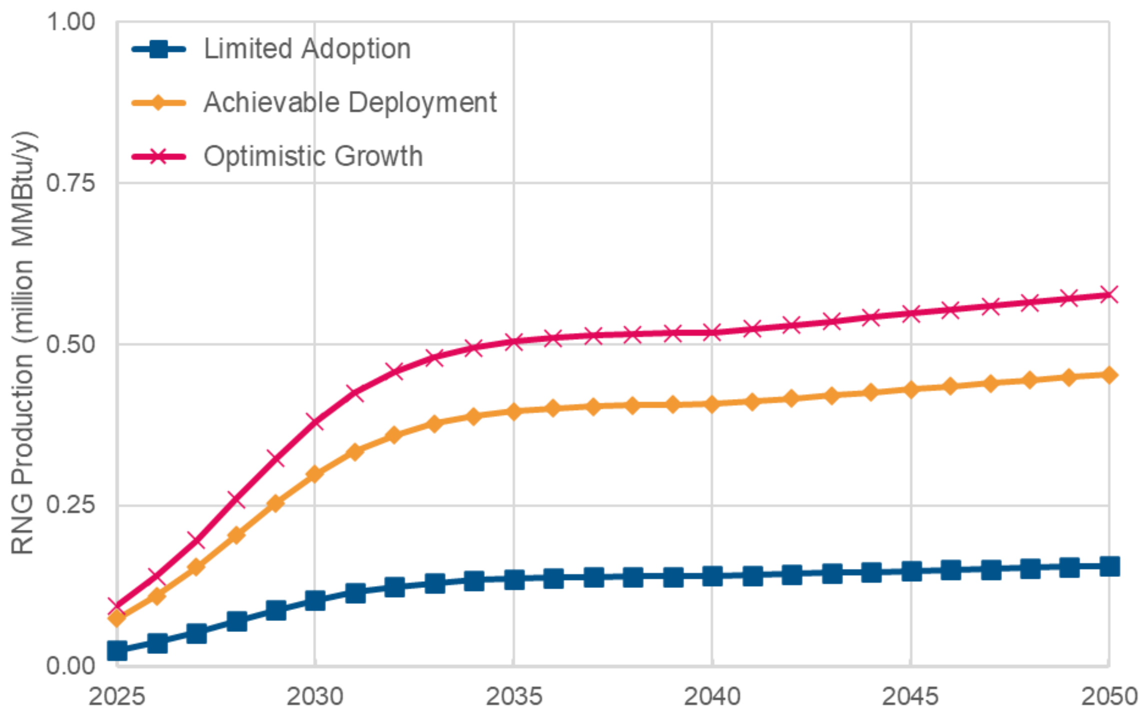
Food Waste

ICF developed the following assumptions for the RNG production potential from food waste in the three scenarios:

- In the Limited Adoption scenario, ICF assumed that 40% of available food waste would be diverted to AD systems.
- In the Achievable Deployment scenario, ICF assumed that 55% of available food waste would be diverted to AD systems.
- In the Optimistic Growth scenario, ICF assumed that 70% of available food waste would be diverted to AD systems.

The figure below shows the Limited Adoption, Achievable Deployment and Optimistic Growth RNG resource potential scenarios from the anaerobic digestion of food waste between 2025 and 2050.

Figure 7. Annual RNG Production Potential from Food Waste (million MMBtu/y)



Landfill Gas

To develop the RNG potential from LFG, ICF extracted data from the Landfill Methane Outreach Program (LMOP) administered by the U.S. EPA, which included more than 2,000 landfills, with 128 in Texas and included in the inventory.

The U.S. EPA's LMOP database shows that there are 30 operational, under construction or planned LFG-to-energy projects in Texas. 15 of the projects capture LFG and combust it in reciprocating engines to make electricity, 14 produce RNG, and one landfill has direct use for the energy (e.g., thermal use on-site).

The U.S. EPA currently estimates that there are 53 candidate landfills in Texas that could capture LFG for use as energy—the U.S. EPA characterizes candidate landfills as those that are accepting waste or have been closed for five years or less, have at least one million tons of WIP, and do not have operational, under-construction, or planned projects. Candidate landfills can also be designated based on actual interest by the site.

Table 32. Texas Landfills by Region[24]

Region	Landfills	Landfill-to-Energy Projects	EPA Candidate Landfills
Travis County	4	2	-
Other CTX	2	1	1
Rest of Texas	122	27	52
Texas	128	30	53

There are four large landfills in Travis County that have more than one million tons of WIP, as well as one in neighboring Williamson County, outlined in the table below. Due to the minimal and declining methane production of waste after 25 years in landfills, ICF typically only considers RNG potential from landfills that are either open or were closed post-2000.

Table 33. Landfills in CTX Service Area

Landfill	County	Status	Landfill-to-Energy	RNG Potential (MMBtu/year)
Austin Community RDF	Travis	Open	Electricity	2,115,000
Texas Disposal Systems LF	Travis	Open	Planned	1,549,000
Sunset Farms Landfill	Travis	Closed (2016)	Shutdown	2,138,000
FM 812 Landfill	Travis	Closed (1999)	Shutdown	N/A
Williamson County LF	Williamson	Open	Construction	892,000

Due to the minimal and declining methane production of waste after 25 years in landfills, in building the scenarios ICF considered only landfills that are either open or were closed post-2000. This reduced the number of landfills included in our analysis to 30.

ICF developed assumptions for the resource potentials for RNG production at landfills in the three scenarios, considering the potential at LFG facilities with collection systems in place, LFG facilities that do not have collection systems in place, and candidate landfills identified by the U.S. EPA. As the number of eligible LFG facilities varies significantly by region, ICF applied different proportional limitations depending on the geography, as outlined below.

- In the Limited Adoption scenario, ICF assumed that one of the three LFG facilities in Travis County produce RNG, the candidate landfill in Williamson County does not produce RNG. In the rest of Texas a quarter of LFG facilities across the three categories are assumed to produce RNG. For the rest of the U.S., ICF assumed that RNG could be produced at 40% of

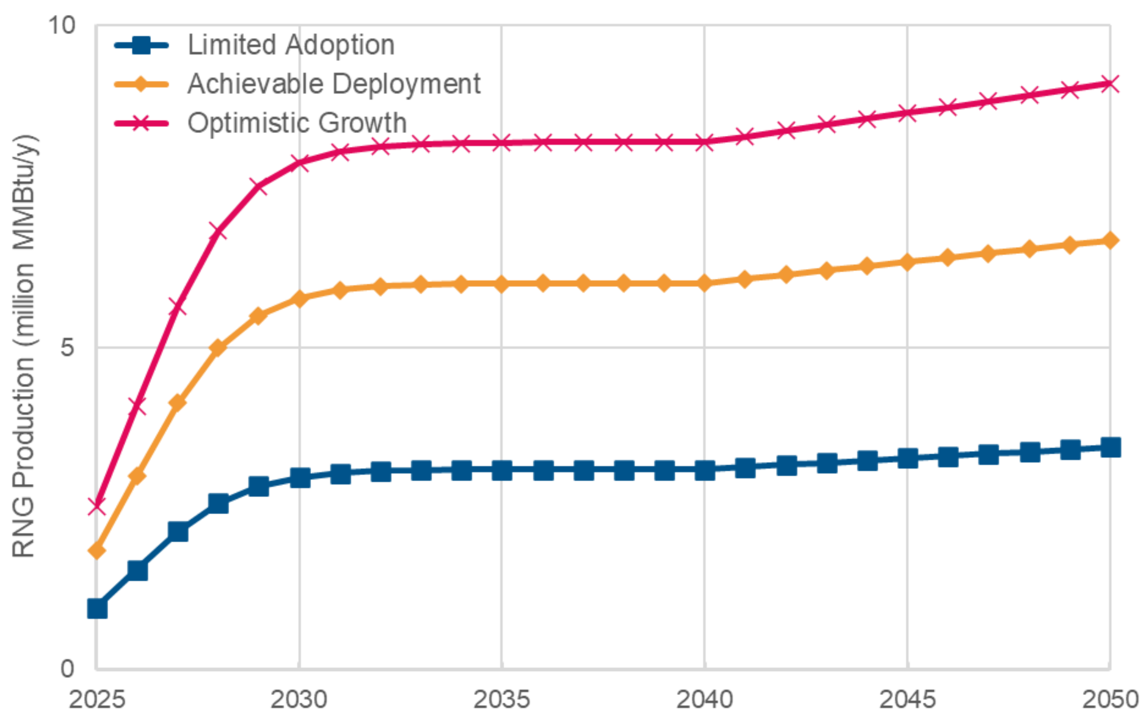
[24] Based on data from the LMOP at the U.S. EPA (updated December 2019).

the LFG facilities that have collection systems in place, 30% of the LFG facilities that do not have collection systems in place, and at 50% of the candidate landfills.

- In the Achievable Deployment scenario, ICF assumed that two of the three LFG facilities in Travis County and the candidate landfill in Williamson County produce RNG. In the rest of Texas one half of LFG facilities across the three categories are assumed to produce RNG. For the rest of the U.S., ICF assumed that RNG could be produced at 50% of the LFG facilities that have collection systems in place, 45% of the LFG facilities that do not have collection systems in place, and at 65% of the candidate landfills.
- In the Optimistic Growth scenario, ICF assumed that all three LFG facilities in Travis County and the candidate landfill in Williamson County produce RNG. In the rest of Texas and 75% of LFG facilities across the three categories are assumed to produce RNG. For the rest of the U.S., ICF assumed that RNG could be produced at 65% of the LFG facilities that have collection systems in place, 60% of the LFG facilities that do not have collection systems in place, and at 80% of the candidate landfills.

The figure below shows the Limited Adoption, Achievable Deployment and Optimistic Growth RNG resource potential from LFG between 2025 and 2050.

Figure 8. Annual RNG Production Potential from Landfill Gas (million MMBtu/y)



Water Resource Recovery Facilities

There are 551 WRRFs in Texas, with a total flow of over 1,850 MGD. There are 13 WRRFs in Travis County, representing flow of 100 MGD, with a further 16 WRRFs in the surrounding CTX counties, but 15 of these are small WRRFs with a combined flow of 15 MGD.

Of the 551 WRRFs, 35 have anaerobic digestion systems with a total flow of 680 MGD, or 38% of Texas's total flow. While none of these WRRFs with anaerobic digestion systems are in Travis County or the surrounding CTX counties, it is worth noting that there is an anaerobic digestion system at the Hornsby Bend biosolids management plant and takes in feedstock from the two largest WRRFs by flow in Travis County, the South Austin Regional and Walnut Creek facilities (see box below for more detail).

WRRFs and RNG Potential in Austin

Austin Water has two major wastewater treatment plants in Travis County: Walnut Creek and South Austin Regional. The water utility also manages a biosolids facility at Hornsby Bend, which has a well-established anaerobic digestion system, including eight digesters.

The treatment processes at the two WRRFs generate sludge that is pumped directly to the Hornsby Bend facility. These solids are then processed at the facility to produce compost for land application and public sales.

As part of this process the digesters also produce raw biogas. Over 600 standard cubic feet per minute (scfm) of biogas is produced, and this is forecast to grow to 800–1,000 scfm by 2040, largely driven by population growth. Currently, the facility utilizes less than half of the biogas for beneficial on-site use: a portion is used to fuel a combined heat and power (CHP) system for power and heat generation, and another portion fuels hot water boilers as needed for digester heating. The excess biogas not utilized in the CHP system or boilers is flared to the ambient atmosphere.

The Hornsby Bend facility provides an opportunity for more productive and enhanced uses of the waste feedstock from the two WRRFs, and avoid the flaring of excess biogas. Investment in the conditioning and upgrade of the biogas to produce pipeline-quality RNG would provide a near-term opportunity for the development, production and injection of locally-sourced RNG. In addition, the facility is located adjacent to ONE Gas's natural gas distribution infrastructure along State Route 973, avoiding more costly and challenging pipeline interconnection requirements.

RNG produced from Hornsby Bend could be directed towards use in the transportation sector, potentially providing environmental credits to offset the higher production costs associated with RNG. The role and benefits of RNG consumption in the transportation sector is discussed in more detail in Section 6.

The table below summarizes WRRFs by flow and RNG potential.

Table 34. Texas WRRFs by Existing Flow [25]

Region	Large WRRFs (>7.25 MGD)	Small WRRFs (<7.25 MGD)	Total Flow (MGD)	RNG Potential (MMBtu/y)
Travis County	3	10	100.6	257,000
Other CTX	1	15	31.2	80,000
Rest of Texas	41	481	1,719.2	4,395,000
Texas	45	506	1,850.9	4,731,000

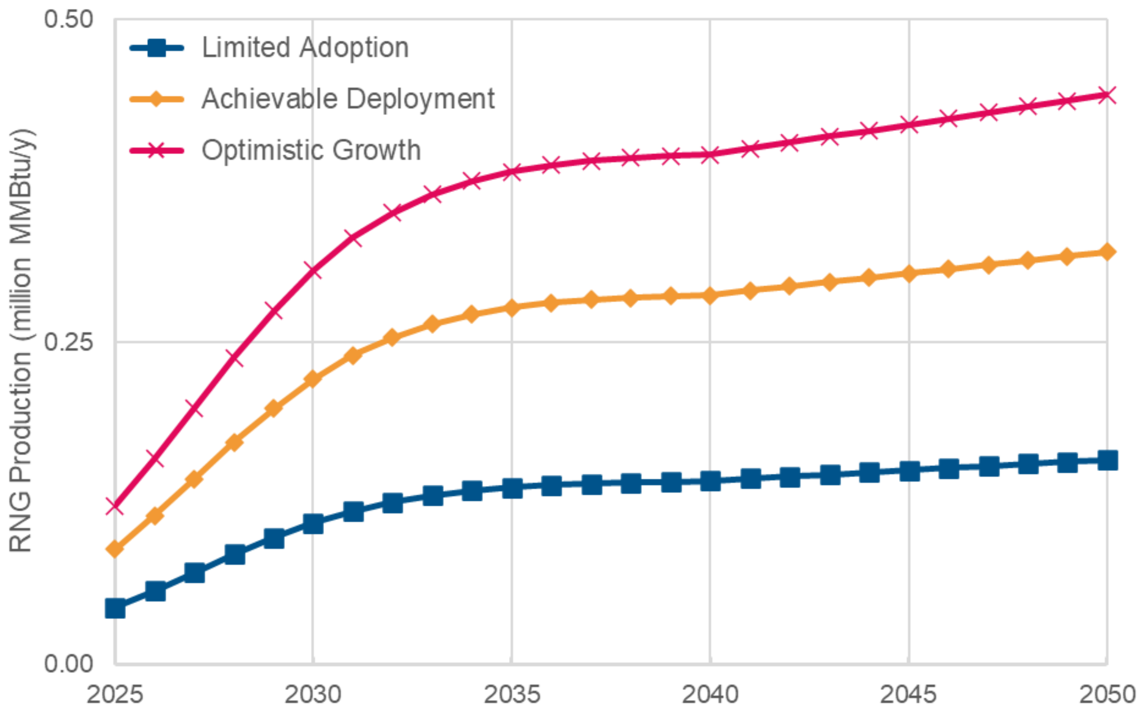
Similar to LFG facilities, as the number of WRRFs varies significantly by region, ICF applied different proportional limitations depending on the geography, as outlined below. ICF developed the following assumptions for the resource potentials for RNG production at WRRFs in the three scenarios:

- In the Limited Adoption scenario, ICF assumed that one of the three WRRFs in Travis County with a capacity greater than 7.25 MGD would produce RNG and the large WRRF in Williamson County would not produce RNG. In the rest of Texas and rest of the U.S., ICF assumed that 40% of the WRRFs with a capacity greater than 7.25 MGD would produce RNG.
- In the Achievable Deployment scenario, ICF assumed that two of the three WRRFs in Travis County with a capacity greater than 7.25 MGD and the large WRRF in Williamson County would produce RNG. In the rest of Texas and rest of the U.S., ICF assumed that 50% of the WRRFs with a capacity greater than 3.3 MGD would produce RNG.
- In the Optimistic Growth scenario, ICF assumed all three of the WRRFs in Travis County with a capacity greater than 7.25 MGD and the large WRRF in Williamson County would produce RNG, in addition to the medium-sized WRRF in Hays County. In the rest of Texas and rest of the U.S., ICF assumed that 60% of the WRRFs with a capacity greater than 3.3 MGD would produce RNG.

The figure below shows the Limited Adoption, Achievable Deployment, and Optimistic Growth RNG resource potential from WRRFs between 2025 and 2050.

[25] Based on data from the LMOP at the U.S. EPA (updated December 2019).

Figure 9. Annual RNG Production Potential from WRRFs (million MMBtu/y)



RNG: Thermal Gasification of Biogenic or Renewable Resources

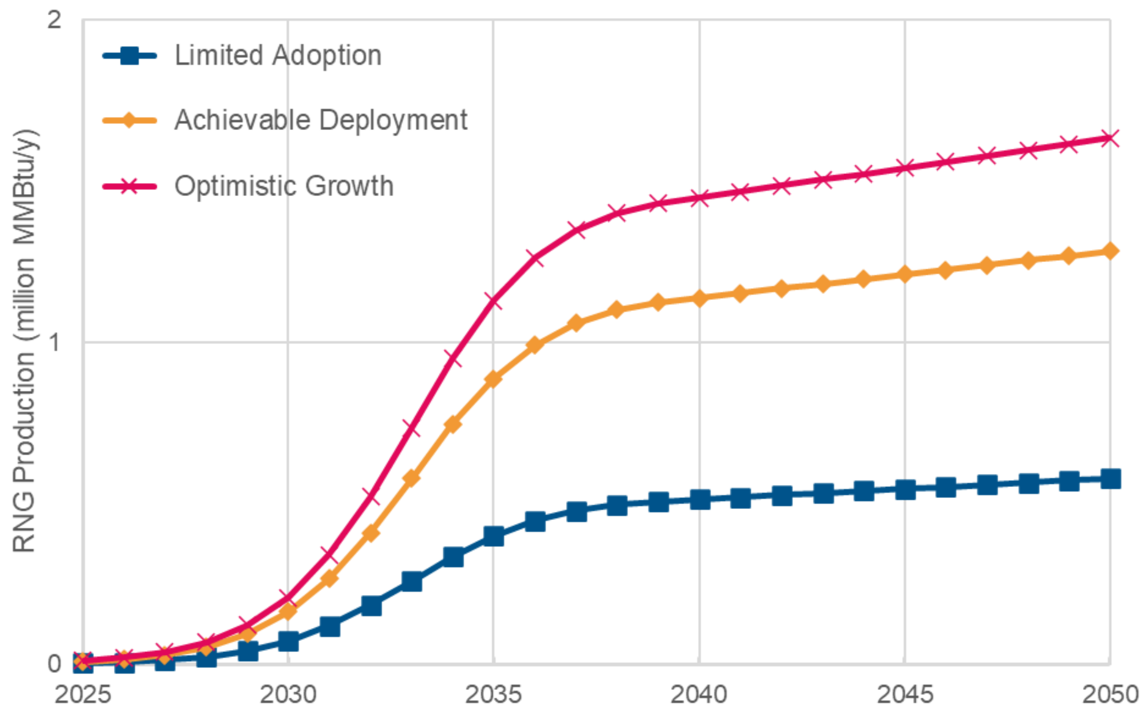
Agricultural Residues

ICF developed the following assumptions for the RNG production potential from agricultural residues in the three scenarios.

- In the Limited Adoption scenario, ICF assumed that 20% of the agricultural residues available at $50/dry ton would be diverted to thermal gasification systems.
- In the Achievable Deployment scenario, ICF assumed that 40% of the agricultural residues available at $50/dry ton would be diverted to thermal gasification systems.
- In the Optimistic Growth scenario, ICF assumed that 50% of the agricultural residues available at $100/dry ton would be diverted to thermal gasification systems.

The figure below shows the Limited Adoption, Achievable Deployment and Optimistic Growth RNG resource potential scenarios from the thermal gasification of agricultural residues between 2025 and 2050.

Figure 10. Annual RNG Production Potential from Agricultural Residue (million MMBtu/y)



Energy Crops

Energy crops are inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production. ICF extracted data from the Bioenergy KDF at $10 price point increments, from $30/ton to $100/ton that showed variation in production potential for energy crops from 2025 out to 2040.

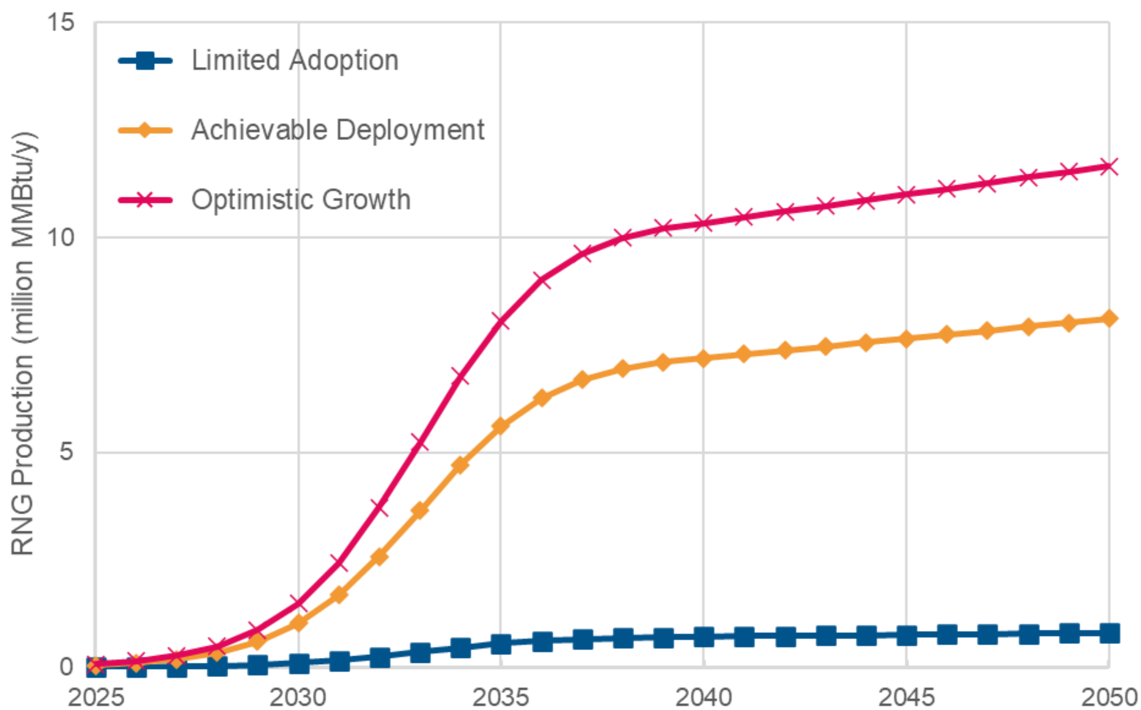
ICF developed assumptions for the RNG production potential from energy crops for the three scenarios:

- In the Limited Adoption scenario, ICF assumed that 20% of the energy crops available at $30/dry ton would be diverted to thermal gasification systems.
- In the Achievable Deployment scenario, ICF assumed that 20-40% of the energy crops available at $40/dry ton would be diverted to thermal gasification systems, depending on the geography.
- In the Optimistic Growth scenario, ICF assumed that 20% of the energy crops available at $50/dry ton would be diverted to thermal gasification systems.

ICF notes that there is significant RNG feedstock potential in Texas from energy crops, with the Achievable Deployment and Optimistic Growth scenarios seeing relatively large volumes of energy crops being used for RNG after 2035, as the thermal gasification technology develops.

Figure 11 below shows the RNG resource potential from the thermal gasification of energy crops between 2025 and 2050 in the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios.

Figure 11. Annual RNG Production Potential from Energy Crops (million MMBtu/y)



Forestry and Forest Product Residues

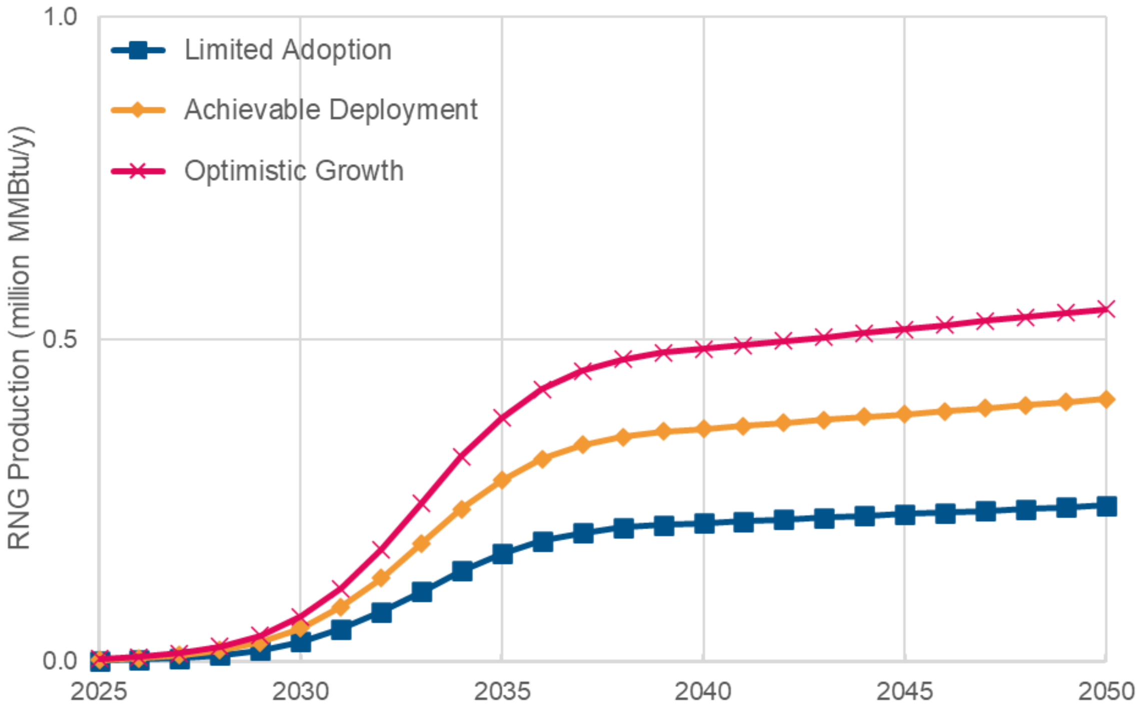
ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood). ICF extracted data from the Bioenergy KDF at three price points, $30/ton, $50/ton and $60/ton, that showed variation in production potential for forest and forest product residue biomass from 2025 out to 2040.

ICF developed the following assumptions for the RNG production potential from forest residues in the three scenarios:

- In the Limited Adoption scenario, ICF assumed that 30% of the forest and forestry product residues available at $30/dry ton would be diverted to thermal gasification systems.
- In the Achievable Deployment scenario, ICF assumed that 50% of the forest and forestry product residues available at $50/dry ton would be diverted to thermal gasification systems.
- In the Optimistic Growth scenario, ICF assumed that 60% of the forest and forestry product residues available at $100/dry ton would be diverted to thermal gasification systems.

Figure 12 below shows the RNG resource potential from the thermal gasification of forestry and forest product residues between 2025 and 2050 in the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios.

Figure 12. Annual RNG Production Potential from Forestry & Forest Product Residue (million MMBtu/y)



Municipal Solid Waste

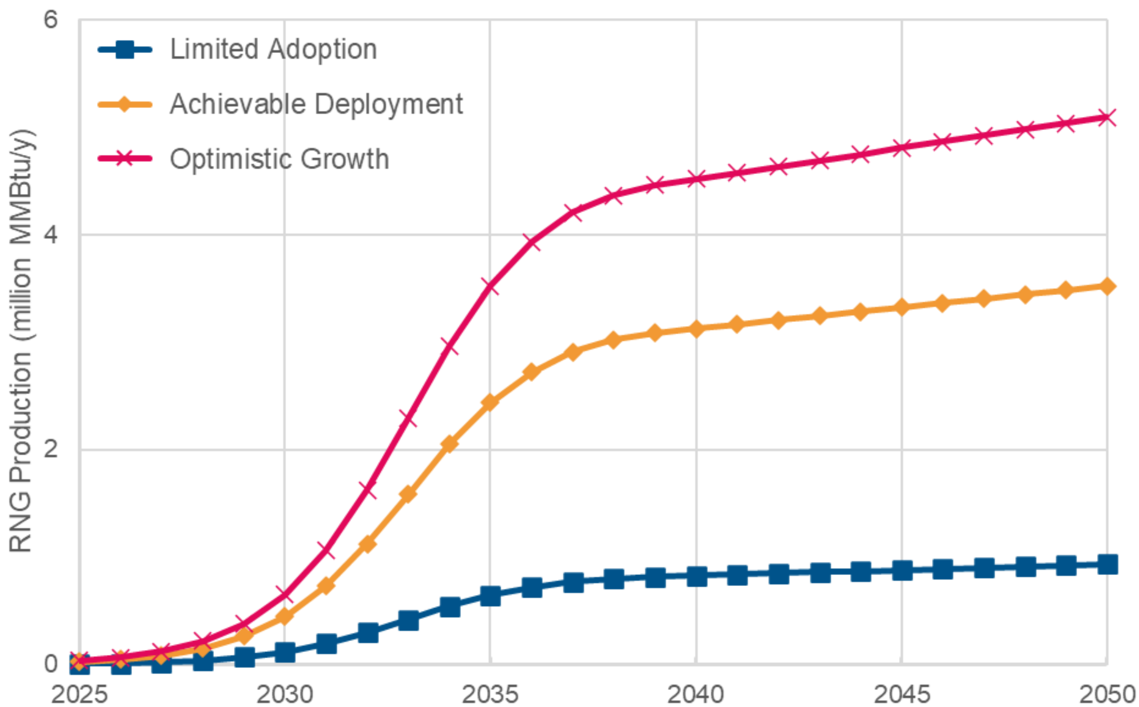
ICF extracted MSW information from the U.S. DOE's Bioenergy KDF, which includes information collected as part of U.S. DOE's Billion Ton Report. ICF limited our consideration to the potential for utilizing MSW that is currently landfilled as a feedstock for thermal gasification; this excludes MSW that is recycled or directed to waste-to-energy facilities. The MSW volumes available at different prices are derived from a variety of sources, including county-level tipping fees and costs associated with sorting.

ICF developed assumptions for the RNG production potential from MSW for the three scenarios:

- In the Limited Adoption scenario, ICF assumed that 30% of the nonbiogenic fraction of MSW available at $30/dry ton from the Bioenergy KDF for paper and paperboard, plastics, rubber and Achievable Deployment, and textiles waste could be gasified.
- In the Achievable Deployment scenario, ICF assumed that 50% of the nonbiogenic fraction of MSW available at $40/dry ton from the Bioenergy KDF for paper and paperboard, plastics, rubber and leather, and textiles waste could be gasified.
- In the Optimistic Growth scenario, ICF assumed that 60% of the nonbiogenic fraction of MSW available at $40/dry ton from the Bioenergy KDF for paper and paperboard, plastics, rubber and leather, textiles, and yard trimmings could be gasified.

The figure below shows the RNG resource potential from the thermal gasification of MSW between 2025 and 2050 in the Limited Adoption, Achievable Deployment and Optimistic Growth scenarios.

Figure 13. Annual RNG Production Potential from MSW (million MMBtu/y)



4. Cost Assessment

Cost Methodology

ICF developed assumptions for the capital expenditures and operational costs for RNG production from the various feedstock and technology pairings outlined previously. ICF characterizes costs based on a series of assumptions regarding the production facility sizes (as measured by gas throughput in units of standard cubic feet per minute [SCFM]), gas upgrading and conditioning and upgrading costs (depending on the type of technology used, the contaminant loadings, etc.), compression, and interconnect for pipeline injection. We also include operational costs for each technology type. Table 36Table 35 below outlines some of ICF's baseline assumptions that we employ in our RNG costing model.

Table 35. Illustrative ICF RNG Cost Assumptions

Cost Parameter	ICF Cost Assumptions
Facility Sizing	▪ Differentiate by feedstock and technology type: anaerobic digestion and thermal gasification. ▪ Prioritize larger facilities to the extent feasible, but driven by resource estimate.
Gas Conditioning and Upgrade	▪ Vary by feedstock type and technology required.
Compression	▪ Capital costs for compressing the conditioned/upgraded gas for pipeline injection.
Operational Costs	▪ Costs for each equipment type—digesters, conditioning equipment, collection equipment, and compressors—as well as utility charges for estimated electricity consumption.
Feedstock	▪ Feedstock costs (for thermal gasification), ranging from $30 to $100 per dry ton.
Financing	▪ Financing costs, including carrying costs of capital (assuming a 60/40 debt/equity ratio and an interest rate of 7%), an expected rate of return on investment (set at 10%), and a 15-year repayment period.
Delivery	▪ Cost of delivering the biogas at a price of $1.20/MMBtu. This cost is in line with financing, constructing, and maintaining a pipeline of about 1 mile in length. The costs of delivering the same volumes of biogas that require pipeline construction greater than 1 mile will increase, depending on feedstock/technology type, with a typical range of $1–$5/MMBtu.
Project Lifetimes	▪ 20 years. The levelized cost of gas was calculated based on the initial capital costs in Year 1, annual operational costs discounted at an annual rate of 5-8% over 20 years, and biogas production discounted at an annual rate of 5-8% for 20 years.

ICF notes that our cost estimates are not intended to replicate a developer's estimate when deploying a project. For instance, ICF recognizes that the cost category "conditioning and upgrading" actually represents an array of decisions that a project developer would have to make with respect to CO_2 removal, H_2S removal, siloxane removal, N_2/O_2 rejection, deployment of a thermal oxidizer, etc.

In addition, these cost estimates do not reflect the potential value of the environmental attributes associated with RNG, nor the current markets and policies that provide credit for these environmental attributes. While this section focuses purely on the costs associated with the production of RNG, Sections 5 and 6 discuss in more detail the market prices for RNG and the associated value of the environmental characteristics of RNG.

Furthermore, we understand that project developers have reported a wide range of interconnection costs, with numbers as low as $200,000 reported in some states, and as high as $9 million in other states. We appreciate the variance between projects, including those that use anaerobic digestion or thermal gasification technologies, and our supply-cost curves are meant to be illustrative, rather than deterministic. This is especially true of our outlook to 2050—we have *not* included significant cost reductions that might occur as a result of a rapidly growing RNG market or sought to capture a technological breakthrough or breakthroughs. For anaerobic digestion and thermal gasification systems we have focused on projects that have reasonable scale, representative capital expenditures, and reasonable operations and maintenance estimates.

To some extent, ICF's cost modeling does presume changes in the underlying structure of project financing, which is currently linked inextricably to revenue sharing associated with environmental commodities in the federal Renewable Fuel Standard (RFS) market and California's Low Carbon Fuel Standard (LCFS) market. Our project financing assumptions likely have a lower return than investors may be expecting in the market today; however, our cost assessment seeks to represent a more mature market to the extent feasible, whereby upward of 1,000-4,500 tBtu per year of RNG is being produced. In that regard, we implicitly assume that contractual arrangements are likely considerably different and local/regional challenges with respect to RNG pipeline injection have been overcome.

Table 36 provides a summary of the different cost ranges for each RNG feedstock and technology.

Table 36. Summary of Cost Ranges by Feedstock Type

	Feedstock	Cost Range ($/MMBtu)
Anaerobic Digestion	Landfill Gas	$9.90 – $15.31
	Animal Manure	$22.00 – $45.16
	Water Resource Recovery Facilities	$10.87 – $33.26
	Food Waste	$20.40 – $29.60
Thermal Gasification	Agricultural Residues	$18.50 – $51.60
	Forestry and Forest Residues	$17.30 – $31.00
	Energy Crops	$18.30 – $56.10
	Municipal Solid Waste	$17.30 – $36.10

RNG from Anaerobic Digestion

Animal Manure

ICF developed assumptions for the region by distinguishing between animal manure projects, based on a combination of the size of the farms and assumptions that certain areas would need to aggregate or cluster resources to achieve the economies of scale necessary to warrant an RNG project. There is some uncertainty associated with this approach because an explicit geospatial analysis was not conducted; however, ICF did account for considerable costs in the operational budget for each facility assuming that aggregating animal manure would potentially be expensive.

Table 37 includes the main assumptions used to estimate the cost of producing RNG from animal manure.

Table 37. Cost Consideration in Levelized Cost of Gas Analysis for RNG from Animal Manure

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 15-25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $0.5 million ▪ $1 million ▪ $0.2–$0.5 million
Other	▪ Value of digestate ▪ Tipping fee	▪ Valued for dairy at about $100/cow/y ▪ Excluded from analysis
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 8%

ICF reports a range of costs for RNG from animal manure at $22.0/MMBtu to $45.2/MMBtu for ONE Gas's CTX Service Area. The low end of the RNG costs from animal manure are slightly higher in the study area than in other areas (as reported, for instance, in ICF's analysis for the American Gas Foundation) because of the average farm size for cows—dairy, beef, and heifers—is smaller than in other areas. For instance, ICF has developed cost estimates for farms that have upwards of 20,000 to 30,000 cows. By comparison, ICF analysis suggests that the larger operations in ONE Gas's CTX Service Area have upwards of 10,000 cows. Furthermore, the animal manure operations in ONE Gas's CTX Service Area tend to be non-dairy cow operations, including beef cows, heifers and calves, and chicken operations (e.g., Gonzales has about ten large poultry operations). These operations tend to face higher costs because the costs of manure management are higher (the operations in general are not as concentrated as dairy farms, thereby requiring more costly manure aggregation).

Food Waste

ICF made the simplifying assumption that food waste processing facilities would be purpose-built and be capable of processing 60,000 tons of waste per year. ICF estimates that these facilities would produce about 500 SCFM of biogas for conditioning and upgrading before pipeline injection. In addition to the other costs included in other anaerobic digestion systems, we also included assumptions about the cost of collecting food waste and processing it accordingly (see Table 38).

Table 38. Cost Consideration in Levelized Cost of Gas Analysis for RNG from Food Waste Digesters

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 95% ▪ 60,000 tons per year
Dedicated Equipment	▪ Organics processing ▪ Digester	▪ $10.0 million ▪ $12.0 million
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 million ▪ $1.0 million
Utility Costs	▪ Electricity: 28 kWh/MMBtu ▪ Natural Gas: 5% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1.5 FTE for maintenance ▪ Miscellany	▪ 15% of installed capital costs
Other	▪ Tipping fees	▪ Varied by region; used weighted average of $49.07 (see Table 39)
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $0.5 million ▪ $1 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

ICF assumed that food waste facilities would be able to offset costs with tipping fees. ICF used values presented by an analysis of municipal solid waste landfills by Environmental Research & Education Foundation (EREF). The tipping fees reported by EREF for 2018 are shown in Table 39.

Table 39. Average Tipping Fee by Region ($/ton)[26]

Region	Tipping Fee
CTX Service Area	
Texas Disposal Systems LF[27]	$55.00
Regional	
Texas, statewide average	$37.78
South Central: AR, LA, NM, OK, TX	$34.80
Rest of U.S.	
Northeast: CT, DE, ME, MD, MA, NH, NJ, NY, PA, RI, VA, WV	$67.39
Pacific: AK, AZ, CA, HI, ID, NV, OR, WA	$68.46
Midwest: IL, IN, IA, KS, MI, MN, MO, NE, OH, OH, WI	$46.89
Mountains / Plains: CO, MT, ND, SD, UT, WY	$43.57
Southeast: AL, FL, GA, KY, MS, NC, SC, TN	$43.32
National Average	***$55.11***

The values listed in Table 39 are generally the fees associated with tipping municipal solid waste—the tipping fees for construction and debris tend to be higher because the materials take up more space in landfills. ICF developed our cost estimates assuming that anaerobic digesters discounted the tipping fee for food waste compared to MSW landfills by 20%.

ICF reports an estimated cost of RNG from food waste of $20.4/MMBtu to $29.6/MMBtu.

Landfill Gas

ICF developed assumptions for each region by distinguishing between four types of landfills: candidate landfills[28] without collection systems in place, candidate landfills with collection systems in place, landfills[29] without collection systems in place, and landfills with collections systems in place.[30] For each region, ICF further characterized the number of landfills across these four types of landfills, distinguishing facilities by estimated biogas throughput (reported in units of SCFM of biogas).

For utility costs, ICF assumed 25 kWh per MMBtu of RNG injected and 6% of geological or fossil natural gas used in processing. Electricity costs and delivered natural gas costs were reflective of industrial rates reported at the state level by the EIA.

[26] Environmental Research & Education Foundation, Analysis of MSW Landfill Tipping Fees–April 2019. Retrieved from www.erefdn.org.
[27] TDS, 2020. https://texasdisposal-https-texasdisposalsys.netdna-ssl.com/wp-content/uploads/2020/03/New-TDS-Gate-Rates-March-2020-Final.pdf
[28] The EPA characterizes candidate landfills as one that is accepting waste or has been closed for five years or less, has at least one million tons of WIP, and does not have an operational, under-construction, or planned project. Candidate landfills can also be designated based on actual interest by the site.
[29] Excluding those that are designated as candidate landfills.
[30] Landfills that are currently producing RNG for pipeline injection are included here.

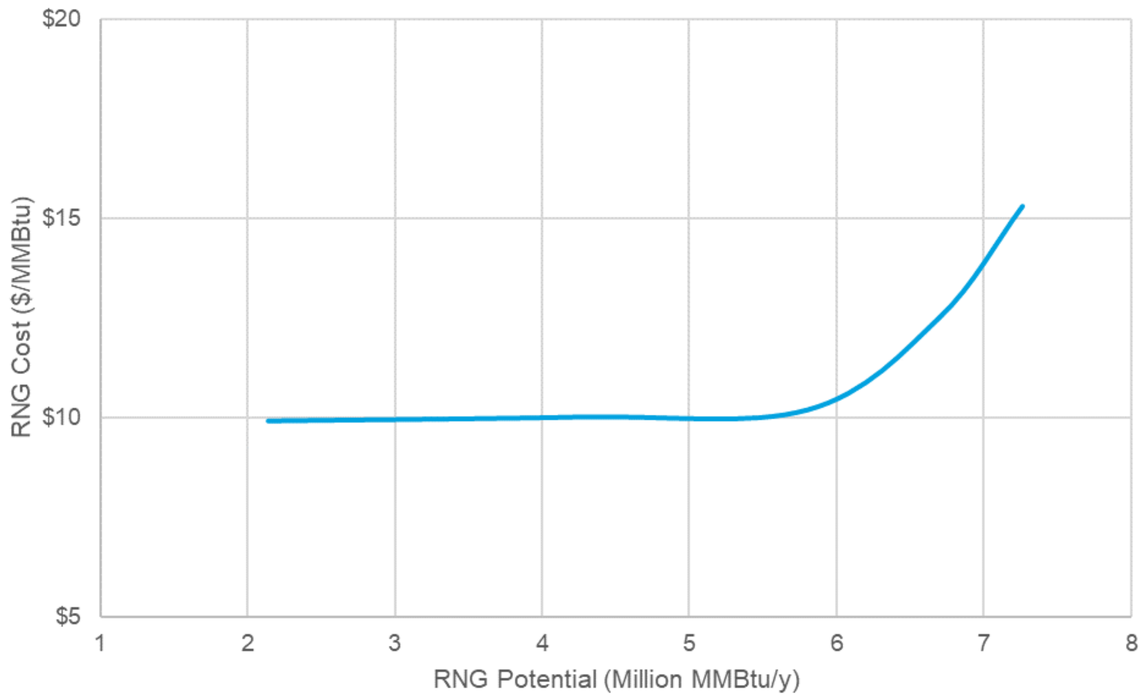
Table 40 summarizes the key parameters that ICF employed in our cost analysis of LFG.

Table 40. Cost Consideration in Levelized Cost of Gas Analysis for RNG from Landfill Gas

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ \$2.3 to \$7.0 million, depending on facility ▪ \$0.3 to \$1.0 million, depending on facility ▪ \$1.0 to \$2.5 million, depending on facility
Utility Costs	▪ Electricity: 25 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ \$3.00–\$8.25/MMBtu; average of \$4.75/MMBtu for region
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ \$0.5 million ▪ \$1 million ▪ \$0.2–\$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

Figure 14 includes ICF's estimates for the RNG from landfill gas supply curve for ONE Gas's CTX Service Area, ranging from about \$10/MMBtu to around \$15/MMBtu—this includes the five landfills, four of which are in Travis County and the fifth in Williamson County. The four facilities in Travis County are currently producing electricity, but could be converted to RNG production, and the facility in Williamson County (operated by Waste Management) is currently slated to start producing RNG for pipeline injection in 2020.

Figure 14. Supply-Cost Curve for RNG from Landfill Gas ($/MMBtu vs million MMBtu)



Water Resource Recovery Facilities

ICF developed assumptions for each region by distinguishing between WRRFs based on the throughput of the facilities. The table below includes the main assumptions used to estimate the cost of producing RNG at WRRFs.

Table 41. Cost Consideration in Levelized Cost of Gas Analysis for RNG from WRRFs

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor	▪ 95%
Installation Costs	▪ Construction / Engineering ▪ Owner's cost	▪ 25% of installed equipment costs ▪ 10% of installed equipment costs
Gas Upgrading	▪ CO_2 separation ▪ H_2S removal ▪ N_2/O_2 removal	▪ $2.3 to $7.0 million, depending on facility ▪ $0.3 to $1.0 million, depending on facility ▪ $1.0 to $2.5 million, depending on facility
Utility Costs	▪ Electricity: 26 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh; average of 6.5 ¢/kWh for region ▪ $3.00–$8.25/MMBtu; average of $4.75/MMBtu for region
Operations & Maintenance	▪ 1 FTE for maintenance ▪ Miscellany	▪ 10% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $0.5 million ▪ $1 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

ICF reports an estimated cost of RNG from WRRFs of $10.9/MMBtu to $33.3/MMBtu. The low end of the range represents the Hornsby Bend facility, a biosolids facility that receives the residual sludge from wastewater treatment at Walnut Creek and South Austin Regional; whereas the higher end of the range represents the smaller Brushy Creek Regional facility in Round Rock.

RNG from Thermal Gasification

ICF used similar assumptions across the thermal gasification of feedstocks, including agricultural residue, forestry residue, energy crops, and MSW.[31] There is considerable uncertainty around the costs for thermal gasification of feedstocks, as the technology has only been deployed at pilot scale to date or in the advanced stages of demonstration at pilot scale. This is in stark contrast to the anaerobic digestion technologies considered previously. ICF reports here on a range of facilities processing different volumes of feedstock (in units of tons per day, or tpd) that we employed for conducting the cost analysis.

Table 42. Thermal Gasification Cost Assumptions

Factor	Cost Elements Considered	Costs
Performance	▪ Capacity factor ▪ Processing capability	▪ 90% ▪ 1,000–2,000 tpd
Dedicated Equipment & Installation Costs	▪ Feedstock handling (drying, storage) ▪ Gasifier ▪ CO_2 removal ▪ Syngas reformer ▪ Methanation ▪ Other (cooling tower, water treatment) ▪ Miscellany (site work, etc.) ▪ Construction / Engineering	▪ $20–22 million ▪ $60 million ▪ $25 million ▪ $10 million ▪ $20 million ▪ $10 million ▪ All-in: $335 million for 1,000 tpd
Utility Costs	▪ Electricity: 30 kWh/MMBtu ▪ Natural Gas: 6% of product	▪ 4.6–13.7 ¢/kWh ▪ $3.00–$8.25/MMBtu
Operations & Maintenance	▪ Feedstock ▪ 3 FTE for maintenance ▪ Miscellany: water sourcing, treatment/disposal	▪ $30–$100/dry ton ▪ 12% of installed capital costs
For Injection	▪ Interconnect ▪ Pipeline ▪ Compressor	▪ $0.5 million ▪ $1 million ▪ $0.2–$0.5 million
Financial Parameters	▪ Rate of return ▪ Discount rate	▪ 10% ▪ 7%

[31] Note that MSW here refers to the non-organic, nonbiogenic fraction of the MSW stream, which is assumed to be a mix of, including, but not limited to construction and demolition debris, plastics, rubber and leather, etc.

ICF applied these estimates across each of the four feedstocks, their corresponding feedstock cost estimates, and assumed that the smaller facilities processing 1,000 tons per day would represent 50% of the processing capacity, and that the larger facilities processing 2,000 tons per day would represent the other 50% of the processing capacity. The number of facilities built in each region was constrained by the resource assessment.

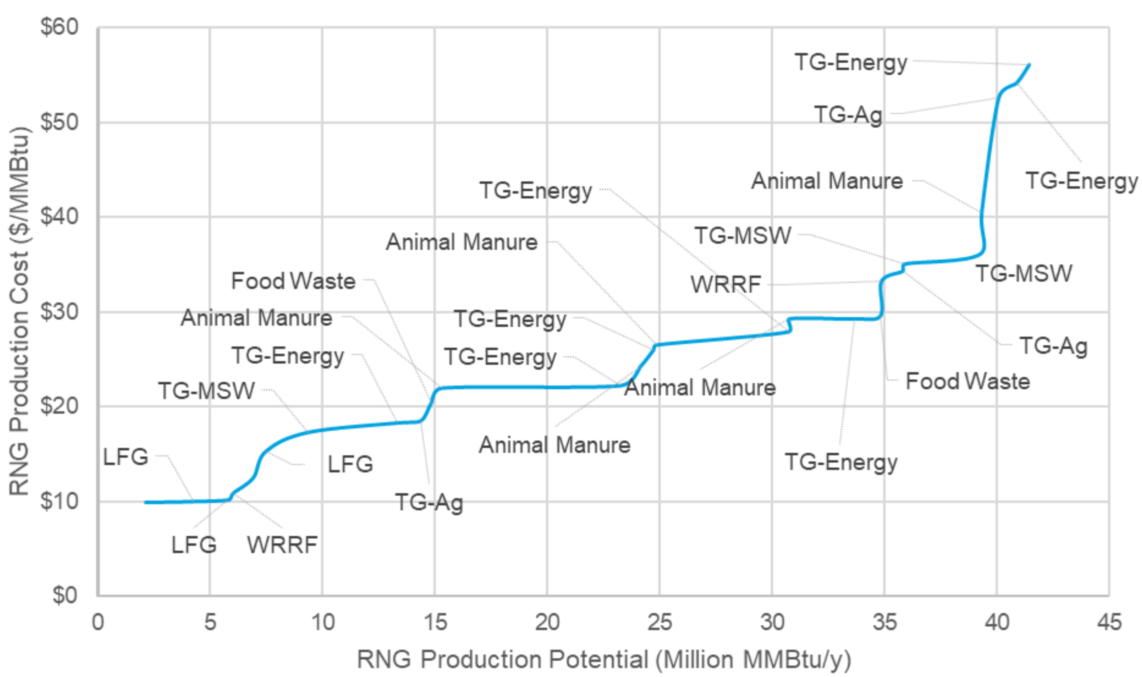
ICF reports an estimated levelized costs of RNG from thermal gasification as follows:

- Agricultural residues: $18.5/MMBtu to $51.6/MMBtu
- Forestry and forest residues: $17.3/MMBtu to $31.0/MMBtu
- Energy crops: $18.3/MMBtu to $56.1/MMBtu
- MSW: $17.3/MMBtu to $36.1/MMBtu

Combined Supply-Cost Curve for RNG

The figure below represents the supply-cost curve for RNG in ONE Gas's CTX Service Area, including resource potential (along the x-axis) and the estimated cost to deliver that RNG (along the y-axis). For the sake of reference, we have also included the contribution to each step in the supply curve—shown as landfill gas (LFG), animal manure, food waste, WRRFs, thermal gasification (with three feedstocks: energy crops (Energy), agricultural residues (Ag), and the non-biogenic fraction of municipal solid waste (MSW)). As highlighted previously, the front end of the supply curve is comprised of landfill gas and WRRFs, with the larger thermal gasification systems expected to be cost competitive in the 2040 timeline. The more immediately available opportunities from the anerobic digestion of animal manure and food waste are likely available in the range of $20/MMBtu. The back-end of the supply curve is driven by higher costs of anaerobic digestion at smaller farms and smaller thermal gasification facilities.

Figure 15. Combined Supply-Cost Curve for RNG in CTX Service Area ($/MMBtu vs million MMBtu)



5. GHG Accounting and Cost-Effectiveness

GHG Accounting Framework and Methodology

The GHG emissions of RNG, typically called a carbon intensity (e.g., grams of CO_2 equivalents per MJ of fuel), varies primarily based on the source of the fuel (i.e., feedstock), but can be impacted by other factors such as production efficiency and location as well as transmission distances. The assessment method and scope can also have a significant impact on how RNG carbon intensities and emissions are estimated and reported. This section provides a summary of commonly used GHG emission accounting methods and how they relate to the GHG emission profiles of RNG production and consumption.

Overview of Accounting Methods

GHG emission accounting for a given source of emissions relies on the application of an emission factor to activity data. In the example below, we use an emission factor for Texas's average electricity mix to determine the annual GHG emissions associated with an average Texas household's electricity consumption using data from the EPA[32] and EIA:[33]

$$446\ \frac{g\ CO_2e}{kWh} \times 14{,}300\ \frac{kWh}{house} = 6.4 \times 10^6\ \frac{g\ CO_2e}{house}$$

Emissions accounting becomes more complex when an assessment scope includes a diverse set of sources. This is most often seen in GHG emission inventories for agencies, corporations, and jurisdictions (e.g., community, city, county, state, country) where entities must account for a wide range of sectors (e.g., transportation, energy, agriculture). Each sector has an array of emissions sources with unique variations in emission factors, activity data, and other aspects to consider.

GHG emission profiles can be complex for specific products or resources, when a scope may consider elements outside of product use, such as emissions from supply chains, co-products, and disposal. For example, California's LCFS relies on a lifecycle assessment approach for estimating carbon intensities of transportation fuels. As a result, LCFS emissions for a specific transportation fuel pathway

Lifecycle Assessment

California's LCFS, consumption-based inventories, and GHG Protocol's Scope 3 include all GHG emissions from a product or resource's lifecycle. This relies on an approach called lifecycle assessment (LCA). LCA allows for a holistic GHG accounting approach that considers all lifecycle aspects from raw resource extraction to final disposal (i.e., "cradle to grave"). For RNG and transportation fuels, Argonne National Laboratories' GHGs, Regulated Emissions, and Energy Use in Transportation (GREET) model is the most commonly relied on resource.

[32] US EPA, 2020. eGRID. Available at: https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid
[33] US EIA. 2018. Household Energy Use in Texas. Available at: https://www.eia.gov/consumption/residential/data/2015/

include all emission sources in the fuel lifecycle from resource extraction to final consumption in a vehicle.

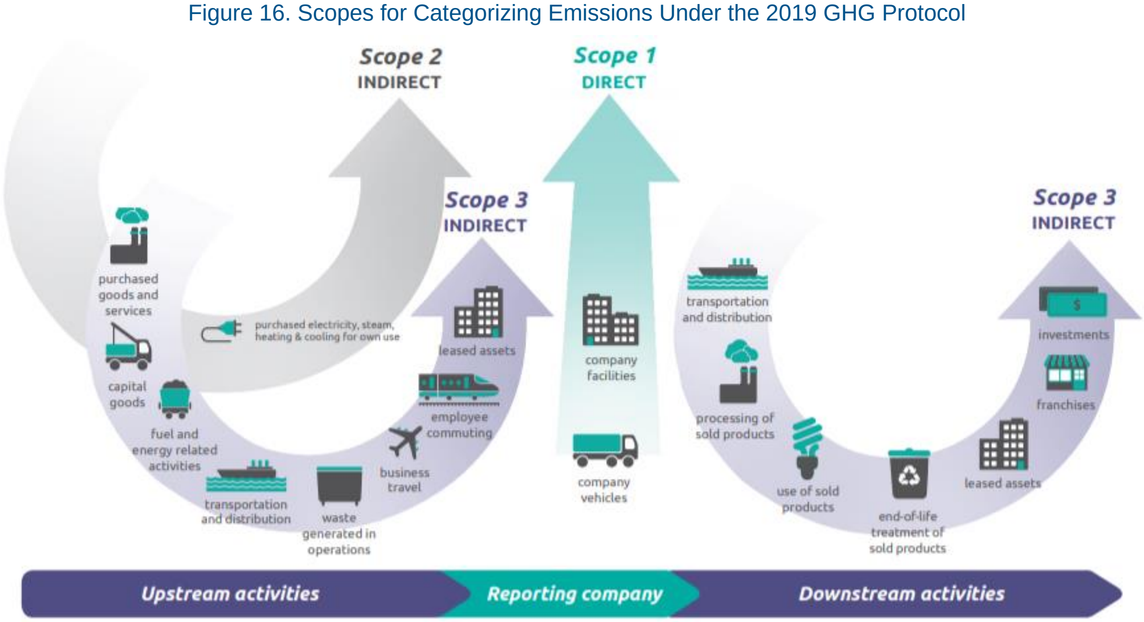
GHG emission accounting for inventories typically relies on guidance from the Intergovernmental Panel on Climate Change (IPCC) developed in 2006.[34] The IPCC provides guidance for different levels of detail depending on the availability of data and capacity of the inventory team for all sectors typically considered in a GHG inventory. GHG emission reporting programs that address a specific sector or subsector, like the LCFS, may have unique guidelines that diverge from IPCC and typical inventories in accounting methods.

Greenhouse Gas Protocol

The GHG Protocol is a commonly used set of reporting standards developed by the World Resources Institute and the World Business Council for Sustainable Development. A GHG Protocol-based approach is most common with corporations, but still incorporates many of the same sources and emission factors used by jurisdictions and public agencies.

The GHG Protocol uses "Scope" levels to define the different sources and activity data included within an assessment. Instead of thinking in terms of geographic or sector-based boundaries, the Protocol groups emissions in direct and indirect categories through these Scopes. Figure 16 shows how the Protocol groups these emission sources by Scopes, and how they relate to an organization's operations.

Figure 16. Scopes for Categorizing Emissions Under the 2019 GHG Protocol



Organizations most often may limit their assessment to Scope 1 and 2 emissions, which includes directly controlled assets. Scope 3 emissions reflect a lifecycle assessment approach that includes supply chain activities and associated, but not directly controlled, organizations.

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[34] IPCC. 2006. 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Available at: https://www.ipcc-nggip.iges.or.jp/public/2006gl/.

There is often confusion about who can claim and monetize the environmental benefits of RNG production and consumption across various stakeholders and GHG reporting structures. For example, a corporation based in California buys RNG from a fuel distributor to fuel their fleet of shuttle buses. The RNG was produced out of state and transported and sold in California to take advantage of the LCFS credit program. The value of the LCFS credits are owned and monetized by the various actors within the fuel production supply chain. However, the corporation purchasing the RNG as an end user can still factor in the fuel's low carbon intensity into their corporate emissions accounting by including the volumes purchased in their Scope 1 emissions.

RNG and GHG Accounting

There are two broad methodologies to account for the GHG emissions from RNG: a combustion accounting framework or a lifecycle accounting framework. A combustion GHG accounting framework is the standard approach for most volumetric GHG targets, inventories and mitigation measures (e.g. carbon taxes, cap-and-trade programs and RPS programs) as they are more closely tied to a particular jurisdiction—where the emissions physically occur.

Figure 17 details the differences between the two accounting frameworks relative to RNG production.

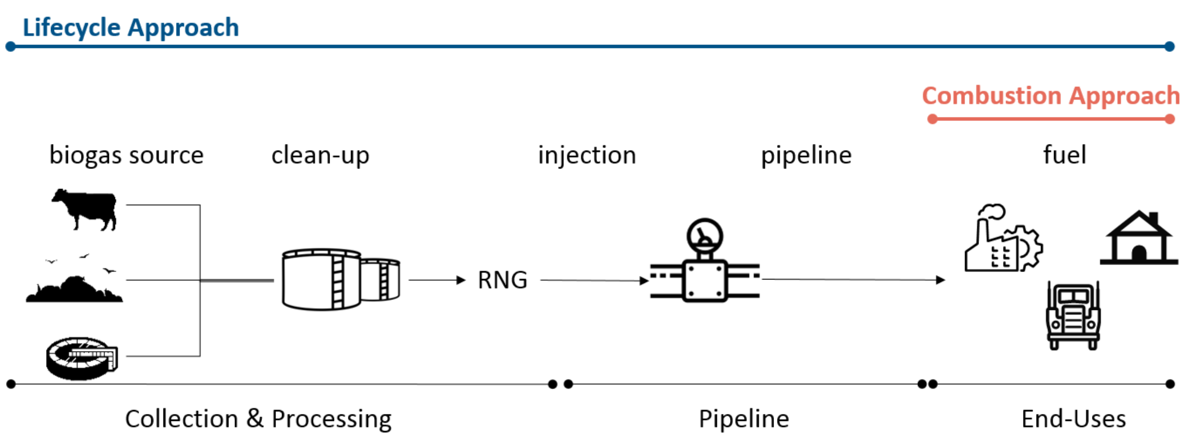
Accounting for Biogenic Emissions

IPCC guidelines state that CO_2 emissions from biogenic fuel sources (e.g., biogas- or biomass-based RNG) should not be included when accounting for emissions in combustion; only CH_4 and N_2O are included.

This is to avoid any upstream "double counting" of CO_2 emissions that occur in the agricultural or land use sectors per IPCC guidance. Other approaches exclude biogenic CO_2 in combustion as it is assumed that the CO_2 sequestered by the biomass during its lifetime offsets combustion CO_2 emissions.

This method of excluding biogenic CO_2 is still commonly practiced for RNG users and producers. For example, LA Metro did not include CO_2 emissions in the combustion of RNG in the agency's most recent CAAP.

Figure 17. GHG Accounting Frameworks for RNG Production



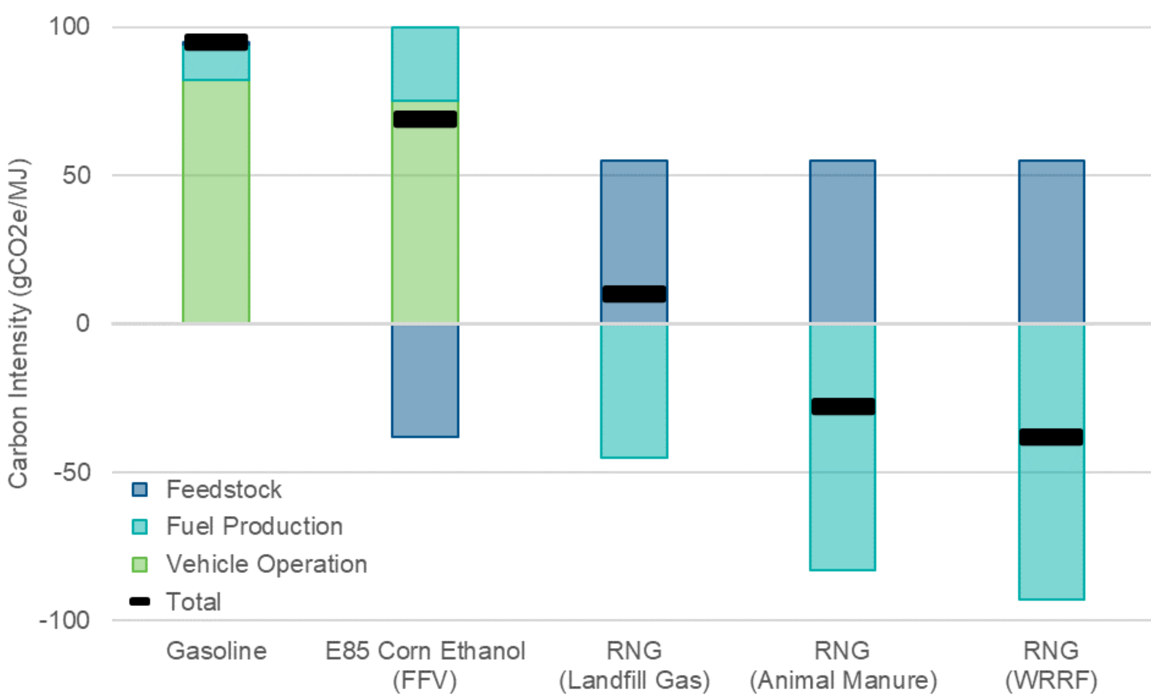
Using the combustion framework, the CO_2 emissions from the combustion of biogenic renewable fuels are considered zero, or carbon neutral. In other words, RNG has a carbon intensity of zero. This includes RNG from any biogenic feedstock, including landfill gas, animal manure, and food waste. Upstream emissions, whether positive (electricity emissions associated with biogas processing) or negative (avoided methane emissions), are not included. RNG procurement strategies do not necessarily need to differentiate RNG by lifecycle carbon intensity, given that RNG in a combustion accounting approach is zero-rated and carbon neutral.

When using a lifecycle accounting methodology RNG's carbon intensity (i.e., GHG emissions per unit of energy) varies substantially between feedstocks and production methods. Carbon intensities can also vary by the location of production and how the fuel is transported and distributed. The GHG accounting methods and scopes previously discussed dictate which of RNG's lifecycle elements are included as a carbon intensity in emissions reporting.

Variations in Production

Figure 18 shows how these different lifecycle elements contribute to RNG's overall carbon intensity for a selection of RNG sources using Argonne's GREET model[35]: landfill gas, animal waste AD, wastewater sludge AD, and MSW AD. We have also included corn ethanol (E85 blend) and gasoline as reference points. Note that in the GREET model, the original sourcing of RNG is considered "fuel production" and not feedstock operations.

Figure 18. Summary of Carbon Intensities for Transportation Fuels Across Lifecycle Stages[36]



[35] Argonne National Laboratory, 2019. Available at: https://greet.es.anl.gov/
[36] Ibid.

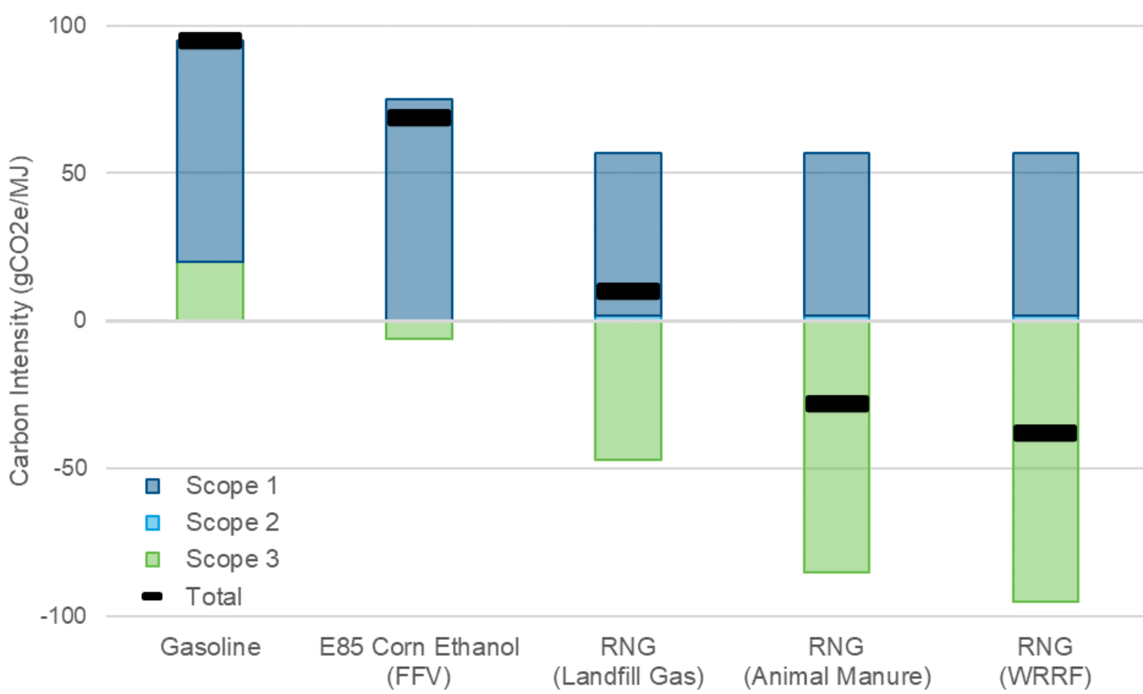
The biggest variations in RNG production come from the associated emissions credits from the different RNG sources. For landfill gas, animal waste, and wastewater sources, GREET assigns a significant credit for the reduction in vented and flared methane that would have occurred in absence of the production of RNG.

Depending on the reporting standard and scope, different credits may be included or excluded. The California LCFS has a similar scope in accounting for credits as the GREET results shown above. Other programs or jurisdictional inventories may exclude these credits or incorporate them into other emission sectors.

Variations Based on Accounting Method

Figure 19 shows the same GREET results from Figure 18 grouped into the GHG Protocol Scopes. Scope 1 is limited to the tailpipe emissions and Scope 3 includes all aspects of feedstock and fuel production activities. For RNG we have grouped the compression of gas before use into Scope 2, assuming electricity is used in compression.

Figure 19. RNG Lifecycle Carbon Intensity by Different GHG Protocol Scopes Using GREET Results[37]



Many organizations, jurisdictions, and corporations may limit their emissions reporting to just Scope 1 and Scope 2 emissions, which reflect a production or activity-based accounting approach. Some programs, like the LCFS, include all GHG Protocol Scopes with its lifecycle assessment approach. This means that if Scope 3 or lifecycle emission are excluded in reporting, the potential emission benefits of RNG will not be attributed to that reporting organization. A jurisdiction or organization using a consumption-based approach, or including

[37] GHG Protocol, 2019. Guidance. Available at: https://ghgprotocol.org/guidance-0

Scope 3 emissions, would report a lower or negative carbon intensity for RNG, depending on the feedstock.

For example, the Los Angeles County Metropolitan Transportation Authority (LA Metro) is working to shift its entire directly operated bus fleet to RNG as soon as possible. Many of the potential RNG feedstocks that LA Metro may use have a negative carbon intensity under the emissions scope of the LCFS (e.g., animal waste, wastewater anaerobic digestion pathways). However, LA Metro's recent Climate Action and Adaptation Plan[38] included only Scope 1 and 2 emissions, which meant that RNG had net positive emissions from compression and combustion regardless of the feedstock.

Approach to RNG GHG Emission Factors

As noted in more detail in the previous sub-section, the GHG emissions associated with the production of RNG vary depending on a number of factors including the feedstock type, collection and processing practices, and the type and efficiency of biogas upgrading. For the purposes of this report, ICF determined the lifecycle carbon intensity (CI) of RNG up to the point of pipeline injection. This includes feedstock transport and handling, gas processing, and any credits for the reduction of flaring or venting methane that would have occurred in absence of the RNG fuel production.

Figure 20 below presents the ranges of lifecycle CIs for different RNG feedstocks up to the point of pipeline injection for the EIA's West South Central Census Region, which includes Texas. These estimates are based on a combination of Argonne National Laboratory's GREET model, California Air Resources Board's modified California GREET model,[39] and ICF analysis. Table 43 that follows includes the lifecycle CIs for EIA's other census regions.

[38] LA Metro, 2019 https://media.metro.net/projects_studies/sustainability/images/Climate_Action_Plan.pdf
[39] ARB, 2019. https://ww3.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm

Figure 20. Lifecycle GHG Emission Factor Ranges for RNG Feedstocks, West South Central Region

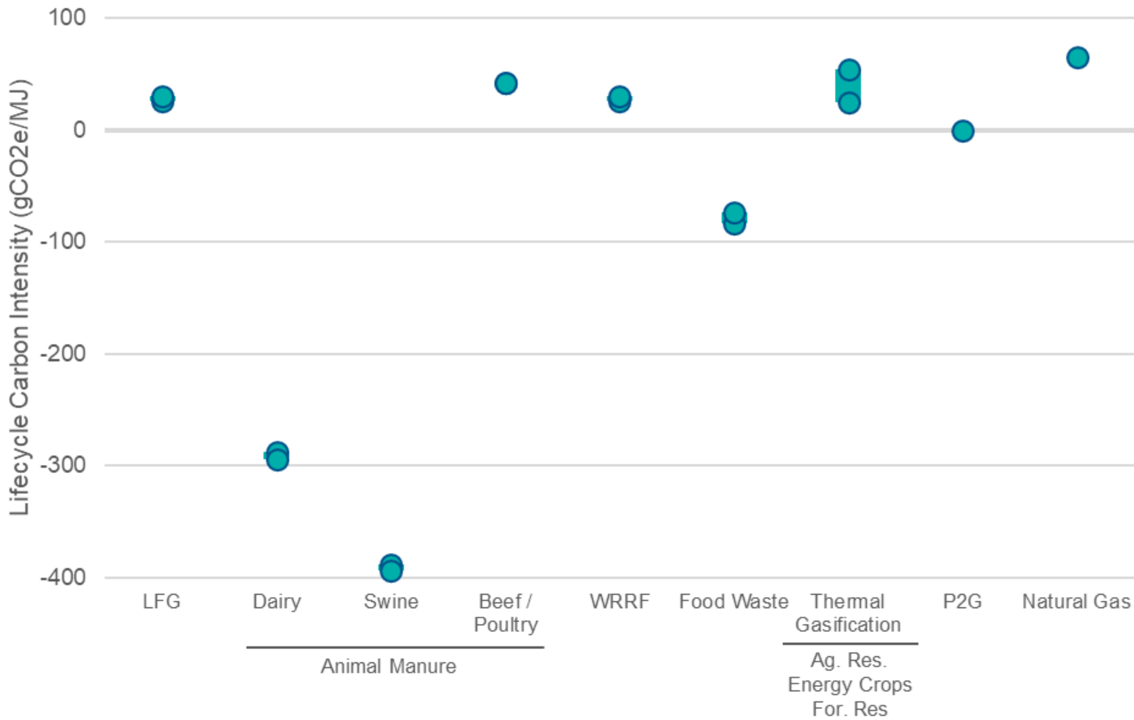


Table 43. Lifecycle GHG Emission Factor Ranges for RNG Feedstocks by Region, gCO_2e/MJ

Fuel	New England	Mid-Atlantic	South Atlantic	East North Central	West North Central	East South Central	Mountain	Pacific
LFG	18 – 26	15 – 21	22 – 26	28 – 34	28 – 32	26 – 28	21 – 32	13 – 29
Animal Manure								
Dairy	-304 – -294	-308 – -300	-299 – -294	-292 – -285	-292 – -286	-294 – -292	-300 – -286	-310 – -290
Swine	-404 – -394	-408 – -400	-399 – -394	-392 – -385	-392 – -386	-394 – -392	-400 – -386	-410 – -390
Beef/Poultry	36 – 36	31 – 31	36 – 36	46 – 46	44 – 44	38 – 38	44 – 44	41 – 41
WRRF	18 – 26	15 – 21	22 – 26	28 – 34	28 – 32	26 – 28	21 – 32	13 – 29
Food Waste	-97 – -82	-104 – -91	-90 – -82	-79 – -68	-79 – -70	-83 – -79	-91 – -70	-108 – -76
Agricultural Res.	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
Forestry Res.	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
Energy Crops	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
MSW	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55	25 – 55
Natural Gas	65	65	65	65	65	65	65	65

ICF notes the following about these emission factors:

- The lowest carbon intensities are from feedstocks that prevent the release of fugitive methane, such as the collection and processing of dairy cow manure.
- RNG from WRRFs has the same CI range as landfill gas because both feedstocks start with raw biogas that is processed by the same type of gas upgrading equipment.

- Agricultural residue, energy crops, forestry products and forestry residues, as well as MSW all have the same CI range based on the thermal gasification process required to create biogas from woody biomass. This is an energy-intensive process, but inclusion of renewables and co-produced electricity on-site can reduce the emissions impact of gas production.

After the point of injection, RNG is transported through pipelines for distribution to end users. The CI of pipeline transmission depends on the distance between the gas upgrading facility and end use. The GREET model applies 5.8 grams of CO_2e per MMBtu-mile of gas transported as the pipeline transmissions CI factor. If the gas will be used in the transportation sector, and therefore requires compression, another 3–4 gCO_2e is added onto the CI. For reference, the tailpipe emissions of use in a heavy-duty truck are around 60 gCO_2e/MJ.

GHG Cost-Effectiveness

The GHG cost-effectiveness is reported on a dollar-per-ton basis and is calculated as the difference between the emissions attributable to RNG and fossil natural gas. For this report, ICF followed IPCC guidelines and does not include biogenic emissions of CO_2 from RNG. The cost-effectiveness calculation is simply as follows:

$$\Delta(RNG_{cost}, Fossil\ NG_{cost}) \big/ 0.05306\ MT\ CO_{2e}$$

where the RNG_{cost} is simply the cost from the estimates reported previously. For the purposes of this report, we use a fossil natural gas price equal to the 3-year rolling average Henry Hub spot price reported by the EIA,[40] calculated as $2.96/MMBtu (in $2019).

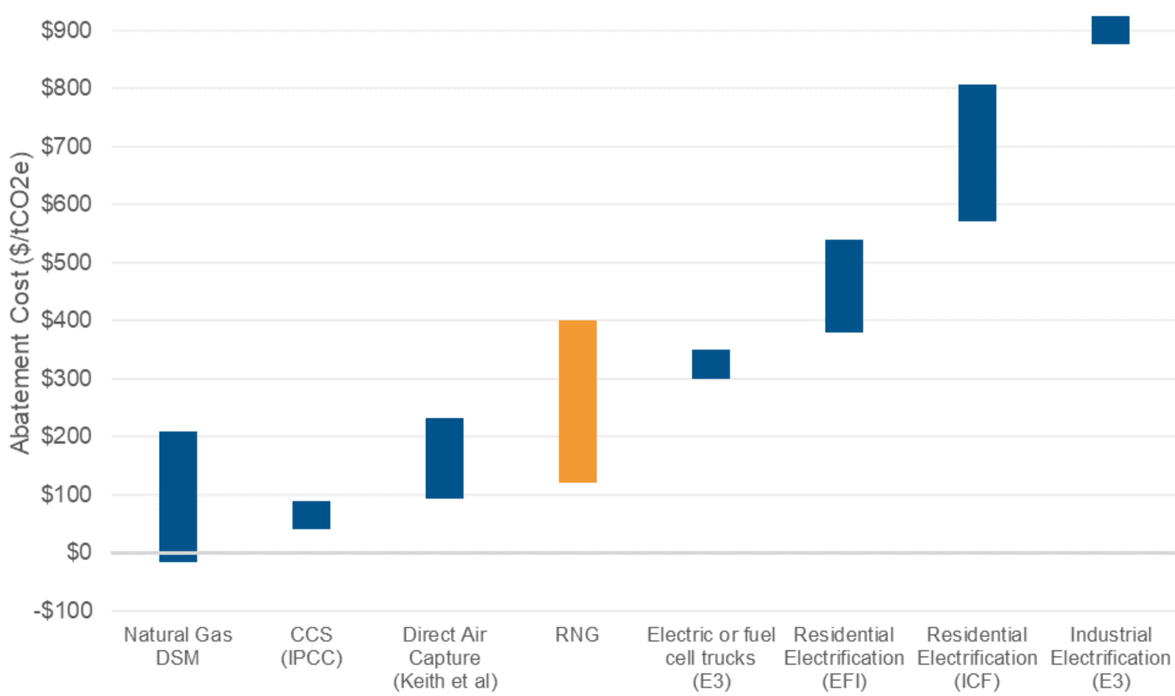
In other words, the front end of the supply-cost curve is showing RNG of just under $10/MMBtu, which is equivalent to about $120 per metric ton of carbon dioxide equivalent (tCO_2e). As the estimated RNG cost increases to $25/MMBtu, we report an estimated cost-effectiveness of about $400/$tCO_2e$. This range in cost for RNG can be converted to provide an equivalent range for the cost-effectiveness of RNG for GHG emission reductions, in dollars per ton of carbon dioxide equivalent.

Estimating the cost-effectiveness of different GHG emission reduction measures is challenging and results can vary significantly across temporal and geographic considerations. Figure 21 shows a comparison of selected measures across various key studies for specific abatement measures that are likely to be required for economy-wide decarbonization in the 2050 timeframe, including natural gas demand side management (DSM),[41] carbon capture and storage (CCS),[42] RNG (from this study), direct air capture (whereby CO_2 is captured directly

[40] EIA, Natural Gas Data, available online at https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm
[41] See Con Edison's Smart Usage Rewards program (https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/smart-usage-rewards/smart-usage-rewards-for-reducing-gas-demand) and National Grid's Demand Response Pilot program (https://www.nationalgridus.com/GDR).
[42] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck,

from the air and a concentrated stream is sequestered or used for beneficial purposes),[43] battery electric trucks (including fuel cell drivetrains),[44] and electrification of certain end uses (including buildings and in the industrial sectors).[45,46]

Figure 21. GHG Abatement Costs, Selected Measures, $\$/tCO_2e$



M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

43 Keith, DW; Holmes, G; St Angelo D; Heidel, K; A Process for Capturing CO2 from the Atmosphere, *Joule*, 2 (8), p1573-1594. https://doi.org/10.1016/j.joule.2018.05.006

44 E3, 2018. Deep Decarbonization in a High Renewables Future, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf

45 Energy Futures Initiative (EFI), 2019. Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf.

46 ICF, 2018, Implications of Policy-Driven Residential Electrification, https://www.aga.org/globalassets/research--insights/reports/AGA_Study_On_Residential_Electrification.

GHG Emissions from RNG Resource Assessment

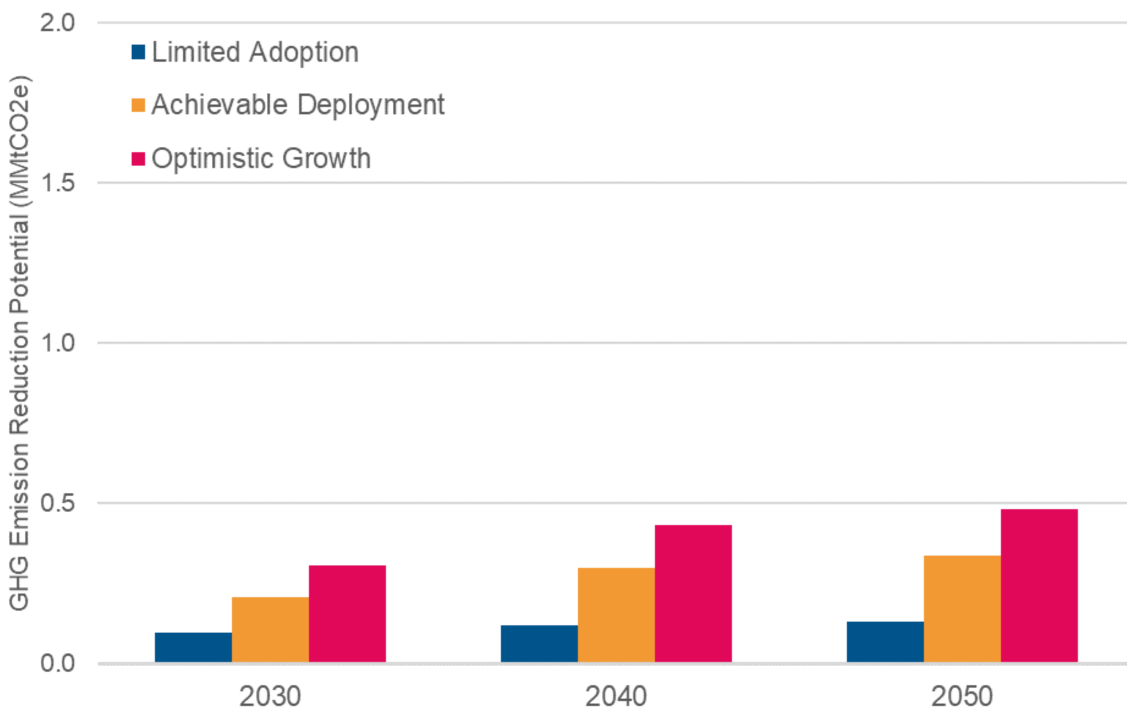
ICF applied the emission factors from the aforementioned combustion and lifecycle accounting approaches to estimate the GHG reduction potential across each of the RNG potential scenarios for Travis County, ONE Gas's CTX Service Area, and overall when including the rest of Texas and nationally, as reported previously in Section 3.

Combustion Accounting Framework

ICF reiterates that a combustion GHG accounting framework is the standard approach for most volumetric GHG targets, inventories and mitigation measures as they are more closely tied to where the emissions physically occur. When applying the combustion approach, the emission reduction estimates for the each scenario can be more easily compared to existing GHG inventories, such as the City of Austin's emissions by end use sector as shown in Figure 25. The lifecycle accounting GHG emission estimates included in the following section are not directly comparable to the City of Austin's GHG inventory.

The figures below show the range of GHG emission reductions using a combustion accounting framework, in units of million metric tons of CO_2e ($MMtCO_2e$). ICF estimates that 0.13 to 0.48 $MMtCO_2e$ of emissions could be reduced per year by 2050 through the deployment of RNG projects located in Travis County, shown in Figure 22.

Figure 22. Travis County RNG Emission Reduction Potential by Scenario, $MMtCO_2e$ (Combustion)



Expanding the geographic footprint to include RNG feedstocks from the surrounding CTX Service Area counties, this increases to between 0.23 and 1.12 $MMtCO_2e$ per year in 2050. ICF estimates that 0.45 to 1.78 $MMtCO_2e$ of emissions could be reduced per year by 2050 through the utilization of RNG feedstocks from outside the immediate City of Austin region, as reflected in the scenario totals.

Figure 23. CTX Service Area RNG Emission Reduction Potential by Scenario, $MMtCO_2e$ (Combustion)

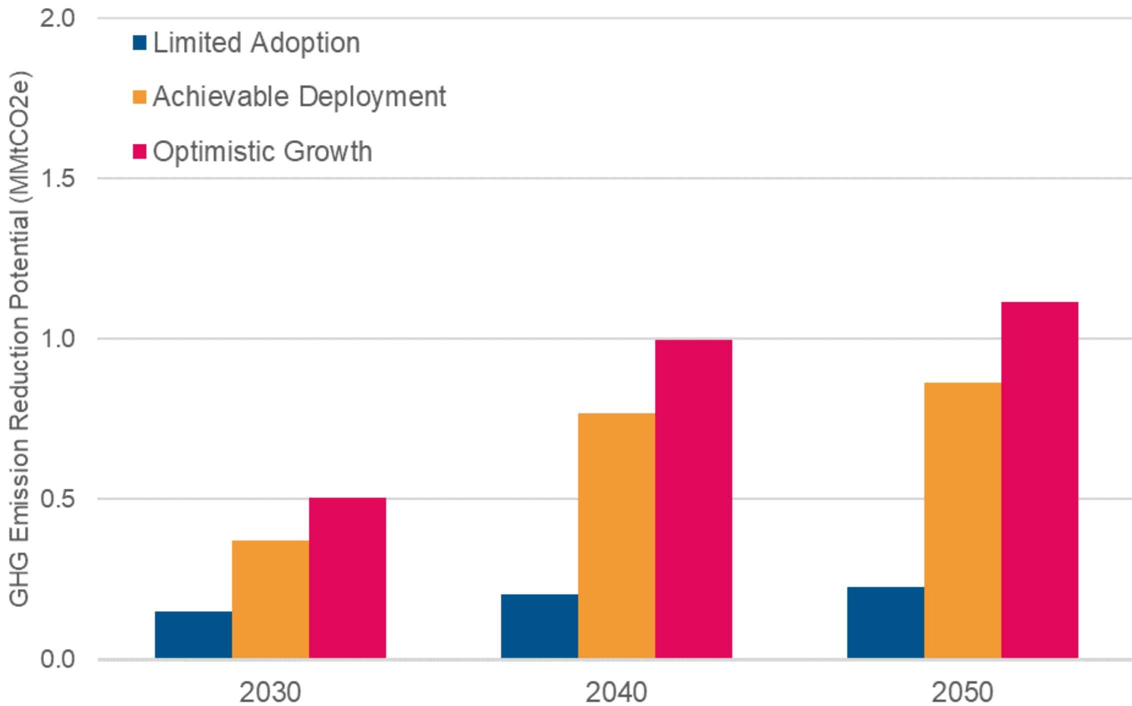
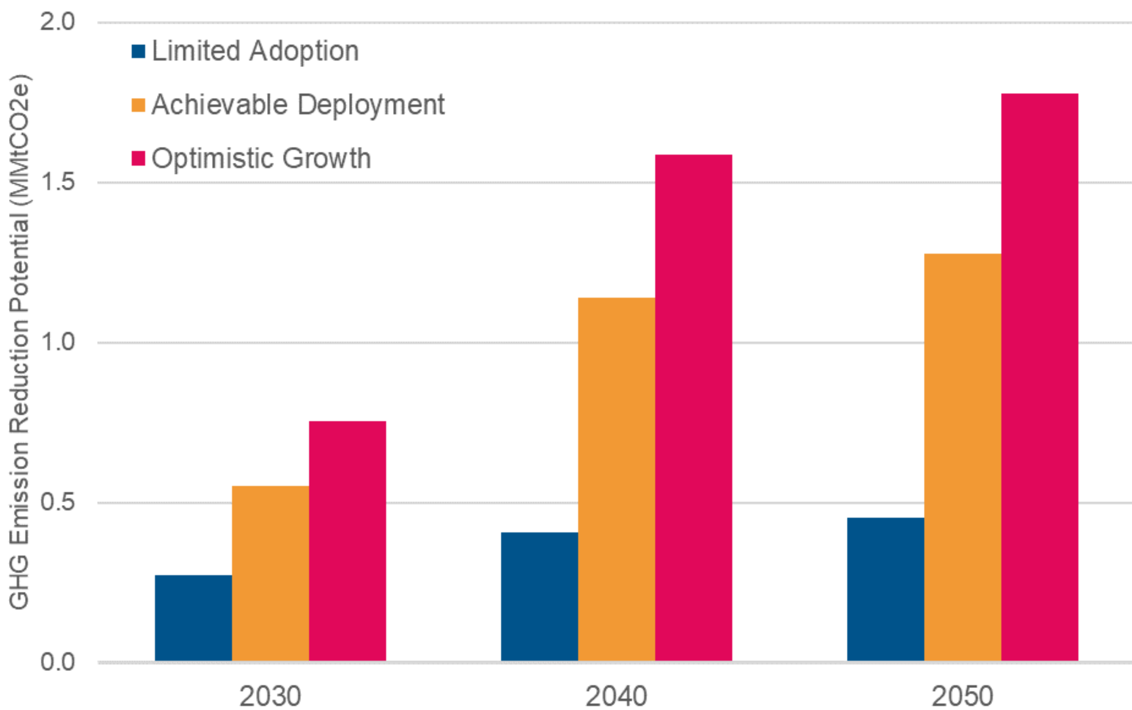
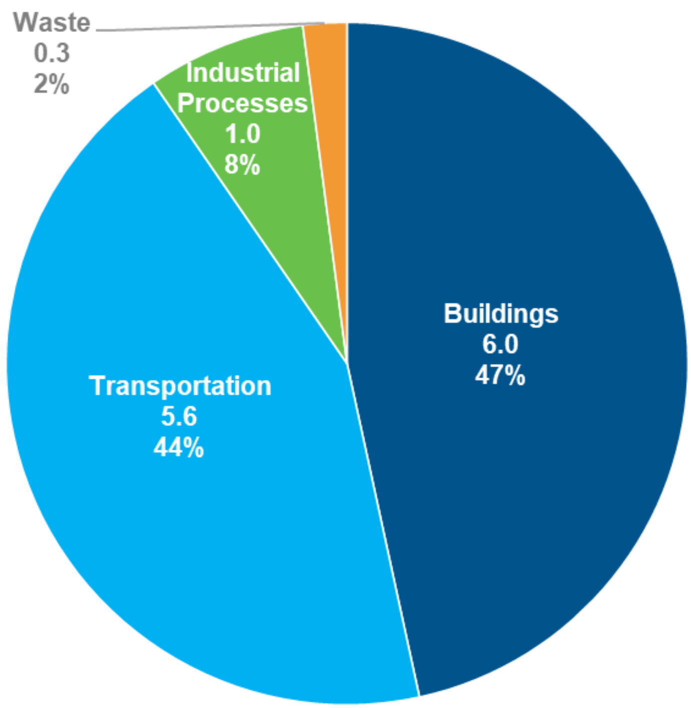


Figure 24. Total RNG Emission Reduction Potential by Scenario, $MMtCO_2e$ (Combustion)



By way of comparison, the City of Austin's total GHG emissions were 12.9 $MMtCO_2e$ in 2018, shown in Figure 25 below.[47] The City of Austin GHG inventory does not disaggregate natural gas and electricity consumption in the buildings and industrial end use sectors.

Figure 25. City of Austin GHG Emissions by End Use Sector, $MMtCO_2e$

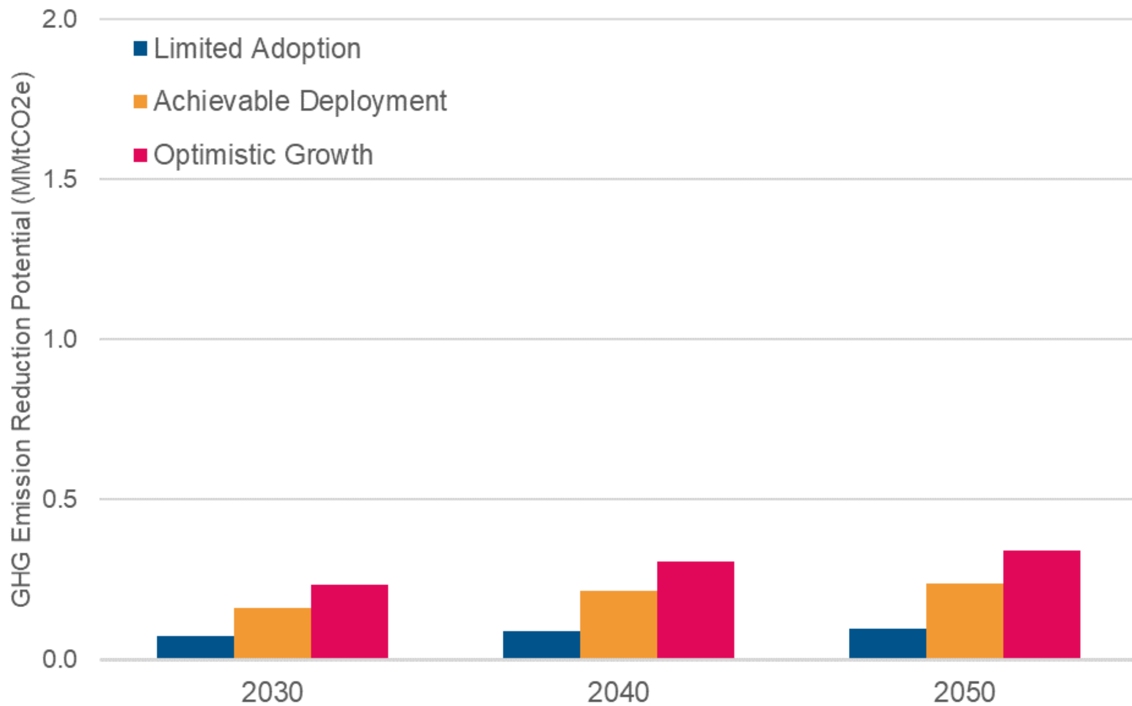


[47] City of Austin, 2020. Austin Community Climate Plan, https://public.tableau.com/profile/cavan.merski#!/vizhome/CommunityInventoryMetricSprintDashboard/trend

Lifecycle Accounting Framework

The figures below show the range of GHG emission reductions using a lifecycle accounting framework, in units of $MMtCO_2e$. ICF estimates that 0.10 to 0.34 $MMtCO_2e$ of emissions could be reduced per year by 2050 through the deployment of RNG projects located in Travis County, shown in Figure 26 below.

Figure 26. Travis County RNG Emission Reduction Potential by Scenario, $MMtCO_2e$ (Lifecycle)



As shown in the figure above and figures below, the emission reduction estimates using a lifecycle approach are largely lower relative to the estimates for the combustion approach. This is driven by the additional upstream emissions associated with the production of RNG from various feedstocks, counterbalanced by extra emission reductions primarily from avoided methane emissions, such as those from RNG produced from animal manure (see Figure 20 above).

Expanding the geographic footprint to include RNG feedstocks from the surrounding CTX Service Area counties, this increases to between 0.18 and 0.75 $MMtCO_2e$ per year in 2050. ICF estimates that 0.56 to 1.60 $MMtCO_2e$ of emissions could be reduced per year by 2050 through the utilization of RNG feedstocks from outside the immediate City of Austin region, as reflected in the scenario totals.

Figure 27. CTX Service Area RNG Emission Reduction Potential by Scenario, $MMtCO_2e$ (Lifecycle)

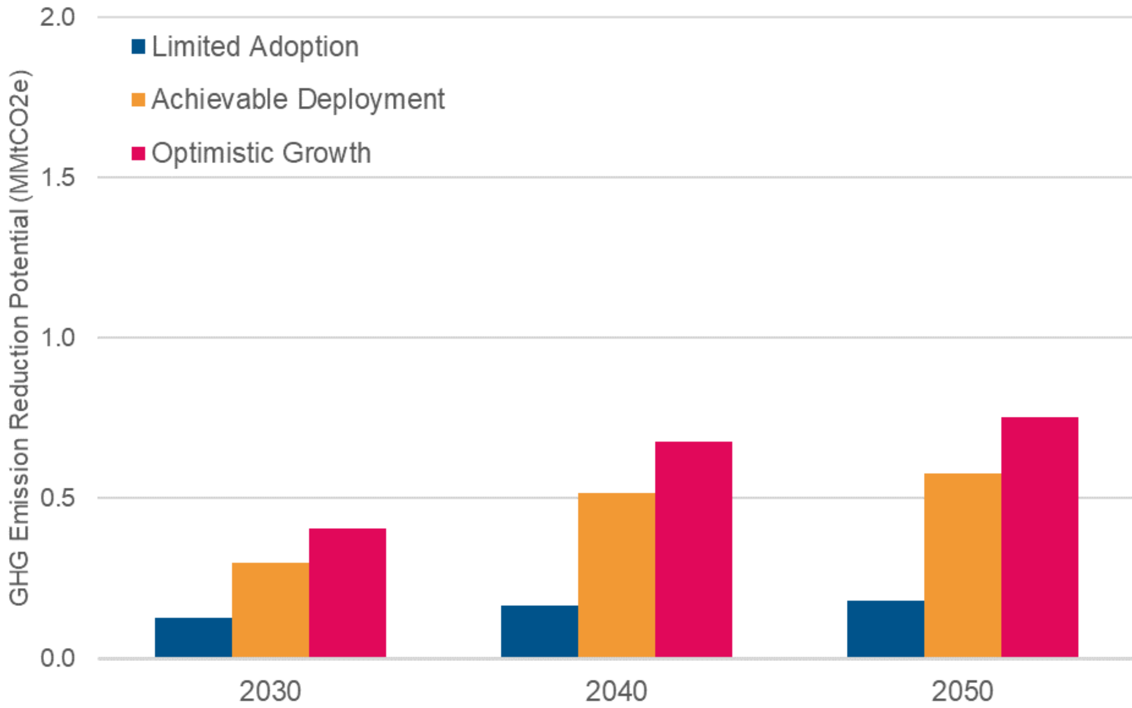
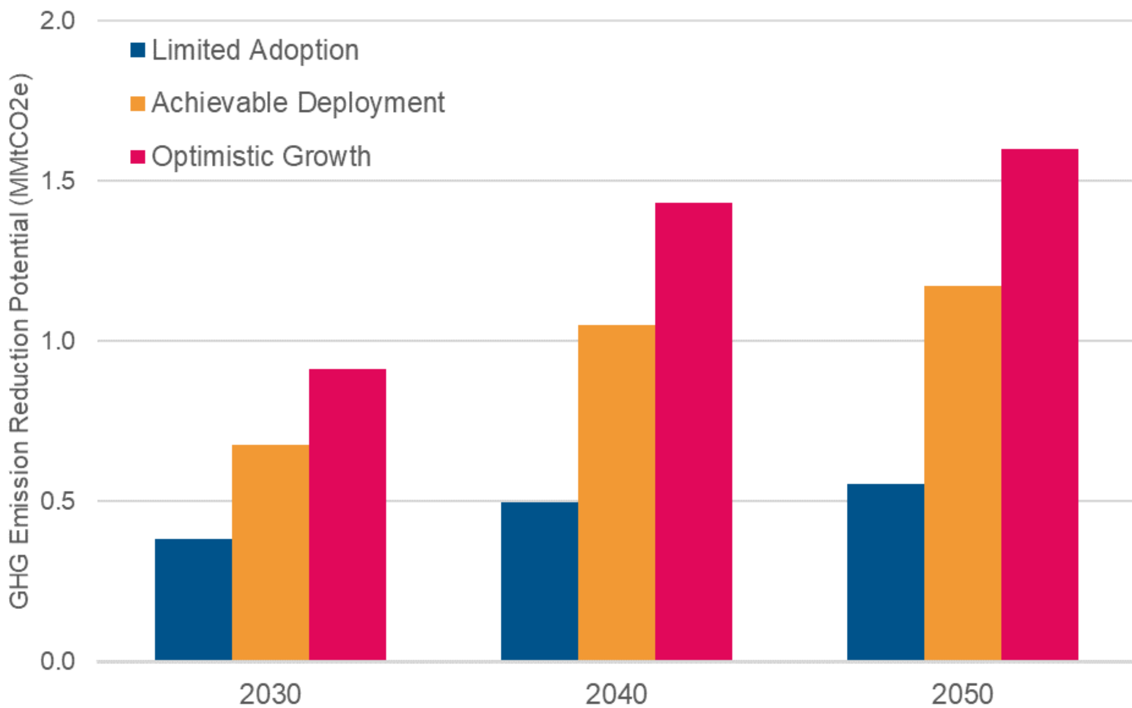


Figure 28. Total RNG Emission Reduction Potential by Scenario, $MMtCO_2e$ (Lifecycle)



6. RNG Policy Assessment

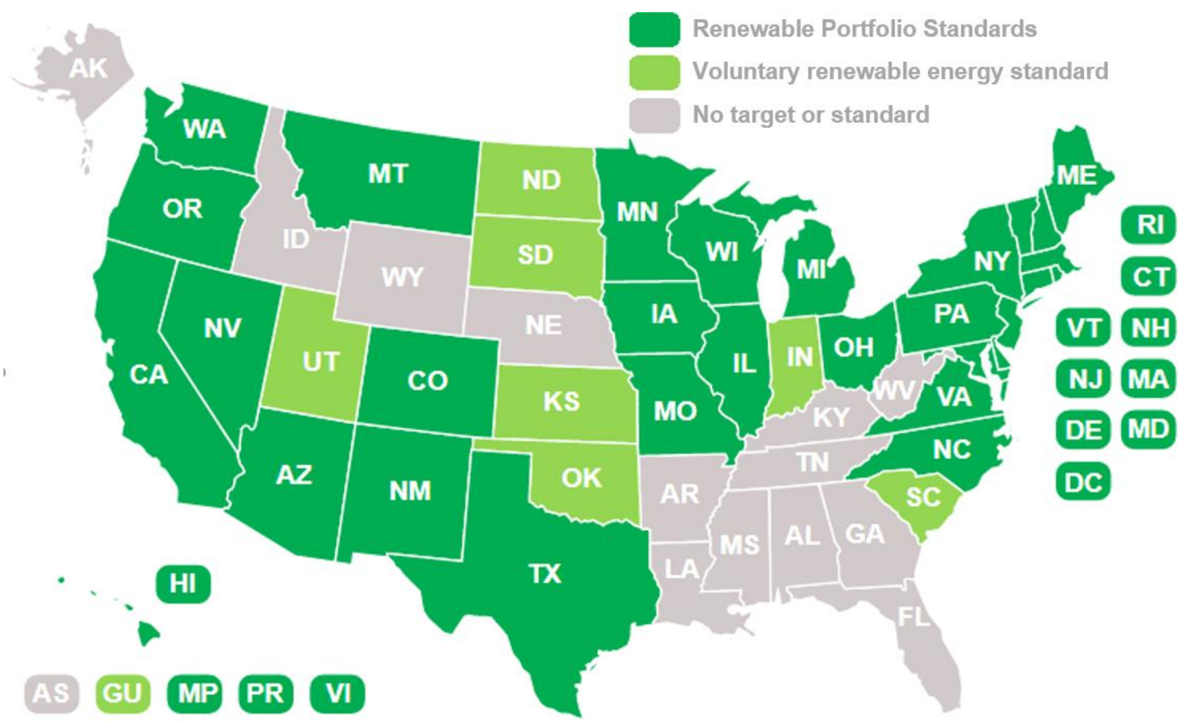
Review of End-Use Markets

RNG is a pipeline-quality gas that is fully interchangeable with conventional natural gas. As RNG is a “drop-in” replacement for natural gas, it can be safely employed in any end use typically fueled by natural gas, including electricity production, heating and cooling, and industrial applications, and as a transportation fuel. This section discusses the use of RNG for electricity generation, in the transportation market, and for pipeline injection. Interest in RNG has increased considerably over the last several years, especially for use in transportation.

Electricity Generation

Before the recent movement of RNG into the transportation sector, most biogas has been combusted on-site to generate electricity. The renewable electricity is typically used to comply with a Renewable Portfolio Standard (RPS), which requires a certain share of all final end user electricity consumption to come from eligible renewable generation technologies. 30 states and D.C. have passed mandatory renewable generation requirements or goals and seven more have passed voluntary standards or goals. Most of these programs include landfill gas as an eligible renewable resource, while some also include wastewater treatment plants and anaerobic digestion. Figure 29 shows the RPS requirements across the United States.

Figure 29. Renewable Portfolio Standards[48]



[48] National Conference of State Legislatures, 2020. https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx

Texas established a Renewable Generation Requirement in 1999, mandating 10,000 MW of installed renewable energy capacity by 2025, although Texas surpassed that target in 2009. Biomass-based waste products, including landfill gas, are eligible renewable energy technologies. There are nine landfill gas facilities currently participating in Texas's Renewable Energy Credit trading program, generating over 335 GWh of electricity in 2019.[49] Along with the statewide Renewable Generation Requirement, the City of Austin's community utility, Austin Energy, has set aggressive electric decarbonization objectives, with a goal of carbon-free electricity generation by 2035.[50]

The design of each RPS requirement varies by target and timing, type of renewable generation allowed, geographic scope within which a generator might be eligible to meet the standard, enforcement mechanisms, and escape clauses. State RPS programs face a number of near-term changes, two of the largest being the availability of federal tax incentives, namely the Investment Tax Credit and the Production Tax Credit.

Load-serving entities (LSEs) demonstrate compliance with a state's RPS by retiring Renewable Energy Credits (RECs). One REC is equal to one megawatt-hour of eligible renewable energy generation. RECs can be embedded in contracts for renewable energy or purchased on the open market. If an LSE is unable to acquire the necessary number of RECs, it will have to pay a penalty fee as set by the state. These fees, known as Alternative Compliance Payments (ACPs), act as a ceiling on REC prices.

The history of RECs in the renewable electricity market provides valuable lessons for RNG deployment. Stakeholders contemplated the concept of RECs as California considered an RPS in the mid-1990s, and this continued as multiple utilities and states advanced renewable electricity initiatives. The first retail REC product was sold in 1998.[51] REC markets helped to foster and stimulate growth of renewable power markets, as shown in Figure 30. By 2008, just five years after NREL started tracking renewable power markets in 2003, it was reported that REC markets accounted for nearly 65% of the annual renewable electricity consumed, which was three to four times greater than what was being consumed in utility green pricing programs or in competitive markets. Furthermore, this growth was occurring as the market continued to expand at a compound annual growth rate of 45%.[52,53]

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[49] Public Utility Commission of Texas, 2020. 2019 Annual Report of the REC Program, https://www.texasrenewables.com/staticReports/Annual%20Report/2019%20ERCOT%20Annual%20REC%20Report.pdf

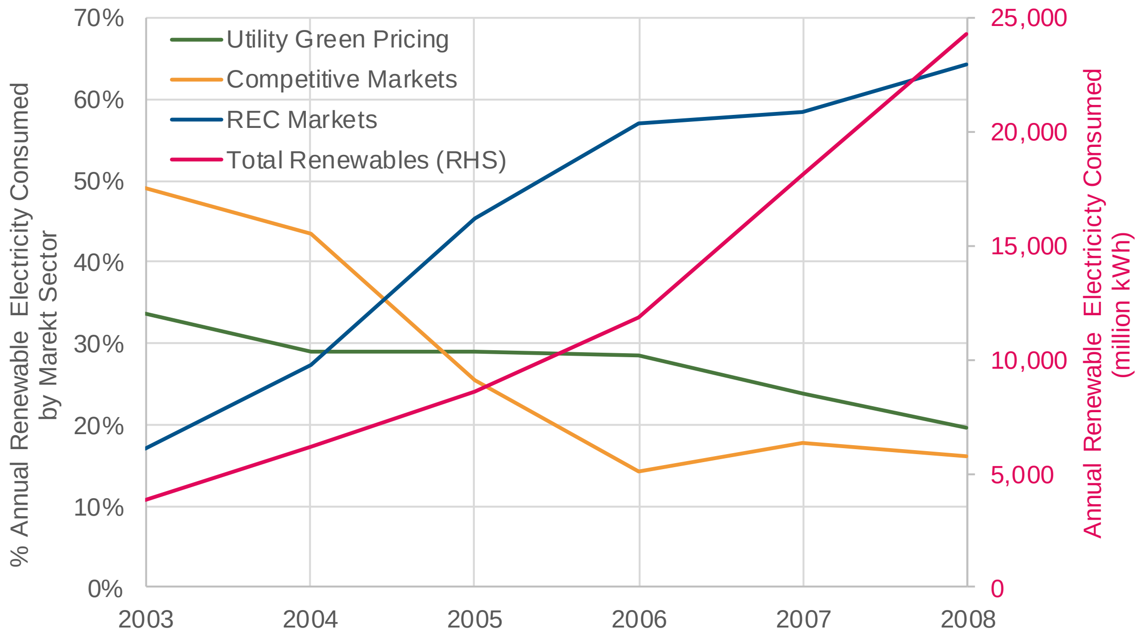
[50] Austin Energy, 2020. Austin Energy Resource, Generation and Climate Protection Plan to 2030, https://austinenergy.com/wcm/connect/6dd1c1c7-77e4-43e4-8789-838eb9f0790d/gen-res-climate-prot-plan-2030.pdf?MOD=AJPERES&CVID=n85G1po

[51] NREL, Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges, January 2005, NREL/TP-620-37388. https://www.nrel.gov/docs/fy05osti/37388.pdf

[52] NREL, Green Power Marketing in the United States: A Status Report (Tenth Edition), December 2007, NREL/TLP-670-42502, https://www.nrel.gov/docs/fy08osti/42502.pdf.

[53] NREL, Green Power Marketing in the United States: A Status Report (2008 Data), September 2009, NREL/TLP-6A2-46851, https://www.nrel.gov/docs/fy08osti/42502.pdf.

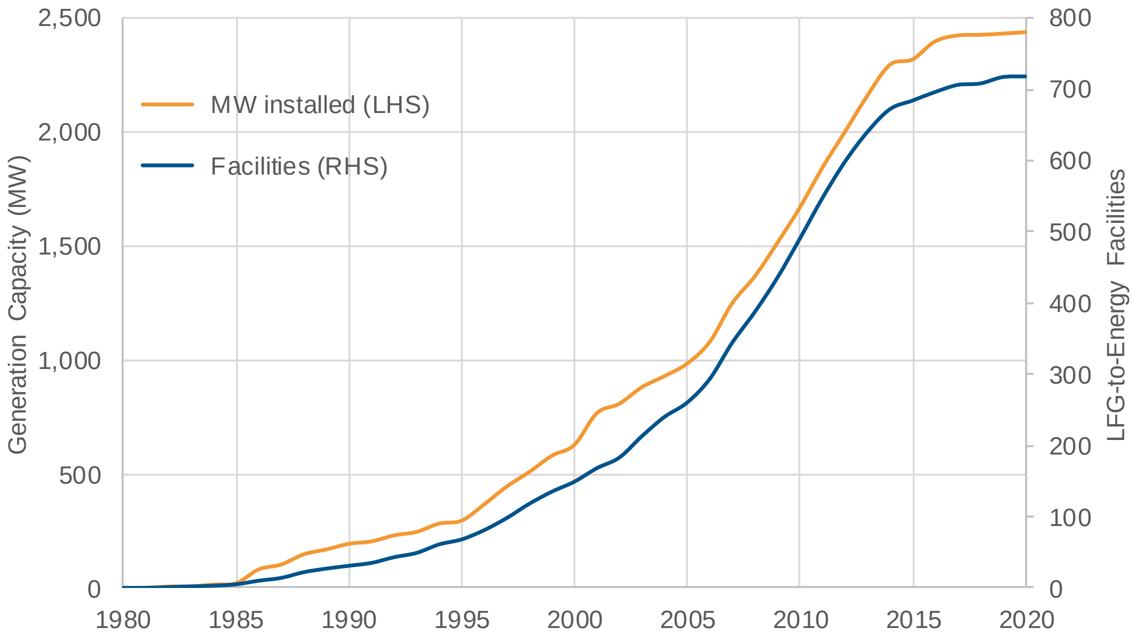
Figure 30. Percent and Total Renewable Electricity Consumption by Market Sector, 2003–2008



A primary feature of RPS policies is the segmentation of the renewable requirements into "Tiers" or "Classes." These Classes are differentiated by eligibility criteria, which may include technology type, geography, or vintage. RPS Classes may also represent "carve-out" requirements, which require that a subset of the overall RPS target come from a specific technology, such as Landfill Gas or Anaerobic Digestion.

Landfill gas plays a substantive role in many RPS programs. The EPA database of Landfill Gas Energy Projects indicates that there are currently more than 450 operational LFG-to-electricity projects with a capacity exceeding 2,000 MW—see Figure 31. There has been a noticeable decrease in the rate of installed capacity and facilities since 2014. For instance, for the years 2005–2014, an average of 26 new facilities were brought online annually with installed capacity of 318 MW annually. This has decreased to just 4–5 facilities annually over the last four years, with an installed capacity of just 25 MW annually. This is likely due to the availability of RINs and, to a lesser extent, LCFS credits. ICF anticipates this trend to continue plateauing for LFG-to-electricity projects as investors seek out higher value in the LCFS and RIN markets.

Figure 31. Facilities and Installed Capacity of LFG-to-Electricity Facilities[54]



Transportation

NGVs consume natural gas as compressed natural gas (CNG) or liquefied natural gas (LNG). Natural gas as a transportation fuel is primarily used in transit buses and fleet applications (including refuse haulers and over-the-road trucks), with over 175,000 NGVs on U.S. roads today. The more recent expansion of natural gas use in transportation is typically linked to goods movement and regional or short haul applications operating at or near port facilities.

NGVs are the most cost-effective vehicle technology to reduce local air pollutants and smog from heavy-duty trucks and buses. The latest commercially available natural gas engines are 90% cleaner than the EPA's current NOx emissions requirement, and 90% cleaner than the cleanest diesel engine.[55]

In addition, NGVs can be fueled with RNG with no changes to equipment or adverse impacts on performance. Over the last five years, RNG production for use as a transportation fuel has increased nearly six-fold, with over a third of all NGV fuel use relying on RNG in 2019.[56] This rise in RNG consumption in NGVs has been largely driven by the environmental crediting incentives provided by the federal RFS and carbon constraining policies like California's LCFS and Oregon's CFP, discussed in more detail below.

[54] ICF Analysis of LMOP Database.
[55] EPA and California Air Resources Board, 2018.
[56] NGV America, 2020. https://www.rngcoalition.com/infographic

RFS Program and RIN Prices

The RFS program sets volumetric targets for blending biofuels into transportation fuels across the entire United States—compliance is tracked through the production and retirement of Renewable Identification Numbers (RINs).[57] In most cases, a RIN is generally reported as an ethanol gallon equivalent. In 2013, the EPA determined that RNG qualified as an eligible fuel and could generate 'D3' RINs, with landfill RNG qualifying after meeting cellulosic content and GHG reduction thresholds. This led to a rapid expansion of RNG projects for pipeline injection and subsequent RNG use as a transportation fuel in NGVs.

In 2017, nearly 300 million RINs were generated by RNG projects domestically, with the RINs valued at approximately $2.50–$3.00 each, the equivalent of $29–$35/MMBtu of RNG. In 2018, these RINs traded lower along with other categories of RINs, but remained more resilient than other categories with a range of $2.00–$2.60 per RIN ($23–$30/MMBtu).

In 2019, the D3 RIN price was at historically low levels, around $0.60 per RIN, equivalent to roughly $7/MMBtu. In early 2020, the D3 RIN market showed signs of returning to its previous structure, before trailing off with other components of the energy complex due to the Covid-19 pandemic. However, that market has recently started to rebound and D3 RIN prices have maintained steady pricing above $1.50 in May and June 2020. ICF expects the prices to increase in Q3 and Q4 of this year. Furthermore, ICF forecasts a D3 RIN price in the range of $2.10 to $2.40 for 2021 based on the current outlook for gasoline pricing.[58]

California LCFS Program and Credit Prices

In California, carbon emissions are constrained based on a combination of California's Cap-and-Trade program and complementary measures, such as the LCFS program. The LCFS program targets the GHG emissions from transportation fuels. Low carbon fuels—such as ethanol, biodiesel, renewable diesel, and RNG—that are deployed in California have the potential to earn LCFS credits in the state-level LCFS program as well as RINs in the federal RFS program. Fuel providers are able to generate value in both the LCFS and the RFS programs by rule. The programs are implemented by tracking two different environmental attributes: the state-level LCFS program enables fuel providers to monetize the GHG reductions attributable to the fuel, whereas the federal-level RFS program monetizes the volumetric unit of the renewable fuel. This ability to "stack" environmental credits has led to significant increases in the volume of biodiesel, renewable diesel, and RNG consumption in California.

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[57] The RFS has four nested categories of fuels: renewable biofuels, advanced biofuels, biomass-based diesel and cellulosic biofuels, which are each represented by a different RIN type. RINs are the tradeable commodity in the RFS, with most RINs equivalent to one gallon of ethanol. RNG is eligible to generate D3 RINs, representing the cellulosic biofuel category, with one MMBtu of RNG equivalent to 11.67 gallons of ethanol (or RINs) based on energy density.

[58] Small refiners (i.e., those with an average annual crude oil input less than 75,000 barrels per day) are allowed to petition the U.S. EPA for an economic hardship waiver from their obligations under the federal RFS—these are referred to as small refinery exemptions (SREs). The rate of SREs submitted and granted have more than quadrupled under the Trump Administration, undercutting the renewable volume obligations (RVO) annually by about 10%. As a result of these exemptions, up to 2019 the D3 RIN market had been significantly over-supplied, and prices collapsed.

ICF estimates that 65–70% of the 30–35 BCF (390–450 million diesel gallons) of RNG produced in 2018 was delivered to California, generating both the RINs and the LCFS credits. In 2017, LCFS credits traded for $60–$115/ton, which was equivalent to about $3–$6/MMBtu of RNG from landfills, and $20–38 for animal manure (dairy) RNG. In 2018, prices rose past $150 per ton, and traded up into the low $190s per ton. More recently, throughout 2019 and into 2020, LCFS credits have consistently traded above $190/ton.

In late 2019, CARB considered and adopted a maximum tradeable price for LCFS credits equivalent to the value of credits established in the Credit Clearance Market—equal to $200/ton in 2016 dollars and adjusted for inflation. This went into effect January 1, 2020. This change has transitioned the program to a hard cap. In ICF's view, there are limited ways that regulated parties could avoid the hard cap and pay a higher price—ICF anticipates that this would require paying a higher price on the physical fuel (e.g., ethanol) being purchased by a regulated party. ICF considers this possible, but unlikely given the risk of drawing the ire of CARB for circumventing the intended cap on credit prices.

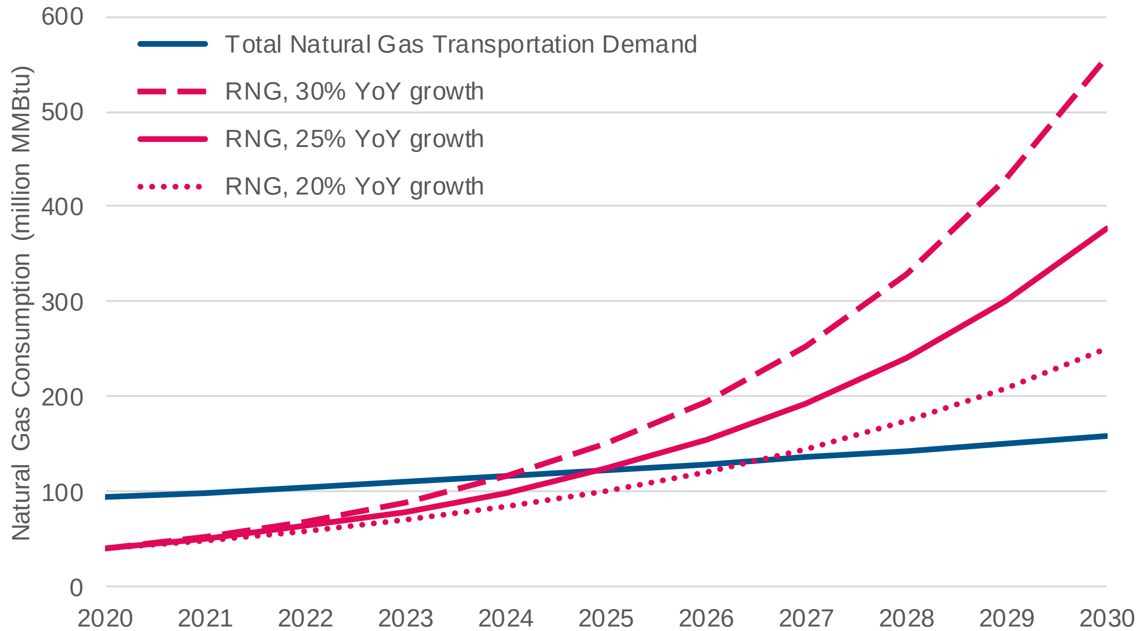
RNG Consumption in Transportation

The chart below shows ICF's estimates for total natural gas consumption as a transportation fuel in the U.S. and forecasted RNG production capacity. These estimates are based on a combination of national-level data from the EIA, California-specific data reported via the LCFS program, and ICF's analysis of potential RNG projects. In this scenario, we assume a growth rate of natural gas at about 5% year-over-year out to 2030. For RNG, we show year-over-year growth between 20% and 30% out to 2030.

Figure 32 helps demonstrate the potential for suturing the demand for natural gas as a transportation fuel with RNG production in the 2024–2027 timeline. This rising RNG consumption in the transportation sector is shown by the largest RNG procurement agreement between Clean Energy and logistics company UPS, where UPS will fuel its CNG vehicle fleet with RNG.[59]

[59] GreenBiz, 2019. 'UPS to buy huge amount of renewable natural gas to power its truck fleet', https://www.greenbiz.com/article/ups-buy-huge-amount-renewable-natural-gas-power-its-truck-fleet

Figure 32. Natural Gas as a Transportation Fuel



Most of the RNG that is currently delivered to and dispensed in California is derived from landfills. ICF anticipates a shift towards lower carbon intensity RNG from feedstocks such as the anaerobic digestion of animal manure and digesters deployed at WRRFs. Over time, these lower-carbon sources will likely displace higher-carbon intensity RNG from landfills. The role of RNG post-2020 in the LCFS program will be determined by the market for NGVs. If steps are taken to foster adoption of NGVs, particularly in the heavy-duty sector(s), then this will be less of an issue. The introduction of the low-NOx engine (currently available as 9L, 12L, and 6.7L engines) from Cummins may help jumpstart the market, especially with a near-term focus on NOx reductions in the South Coast Air Basin, which is in severe non-attainment for ozone standards.

In an RNG transportation saturation scenario, there are many outcomes—we consider two. In one case, a share of the RIN price would have to be dedicated to inducing demand; in another case, the RIN price would have to go up to reflect the higher cost of dispensing a marginal unit of natural gas (rather than just displacing the fueling of fossil natural gas with renewable natural gas). In other words, there is some cost associated with getting additional supply on the system, and that can come out of either existing RIN pricing or increasing RIN pricing to account for that. To summarize, ICF anticipates that for RNG in the transportation sector to continue growing, market actors must be savvier with respect to pricing the fuel more competitively.

Transportation Demand in Austin and the CTX Service Area

The transportation sector remains an area of untapped demand for RNG in Austin and the surrounding region, and a viable near-term opportunity to direct relatively cost-effective RNG supply. The region is home to operators of large and small NGV fleets, including the City of

Austin, other local governments, and corporate fleets, which could provide feasible starting points to drive RNG demand.[60]

NGVs fueled by RNG would be eligible to generate RINs under the RFS program, presenting opportunities for participants in the NGV and RNG markets in the Austin region to capture the associated value of RINs. While contractual arrangements can vary substantially, fleet owners and operators, infrastructure owners, and natural gas distributors can all potentially facilitate and benefit from RNG deployment.

Pipeline (Stationary)

Lastly and crucially for long-term decarbonization strategies, RNG is also a drop-in replacement for pipeline natural gas used in stationary applications, such as for heating and cooling, and commercial and industrial applications. As currently constructed, in general the policy framework does not encourage RNG use in these stationary applications, instead directing RNG consumption to the transportation and electricity generation sectors.

However, there is growing interest from some policymakers and industry stakeholders to grow the production of RNG for pipeline injection and stationary end-use consumption. With deep decarbonization goals becoming more prevalent, the ability to use an existing energy system to deliver significant emission reductions is highly valuable. RNG as a decarbonization approach for stationary energy applications provides two critical advantages relative to other measures:

- Utilizes existing natural gas transmission and distribution infrastructure, which is highly reliable and efficient, and already paid for, and
- Allows for the use of the same consumer equipment as conventional gas (e.g., furnaces, stoves), avoiding expensive retrofits and upgrades required for fuel-switching.

There is growing activity outside the transportation sector, and in particular the construct of the LCFS program, where so much attention is paid today. Southern California Gas Company (SoCalGas) announced that they intend to have 5% RNG on their system by 2022 and 20% by 2030. SoCalGas is also seeking approval to allow customers to purchase RNG as part of a voluntary RNG tariff program. Despite the challenges of its bankruptcy, Pacific Gas & Electric is close to announcing a more nuanced approached to its RNG strategy.

Momentum for RNG is not just in California where carbon-constraining policies are the most restrictive in the United States. Gas utilities and local distribution companies (LDCs) are either volunteering or being forced to take a closer look at RNG across the country:

- Approved in 2017, Vermont Gas offers a voluntary RNG tariff program, providing retail gas customers the opportunity to purchase RNG in amounts proportionate to their monthly requirements.
- Consolidated Edison is very focused on RNG for pipeline injection as part of its consideration for the future of heating.

[60] Lone Star Clean Fuels Alliance, 2018. 2017 Transportation Technology Deployment Report, https://lonestarcfa.org/wp-content/uploads/2018/04/Clean-Cities-2017-Annual-Report-TX-Lone-Star-Clean-Fuels-Alliance-Central-Texas-Expanded-Edition.pdf

- National Grid's New York City Newtown Creek RNG demonstration project will be one of the first facilities in the U.S. that directly injects RNG into a local distribution system using biogas generated from a water and food waste facility.
- The joint venture between Dominion Energy and Smithfield Foods is set to become the largest RNG producer in the U.S., developing animal manure-based RNG in North Carolina, Virginia, and Utah, with plans to expand to California and Arizona.

Driven by corporate sustainability goals and customer preferences, a growing number of large end users of natural gas are looking into RNG as an option to reduce GHG emissions. Global cosmetics manufacturer L'Oréal uses RNG from a nearby landfill facility at its plant in Kentucky. L'Oréal's long-term purchase commitment for the RNG was a key underwriting component that led to the financing of the LFG project.

In ICF's view, the renewed focus on pipeline injection and consumption of RNG by utilities, LDCs, and large end users is an overwhelmingly positive signal for the RNG developer community. While there is clearly a near-term focus on reaping the benefits of credits generated in the LCFS program and RINs in the RFS program, the long-term potential for increased volumes of RNG outside the transportation sector is considerably more robust than many stakeholders may realize. With appropriate incentives that fully capture the environmental benefits of RNG, the end-use demand for RNG from stationary applications is substantial, in contrast to the limited demand in the transportation sector.

Interconnection and Gas Quality

For RNG to be suitable for introduction into the natural gas pipeline network, the initial raw biogas must be adequately processed to meet gas quality and end-use application standards. At a high level, this typically involves concentrating the methane content and removing any problematic constituents.

While RNG is fundamentally interchangeable with conventional natural gas, different RNG feedstocks pose different challenges for gas quality and composition. For example, raw (unprocessed) biogas from a landfill facility is different than biogas from a dairy digester. Biogas constituents of classes vary by feedstock and conversion technology, and testing requirements need to be aligned to optimize results and processing requirements. ONE Gas's acceptable gas quality terms for normal operations depend on a variety of factors, including the dilution of RNG when injected into the system and the feedstock type. Table 44 below shows an example of limits.

Table 44. Illustrative ONE Gas Quality Considerations for RNG Injection

Gas Quality Term	Generally Acceptable Limit
Hydrogen Sulfide	0.25 g/100 scf
Total Sulfur	5 g/100 scf
Carbon Dioxide (CO_2)	≤ 2.0%, by volume
Oxygen (O_2)	≤ 0.2%, by volume
Total Inerts (% by volume including O_2 and nitrogen)	≤ 5%, by volume
Heating Value	900 – 1,100 Btu
Temperature	40 – 140 °F
Water or Liquid Hydrocarbons	0
Water Vapor	< 7 lb/MMscf
Non-Hydrocarbon Gas	≤ 4%, by volume
Mercury	0.06 $\mu g/m^3$
Siloxanes	0.00 mg/m^3
Halocarbons	6.22 ppmv

Each element has a differing impact on gas quality and safety, interchangeability, end-use reliability and pipeline integrity. If a constituent is not reasonably expected to be found above background levels at the point of interconnect for the RNG, then testing may not be necessary. An additional challenge is that while some constituents may not present a problem in isolation, the interaction between different constituents could result in negative impacts on the pipeline or end-use applications.

Substantial research, testing and analysis has been done to better understand the composition of raw biogas from different feedstocks compared to traditional pipeline-quality natural gas delivered into the natural gas system. In parallel, significant technology advancements have been achieved in processing and treating raw biogas to address trace constituents and the concerns of pipeline operators and end users.

For example, at the direction of the California Public Utilities Commission, the California Council on Science and Technology (CCST) assessed acceptable heating values and maximum siloxane specifications for RNG. CCST found that keeping the current minimum Wobbe Number requirement for RNG while relaxing the heating value specification to a level near 970 Btu/scf would not likely impact safety or equipment reliability. In relation to siloxanes, the CCST found that some RNG feedstocks are very unlikely to harbor siloxanes (e.g. dairy waste, agricultural residues or forestry residues), and less stringent monitoring requirements would be needed. The CCST also recommended a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes, due to inconclusive evidence for other RNG feedstocks.[61]

However, the lack of a consistent approach to evaluate RNG quality and constituent composition remains a challenge to the broader acceptance of different RNG feedstocks and inhibits the development of RNG as a source for pipeline throughput. The industry is still learning about RNG and the impact on pipeline infrastructure and end use, and it is in the industry's best interest to continue research, collaboration, and dissemination of biogas processing and RNG pipeline injection experience, particularly as more RNG facilities come online.

An evidence-based, common-sense framework is needed to assess the composition and interchangeability of RNG with conventional natural gas supplies and pipeline requirements. As currently constructed, the processes, requirements, and agreements that facilitate the pipeline connection of RNG projects are not uniform, resulting in commercial and technical uncertainties for stakeholders that limit the efficiency and, potentially, the viability of different RNG projects.

Instead, a consistent and impartial approach to assess the commercial and technical potential of each project is required to encourage the introduction of RNG from a range of biomass feedstocks, without compromising the safety or reliability of the pipeline or end-use applications. In addition, a uniform approach would provide greater certainty for all parties regarding safety, reliability, and interchangeability.

Regulatory and Policy Opportunities

The aforementioned regulatory and policy incentives for the use of RNG as a transportation fuel have helped spur substantial investment in new RNG projects nationwide. However, the demand for RNG as a transportation fuel is limited and tied to the growth of NGVs. Therefore, a regulatory and policy structure that supports the cost-effective use of pipeline-injected RNG as a GHG mitigation strategy is paramount to the long-term success for RNG.

Today, a handful of state-level policies are in place that are helping to shape the outlook for RNG beyond transportation, including the legislation summarized below.

- Oregon SB 98: allows natural gas utilities to make "qualified investments" and procure RNG from 3rd parties to meet portfolio targets for the percentage of gas purchased for distribution to retail customers. The RNG portfolio targets range from 5% between 2020 and 2024 to 30% between 2045 and 2050.
- California SB 1440: requires the California Public Utility Commission to establish RNG procurement goals or targets on natural gas investor-owned utilities. The legislation stipulates that the goals and targets need to be a cost-effective means of achieving reductions in short-lived climate pollutants and other GHG emission reductions.
- Nevada SB 154: authorizes natural gas utilities to engage in RNG activities and to recover the reasonable and prudent costs of such activities, including the purchase of and production of RNG. The legislation also includes voluntary procurement targets of not less

[61] CCST, 2018. Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications, https://ccst.us/reports/biomethane/.

than 1% of the total amount of gas sold by 2025, not less than 2% by 2030, and not less than 3% by 2035.

An existing suite of regulatory initiatives and policies could help support RNG deployment in the near- to long-term future. These include conditioning and interconnection tariffs, voluntary offerings paid by customers, and a renewable gas standard, summarized in the following subsections.

Condition and Interconnection Tariffs

As outlined in Section 4, the costs of biogas conditioning and upgrading can be expensive; similarly, interconnection costs can be prohibitive for some project developers. These costs are the primary capital outlays at the outset of a project and have a material impact on the ability of projects to get financed. Under a tariff structure, the producer can avoid the significant upfront capital costs that can often impede project development.

Conditioning and interconnection tariffs allow utilities or LDCs to build and operate the upgrading and interconnection facilities, while recovering capital and operation and maintenance costs from the project developer at a pre-determined rate. Examples of where this has been done include:

- SoCalGas has a biogas conditioning and interconnection tariff; it "is an optional tariff service for customers that allows SoCalGas to plan, design, procure, construct, own, operate and maintain biogas conditioning and upgrading equipment on customer premises."[62]
- TECO Peoples Gas in Florida had a tariff for biogas conditioning and upgrading approved in December 2017, and have since made modifications to the tariff to accommodate the receipt of RNG from biogas producers and an updated rate schedule for conditioning services.[63]
- Southwest Gas Company (SWGC) in Arizona has a biogas services tariff enabling them to enter into a service agreement with a biogas or RNG producer, and includes requirements for access to the production facilities, interconnection facilities, and gas quality testing facilities.[64]

Voluntary and Mandatory Programs

Utilities may offer opt-in voluntary programs to customers to help reduce the environmental impact of their energy supply. This is more common for electric utilities, such as Austin Energy's GreenChoice program, which is a voluntary program that allows residential and commercial customers to opt-in and purchase electricity generated from Texas-based wind power projects.[65] Similar programs can be developed for gas utility customers, but for RNG consumption rather than renewable electricity.

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[62] SoCalGas, information retrieved from https://www.socalgas.com/for-your-business/power-generation/biogas-conditioning-upgrading.
[63] TECO Peoples, tariff is available online at https://www.peoplesgas.com/files/tariff/tariffsection7.pdf.
[64] SWGC, Schedule No. G-65, Biogas and Renewable Natural Gas Services , available online at https://www.swgas.com/1409197529940/G-65-RNG-02262018.pdf.
[65] Austin Energy, 2020. https://austinenergy.com/ae/green-power/greenchoice/greenchoice-renewable-energy

Examples of voluntary programs include:

- Vermont Gas has had a voluntary program in place since 2018 for various blends of RNG. Vermont Gas customers consume about 6 BCF of RNG, which is sourced from Canada.[66]
- In April 2020 SoCalGas and San Diego Gas & Electric (SDG&E) requested settlement approval from the CPUC to offer a voluntary RNG Tariff program to their residential, small commercial, and industrial customers. SoCalGas and SDG&E have proposed to recoup program costs through rates charged to program participants.[67]
- National Grid proposed a Green Gas Tariff offering in April 2019 that will enable its customers to voluntarily purchase RNG to meet all or a portion of their energy needs. National Grid designed the tariff with four tiers, providing consumers with multiple options regarding the extent to which they want to green their gas.
- FortisBC, the main gas utility in the Canadian Province of British Columbia, has had a voluntary RNG tariff program since 2011, which has spurred RNG production in the region.[68]

Voluntary programs and opt-in green tariffs provide near-term opportunities for natural gas utilities, and regulators, to become accustomed to RNG and the RNG market, without requiring substantial and long-term commitments. An appropriate regulatory structure can support small-scale RNG deployment without imposing a large burden on customer bills and avoiding undue risk on the utility. For example, FortisBC's voluntary program provides an RNG cost cap of approximately $20/MMBtu, but the utility has been able to procure RNG at lower costs, with the current bill premium for RNG about $5.50/MMBtu.[69]

In addition, the recently approved voluntary tariff for SoCalGas and SDG&E includes provisions that allow for the true-up of any over or under collections related to the voluntary tariff, with future program charges adjusted to reflect these updates. At a high level these regulatory elements could be replicated to provide customers with choice, as well as minimizing risks for customers, RNG producers and natural gas utilities.

Voluntary markets were critical to the initial growth of renewable electricity, as residential and non-residential customers helped grow demand considerably in the early years of renewable electricity development (see Figure 33).[70,71]

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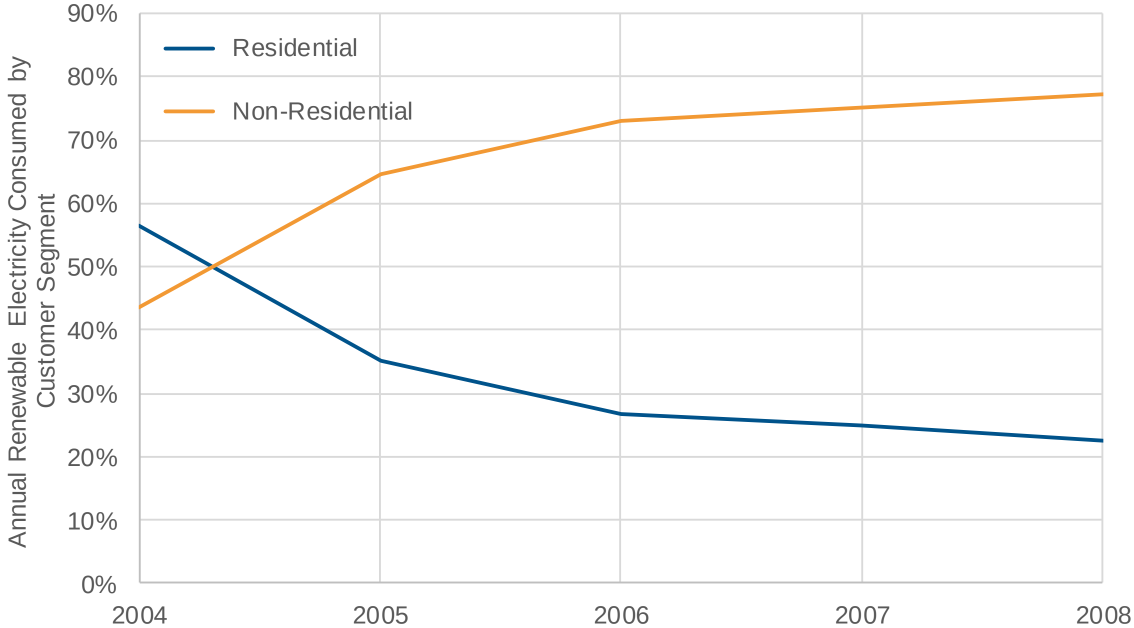
[66] Vermont Gas, 2020. https://www.vermontgas.com/renewablenaturalgas/.
[67] SoCalGas, 2020. Application 19-02-015 https://www.socalgas.com/sites/default/files/Joint%20Motion%20for%20Approval%20of%20Settlement%20-%204-13-20%20Final.pdf
[68] FortisBC, 2020. https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas
[69] FortisBC, 2020. https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas/renewable-natural-gas-rates
[70] NREL, Green Power Marketing in the United States: A Status Report (Tenth Edition), December 2007, NREL/TLP-670-42502, https://www.nrel.gov/docs/fy08osti/42502.pdf.
[71] NREL, Green Power Marketing in the United States: A Status Report (2008 Data), September 2009, NREL/TLP-6A2-46851, https://www.nrel.gov/docs/fy08osti/42502.pdf.

Figure 33. Percent Annual Renewable Electricity Consumption by Customer Segment, 2004–2008



Renewable electricity accounts for more than 20% of today's total electricity generation. However, less than 15 years ago, renewable electricity accounted for less than 1% of total electricity generation as voluntary renewable electricity programs started in earnest. This nascent growth helped achieve some cost reductions, raise consumer awareness, and spur action by non-residential customers. Furthermore, it helped to demonstrate the demand for renewable products, and served as the launching point for more structured regulatory action via renewable portfolio standards.

Renewable Gas Standard (RGS)

The principles of an RGS are straightforward and mimic RPS programs, a common policy tool to introduce a renewable energy procurement requirement for electricity providers. In other words, an RGS would require RNG to be delivered and measured against some benchmark, such as a carbon-based reduction or volumetric target. There are a variety of approaches to RGS implementation, including:

- A free-market approach whereby a procurement target is established and the market simply responds to the price signal according to the supply-cost curve for RNG production.
- A feed-in tariff, or standard offer contracts, would provide clear, reliable pricing for RNG producers. Although this approach provides a clear signal to help producers finance renewable gas projects, without distinguishing between feedstocks, a feed-in tariff has the potential to favor low-cost producers without recognizing the cost-effectiveness of GHG emission reductions.
- The RGS could take on a performance-based approach structure like the LCFS program in California, requiring a percent reduction in the carbon intensity of natural gas by some date. Similarly, the RGS could take on a structure that requires a percent volume target by some

date (different from an absolute volumetric target, as is prescribed in the federal RFS program).

- The coverage of an RGS would not necessarily be limited to just utilities and LDCs, but also encompass all suppliers of natural gas, including third-party suppliers such as natural gas marketers, similar to the broad coverage of RPS programs relative to electric load serving entities.

There are two additional aspects of an RGS that ICF considers critical: 1) tracking and verifying progress toward achieving an RGS and 2) understanding the tradeoffs of various performance-based approaches.

Tracking and Verification

With increased interest in voluntary and compulsory regulations and policies in place supporting the use of RNG, the market for tracking and verifying RNG has advanced rapidly. This will be critical in light of the potential for an RGS. Renewable electricity markets rely on various bodies to track and verify RECs, the primary regulatory currency for RPS programs.

There is no analogous tracking system for RNG today, however, market actors are advancing the concept rapidly to help grow the market for RNG consumption outside of the transportation sector. The Midwest Renewable Energy Tracking System (M-RETS) has been trialing a thermal REC system since July 2019, which includes RNG used in stationary applications such as building heating and cooling. The intent is to provide the same verification and price transparency to the RNG market as exists in the renewable electricity market.

Performance-based Approaches

In 2017 ICF researched and wrote about understanding the tradeoffs between different performance-based approach tradeoffs, focused on volumetric and carbon intensity targets. A performance-based approach should, in principle, provide clear signals to regulated parties and investors regarding the timeline required to achieve program targets, whether it be a carbon intensity target or volumetric target.

The downside of a carbon intensity target is that it may introduce undue complexity to the RGS. For instance, consider the boundary conditions of the lifecycle GHG assessment of dairy digester gas. Without regulations in place to capture and burn the methane that is released, the gas receives a lower carbon intensity for being credited with the avoided emissions from venting methane. Landfill gas, on the other hand, being regulated and required to be captured and burned, receives a lower carbon intensity for being credited with the avoided emissions from flaring methane. The difference in the GHG benefit of avoided methane venting versus avoided methane flaring is tremendous: in the case of the former, you are avoiding methane emissions at a 100-year global warming potential of 25, whereas in the latter you are avoiding carbon dioxide emissions with a global warming potential of 1. Furthermore, if complementary regulations are enacted that improve waste (or manure) management, these could impact the carbon intensity of the RNG, simply by changing the boundary conditions of the analysis.

Another consideration related to a carbon intensity-based approach is the potential for the intent of the program to be expanded unexpectedly to include upstream emission reductions; e.g., methane leaks in the natural gas pipeline. This could provide additional compliance opportunities for utilities that produce additional GHG benefits, but may detract from the intent of stimulating RNG development. Additionally, and similar to the example above, other regulations and programs that address these system improvements could complicate the benefit calculation, creating moving targets and challenging utilities' assessments of investment value for different compliance pathways.

Complementary Measures

Energy Efficiency

Promoting energy efficiency measures is a cost-effective approach to reduce GHG emissions and help contribute to meeting both near- and long-term decarbonization objectives. Energy efficiency measures avoid the need for new energy infrastructure, promote resource conservation, and lower customer bills. Energy efficiency programs are also a large source employment and growth in the energy sector, including for construction, equipment production and manufacturing, installation, maintenance and repair.

Energy efficiency programs can focus on consumer behaviors, such as providing information on energy performance to induce changes in behaviors that lead to energy savings. Typical information includes practical energy conservation tips and recommendations, as well as cross promotions of other utility programs.

Equipment and building upgrades are another form of energy efficiency program. These programs typically include rebates or upfront cost reductions for the purchase and installation of high-efficiency equipment or infrastructure.

Carbon Offsets

Carbon offsets are a method for entities to meet GHG obligations through emission reductions that occur beyond their operations or facilities. A carbon offset represents a reduction of, or avoided, GHG emissions made in one place to compensate for GHG emissions generated at another location. Typically carbon offset credits represent one metric ton of CO_2e, and can be traded, purchased and retired to offset, or balance, GHG emissions elsewhere.

Offset credits are a mechanism to transfer a net GHG emission reduction from one entity to another. In contrast to localized pollutants, as greenhouse gases mix in the atmosphere and have a global climatic effect, it does not matter where GHG emission reductions occur. From a climate impact perspective, the effects are the same if an organization reduces emissions-intensive activities, or enables an equivalent emission-reducing activity somewhere else in the world. Carbon offsets are intended to make it more cost-effective for organizations to pursue GHG emission reductions, particularly if direct emissions abatement opportunities are expensive or not technically feasible.

Carbon offset credits can be generated from a variety of projects across multiple sectors, and can deliver additional economic and environmental benefits for project participants beyond GHG reductions. Costs for developing offset projects can vary significantly depending on the project type. Examples of project activities include:

- Land-use: sustainable forest management, urban forestry, afforestation and avoided deforestation.
- Agriculture: crop management, and avoided methane from livestock.

- Industrial: energy efficiency, ozone-depleting substance (refrigerant and foam) destruction, and fuel switching.
- Transportation: public transit, and traffic management.

A key component of carbon offset projects is 'additionality'. Additionality refers to the concept that the offset would not have occurred in a business-as-usual environment. Additionality tests attempt to ensure that the GHG emission reduction activities credited for an offset project would not have otherwise taken place without the value generated by the offset. Additionality tests include legal, regulatory, financial, barriers, common practice and performance tests. Depending on the complexity and uniqueness of an offset project, a combination of tests can be applied that bests demonstrates additionality.

In the case of natural gas consumption, carbon offsets would offset GHG emissions associated with the combustion of conventional natural gas by residential and commercial customers. Numerous natural gas utilities and suppliers offer customers the opportunity to reduce their carbon footprint through the use of offsets, such as National Gas and Electric, Washington Gas and NW Natural.

There are a number of offset trading platforms and markets where entities can purchase offset credits, including the Climate Action Reserve and American Carbon Registry. The costs to generate offsets, and the market prices for offsets, can vary based on the project as well as the monitoring and verification requirements for offset accreditation. For example, to generate eligible offsets for use in California's cap-and-trade (C&T) program requires project developers to comply with robust accreditation protocols.[72] Different voluntary offset protocols also offer robust accreditation frameworks, such as the global Gold Standard offset framework.[73]

The prices for offsets can also vary significantly, driven by the project itself, as well as the certification and accreditation framework, and other market factors. In general, offsets with accreditation from more robust and comprehensive certification schemes have higher prices. For example, as of June 2020 certified offsets in California's C&T are trading at approximately \$14/tCO_2e.[74] In contrast, Certified Emission Reductions (CER) accredited under the Clean Development Mechanism have traded at less than \$1/tCO_2e for the past five years.[75] Voluntary offset credit frameworks have shown a wide variance in prices, in part driven by the preferences of offset purchasers, including project types and accreditation schemes. In 2018 the transacted prices of various voluntary offset credits ranged from under \$1/tCO_2e to over \$70/tCO_2e.[76]

Offsets provide a relatively cost-effective and immediate opportunity to reduce GHG emissions, whether for an organization to meet climate objectives, or as a mechanism for customers to voluntary offset their carbon footprint. Offsets also offer the potential to reduce GHG emissions in the near-term, allowing time for the development and implementation of other decarbonization

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[72] See CARB's Compliance Offset Program, https://ww3.arb.ca.gov/cc/capandtrade/offsets/offsets.htm.
[73] See the Gold Standard Guide, https://www.goldstandard.org/project-developers/standard-documents.
[74] ICE, 2020. California Carbon Offset Futures Report, https://www.theice.com/marketdata/reports/142
[75] ICE, 2020. CER Futures Report, https://www.theice.com/products/814666/CER-Futures/data?marketId=1240048&span=3
[76] World Bank, 2019. State and Trends of Carbon Pricing 2019, http://documents.worldbank.org/curated/en/191801559846379845/pdf/State-and-Trends-of-Carbon-Pricing-2019.pdf.

technologies and strategies. However, given the ambitious long-term climate objectives of various jurisdictions, including the City of Austin's net zero GHG by 2050 goal, carbon offsets will likely provide a complementary role relative to other decarbonization initiatives, rather than serving as a central strategy for current major sources of GHG emissions.

Waste Diversion

Waste diversion policies can help stimulate and capture RNG feedstock collection. The RNG industry could benefit considerably from complementary policies that help improve the accessibility of feedstocks while improving project development economics. This includes regulations or policies that encourage methane capture, encourage waste diversion and waste utilization, and forest management and thinning requirements.

The City of Austin's Zero Waste by 2040 goal, and accompanying Resource Recovery Master Plan, provides the overall framework for productive waste diversion activities. For example, the Master Plan identifies the enhanced role of the Hornsby Bend facility to process organic wastes such as yard trimmings and potentially food scraps.[77] The objective to capture organic waste streams for productive uses would work in tandem with, and encourage, the expansion of anaerobic digestion capacity, and RNG production and use in the region.

[77] City of Austin, 2011. Resource Recovery Master Plan, https://www.austintexas.gov/sites/default/files/files/Trash_and_Recycling/MasterPlan_Final_12.30.pdf

7. Economic Impact Assessment

IMPLAN Model Overview

In this analysis, the economic impacts were calculated analyzed using the IMPLAN (IMpact analysis for PLANning) online input-output model.[78] Input-output analysis is a form of economic analysis based on the interdependencies between economic sectors. Input-output is commonly used to estimate the impacts to an economy of specific actions, and to analyze the resulting ripple effects.

IMPLAN is developed and maintained by the Minnesota IMPLAN Group, and contains 546 sectors representing all private industries in the United States as defined by the North American Industry Classification System (NAICS) codes. Employment, employee compensation, industry expenditures, commodity demands, and relationships between industries form part of IMPLAN's database.

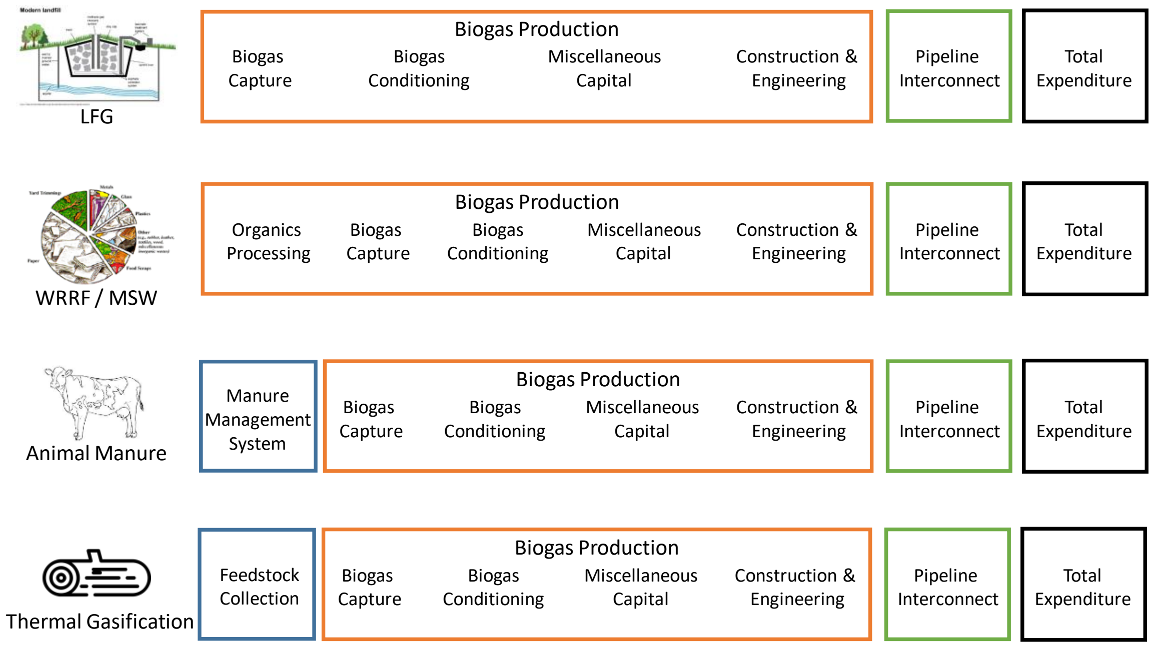
The IMPLAN model is a static input-output framework used to analyze the effects of an economic stimulus on a pre-specified economic region; in this case, on several scales including Travis County, ONE Gas's Central Texas Service Area, and Texas. IMPLAN is considered static because the impacts calculated by any scenario by the model estimate the indirect and induced impacts for one time period (typically on an annual basis).

Modeling Inputs

ICF accounted for multiple expenditures associated with RNG production, including digester equipment, biogas conditioning equipment, miscellaneous support equipment, and construction/engineering costs; as well as pipeline for utility interconnection. These are summarized in Figure 34 below.

[78] IMPLAN was developed by the Minnesota IMPLAN Group (MIG). There are over 1,500 active users of MIG databases and software in the United State as well as internationally. They have clients in federal and state government, universities, as well as private sector consultants. More information is available at www.implan.com

Figure 34. RNG Production Steps Considered in Analysis



In each case, we also included the annualized cost of operating and maintaining RNG production processes, including digester-related equipment, and pipelines. ICF estimated the costs for each RNG pathway by developing illustrative facilities for each feedstock type (as shown in Table 45 below). Table 45 includes the assumed biogas throughput for illustrative facilities by RNG production facility type, in units of standard cubic feet per minute (SCFM).

Table 45. Illustrative RNG Production Facilities Considered, by Feedstock Type

Feedstock Type	Illustrative Facility		
	Small	Medium	Large
Animal Manure			
Biogas output (SCFM)	90	180	300
Share of Facilities	65%	17.5%	17.5%
Landfill Gas			
Biogas output (SCFM)	1,680	2,880	4,800
Share of Facilities	20%	40%	40%
WRRFs			
Biogas output (SCFM)	50	110	530
Share of Facilities	30%	50%	20%
Thermal Gasification			
Feedstock processed (tpd)	200	1,000	2,000
Share of Facilities	60%	20%	20%

Results Overview

The economic impacts of RNG production are characterized by employment, labor income, and industry output.

- **Employment** is reported in terms of annualized job-years. The employment numbers are broken down by direct, indirect, and induced. We also present an employment metric referred to as a jobs multiplier (Table 46), which is the sum of job-years (included direct, indirect, and induced) divided by the direct job-years. This is an indicator of the type of employment activity statewide that is generated by investment in a technology. We also present labor income and labor income per worker. The latter is a coarse estimate of the value of jobs created by the corresponding investment.
- **Economy-wide Impacts**. We present several metrics measuring the impacts to the local economy, including value added and industry output.
  - Value Added measures the value of goods and services and is a measure comparable to net measurements of output such as gross state product (GSP).
  - Industry output multiplier mirrors the jobs multiplier and represents the total industry activity (including direct, indirect, and induced) divided by the direct industry activity. This is an indicator of the type of industry activity statewide that is generated by investment in a technology.

Table 46 below provides a summary of the employment impacts of RNG facilities. Table 46 that follows summarizes the economic impacts for RNG production facilities, including average capital expenditure, value added and output multiplier per facility.

Table 46. Summary of Average Employment Impacts per Facility by RNG Feedstock

Facility Type	Employment (FTE job years)				Income per Worker	Jobs Multiplier
	Direct	Indirect	Induced	Total		
Animal Manure	29	21	30	79	$85,671	2.2
Landfill Gas	73	40	54	167	$84,825	2.3
Thermal Gasification	630	535	546	1,711	$73,069	2.7
WWRFs	133	75	87	295	$77,180	2.7

The estimated income per worker (a proxy for salary) compares favorably with Travis County's and Texas's median household income, as reported by the Census Bureau's American Community Survey at $71,767 and $59,570, respectively.[79] For every job that is created via investment RNG production, our results indicate another two jobs will be created in supporting industries (indirect) and via spending by employees that are either directly or indirectly supported by these industries (induced).

Table 47. Summary of Average Economic Impacts per Facility by RNG Feedstock

Facility Type	Capital Expenditure ($millions)	Value Added ($millions)	Output Multiplier
Animal Manure	$4.2	$10.7	1.9
Landfill Gas	$14.8	$20.7	1.9
Thermal Gasification	$171.6	$165.3	1.9
WWRFs	$14.7	$35.6	1.8

The employment multipliers for the different RNG production facilities are estimated at between 2.2 and 2.7, while the economic output multipliers range from 1.8 to 1.9. These economic multipliers are consistent with other industries. For instance, in a previous study, ICF reviewed the economic potential of innovative crude production technologies, including solar steam generation and solar photovoltaics deployed at oil fields, and we reported output multipliers in the range of 1.5 to 1.7 and a jobs multiplier of 2.6 to 2.7.

The economic and employment impacts are larger for thermal gasification facilities, relative to the anaerobic digestion production facilities. These impacts are driven by higher upfront capital expenditures for thermal gasification facilities, as well as the larger capacity of the facilities. ICF notes that there remains uncertainty around the costs of the thermal gasification technology, with the potential for cost reductions over time that would reduce the economic and employment impacts as shown by the IMPLAN results.

[79] U.S. Census Bureau, 2014-2018 American Community Survey 5-Year Estimates.

The IMPLAN model includes more than 500 industry sectors; Table 48 below highlights the sectors that experienced the highest employment impacts. These sectors have been grouped broadly into two categories: RNG production facilities, and indirect and induced sectors. As noted previously, the indirect and induced sectors are those that are impacted by direct investments in the development of RNG production.

Table 48. Industry Sectors with Highest Increased Employment

Economic Grouping	IMPLAN Sectors
RNG Production Facilities	▪ Construction ▪ Waste management ▪ Commercial and industrial machinery equipment rental ▪ Architectural and engineering services ▪ Concrete product manufacturing ▪ Environmental and technical consulting services ▪ General and consumer goods ▪ Industrial gas manufacturing ▪ Oilseed farming
Indirect & Induced Sectors	▪ Wholesale trade ▪ Real estate ▪ Restaurants ▪ Employment services ▪ Building services and management services ▪ Insurance and brokerage

Table 49 below highlights the sectors that experienced the highest output impacts across the counties, grouped broadly into two categories: RNG production facilities, and indirect and induced sectors.

Table 49. Industry Sectors with Highest Output Impacts

Economic Grouping	IMPLAN Sectors
RNG Production Facilities	▪ Construction ▪ Commercial and industrial machinery equipment rental ▪ Petrochemical manufacturing ▪ Pipeline transportation ▪ General and consumer goods ▪ Natural gas distribution ▪ Architectural and engineering services ▪ Waste management ▪ Oilseed farming
Indirect & Induced Sectors	▪ Petroleum refineries ▪ Petrochemical manufacturing ▪ Wholesale trade ▪ Real estate ▪ Pipeline transportation ▪ Waste management ▪ Air transportation ▪ Truck transportation ▪ Employment services ▪ Oil and gas extraction ▪ Electric utilities

Household Impacts

This study did not directly assess the potential impact of RNG deployment on customer rates or the cost of service for the region's natural gas system. However, the incremental costs to household energy bills from the deployment of RNG can be estimated, although these estimates vary significantly, driven by the range in costs of RNG as outlined in Section 4.

Based on American Gas Association (AGA) estimates, the average residential customer in Texas consumed 49.9 MMBtu of natural gas in 2018.[80] Combined with average city gate and residential delivered prices for natural gas from the EIA, the table below provides a high level summary of the potential annual bill impacts for different blends of RNG at different costs.[81]

[80] AGA, 2019. Average Annual Residential Consumption per Customer by State, https://www.aga.org/contentassets/6894914d95e6467fae106015cbcb2abc/table6-14.pdf

[81] EIA, 2020. Natural Gas Price Data Series, https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PG1_DMcf_a.htm and https://www.eia.gov/dnav/ng/NG_SUM_LSUM_A_EPG0_PRS_DMCF_A.htm

Table 50. Illustrative Texas Household Bill Impacts

Throughput Blend	RNG @ $10/MMBtu		RNG @ $15/MMBtu		RNG @ $20/MMBtu	
	Bill	%	Bill	%	Bill	%
Average Household Bill	*$550*	-	*$550*	-	*$550*	-
1% RNG	$553	0.5%	$555	0.9%	$558	1.4%
2% RNG	$555	0.9%	$560	1.8%	$565	2.7%
3% RNG	$558	1.4%	$565	2.8%	$573	4.1%

While these indicative estimates are helpful to show the near-term impacts of RNG deployment on household bills, ICF emphasizes that the cost-effectiveness of RNG should be measured relative to other emission reduction approaches, and the associated household impacts. As discussed in Section 5 and shown in Figure 21, the range of abatement costs for different long-term GHG mitigation strategies is substantial, and RNG has the potential to be a cost-effective option to decarbonize the energy system.

The above estimated household bill impacts also do not reflect the potential impact of voluntary RNG programs, as discussed in Section 6. Customers that opt-in to a voluntary RNG procurement program, and pay a premium for RNG, would have the potential to offset the bill impacts for other households.

Lastly, the above bill impacts do not reflect the potential use of RNG in the transportation sector, and accompanying environmental credit generation. Revenue from these environmental credits could be used to offset the higher relative costs of RNG, reducing the direct bill impact.

8. RNG Strategic Roadmap

ONE Gas and stakeholders in the gas supply and distribution industry in the region should expect to play a proactive and positive role in supporting the City of Austin's GHG emission reduction goals and delivering emission reductions from the natural gas system. To be a partner in meeting these climate objectives, ONE Gas will need a sustainable and flexible business model that helps decarbonize the natural gas system. In parallel, regulators and policymakers must develop innovative approaches that enable the market for RNG to flourish and take full advantage of the full suite of cost-effective decarbonization strategies.

Deploying RNG

ICF envisions a strategic roadmap to deploy RNG across the components outlined in Figure 35 below.

Figure 35. RNG Strategic Roadmap

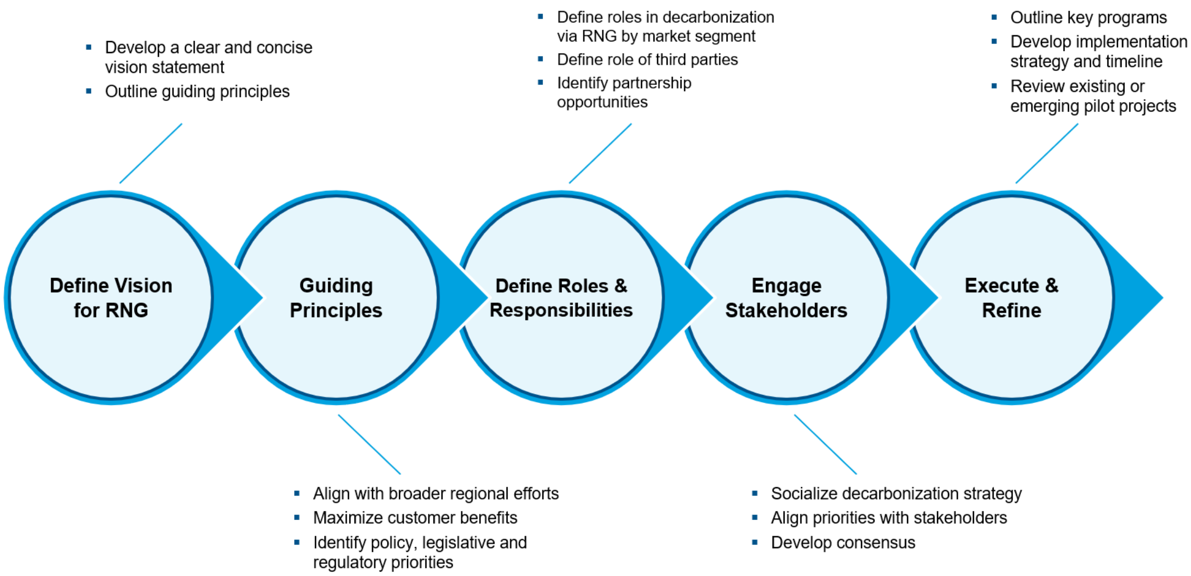


Figure 35 illustrates the Strategic Roadmap process that ICF recommends, including developing guiding principles, defining roles and responsibilities, engaging stakeholders, and executing the plan. ICF notes that the roadmap is portrayed in a linear fashion only for the sake of simplicity. There is nothing about the roadmap or the process that is inherently deterministic. Rather, the roadmap for the region will have to advance iteratively driven by the changing landscape.

The RNG Strategic Roadmap should be socialized across all key stakeholders—with a focus on regulated parties (e.g., gas utilities), key third parties, regulators, and policymakers. The roadmap should also be updated as decarbonization efforts are advanced and refined in the City of Austin and surrounding region.

ICF's overview of the Strategic Roadmap to deploy RNG in the City of Austin and the ONE Gas CTX Service Area is focused on the guiding principles outlined in Figure 35. In the sections that follow, ICF reviews market and regulatory actions that can be taken to deploy RNG. These actions largely (but not exclusively) address the other aspects of the roadmap, including the roles and responsibilities of different stakeholders, how to engage different stakeholders, and execution of various projects to deploy RNG.

As part of this Strategic Roadmap, natural gas industry stakeholders should not just focus on RNG-specific regulations and policies, but adopt a broader perspective and push for the inclusion of RNG in relevant federal and state mechanisms that support clean energy and decarbonization in general. Clean energy grant programs, tax credits, and research and development funding should reflect the critical role that RNG can play in deep decarbonization efforts. For example, RNG investments should receive similar investment tax credits or production tax credits as those currently or previously afforded to renewable electricity generation via wind or solar resources. Similarly, RNG paired with low NOx engines for trucks and buses can help achieve the NOx reduction targets sought through the administration of funds from the Volkswagen settlement and other DOE grants, and help to achieve valuable GHG emission reductions.

RNG Deployment

The potential for RNG in the City of Austin and surrounding region's natural gas system is clear, with aggressive but attainable RNG throughput targets feasible over the medium-term and beyond. ICF's analysis of RNG potential at the local, regional, and national level supports the RNG volumes required to help decarbonize the region's natural gas system. However, ICF notes that for these broader RNG throughput targets to be cost-effective and successful, they would need to cover all natural gas distributors and suppliers in the region, and be supported by a broad and stable regulatory framework that provides a consistent RNG requirement across all suppliers and end users.

ONE Gas is well-positioned to take a leading role to facilitate the necessary development of RNG consumption in the natural gas system in the region, implemented through near-term voluntary throughput targets. Potential targets, and associated RNG volumes and GHG reductions, are outlined in Table 51 below.

Table 51. Illustrative ONE Gas RNG Throughput Targets and Volumes

Target	RNG Volume (MMBtu)	GHG Reductions (tCO_2e)
1% RNG	145,000	8,000
2% RNG	289,000	15,000
3% RNG	434,000	23,000
5% RNG	723,000	38,000
10% RNG	1,446,000	77,000

The RNG volumes and associated GHG emission reductions included in the table are illustrative only, and use ONE Gas's CTX Service Area total sales throughput of 14,460,000 MMBtu in 2019 as the reference level. Actual RNG volumes and emission reductions are dependent on the throughput levels in the specific target year, with forecasting throughput beyond the scope of this study.

The throughput targets are equivalent to proportional reductions in GHG emissions. For example, the deployment of 3% RNG is equal to a 3% reduction in GHG emissions from the direct combustion of total natural gas system throughput. The table also includes illustrative GHG emission reductions applying a combustion accounting approach. The GHG reductions shown in the table are equal to the volume of carbon offsets needed to deliver equivalent emission reductions – with 8,000 offsets required to provide the same emission reductions as 1%, or 145,000 MMBtu, of RNG.

As discussed in Section 3, there are sufficient feedstocks in the CTX Service Area to meet these proposed throughput targets, with potentially 682,000–2,305,000 MMBtu of RNG available for production in 2025, increasing to 3,614,000–16,507,000 MMBtu in 2035, based on ranges from the Limited Adoption and Optimistic Growth scenarios.

Specifically, the three landfills in Travis County have the combined potential to produce more than 5,000,000 MMBtu per year of RNG, while feedstocks from wastewater in Travis County could provide in excess of 250,000 MMBtu per year. These two feedstocks indicate that ONE Gas could meet near-term throughput targets of 1–3% using RNG from a local source, such as a landfill gas facility or the Hornsby Bend facility using wastewater as the RNG feedstock.

The resource scenarios discussed in Section 3 indicate that there are additional RNG resources in the region and beyond that could be accessed to meet broader and more ambitious throughput targets in the medium-term and beyond, including from animal manure, food waste and thermal gasification feedstocks. However, as noted above, a supportive and stable regulatory and policy framework encompassing all of the suppliers in the region's natural gas system would likely be needed to facilitate more aggressive targets. These market- and regulatory-focused efforts that are required to help achieve these targets are discussed in more detail below.

Guiding Principles

To achieve throughput targets outlined above, ONE Gas will need to be guided by a set of consistent and clear principles:

- ***Produce and deliver RNG safely and cost-effectively to participants and end-use customers.*** There is growing interest in RNG from consumers, especially in the commercial and industrial sectors. It is imperative that customers across the region know that market actors are delivering a safe product that helps to cost-effectively reduce the environmental footprint of natural gas operations.
- ***Contribute to broader regional GHG emission reduction objectives.*** The RNG strategy must align with the City of Austin's objectives with respect to GHG emission reductions.

- ***Pursue a flexible regulatory and legislative structure that values RNG deployment appropriately***. The region should seek to develop and support a regulatory and legislative structure that provides sufficient flexibility to achieve cost-effective GHG emission reductions while maintaining safety and reliability. This economy-wide structure should also be balanced and not focused on particular technologies or fuels, given the uncertainties and long timeframes needed to achieve deep decarbonization goals.
- ***Proactively engage with key stakeholders throughout the implementation of the RNG strategy.*** RNG deployment requires close coordination between regulators and stakeholders like gas utilities, LDCs, and investors. Similarly, an effective engagement strategy is needed with potential RNG suppliers (locally and regionally), potential end users in targeted segments (e.g., RNG in City of Austin refuse trucks), and key industry groups (e.g., American Gas Association, Coalition for Renewable Natural Gas).

Market-Based Approaches to RNG Deployment

ICF has focused on three areas for RNG deployment with respect to market-based approaches, including a pragmatic near-term approach to develop interconnection standards for RNG projects, deploy RNG in the transportation sector, and to work as part of a broader coalition to establish common tracking and verification of RNG attributes across end uses and markets.

Develop Interconnection Standards for RNG Projects

A uniform framework that includes the processes, requirements, and agreements that facilitate the pipeline connection of RNG projects would provide more certainty for stakeholders, particularly project developers, and enhance the efficiency and viability of different RNG projects. ONE Gas has already developed these interconnection standards, and is ready to work with potential RNG project developers on interconnection.

Ultimately, ONE Gas and other stakeholders in the region will need to implement a consistent and impartial approach to assess the commercial and technical potential of each project to encourage the introduction of RNG from a range of feedstocks, without compromising the safety or reliability of the pipeline or end-use applications. A uniform approach provides greater certainty for all parties regarding safety, reliability, and interchangeability, and lays the groundwork for expanding RNG consumption into larger and more diverse markets and end uses over the long-term future.

Deploy RNG into the Transportation Market

The transportation sector is a natural fit for the near-term focus of RNG deployment in the region: the combination of higher conventional energy costs and existing incentives makes for a clear opportunity.

Despite its modest demand for natural gas as a transportation fuel, RNG consumption in the transportation sector in Austin and surrounding area has potential for immediate growth. In contrast to other parts of the country, there is currently minimal RNG transportation consumption in the region and significant immediate potential for natural gas transportation demand to be supplied by RNG.

There are opportunities for expanding natural gas consumption in the medium- and heavy-duty vehicle market segments, thereby acting as a conduit for increased RNG deployment. The combination of the total cost of ownership for NGVs and the fueling infrastructure requirements remains a challenge to higher volumes. However, the appropriate combination of policy and market incentives can induce additional growth in NGVs. The regulatory considerations regarding NGV deployment are outlined in the following sub-section.

The market for RNG as a transportation fuel in the region should take advantage of other market forces, notably that California's market for natural gas as a transportation fuel is nearly saturated with RNG. Furthermore, the U.S. EPA continues to increase the mandated volumetric consumption of transportation biofuels like RNG—meaning that suppliers will be seeking to find markets other than California to maximize value. This will require closer coordination amongst market actors, including project developers and suppliers, gas utilities (to distribute the gas), natural gas station owners, and natural gas fleets.

Establish Common Tracking Across RNG Markets

There is increasing interest in RNG deployment across multiple markets. Most RNG today is used either in the transportation sector (typically via pipeline injection) or combusted to make renewable electricity. In both cases, these markets have tracking and verification through RINs in the federal RFS and RECs in renewable energy markets, respectively. RNG use outside of these markets, however, is not subject to tracking or verification.

Although there is no analogous tracking system for RNG today, market actors are advancing the concept rapidly to help grow the market for RNG consumption outside of the transportation sector. As noted previously, the Midwest Renewable Energy Tracking System (M-RETS) has been trialing a thermal REC system since July 2019 with the intent of providing the same verification and price transparency to the RNG market as exists in the renewable electricity market. Similarly, the Center for Resource Solutions (CRS) has initiated a process to develop a Green-e® Renewable Fuels Standard with a stated goal "to accelerate the adoption of RNG, while ensuring that the gas is from sustainable renewable resources, meets the highest environmental standards, and that customers are protected in their purchase and ability to make verifiable usage claims."[82] The draft standard was released in an initial comment period in April 2020, with an anticipated second iteration to be released in Summer 2020 and a finalized standard to be published in Winter 2020.

Tracking will become increasingly important as numerous sectors and regions seek to deploy RNG, and RNG markets expand into multiple and broader end uses over the medium- and long-term. Tracking and verification through certification provides market certainty and can also help assure that markets and credits remain fungible.

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[82] More information is available online via https://www.green-e.org/renewable-fuels.

Regulatory Approaches to RNG Deployment

Supportive government policies and regulatory certainty are needed to encourage the long-term adoption of RNG as a decarbonized fuel beyond current uses in the transportation sector, namely into stationary thermal use applications, such as building heating and cooling. A supportive regulatory framework would allow for the recovery of cost in procuring RNG, update gas rule requirements, reflect the cost-effectiveness of RNG as a decarbonization strategy relative to other measures, and capitalize on complementary measures. This type of regulatory framework would address many of the challenges discussed in this report, including:

- Capitalize on and expand current cost-effective end uses,
- Expand markets beyond current RNG end uses,
- Maximize RNG feedstock production through complementary measures,
- Provide necessary competition for various RNG feedstocks,
- Facilitate opportunities for cost reductions and technology development,
- Ensure the costs and benefits of RNG are appropriately shared by RNG market participants and energy consumers,
- Financially reward the significant environmental value of RNG, and
- Recognize and reflect the critical role RNG can play in decarbonizing the natural gas system, and the energy system as a whole, over the long-term.

ICF recommends a regulatory approach that stages potential RNG programs in the near-, mid-, and long-term horizons in an effort to reconcile conflicting requirements. In general, regulators tend to prefer piloting new customer programs when customer interest, cost assumptions, and the utility's execution capabilities are unconfirmed. This particularly applies to RNG programs because of the emerging aspects of the technology.

Utility commissions and ratepayer advocates' concerns, usually driven by prudence and the need to limit or mitigate the risk for costly stranded assets, may not align with a utility's desire to launch broad market transformation efforts. In addition, transitioning from pilots to larger-scale initiatives may involve additional regulatory review, and this has the potential to create a transition period that disrupts progress toward broader RNG deployment by creating delays. Further, these transitions may have a dampening effect on the market as customers delay further RNG investments until new utility programs become available.

Pilot or Voluntary RNG Procurement Programs

As noted previously in Section 6, utilities can offer opt-in voluntary programs to customers to help reduce the environmental impact of their energy supply. This is more common for electric utilities; however, similar programs can be developed for gas utilities and RNG consumption. ICF recommends a near-term regulatory approach that supports voluntary purchase of RNG through gas utility service providers to help foster market growth, improve customer awareness, and to satisfy nascent demand.

Vermont has already approved a voluntary tariff and utilities in New York and California have filed proposals for approval of voluntary RNG tariffs. In the near-term ICF recommends ONE Gas work with regulators to file a voluntary tariff for RNG deployment, thereby sending a clear and immediate signal to the investor community that the region seeks to be at the forefront of RNG deployment. Voluntary procurement programs will also lay a foundation for establishing RNG demand in end uses beyond the transportation sector.

Expand RNG in Transportation through Infrastructure Investments

The transportation sector is a clear near-term opportunity for regional RNG deployment. However, the long-term opportunity for RNG in the transportation sector is limited because of low demand growth for natural gas as a transportation fuel.

The regulatory market for decarbonizing the transportation sector has favored liquid biofuels at the federal level (via the RFS) and transportation electrification (via the federal tax credit for electric vehicles), with less incentives for natural gas as a transportation fuel. ICF recommends an innovative regulatory structure to enable utilities to invest and recover costs in fueling infrastructure, offer beneficial and attractive tariffs to CNG users, and partner with key stakeholders to deploy CNG in key vehicle market segments. ICF envisions a regulatory structure analogous to the make-ready approach popularized by transportation electrification assessments whereby the utility helps to defray the costs of deploying fueling infrastructure, but site hosts retain ownership and are responsible for interfacing with the consumer.

Similarly, just as electric utilities are increasingly seeking to offer attractive time-of-use pricing for electric vehicle drivers or design demand response programs that incentivize consumers to charge their electric vehicles at certain times of day, ICF foresees attractive CNG tariffs with provisions requiring a minimal throughput of RNG (e.g., as a percent of total flow). ICF also recommends that gas utility service providers be afforded the opportunity to partner strategically with third-party fuel providers. Lastly, ICF recommends a regulatory approach that enables tracking and verification of RNG throughput at CNG stations that enables regulators to impose penalties when minimum RNG throughput targets are not met.

Implementing a Renewable Gas Standard

The RNG market is poised to evolve rapidly over the next three to five years beyond voluntary tariffs and transportation sector demand, and shift into broader stationary end uses. However, in the absence of clearer policy action, RNG deployment has the potential to stall in the same way that emerging renewable energy markets did before RPS programs became more ubiquitous.

Furthermore, the RNG industry faces a difficult transition over the next several years as the transportation sector is increasingly saturated with RNG, and project developers look for new markets and end uses to maximize the value of their project. This transition will be bumpy, and will change the underlying structure of RNG markets in ways that are not entirely understood today. However, the experience of the renewable electricity sector, discussed above, should prove analogous to the opportunities and potential of RNG markets.

In order to smooth the transition to greater RNG deployment over the mid-term future and to achieve the deployment contemplated in the scenarios that ICF developed, an effective and practical policy framework that is conducive for RNG consumption in multiple end uses beyond transportation is required. At a high level, this equates to a regulatory and legislative structure that provides sufficient flexibility to achieve cost-effective GHG emission reductions, and where RNG is viewed as a critical part of broader decarbonization efforts. In this respect, ONE Gas's objective would be:

> *A policy structure that drives consistent demand through a utility procurement mechanism that provides supply and price certainty without disrupting the success and market participation in current programs driving existing RNG deployment.*

A well-designed RGS would meet the above objective and provide access to sustainable and considerable end-use markets outside of the transportation sector. Although there are different policy approaches available, a utility procurement mechanism would drive consistent demand for lowest-cost RNG based on market principles, and provide a robust cost recovery mechanism for utilities. A key advantage of an RGS over other measures, including voluntary programs, is that RGS coverage would not be limited to utilities and LDCs, but also include third-party suppliers such as natural gas marketers, similar to the operation of RPS programs. Over the past five years, different advocacy groups across the U.S. have discussed the concept of an RGS as a procurement policy.

The principles of an RGS are straightforward and mimic renewable portfolio standards. It is important to note that any RNG procurement program would not exist in a vacuum. There is limited, but existing, participation in the RNG market, and there are other goals that must be addressed, including promoting local and regional economic development, addressing environmental equity considerations, and reducing short-lived climate pollutants. Any RGS design should be complementary to other programs currently driving RNG development and flexible enough to enable market innovation that will maximize benefits and minimize costs.

As summarized previously, ICF considers three different approaches towards implementing an RGS:

- **Free market approach**. The free market approach suggests that a procurement target is established, and the market simply responds to the price signal according to a supply-cost curve. ICF notes that while this approach will incentivize lowest-cost resources (likely landfill gas), a slightly more prescriptive design could enable more across-the-board RNG deployment and help achieve other priorities (e.g., local economic development) and deployment (e.g., more diverse feedstock supply).
- **Feed-in tariff**. A feed-in tariff, or standard offer contracts, would provide clear, reliable pricing for RNG producers. Although this approach provides a clear signal to help producers finance renewable gas projects, without distinguishing between feedstocks, a feed-in tariff has the potential to favor low-cost producers without recognizing the cost-effectiveness of GHG emission reductions.

  For instance, to incentivize higher-cost pathways, the feed-in tariff would need to be set at a level that would yield considerable windfall profits to lower-cost pathways (e.g., landfill gas). Some markets have included a degradation mechanism for feed-in tariffs to encourage technology cost reductions. However, it is unclear to what extent a simple degradation mechanism could be effective considering the cost disparities expected for different sources of RNG, which may also have varying levels of technology maturity and cost-reduction pathways.

- **Performance-based approach**. The RGS could take on a structure that requires a percent volume target by some date (different from an absolute volumetric target, as is prescribed in the federal RFS program). Similarly, an RGS could take on a structure like California's LCFS program, requiring a percent reduction in the carbon intensity of natural gas by some date.
  - Carbon intensity targets and percent volume targets should, in principle, provide clear signals to regulated parties and investors regarding the timeline required to achieve program targets.
  - The downside of a carbon intensity target is that it may introduce undue complexity to the RGS. For instance, consider the boundary conditions of the lifecycle GHG assessment of dairy digester gas. Without regulations in place to capture and burn the methane that is released, the gas receives a lower carbon intensity for being credited with the avoided emissions from *venting* methane. Landfill gas, on the other hand, being regulated and required to be captured and burned, receives a lower carbon intensity for being credited with the avoided emissions from *flaring* methane. The difference in the GHG benefit of avoided methane venting versus avoided methane flaring is significant: In the case of the former, avoided vented methane emissions have a global warming potential of 25, whereas in the latter, you are avoiding carbon dioxide emissions with a global warming potential of 1. In addition, new regulations can inadvertently change the boundary conditions of the analysis.
  - Another consideration related to a carbon intensity-based approach is the potential for the intent of the program to be expanded unexpectedly to include upstream emission reductions, such as methane leaks in the natural gas pipeline. This could provide additional compliance opportunities for utilities that produce additional GHG benefits, but may detract from the intent of stimulating RNG development. Additionally, and similar to the example above, other regulations and programs that address these system improvements could complicate the benefit calculation, creating moving targets and challenging utilities' assessments of investment value for different compliance pathways.

Ultimately, ICF recommends an RGS taking on a hybrid of these approaches with the primary objective of accelerating market development of RNG through supply and price certainty. Despite the success of RNG deployment in the transportation sector, there is still unrealized investment and growth in the sector because of uncertainty linked to existing regulatory programs.

As noted previously, there is clearly a high value proposition for RNG used as a transportation fuel. This value can be leveraged by an RGS to maximize benefits and minimize ratepayer costs, while helping to serve as a diversification strategy for the RNG market. An RGS can provide investors, developers, and utilities with the policy certainty they seek to cost-effectively contribute to decarbonization efforts. The RGS also has the potential to help maintain and build upon the success of the programs that have enabled rapid growth in the RNG market over the last five years.

Appendix

U.S. DOE Billion Ton Study

The U.S. Department of Energy (DOE) has been quantifying the potential of U.S. biomass resources, under biophysical and economic constraints, for production of renewable energy and bioproducts since 2005. The 2016 *Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy* (BT16) is the third iteration of the DOE's efforts. BT16 reflects the most recent estimates of potential biomass in the U.S. that could be available for new industrial uses in the future.[83]

BT16 builds on previous research to address three broad questions:

- What is the potential economic availability of biomass resources using the latest-available yield and cost data?
- How does the addition of algae, miscanthus, eucalyptus, wastes, and other energy crops affect potential supply?
- With the addition of transportation and logistics costs, what is the economic availability of feedstocks delivered to the biorefinery?

At a high level, BT16 builds on DOE's previous analyses through:

- Updated farmgate/roadside analysis using the latest available data and specified enhancements,
- Additional feedstocks, including algae and specified energy crops, and
- Expanded analysis to include a scenario to illustrate the cost of transportation to biorefineries under specified logistical assumptions.

ICF utilized BT16, and the underlying data in the Bioenergy Knowledge Framework, to develop the RNG production inventory for specific feedstocks: food waste, agricultural residues, energy crops, forestry and forest product residues, and municipal solid waste. The assumptions and methodology used to estimate biomass volumes for each feedstock are outlined in the following sections.

Food Waste

Food waste as an RNG feedstock includes industrial, institutional and commercial food processing wastes, but does not include residential food waste. The National Renewable Energy Laboratory (NREL) has estimated that 20.6 million wet tons of food waste were generated in 2012. BT16 assumes that 65% of this food waste would be available at a biomass price of $40/dry ton, with a moisture content factor of 70% delivering a national total of 4.0 million dry tons. This food waste estimate adopts a conservative approach, and is lower than other regional or state-based estimates, such as from the California Biomass Collaborative.

[83] DOE, 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks, http://energy.gov/eere/bioenergy/2016-billion-ton-report.

Using the BT16 national food waste figure, ICF applies county-level population-weighted factors to estimate localized food waste estimates.

Agricultural Residues

Agricultural crop residues covered in BT16 and included in the U.S. DOE Bioenergy KDF include corn stover, cereal (wheat, oats, and barley) straws, and sorghum stubble. These crop residues require no additional cultivation or land and represent near-term opportunity feedstocks.

ICF extracted information from the Bioenergy KDF database on the following agricultural residues relevant to Texas: corn stover, sorghum stubble and wheat straw. These estimates are based on modeling undertaken as part of BT16, and utilizes the Policy Analysis System (POLYSYS), a policy simulation model of the U.S. agricultural sector.

The POLYSYS modeling framework simulates how commodity markets balance supply and demand via price adjustments based on known economic relationships, and is intended to reflect how agricultural producers respond to new and different agricultural market opportunities, such as for biomass. Available biomass is constrained to not exceed the tolerable soil loss limit of the USDA Natural Resources Conservation Service and to not allow long-term reduction of soil organic carbon

POLYSYS simulates exogenous price changes introduced as a farmgate price, which then solves for biomass supplies that may be brought to market in response to these prices. The farmgate price is held constant nationwide in all counties over all years of the simulation to allow farmers to respond by changing crops and practices gradually over time. [84]

Agricultural residue volumes are then derived from these estimates at a county level, and reflect total aboveground biomass produced as byproducts of conventional crops, and then limited by sustainability and economic constraints. Not all agricultural residues are made available, as crop residues often provide important environmental benefits, such as protection from wind and water erosion, maintenance of soil organic carbon, and soil nutrient recycling. Collection of residues is also limited to operationally available removals or sustainably available removals, whichever is most limiting.

In the simulations no land use change is assumed to occur, except within the agricultural sector (i.e. forested land is not converted to agricultural land for agricultural residue or energy crop purposes).

Energy Crops

The assessment of energy crop potential utilizes the same modeling framework for agricultural residues, including POLYSYS, outlined above. The following are brief descriptions of energy crops included in BT16 and ICF's analysis.

[84] US DOE, 2016. 2016 Billion Ton Report, https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.

- Biomass sorghum: annual herbaceous crop, currently grown in rotation throughout the Southeast and Great Plains for grains and forage. Biomass sorghum exhibits non-photoperiod sensitivity and drought tolerance.
- Energy cane: a perennial tropical grass with high yield potential across the Gulf South. Low-sugar, high-cellulose varieties (a hybrid of commercial and wild sugar cane species) can be established, managed, and harvested using existing sugar-cane industry equipment.
- Eucalyptus: short-rotation woody crop ideal for Gulf States as well as Georgia and South Carolina.
- Miscanthus: sterile triploid with low nutrient requirements and wide adaptability across cropland.
- Pine: tree representing the major commercial tree crop in the South, can be adapted to grow in high density on agricultural land assuming 8-year rotations.
- Poplar: short-rotation woody crop with great potential in the Lake States, the Northwest, the Mississippi Delta, and other regions.
- Switchgrass: model perennial native grass, with wide range and potential distribution.
- Willow: short-rotation woody crop assumed to be managed on a 20-year cycle and harvested at 4-year growth stages. It is being commercialized widely in the Northeast.

Specific input assumptions include yield improvements and land-use constraints, discussed in more detail below.

Yield improvements: field data indicates the potential for higher biomass yields in the future. BT16 applied yield improvement assumptions in this analysis by scenario, ranging from 1% to 4%, based on DOE research and stakeholder collaboration. Energy crop yields were derived from modeling of crop yields based on data from the Sun Grant Regional Feedstock Partnership in coordination with the Oregon State University PRISM (Parameter-elevation Relationships on Independent Slopes Model) modeling group. Modeled crop yield is generated with PRISM-EM based upon PRISM biweekly climate variables including precipitation, minimum temperature, maximum temperature, and Soil Survey Geographic Database soil pH, drainage, and salinity.

For the purposes of ICF's RNG analysis, the yield assumptions did not provide significant variations in feedstock production over the long-term, with biomass price instead delivering greater variation. For this reason we focused on biomass prices as an assumption in the RNG production potential scenarios.

Land-use constraints: in addition to the constraint of available land, there are annual constraints (5% of permanent pasture, 20% of cropland pasture, 10% of cropland) and cumulative constraints (40% of permanent pasture, 40% of cropland pasture, 10% of cropland) applied to the model regarding land that can be converted to energy crops. These constraints are also bound by the management-intensive grazing (MiG) constraint of 1.5 acres of MiG required for one acre of pasture converted to energy crops. Eligible pasture is defined as having greater than or equal to 25 inches of annual precipitation, which excludes irrigated pasture acres amounting to 47.1 million acres of land nationally.

Rather than shifting existing agricultural production (e.g. corn and soy) to energy crop production, the BT16 modeling shows that energy crops are largely grown on idle or available pasture lands, particularly at lower farmgate prices.

Forestry and Forest Product Residues

ICF extracted information from the U.S. DOE Bioenergy KDF, which includes information on forest residues such as thinnings, mill residues, and different residues from woods (e.g., mixedwood, hardwood, and softwood).[85] The Bioenergy KDF estimates are used in BT16 and are based on ForSEAM, a linear programming model constructed to estimate forestland production over time, including for both traditional forest products but also products that meet biomass feedstock demands.

The ForSEAM model assumes that projected traditional timber demands will be met and estimates costs, land use, and competition between lands. The forestry and forest product residue estimates also reflect a cost minimization framework that minimizes the total costs (harvest costs and other costs) under a production target goal in addition to land, growth, and other constraints. The cost minimization framework includes the POLYSYS model as well as IMPLAN, an input-output model that estimates impacts to the economy.

ForSEAM estimates biomass potential from timber stand information across the conterminous United States. The model estimates the costs, the locations, and the kinds of biomass available to meet a prescribed demand. The demands are derived from the Forest Product Demand Component. This component is based on six USDA Forest Service scenarios with estimates developed by USFPM.

ForSEAM was constructed to estimate forestland production for traditional forest products and to meet biomass feedstock demands. The supply component includes general forest production activities for 305 production regions or agricultural statistic districts and is placed in a national linear programming model. Each region has a set of production activities defined by the scenario demands. These production activities include sawtimber, pulpwood, and biomass (fuelwood is defined as biomass for this report). Sawtimber and pulpwood harvest activities generate forest residues that can be harvested for energy and bioproducts, and whole trees can be removed for biomass under some specific assumptions of size. High-value sawtimber is never harvested for biomass.

ForSEAM and the underlying Forestry Inventory and Analysis (FIA) database provides the basis for determining how demand is met for conventional products such as sawtimber and pulpwood out to 2040. The demands are based on a set of projections for U.S. forests and forest products markets under varying market conditions. Scenarios evaluated in ForSEAM include combinations of housing demand, wood energy demand, and plantation management intensity.

The baseline scenario represents the lowest level of wood energy demands. In the moderate and high wood energy demand scenarios, feedstock prices rise sufficiently to reduce paper and paperboard production levels by 1% and 3%, respectively, below the baseline in 2040. In the high-demand scenario, impacts on prices are ameliorated somewhat by an assumed increase in investment in southern pine plantation management that would be expected as prices for softwood small roundwood increase. In addition, increases in timberland area (in USFPM/GFPM) are projected based on the assumption that increasing prices lead to increased

[85] Bioenergy Knowledge Discovery Framework, 2016. Billion Ton 2016 Data Explorer, https://bioenergykdf.net/map?model=bt16

land rents, and increasing land rents lead to increased conversion of marginal agricultural land to timberland.

Not all forestland in the United States is considered in the analysis, with only the conterminous United States is included. All protected, reserved, and non-roaded forestland is excluded. The analysis is restricted to only timberland instead of all forestlands. Although conventional products are removed from slopes greater than 40% using cable systems, no logging residues are recovered, leaving 100% on the site. Harvest in each state is also restricted to not exceed annual growth. There is no road construction, as only forest tracts located within a half mile of the roads are harvested. The current-year forest attributes reflect previous years' harvests and biomass removals, which means that dynamic stand tracking of forest growth is incorporated into the model and the analysis. Another underlying assumption is the retention of biomass to protect the site and maintain soil carbon. Also, there was no conversion of natural stands to plantations.

A final major assumption is that there are no forestland losses over the modeling time period and no land cover changes in the model. This means that fast-growing plantations specifically for biomass are not established after the harvest of a natural stand. All harvested stands are assumed to regenerate back to, and according to, the original cover. Natural stands regenerate to hardwood, softwoods, or mixed, as they were previously. Plantations are regenerated as plantations. An unfortunate downside to this approach is that insufficient amounts of biomass are generated in the out years of the modeling period to meet the high-demand scenarios. These scenarios were developed based on the establishment of millions of acres of plantations to be grown for biomass.

Shadow prices[86] are developed for the demand scenario biomass amounts. The shadow prices and the associated acres for the scenario demands (dry tons of biomass) are reported by product type (logging residues or whole-tree biomass), as well as other parameters of the study, across selected years. These shadow prices for the scenario demands are used to develop conventional supply curves to estimate biomass availability at roadside for a given cost. The out-year biomass availabilities are slightly reduced with the underlying assumption that no biomass plantations were established on forestland for the baseline example. In other scenarios, such as the supposedly highest biomass demand, there were even more significant reductions in out years, especially 2040, because biomass plantations were not established.

Municipal Solid Waste

In BT16 and the BKF, municipal solid waste (MSW) is defined as mixed commercial and residential wastes generally destined for landfill or incineration disposal, as well as yard trimmings. MSW categories available for bioenergy include paper and paperboard, plastics, rubber and leather, textiles, food wastes, and yard trimmings. Food wastes, such as those from industrial sources, are not included in the MSW data. Although MSW estimates represent gross supplies currently landfilled, not all of this supply is economically available due to preprocessing

[86] In this instance a shadow price is not market price, but an estimate of the economic value of the biomass in question.

cost considerations. MSW consists of a variety of items, ranging from organic food scraps to discarded furniture, packaging materials, textiles, batteries, appliances, and other materials.

MSW volumes are derived from U.S. EPA per-person MSW generation estimates of 2.36 lb per day (with moisture), after accounting for reduction, reuse, recycling and waste-to-energy.[87] This per-person figure is then applied to population data and category fractions to generate MSW estimates at a county level. The national MSW total is a conservative estimate relative to other national and regional analysis.

The prices of garbage supplies available after sorting are unknown. Price estimates for sorted organic fractions are generated using state-level average MSW tipping fees, with ICF applying regional- and facility-level tipping fee data if available. All supplies and prices are converted to dry tons and to a dollar per dry ton basis assuming the following moisture contents: food wastes 70%, yard trimmings 60%, paper and paperboard 15%, textiles 15%, rubber and leather 10%, and plastics 10%.

[87] US EPA, 2015. Advancing sustainable materials management: Facts and figures 2013 https://www.epa.gov/sites/production/files/2015-09/documents/2013_advncng_smm_rpt.pdf

Resolution Supporting Pipeline Quality Biomethane Development as a Renewable Gas Resource in the Clean Energy Economy

WHEREAS, Critical legislation is under consideration in the U.S. House of Representatives and the U.S. Senate that seeks to create clean energy jobs, achieve energy independence, mitigate the effects of climate change, and transition to a clean energy economy; *and*

WHEREAS, The transformation to a clean energy economy and sustainable American economic and international policy leadership will require properly designed market incentives, as well as increased investment in human and technological capital; *and*

WHEREAS, Transitioning to a clean energy economy will require a robust portfolio of cost-effective and environmentally benign renewable energy resources that achieve greenhouse gas reductions and provide safe, affordable, and reliable energy to consumers; *and*

WHEREAS, According to the Energy Information Administration, natural gas consumption accounted for 23.9 percent[1] of total primary energy consumption (99.4 quads) in the United States in 2008, and will continue to be a strategic resource that delivers significant greenhouse gas reductions, enables the development of intermittent renewable resources such as wind and solar, and provides a foundational fuel for residential, commercial and industrial end-use; *and*

WHEREAS, Emerging renewable sources of natural gas have great potential to complement the critical role of traditional natural gas supplies in the clean energy economy; *and*

WHEREAS, Biogas is derived from the decay of organic materials through anaerobic digestion and thermal gasification, and varies in chemical composition but is primarily comprised of methane, a greenhouse gas which is at least 20 times more potent than carbon dioxide when directly released to the atmosphere;[2] *and*

WHEREAS, Methane from renewable gas can be captured, cleaned, and converted into biomethane through the use of proven gas conditioning technologies, transported by the existing gas pipeline system, stored and/or delivered for productive use in renewable electricity generation, clean transportation, or commercial, industrial and residential end use; *and*

WHEREAS, Biogas from manure, agricultural and food waste, landfills, wastewater treatment facilities, sustainable biomass, and other viable sources could provide a significant renewable gas resource, which, when conditioned into pipeline quality biomethane, is interchangeable with conventional natural gas,[3] efficient in the use of existing natural gas storage, transmission, and distribution infrastructure, and is a suitable renewable fuel for use in the transportation sector and in today's most efficient combined-cycle natural gas-powered electric generation facilities; *and*

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1 *Electric Power Monthly*. United States Energy Information Administration, 15 Oct. 2009. Web. 3 Nov. 2009. <http://www.eia.doe.gov/emeu/mer/pdf/pages/sec1_7.pdf>

2 Eaves, Michael, Clean Energy. "Biomethane Renewable Natural Gas: California Energy Commission Workshop on Natural Gas and Propane Vehicles." September 18, 2009.

3 Renewable Energy Institute, "EPA Moves Closer to Regulating Greenhouse Gas Emissions." 18 April 2009.

WHEREAS, Federal incentives are available for renewable electricity from solar, wind, biomass, and geothermal resources, but are not available for the development or production of renewable pipeline quality biomethane; *and*

WHEREAS, The current Renewable Electricity Production Tax Credit provides a per-kilowatt-hour production tax credit for wind and geothermal projects, and a per-kilowatt-hour production tax credit for on-site generation from biomass and landfill gas projects;[4] *and*

WHEREAS, The current Business Energy Investment Tax Credit[5] provides a 30 percent federal investment tax credit or grant for solar, wind and fuel cell facilities, and a 10 percent investment tax credit or grant for geothermal, microturbines, and combined heat and power energy facilities; *and*

WHEREAS, Renewable pipeline biomethane facilities do not qualify for investment tax credit incentives under the Business Energy Investment Tax Credit, and renewable pipeline biomethane production does not qualify for production tax credit incentives under the current Renewable Electricity Production Tax Credit; *and*

WHEREAS, There are current legislative proposals under consideration in the U.S. House of Representatives and the U.S. Senate that would support the development of renewable pipeline quality biomethane by providing incentives that are comparable to existing incentives for the development of other forms of renewable electricity; *now, therefore be it*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2010 Winter Committee Meetings in Washington, D.C., supports the role and development of biogas, and in particular, pipeline quality biomethane, as a feasible renewable fuel in an effort to capture methane greenhouse gas emissions and simultaneously provide an alternative source of renewable energy; *and be it further*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners supports federal incentives for the development of pipeline quality biomethane that are *en par* with incentives currently afforded to other resources for the production of renewable electricity; *and be it further*

RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissioners urges the U.S. Senate and the U.S. House of Representatives to approve legislation as a means to provide unequivocal support for pipeline quality biomethane development in order to achieve significant greenhouse gas reductions in the transition to a clean energy economy.

Sponsored by the Committee on Gas
Adopted by the NARUC Board of Directors February 17, 2010

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4 *The American Jobs Creation Act of 2004* (H.R. 4520) expanded the Production Tax Credit (PTC) to include additional eligible resources: geothermal energy, open-loop biomass, solar energy, small irrigation power, landfill gas and municipal solid waste combustion -- in addition to the formerly eligible wind energy, closed-loop biomass, and poultry-waste energy resources. However, while this includes anaerobic digestion for landfill gas, it does not apply specifically to biomethane production for pipeline use. *See* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=1&ee=1 for more information.

5 The federal business energy investment tax credit available under 26 USC § 48 was expanded significantly by the *Energy Improvement and Extension Act of 2008* (H.R. 1424), enacted in October 2008. However, this does not apply specifically to facilities for biomethane pipeline facilities. *See* http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=1&ee=1.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF STACEY L. MCTAGGART

BEFORE ME, the undersigned authority, on this day personally appeared Stacey L. McTaggart who having been placed under oath by me did depose as follows:

1. "My name is Stacey L. McTaggart. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Rates and Regulatory Director for Texas Gas Service, a division of ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Stacey L. McTaggart

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey L. McTaggart on this 21st day of May 2024.

Erlinda Alvarado

Notary Public in and for the State of Texas

ERLINDA ALVARADO
NOTARY PUBLIC
ID# 133935107
State of Texas
Comm. Exp. 08-29-2026

WORKPAPERS

TO

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

Workpapers to the Direct Testimony of Stacey L. McTaggart are being provided in electronic format.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

DIRECT TESTIMONY

OF

STACEY R. BORGSTADT

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

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DIRECT TESTIMONY OF STACEY R. BORGSTADT

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stacey R. Borgstadt. My business address is 15 East Fifth Street, Tulsa, Oklahoma.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by ONE Gas, Inc. ("ONE Gas") as the Director of Corporate Rates and Regulatory Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Master's Degree in Business Administration with a concentration in information systems from Lindenwood University in 2001 and a Bachelor of Science Degree in accounting from Missouri Valley College in 1996. From June 1996 to August 1998, I served as a Corporate Accountant for Dollar Rent-A-Car. From August 1998 to January 2004, I served in the internal audit departments of Enterprise Rent-A-Car, Cornerstone Propane and Dollar Rent-A-Car. I worked as a Senior Audit Associate at KPMG LLP from January 2004 to November 2005.

I began my employment with ONEOK, Inc. ("ONEOK") on November 21, 2005, as a Project Leader in the Internal Audit Department. I began serving as Manager of Rates and Regulatory Analysis in October 2007 while at ONEOK and retained that position with ONE Gas after its separation from ONEOK. I was promoted to Director of Corporate Rates and Regulatory Compliance in January 2020.

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR OF CORPORATE RATES AND REGULATORY COMPLIANCE.

A. My responsibilities include assisting the Divisions of ONE Gas, including Texas Gas Service Company ("TGS" or the "Company"), with the review and analysis of company financial data and records, and preparation of and participation in rate cases and other regulatory filings and related activities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony in proceedings before the Oklahoma Corporation Commission ("OCC"), Kansas Corporation Commission ("KCC") and the Railroad Commission of Texas ("Commission") regarding the same general subject matters that I am testifying to in this case. A list of the dockets in which I have testified is provided as Exhibit SRB-1.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony:

1. Provides an overview of ONE Gas' organizational structure, which includes Shared Services at the corporate level and Direct TGS service areas;
2. Explains and supports ONE Gas' cost allocation methodology, including causal allocations and the ONE Gas Distrigas ("Distrigas") formula;
3. Supports the reasonableness of certain rate base adjustments, including Corporate and Division capital investments, prepayments and depreciation and amortization expense allocated to the Central-Gulf Service Area ("CGSA");
4. Explains and supports TGS's operating expense adjustments for Shared Services and Corporate, including adjustments for rent and lease operating expense, injuries and damages, the Distrigas allocation and miscellaneous operating expenses;

5. Explains and supports adjustments associated with payroll, overtime and payroll related taxes and benefits; and
6. Supports recovery of incentive compensation.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THE RATE CASE?

A. My testimony relates to Company witness Marie J. Michels' direct testimony as she supports the CGSA Direct service area rate base and expense adjustments, whereas I support allocated Corporate and TGS Division rate base and expense adjustments. Company witnesses Jeffrey J. Husen and Alejandro Limón also support the Company's request for capital investment cost recovery. My testimony also relates to Company witness Megan Z. Gough's direct testimony that addresses employee compensation and benefits.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring the following schedules:

RATE BASE:	
Schedule B (Rate Base)	Co-Sponsor with Marie J. Michels
Schedule B-2 (Prepays)	Co-Sponsor with Marie J. Michels
Schedule C (Plant)	Co-Sponsor with Marie J. Michels
Schedule C-1 (CCNC)	Co-Sponsor with Marie J. Michels
Schedule D (Reserves)	Co-Sponsor with Marie J. Michels
OPERATING INCOME:	
Schedule G (Summary of Operating Revenue & Expense Adj)	Co-Sponsor with Marie J. Michels and Zane M. Drummond
Schedule G-4 (Base Payroll)	Sponsoring
Schedule G-5 (Overtime Payroll)	Sponsoring
Schedule G-6 (Benefits & Payroll Related Taxes)	Sponsoring
Schedule G-8 (Incentive Compensation)	Sponsoring
Schedule G-9 (Miscellaneous Adjustments)	Co-Sponsor with Marie J. Michels
Schedule G-10 (Rents & Leases)	Co-Sponsor with Marie J. Michels
Schedule G-13 (Injuries and Damages)	Sponsoring
Schedule G-14 (Advertising)	Co-Sponsor with Marie J. Michels
Schedule G-15 (Depr Amort)	Co-Sponsor with Marie J. Michels
Schedule G-21 (Distrigas Allocation)	Sponsoring
Schedule G-22 (Causal Allocation)	Sponsoring

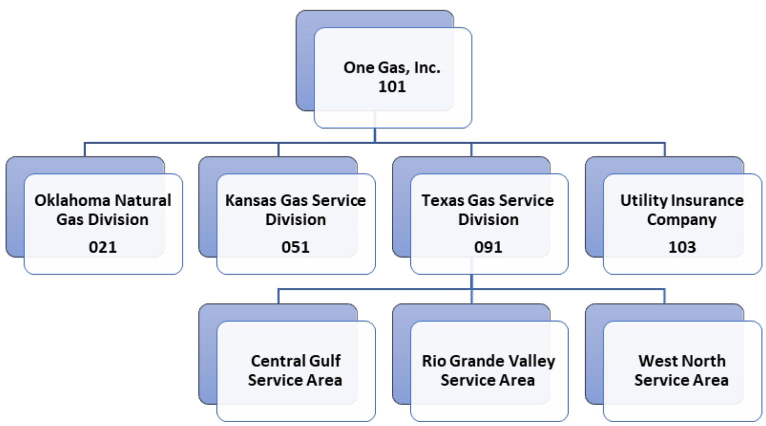
Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

II. <u>ORGANIZATIONAL STRUCTURE OVERVIEW</u>

Q. HOW IS ONE GAS ORGANIZED?

A. As shown in the chart below, ONE Gas has three divisions, TGS, Oklahoma Natural Gas and Kansas Gas Service ("KGS"), that together serve more than 2.3 million customers, and an affiliate company, Utility Insurance Company ("UIC"), a wholly-owned captive insurance subsidiary. Company witness Jaime D. Shelton discusses UIC in more detail in her direct testimony.



Q. DOES THE UTILITY SERVICE PROVIDED BY TGS IN THIS SERVICE AREA INCLUDE CENTRALIZED SERVICES?

A. Yes, both ONE Gas and TGS Division provide certain necessary, centralized services for TGS's direct service areas. Providing certain consolidated or centralized services reduces operational redundancies and helps achieve economies of scale. These common centralized services are more efficiently provided at the TGS Division or Corporate level and are considered "Shared Services" costs because company personnel provide support to all ONE Gas Operating Divisions, including TGS's service areas. The activities performed through these cost centers are subject to cost assignment using the methodology set forth below.

Q. HAS THE COMPANY INCLUDED THE COSTS ASSOCIATED WITH PROVIDING SHARED SERVICES TO THE CGSA IN THE REVENUE REQUIREMENT?

A. Yes. The Company has included these costs in the filing. As described in my testimony below, during the test year, services were provided to the CGSA by TGS Division and ONE Gas employees, and the costs associated with those services are allocated to the CGSA and included in the requested revenue requirement.

Q. IS A PORTION OF UIC PREMIUMS FOR ONE GAS AND TGS INCLUDED IN THE COMPANY'S REQUESTED REVENUE REQUIREMENT FOR THE CGSA?

A. Yes. A portion of UIC premiums for ONE Gas and TGS is included as allocated costs to the CGSA in the amount of $4,588,370. A complete list containing the UIC premiums included in rate base and operations and maintenance ("O&M") expense allocated to the CGSA is attached to my testimony as Exhibit SRB-2. Ms. Shelton provides direct testimony describing UIC and its services, and Ms. Michels discusses the Company's compliance with the associated affiliate standard.

III. <u>COST ALLOCATION METHODOLOGY</u>

Q. WHAT IS THE PURPOSE OF COST ALLOCATIONS?

A. The purpose of cost allocations is to determine and reasonably allocate each business entity's proportionate share of costs for certain support services it receives from TGS Division and ONE Gas. Because the costs to provide these services are "shared" by multiple business entities and/or service areas, cost responsibility for these services must be reasonably allocated among the various

ONE Gas business entities and TGS's service areas. These allocations are accomplished by applying ONE Gas' cost allocation methodology.

Q. PLEASE DESCRIBE ONE GAS' COST ALLOCATION METHODOLOGY.

A. The costs incurred by ONE Gas or any of its business entities can be described as either direct or indirect. A direct cost can be fully attributed to a specific business entity or service area, so those costs are directly assigned to that specific business entity or service area. Conversely, indirect costs are costs that cannot be attributed to a specific business entity or service area and thus are allocated in accordance with the ONE Gas cost allocation methodology. For instance, if costs cannot be directly assigned, but a cost causation measurement can be identified, then these indirect costs are allocated based on a causal relationship, such as customer count, and would be considered shared costs, which are discussed further below. Any remaining indirect costs that cannot be allocated in that manner are allocated using the formula known as Distrigas.

Q. PLEASE EXPLAIN DIRECT COSTS.

A. Direct costs are those costs that can be identified and directly assigned to the service area. Costs are directly assigned for services such as meter reading, leak surveys, field customer service, fleet expenses, certain information technology services ("IT"), line location services and facilities management.

Q. PLEASE EXPLAIN INDIRECT COSTS AND HOW THE INDIRECT COSTS ARE ALLOCATED.

A. Indirect costs are those costs incurred to provide services that cannot be directly assigned to a business entity or service area; thus, these costs are considered shared costs. Therefore, these costs are shared among multiple business entities. Indirect or shared costs are allocated to each business entity either on a causal basis or through Distrigas. Indirect costs allocated using causal relationships are based on specific cost causation measurements such as participation level, activity level, output level or resource consumption. Examples of indirect costs include Customer Information Center ("CIC") services, credit and collections and TGS general accounting. Employee health and welfare benefits for active employees that can be measured by output level such as by employee headcount for each respective business entity, the Billing Control Group as a percentage of customer count or Accounts Payable using a percent of invoice processing volume by business entity are other examples of indirect costs. These costs are then further allocated to the TGS service areas based on the ratio of customers in each service area to the total number of TGS customers in all TGS service areas.

Indirect costs that cannot be charged directly or cannot be associated with an identifiable causal relationship are allocated through Distrigas.

Q. PLEASE DESCRIBE THE SERVICES AND COSTS ALLOCATED THROUGH DISTRIGAS.

A. ONE Gas provides many services that benefit all its business entities, including TGS. Those Corporate service operating costs are recorded on ONE Gas' financial books and are then allocated to the various ONE Gas business entities using the Distrigas factor.

A general summary of Corporate services is provided below. A complete list containing a more detailed explanation of each Corporate service and associated allocation can be found in the Corporate Allocation Manual ("CAM") attached to my testimony as Exhibit SRB-3.

- Human Resources - Provides professional development and training programs for active employees.
- IT - Supports ONE Gas' business entities by developing and administering disaster recovery, data backup and recovery, cyber-security, data center and support of all ONE Gas and Company technology.
- Finance and Accounting - Supports ONE Gas' business entities by administering processes related to corporate accounting, financial

reporting, tax, credit, risk and insurance, internal audit, financial planning, investor relations, directors and officers liability insurance and business development.

- General Counsel - Supports ONE Gas' business entities by administering processes related to legal aspects of day-to-day business activities such as board of directors' compensation, regulatory affairs and commercial contracts.
- Corporate Communications - Supports ONE Gas' business entities by administering processes related to corporate communications efforts directed to employees and external stakeholders.
- Corporate Services - Supports ONE Gas' various business entities by developing and administering programs and processes that facilitate general day-to-day business activities such as purchasing, facilities, business continuity and environmental safety and health initiatives.

Finally, as noted in the CAM, certain miscellaneous costs such as rent and utilities impacting all business entities are also allocated. All costs allocated to TGS, including UIC premiums, are then further allocated to the TGS service areas based on the ratio of customers in each service area to the total number of TGS customers in all TGS service areas.

Q. WOULD THE SAME TYPES OF SERVICES AS THOSE PROVIDED BY TGS DIVISION AND ONE GAS BE REQUIRED IF THE CGSA WAS A STAND-ALONE BUSINESS?

A. Yes, these services would need to be provided even if the CGSA was a stand-alone business. The CGSA would likely have to independently provide these services if the services were not provided by TGS Division or ONE Gas. However, having these services performed centrally is efficient, allows for economies of scale and for the costs of those services to be spread across the business and service areas for which the services are provided. These services are necessary for the operation of any gas utility business, regardless of whether the service is performed centrally or on a decentralized basis at the service area level.

Q. PLEASE DESCRIBE THE HISTORY OF THE DISTRIGAS ALLOCATION METHODOLOGY.

A. The Distrigas method was first approved in 1987 by the Federal Energy Regulatory Commission ("FERC") in a rate proceeding for a natural gas transmission company, Distrigas of Massachusetts Corporation.[1] The formula used by Distrigas of Massachusetts Corporation was a slight modification of the old Massachusetts formula (a three-part formula consisting of gross plant, gross revenues and labor) which, prior to the acceptance of the Distrigas method, was widely accepted by numerous regulatory agencies across the country. In its opinion, FERC accepted the Modified Distrigas method (a three-part formula consisting of gross plant, net revenues and labor) as a reasonable and acceptable methodology for allocating costs for ratemaking purposes.

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED USING THE DISTRIGAS METHOD.

A. The Distrigas Method ONE Gas uses ensures that ONE Gas allocates Corporate costs to each Division on a consistent basis by applying the same cost-causation principles and methodology. This method uses a three-factor formula comprised of: (1) gross plant and investments; (2) operating income (income before interest expense and income taxes); and (3) labor expense. As with the Modified Distrigas Method, the factors are individually calculated and then a simple average is calculated using the three component percentages.

Distrigas utilizes gross plant and investments rather than just gross plant in the event that ONE Gas invests in business(es) that are not directly operated by ONE Gas.[2] These modifications further refine the Distrigas Method to fairly and reasonably allocate the costs to the ONE Gas business entities, including TGS.

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[1] *Distrigas of Mass. Corp.*, 41 FERC ¶ 61205 (F.E.R.C. 1987).
[2] Currently, ONE Gas has no investment in businesses that are not operated by ONE Gas. ONE Gas also uses operating income rather than net revenues as an allocator to eliminate the cost of gas component.

Q. HAS THE SAME COST ALLOCATION METHODOLOGY BEEN APPLIED IN PRIOR ONE GAS PROCEEDINGS?

A. Yes, it has. This methodology has been used since 1994 to allocate Corporate costs. It is important to ONE Gas to have a common allocation methodology approved by the regulatory agencies in the states in which it operates to ensure that the method is fair to each of the ONE Gas business entities and their customers. This methodology is currently used in Texas and was applied in the Company's Gulf Coast Service Area in Gas Utilities Docket ("GUD") No. 10488, West Texas Service Area in GUD No. 10506, Central Texas Service Area in GUD No. 10526, Rio Grande Valley Service Area in GUD No. 10656, North Texas Service Area in GUD No. 10739, Borger-Skellytown Service Area in GUD No. 10766, Central-Gulf Service Area in GUD No. 10928, West North Service Area in Docket No. OS-22-00009896 ("Docket No. 9896"); and most recently the Rio Grande Valley Service Area in Docket No. OS-23-00014399 ("Docket No. 14399").[3]

Additionally, the OCC[4] has approved the use of the cost allocation method used by ONE Gas in prior rate cases. This methodology is also currently used in Kansas. The KCC accepted ONEOK's allocation methodology in a settled 2005 KGS rate case and ONE Gas' allocation methodology in the 2016 and 2018 KGS rate cases.

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[3] *See also, Appeal of Texas Gas Service Company from the Actions of the Cities of Lockhart, Luling, Cuero, Gonzales, Nixon, Shiner and Yoakum, and, Statement of Intent filed to Increase Rates in the Unincorporated Areas of the South Texas Service Area*, GUD No. 9770, Final Order at Finding of Fact ("FoF") No. 36 (Apr. 24, 2008); and *Petition of the De Novo Review of the Denial of the Statements of Intents filed Texas Gas Service Company by the Cities of El Paso, Anthony, Clint, Horizon City, Socorro, and Village of Vinton, Texas*, GUD No. 9988, Final Order at FoF No. 23-24 (Dec. 14, 2010).

[4] *In the Matter of the Application of Oklahoma Natural Gas Company, a Division of ONEOK, Inc., for Review and Change or Modification in its Rates, Charges, Tariffs and Terms and Conditions of Service,* Cause No. PUD 200400610, Order No. 512287 Final Order at 113 of 134 (Oct. 4, 2005).

Q. IS ONE GAS' COST ALLOCATION METHODOLOGY A REASONABLE METHODOLOGY TO ALLOCATE CORPORATE COSTS?

A. Yes, it is. As mentioned above, ONE Gas' cost allocation methodology allows ONE Gas to allocate Corporate costs to each of its Divisions on a consistent basis by applying the same cost-causation principles and methodologies. Furthermore, this methodology has been previously approved as a reasonable means of allocating Corporate costs by this Commission, the FERC,[5] the OCC and accepted by the KCC.

IV. RATE BASE ADJUSTMENTS

Q. WHAT IS RATE BASE?

A. Rate base is the Company's invested capital that is used and useful in providing safe and reliable gas utility service to its customers. The Company's rate base is summarized on Schedule B and is classified into three components: (1) Net Plant in Service ("PIS"); (2) Other Rate Base Items; and (3) Non-Investor Supplied Funds. Ms. Michels further discusses in her direct testimony Direct rate base and its three components.

Q. WHY IS IT NECESSARY TO INCLUDE CORPORATE AND TGS DIVISION INVESTMENTS IN RATE BASE?

A. Corporate and TGS Division investment assets are necessary to the provision of utility service to TGS and the CGSA but are not reflected in the CGSA Direct costs; thus, an adjustment is necessary to include these investments in rate base to determine the revenue requirement. This is the same approach TGS took in prior statements of intent, which the Commission approved in GUD Nos. 9770, 9988, 10506, TGS's last fully litigated rate case in Docket No. 9896 and TGS's settled

[5] *Distrigas of Mass. Corp.,* 41 FERC ¶ 61205.

cases GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928 and Docket No. 14399.[6]

Q. WHICH RATE BASE ITEMS DO YOU ADDRESS?

A. I address the rate base items for capital costs that are allocated from ONE Gas or TGS Division to the CGSA. These rate base items include prepayments, materials and supplies, Net PIS, Construction Completed Not Classified ("CCNC") and Accumulated Reserves for Depreciation and Amortization. Schedule B contains a summary of all rate base items.

Q. PLEASE DISCUSS THE RATE BASE ADJUSTMENTS ASSOCIATED WITH PREPAYMENTS.

A. Prepayments are a component of rate base and are defined as amounts paid for in advance of the goods or services being received in the future. ONE Gas and TGS Division prepayments allocated to the CGSA represent advances for items such as annual equipment and software maintenance agreement fees; software license fees; insurance policy premiums for general liability; automobile and workers' compensation and other miscellaneous prepaid items. ONE Gas and TGS Division prepayments are provided on Schedule B-2 and Workpapers B-2.a.1 and B-2.b.1. Prepayments are included in rate base because they reflect an investment ONE Gas and TGS made for the provision of utility service and are similar to the treatment of ONE Gas and TGS Division capital investments.

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[6] *See* GUD No. 9770, Final Order at FoF No. 27; GUD No. 9988, Final Order at FoF No. 10; *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA)*, GUD No. 10506, consol., Final Order at FoF No. 110 (Sept. 27, 2016); and *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at FoF No. 40 (Jan. 18, 2023).

Q. DO THE INVESTMENTS IN PREPAYMENTS DESCRIBED ABOVE INCLUDE ANY AFFILIATE COSTS?

A. Yes. As discussed in the direct testimony of Ms. Shelton, ONE Gas formed a wholly owned captive insurance subsidiary, UIC, in 2017 to provide insurance to ONE Gas and its Divisions. Some UIC premiums are included in Corporate and TGS Division costs that are allocated to the CGSA. A complete list containing UIC premiums included in rate base is attached to my testimony as Exhibit SRB-2. Also, Ms. Michels explains in her direct testimony how these costs comply with the affiliate standard.

Q. HOW WERE THE PREPAYMENT AMOUNTS CALCULATED?

A. The prepayment balances were calculated by taking the average balance over 13 months, which allows TGS to normalize fluctuations in prepayment accounts during the test year. The average 13-month balance was adjusted to: (1) remove activity for which the Company is not seeking recovery, and (2) reflect annualization of the cost allocation percentages for the first quarter of 2024.

Q. IS IT REASONABLE TO INCLUDE ONE GAS AND TGS PREPAYMENTS AS PART OF THE CALCULATION OF THE COST OF SERVICE IN THIS CASE?

A. Yes. Prepayments are expenditures necessary for the provision of utility service by TGS but are not reflected in the CGSA Direct costs; thus, prepayments are appropriately included in rate base. This is the same approach TGS has taken in prior statements of intent, which the Commission has previously approved.[7]

[7] *See also* GUD No. 9988, Final Order; GUD No. 10506, consol., Final Order; and Docket No. OS-22-00009896, consol., Final Order.

Q. NEXT, PLEASE EXPLAIN THE ONE GAS AND TGS DIVISION CAPITAL INVESTMENT, ALLOCATED TO THE CGSA, SHOWN ON SCHEDULES C, C-1, AND D.

A. ONE Gas' net PIS (gross plant less accumulated reserves), allocated from Corporate to TGS, is $46,379,891. The TGS Division net PIS is $8,394,538. The CGSA allocated share of these amounts is 46.7362%, or $25,599,487, based on the number of customers in the CGSA relative to the total number of TGS customers. Net PIS costs are shown on Workpapers C.b, C.c, C-1.b, C-1.c, D.b and D.c.

Q. PLEASE DESCRIBE ANY SIGNIFICANT CORPORATE OR TGS DIVISION CAPITAL INVESTMENTS MADE SINCE THE LAST RATE CASE AND REFLECTED ON SCHEDULES C AND C-1.

A. Corporate and TGS Division capital expenditures made since the last rate case and reflected on Schedules C and C-1 primarily consist of investments in a new CIC that TGS uses to meet customer needs in all service areas, pipeline monitoring systems and computer software and hardware. Examples of those investments include:

- The purchase and renovation of a manufacturing facility into functional office space to adequately accommodate operation of TGS's CIC located in El Paso. The previous CIC facility was not large enough to accommodate the employees necessary to perform daily operations and resulted in two to four employees sharing office space originally made for one employee. The old location also had unsafe employee parking conditions resulting in employees parking on the street and surrounding neighborhoods. The new facility renovation process included replacing the building's electrical system; repairing plumbing systems; installing fire system equipment; and adding a generator system for emergency response needs. Additional technological renovations included installing hardware such as digital screens and camera systems into conference rooms; servers, uninterruptible power supplies, and Wi-Fi network extenders to provide employees with a reliable network and access control and video surveillance systems, providing employees with a secure work environment.

- The building of a training center for all ONE Gas field employees which includes classrooms, a simulation city, an excavation site and a fire school. The training center provides field employees with the opportunity to train in a classroom setting as well as in hands-on scenarios. In the simulation city, employees practice situations such as turning on a customer's natural gas, performing gas leak investigations and locating gas pipelines.

- Enhancements made to ONE Gas' pipeline monitoring systems to increase visibility and safety. These enhancements include: (1) capturing high-accuracy global positioning system ("GPS") data for newly installed assets and integrating ONE Gas' geographic information system (GIS) data for existing assets with the GPS data in order to increase the accuracy of compliance related activities that rely on locational data such as leak surveys and line location, (2) replacing outdated third-generation (3G) modems used to communicate pipeline visibility data between gas sites and Supervisory Control and Data Acquisition (SCADA) Gas Control with fourth-generation (4G) modems that utilize long-term evolution (LTE) technology, (3) building an emergency incident forecast model used by operations employees when scheduling field personnel in order to better allocate resources and reduce the time it takes to respond to an emergency incident, (4) implementing a software program available to all ONE Gas employees to report non-emergency pipeline safety concerns, suggest process improvements, and acknowledge employee actions that exemplify safety practices and (5) updating ONE Gas' pipeline modeling software, Synergi, to integrate with the Area Isolation Module in order to perform calculations necessary to evaluate how various system outages would impact customers.

- Improvements and additions made to ONE Gas' cybersecurity software. ONE Gas implemented additional cybersecurity measures to: (1) monitor and manage which software applications can operate on ONE Gas equipment; (2) evaluate the effectiveness of security controls implemented to mitigate or block threats; (3) increase ONE Gas' ability to detect and stop malicious infections by decrypting data moving across its network; and (4) immediately disconnect ransomware and other advanced threats from computers on the ONE Gas network.

- Improvements and additions made to ONE Gas' physical security protection. These improvements include the installation of: (1) access control panels and surveillance cameras throughout ONE Gas and its Divisions; (2) network video recorders at ONE Gas operation locations; and (3) software used to authenticate employees attending meetings and trainings.

- Improvements made to ONE Gas' Banner application to increase the efficiency and productivity of customer service representatives ("CSRs"). Banner is ONE Gas' billing system, which contains records of ONE Gas' approximately 2.3 million customers, premises, services, accounts, meter readings, and other information critical to providing reliable billing and customer service. These enhancements shortened the time needed for CSRs to service customer calls by: (1) replacing the existing Banner CSR screens with a more user friendly web based application; (2) incorporating the Microsoft Dynamics Customer

Relationship Management application to track customer activities such as meter reading dates, billing dates and pay arrangement installments; (3) creating process based screens which consolidated various screens and reduced the number of data sources; and (4) automating business processes related to tracking customer data and contact information which were previously manually completed.

- Continuous updates and additions to technology infrastructure such as data centers, disaster recovery, storage, servers, networking and backups.

Costs related to the projects detailed above or very similar projects were approved for recovery by the Commission in Docket Nos. 9896 and 14399.

Q. WERE THE TGS DIVISION AND CORPORATE PROJECTS AND RELATED CAPITAL EXPENDITURES PRUDENT, REASONABLE AND NECESSARY?

A. Yes, they were. Corporate capital and TGS Division investment are necessary for the provision of service in the TGS service areas. These expenditures, including investment in technology systems and software, provide critical services supporting all employees in their efforts to provide service safely and reliably to customers in the CGSA. If a technology system becomes unavailable, operations may be impaired. Additionally, ONE Gas and TGS maintain office and training spaces for employees to adequately and safely provide reliable gas service to customers. Thus, it is necessary to provide reliable technology systems, infrastructure and office/training facilities to minimize disruption to customers and employees, who provide either indirect support or direct service to customers through leak detection, emergency response, customer billing, dispatching and scheduling of service calls, to protect sensitive customer information, enhance cybersecurity, improve website functionality and maintain office/training facilities. The direct testimony of Mr. Limón supports the overall reasonableness, necessity and prudence of the capital investment costs TGS is requesting in this case.

Q. DID YOU MAKE ANY ADJUSTMENTS TO ONE GAS AND TGS DIVISION PIS, CCNC OR ACCUMULATED RESERVE?

A. Yes. The Company has made adjustments to remove Corporate and TGS Division costs for activities such as: (1) plant additions, transfers or retirements mistakenly coded to the CGSA, (2) costs for meals greater than $25 per person, exclusive of taxes and tip amounts, and hotel stays greater than $175 per night, exclusive of taxes;[8] (3) duplicative Vertex sales tax and (4) aviation. These adjustments are reflected in Workpapers C.b, C.c, C-1.b, C-1.c, D.b, and D.c.

V. OPERATING EXPENSE ADJUSTMENTS

Q. WHAT IS SHOWN ON WORKPAPER G.a.2.a?

A. The Shared Services per book amount, including Distrigas, that I am supporting totals $97,598,496, of which $45,613,828 is allocated to the CGSA. Workpaper G.a.2.a provides a summary showing the TGS allocated test year amount along with an O&M expense factor calculation applied to the adjustments.

Q. DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE G-9.

A. Schedule G-9 contains miscellaneous adjustments to remove expenses not currently allowed for regulatory recovery such as civic activities, sponsorships, charitable contributions and legislative activities. Additional adjustments include the removal of royalty fees and an adjustment to account for the known and measurable change in insurance costs.

Q. DESCRIBE THE RENT ADJUSTMENT SHOWN ON SCHEDULE G-10.

A. Schedule G-10 annualizes test year expense for rent and common area maintenance costs to reflect known and measurable changes. These adjustments are consistent with the methodology used in prior statements of intent and with prior Commission decisions.

[8] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and the Gulf Coast Service Area*, GUD No. 10928, consol., Final Order at FoF No. 71-72 (Aug. 4, 2020).

Q. DESCRIBE THE ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE SHOWN IN SCHEDULE G-13.

A. The injuries and damages expense on Schedule G-13 consists of TGS's workers' compensation, auto liability and general liability insurance paid claims. These costs fall within TGS's self-insurance limitation and therefore are not recovered from TGS's insurance provider. The adjusted expense on Schedule G-13 was first computed by averaging all claims paid for the period of January 2020 through December 2023 (four years). Next, injuries and damages expense for the 12 months ending December 2023 was subtracted from the average claims paid (four-year average) to determine the additional adjustment to test year expense. Ms. Shelton testifies regarding UIC and the self-insurance limitation.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE NORMALIZATION OF INJURIES AND DAMAGES EXPENSE OVER A FOUR-YEAR PERIOD?

A. Yes, in GUD Nos. 9988, 10506, and Docket No. 9896, the Commission found that it is reasonable to normalize this expense over a four-year period. The Commission also approved this treatment in TGS rate cases in GUD Nos. 10488, 10526, 10656, 10739, 10766, 10928 and Docket No. 14399, all of which were resolved through settlement agreements.

Q. PLEASE EXPLAIN HOW THE DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENT ON SCHEDULE G-15 IS CALCULATED.

A. Adjusted depreciation or amortization expense is calculated by multiplying the depreciation/amortization rates by depreciable PIS. Test year depreciation expense is subtracted from total adjusted depreciation expense to calculate the adjustment to test year expense reflected on Schedule G-15. Most Corporate plant depreciation rates and amortization periods were developed in Dr. White's 2015 depreciation study, approved in TGS's last fully litigated rate case in Docket

No. 9896, and approved in TGS's settled cases in Docket No. 14399 and GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928.[9] Corporate depreciation rates and amortization periods are consistent throughout ONE Gas and its Divisions. The KCC[10] and OCC[11] have also approved these depreciation rates. For certain new investments in accounts that were not considered in the 2015 depreciation study, initial depreciation rates were determined based on previous company experience and the judgment of those responsible for developing and managing these assets. The Company proposes to continue the use of existing depreciation rates for ONE Gas plant.

Dr. White conducted a 2022 depreciation study to determine the depreciation rates for TGS Division plant. This study was approved in TGS's last fully litigated rate case, Docket No. 9896, and the Company has applied these depreciation rates to TGS Division plant in this statement of intent filing. Dr. White describes in his direct testimony the depreciation study and resulting depreciation rates requested in this case.

Q. WHY IS IT APPROPRIATE TO USE EXISTING DEPRECIATION RATES AND AMORTIZATION PERIODS APPROVED BY THE COMMISSION TO CALCULATE THE DEPRECIATION AND AMORTIZATION EXPENSE FOR CORPORATE ASSETS?

A. These depreciation rates were subject to a comprehensive review in seven different Texas rate cases and are already being utilized by TGS statewide, including the Rio Grande Valley and West North Service Areas. If the regulatory authority were to now establish parameters for Corporate assets in the CGSA that

[9] *See* GUD No. 10506, consol., Final Order at FoF No. 77; and Docket No. OS-22-00009896, consol., Final Order at FoF No. 87.

[10] *In the Matter of the Application of Kansas Gas Service, a Division of ONE Gas, Inc. for Adjustment of its Natural Gas Rates in the State of Kansas,* Docket No. 16-KGSG-491-RTS, Order Approving Unanimous Settlement Agreement at FoF No. 14 (Nov. 29, 2016).

[11] *Application of Oklahoma Natural Gas Company, a Division of ONE Gas, Inc., for Approval of its Performance Based Rate Change Plan Calculations for the Twelve Months Ending December 31, 2016, Energy Efficiency True-Up and Utility Incentive Adjustments for Program Year 2016, and Changes or Modifications to its Tariffs.* Cause No. PUD 201700079, Order No. 666781 Final Order Approving Joint Stipulation and Settlement Agreement (Aug. 9, 2017).

are different from those utilized in other Texas jurisdictions and ONE Gas Divisions, ONE Gas and TGS would have two sets of depreciation/amortization periods for the exact same assets. This difference would require ONE Gas to modify its current accounting system to track assets, accumulated reserve and depreciation/amortization specifically for the CGSA, which would be a complicated and costly process.

Q. PLEASE EXPLAIN THE DISTRIGAS ALLOCATION ADJUSTMENT REFLECTED ON SCHEDULE G-21.

A. Schedule G-21 and Workpaper G-21.a provide the monthly per book Distrigas allocation to TGS, along with the factors used to calculate the allocation percentages. An adjustment to reflect the known and measurable change in the Distrigas allocation factor as of the first quarter of 2024 is also included on Schedule G-21. This adjustment is consistent with the methodology and Commission decisions mentioned above.

Q. PLEASE IDENTIFY THE SHARED SERVICES CAUSAL ALLOCATION INFORMATION REFLECTED ON SCHEDULE G-22.

A. Schedule G-22 and Workpaper G-22.a show the monthly per book Shared Services causal allocations to TGS, along with the factors used to calculate the causal allocation percentages.

VI. PAYROLL, OVERTIME AND PAYROLL RELATED TAXES AND BENEFITS

Q. WHAT IS BASE PAYROLL?

A. Base pay or base payroll represents an employee's base salary or hourly wages. Through the Common Salary Review process, base pay is reviewed at least annually for all employees resulting in pay increases, if applicable, in December. Ms. Gough discusses base pay and its components in her direct testimony.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO BASE PAYROLL PROVIDED ON SCHEDULE G-4.

A. Schedule G-4 contains adjustments to payroll expense to annualize the changes in salary or hourly wages for services that employees provided to the CGSA as well as employees whose costs are allocated through Shared Services during the test year. Adjusted base salaries were calculated by annualizing test year payroll at December 31, 2023. This adjustment annualizes the changes in the number of employees, promotions and salary adjustments occurring during the test year. Total test year payroll was then subtracted from the calculated annualized payroll level, including the December 2023 Common Salary Review increase, to determine the allocable base payroll adjustment that was multiplied by allocation factors and by the payroll O&M expense ratio to determine the adjusted O&M expense amount applicable to the CGSA. The allocable base payroll adjustment was then assigned to O&M expense accounts based on the accounts to which test year payroll expense was recorded. This is the same adjustment TGS made to base payroll in Docket No. 14399, which was not challenged.

Q. PLEASE DESCRIBE THE EXPENSE ADJUSTMENT SHOWN ON SCHEDULE G-5.

A. Schedule G-5 contains adjustments to overtime expense for hourly employees who are based in the CGSA, as well as TGS Division and Corporate employees whose costs are allocated through Shared Services. The adjusted hourly base payroll calculated on Schedule G-4 was multiplied by the test year overtime percentage (which is test year overtime as a percentage of test year hourly base pay) to determine annualized overtime payroll. Total test year overtime payroll was then subtracted from the annualized overtime payroll to determine the allocable overtime payroll adjustment. This adjustment was multiplied by allocation factors and the payroll O&M expense ratio to determine the adjusted

O&M overtime payroll expense amount applicable to the CGSA. This amount was then assigned to O&M expense accounts based on the accounts to which test year payroll expense was recorded. Overtime pay is a reasonable and necessary component of employee compensation, and it is appropriate to include overtime pay in the annualized payroll amount to be recovered through rates. This is the same adjustment TGS made to overtime expense in Docket No. 14399, which was not challenged.

Q. DESCRIBE THE BENEFITS AND PAYROLL TAXES ADJUSTMENT SHOWN ON SCHEDULE G-6.

A. Schedule G-6 contains the adjustment to recognize the change in benefits and payroll tax based on the annualization of the labor increases for employees performing work in the CGSA as well as TGS Division and Corporate employees whose costs are allocated through Shared Services. The adjustment includes a cost per payroll dollar for payroll taxes and for those benefits that vary based on labor cost. Benefits that vary based on labor cost include pension, other post employment benefits and medical reserve. The benefit cost per payroll dollar was calculated based on the most recently available data for payroll tax and benefits costs. These calculations are shown on Workpaper G-6.b. Additional benefits such as profit-sharing amounts, 401(k) company match, tuition reimbursement and employee assistance programs, are reflected on Schedule G-6 and Workpaper G-6.b and represent test year actual amounts. The proforma base and overtime payroll from Schedules G-4 and G-5, respectively, were then multiplied by the calculated benefit and payroll tax per payroll dollar ratios that were developed on Workpaper G-6.b to determine the annualized benefits and payroll tax. The total test year benefits and payroll tax were then subtracted from the annualized benefits and payroll tax to determine the allocable benefits and payroll tax adjustment. This amount was then multiplied by allocation factors and the payroll

O&M expense ratio to determine the adjusted O&M expense amount applicable to the CGSA. This amount was then assigned to O&M expense accounts based on the accounts to which test year payroll expense was recorded as shown on Workpaper G-6.a. This is the same adjustment TGS made to benefits and payroll taxes in Docket No. 14399, which was not challenged.

Q. WHAT IS THE SUPPLEMENTAL EMPLOYEE RETIREMENT PLAN ("SERP") AMOUNT INCLUDED ON SCHEDULE G-6?

A. The SERP amount included in this filing is $681.35 and included on Workpaper G-6. This amount is for direct CGSA employees. The amount was calculated based on December 2023 payroll annualization and the most recently available data for SERP costs; then multiplied by allocation factors and the payroll O&M expense ratio to determine the adjusted O&M expense amount applicable to the CGSA.

Q. HAS THE COMMISSION APPROVED RECOVERY OF SERP COSTS FOR TGS?

A. Yes. In GUD No. 10506 and Docket No. 9896, the Commission found SERP to be beneficial to recruit and retain executives thus allowing recovery of SERP expenses directly assigned to the service area payroll as reasonable and necessary and supported by the evidence.[12] The Company followed this method for including SERP amounts in this case.

Q. WHAT IS THE BASE YEAR LEVEL OF PENSION AND OTHER POST EMPLOYMENT BENEFITS EXPENSE SHOWN ON WORKPAPER G-6.C?

A. In accordance with Gas Utility Regulatory Act ("GURA") § 104.059, the base year or current year level of pension and other post employment amounts are shown on Workpaper G-6.c and reflected in the table:

[12] GUD No. 10506, consol., Final Order at FoF No. 86-87; and Docket No. OS-22-00009896, consol., Final Order at FoF No. 71.

Description	Amount
Pension	$16,474
OPEB	$48,343
Total	$64,817

The above amounts are from Schedule G-6 Benefits & Payroll Taxes, which was calculated based on the most recently available data for payroll tax and benefits costs. These amounts were then multiplied by allocation factors and the payroll O&M expense ratio to determine the adjusted O&M expense amount applicable to the CGSA.

VII. RECOVERY OF INCENTIVE COMPENSATION COSTS

Q. HAS THE COMPANY INCLUDED INCENTIVE COMPENSATION COSTS IN THIS FILING CONSISTENT WITH GURA § 104.060?

A. Yes. TGS is requesting recovery of its reasonable and necessary incentive compensation costs applicable to the test year. In accordance with GURA § 104.060, the Company has made an adjustment to remove incentive compensation related to the financial metrics for executive officers whose compensation is required to be disclosed under 17 C.F.R. Section 229.402(a).[13] These executive officers are known as the Named Executive Officers ("NEO") in ONE Gas' Notice of Annual Meeting and Proxy Statement. Ms. Gough also addresses how TGS meets the requirements of GURA § 104.060 to support TGS's request for incentive compensation cost recovery, provides testimony in support of the reasonableness and necessity of TGS's requested incentive compensation costs and describes the nature of the ONE Gas incentive compensation plans and the role these plans have in ONE Gas' overall compensation philosophy. This is the same approach the Company took regarding incentive compensation costs in Docket No. 9896, for which the Commission approved full cost recovery in that litigated proceeding. The

[13] https://www.sec.gov/divisions/corpfin/ecfr/17cfr229.402a.pdf.

Company also followed this approach in Docket No. 14399, which was resolved through settlement.

Q. DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT SHOWN ON SCHEDULE G-8.

A. Schedule G-8 identifies the amount of incentive compensation costs TGS seeks to recover in this case. TGS is seeking recovery of short-term incentive ("STI") and long-term incentive ("LTI") compensation costs for Direct employees, TGS Division employees and ONE Gas employees, excluding incentive compensation related to financial metrics for NEOs.

Q. DESCRIBE THE ADJUSTMENT MADE TO STI COMPENSATION TO EXCLUDE COSTS RELATED TO FINANCIAL METRICS FOR NEOS.

A. The STI attributable to financial metrics for NEOs, including FICA, 401(k) company match and profit-sharing amounts associated with STI, allocated to the CGSA is $198,807. The Company removed the $198,807 amount consistent with GURA § 104.060. Ms. Gough discusses the STI metrics in her direct testimony.

Q. DESCRIBE THE ADJUSTMENT MADE TO LTI COMPENSATION FOR PERFORMANCE STOCK UNITS ("PSUs").

A. The total PSU per book amount in the test year allocated to the CGSA is $902,530 of which $493,161 was attributable to financial metrics for NEOs. Removing that amount results in TGS requesting recovery of $409,369. As discussed in Ms. Gough's direct testimony, PSUs are based upon ONE Gas' performance as measured by its three-year relative total shareholder return. Thus, the Company removed the LTI amount related to PSUs consistent with GURA § 104.060.

Q. WAS AN ADJUSTMENT MADE TO LTI COMPENSATION FOR RESTRICTED STOCK UNITS ("RSUs")?

A. No. As discussed in Ms. Gough's direct testimony, RSUs are not based on the financial performance of ONE Gas. Therefore, no adjustment was made for LTI costs related to RSUs. In TGS's last fully litigated rate case in Docket No. 9896, the Examiners recommended full recovery of LTI in the form of RSUs, which the Examiners acknowledged are based on "non-financial performance" and are "related to employee retention."

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STACEY BORGSTADT – LIST OF PRIOR TESTIMONY

Line	Jurisdiction	Docket	Company	Year
1	Oklahoma Corporation Commission	Cause No. PUD 200900110	Oklahoma Natural Gas	2009
2	City council of the City of Austin	Ordinance no. 2009618-074	Texas Gas Service	2009
3	City Council of the City of El Paso and the Public Utility Regulation Board		Texas Gas Service	2009
4	Railroad Commission of Texas	GUD No. 9988	Texas Gas Service	2010
5	Oklahoma Corporation Commission	Cause No. PUD 201100034	Oklahoma Natural Gas	2011
6	Oklahoma Corporation Commission	Cause No. PUD 201200029	Oklahoma Natural Gas	2012
7	Kansas Corporation Commission	Docket No. 12-KGSG-835-RTS	Kansas Gas Service	2012
8	Oklahoma Corporation Commission	Cause No. PUD 201300032	Oklahoma Natural Gas	2013
9	Railroad Commission of Texas	GUD No. 10488	Texas Gas Service	2015
10	Railroad Commission of Texas	GUD No. 10526	Texas Gas Service	2016
11	Municipalities of Rio Grande Valley		Texas Gas Service	2017
12	Railroad Commission of Texas	GUD No. 10656	Texas Gas Service	2017
13	Railroad Commission of Texas	GUD No. 10739	Texas Gas Service	2018
14	Railroad Commission of Texas	GUD No. 10766	Texas Gas Service	2018
15	Railroad Commission of Texas	GUD No. 10928	Texas Gas Service	2019
16	Railroad Commission of Texas	OS-22-00009896	Texas Gas Service	2022

	A	B	C	D
1	**UIC Premiums Included in Rate Base and Expenses by Service Area**			
2				
3	**Service Area**	**Rate Base**	**Expenses**	**Total**
4	CGSA	1,454,127	3,134,243	**4,588,370**

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**CORPORATE UIC PREMIUMS ALLOCATED TO CGSA**																
2	**TEST YEAR ENDING DECEMBER 31, 2023**																
3																	
4																	
5	**LINE NO.**	**POLICY TYPE**	**DECEMBER 2022[1]**	**JANUARY[1]**	**FEBRUARY[1]**	**MARCH[1]**	**APRIL[1]**	**MAY[1]**	**JUNE[1]**	**JULY[1]**	**AUGUST[1]**	**SEPTEMBER[1]**	**OCTOBER[1]**	**NOVEMBER[1]**	**DECEMBER[1]**		**13 MONTH AVG INCLUDED IN RATE BASE**
6	1	UIC Auto Liability	$ 4,970	$ 4,473	$ 3,976	$ 3,479	$ 2,982	$ 2,485	$ 1,988	$ 1,491	$ 994	$ 497	$ -	$ 10,384	$ 9,440		
7	2	UIC Excess Liability	1,122,660	1,010,394	898,128	785,862	673,596	561,330	449,064	336,798	224,532	112,266	-	1,335,136	1,213,760		
8	3	UIC Property	36,196	27,147	18,098	9,049	-	104,500	95,000	85,500	76,000	66,500	57,000	47,500	38,000		
9	4	UIC Workers Compensation	42,540	38,286	34,032	29,778	25,524	21,270	17,016	12,762	8,508	4,254	-	54,010	49,100		
10	5	UIC Cyber	18,622	-	905,234	822,940	740,646	658,352	576,058	493,764	411,470	329,176	246,882	164,588	82,294		
11	6	**CORPORATE UIC PREMIUMS**	**$ 1,224,988**	**$ 1,080,300**	**$ 1,859,468**	**$ 1,651,108**	**$ 1,442,748**	**$ 1,347,937**	**$ 1,139,126**	**$ 930,315**	**$ 721,504**	**$ 512,693**	**$ 303,882**	**$ 1,611,618**	**$ 1,392,594**		**$ 1,170,637**
12	7	**Allocated to TGS - Distrigas Allocation**														**28.74%**	**336,441**
13	8	**Allocated to CGSA**														**46.7362%**	**157,240**
14																	
15		**Footnotes:**															
16		[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.b.1_Prepayments - ONE GAS Corp Prepayments Detail (CONFIDENTIAL)". Filter on "UIC" in the "Line Description" column to identify the UIC premiums contained in "WKP B-2.b.1_Prepayments - ONE GAS Corp Prepayments Detail (CONFIDENTIAL)".															

TGS DIVISION UIC PREMIUMS ALLOCATED TO CGSA
TEST YEAR ENDING DECEMBER 31, 2023

LINE NO.	POLICY TYPE	DECEMBER 2022[1]	JANUARY[1]	FEBRUARY[1]	MARCH[1]	APRIL[1]	MAY[1]	JUNE[1]	JULY[1]	AUGUST[1]	SEPTEMBER[1]	OCTOBER[1]	NOVEMBER[1]	DECEMBER[1]		13 MONTH AVG INCLUDED IN RATE BASE
1	UIC Auto Liability	$ 5,440	$ 4,896	$ 4,352	$ 3,808	$ 3,264	$ 2,720	$ 2,176	$ 1,632	$ 1,088	$ 544	$ -	$ 10,318	$ 9,380		
2	UIC Excess Liability	4,099,170	3,689,253	3,279,336	2,869,419	2,459,502	2,049,585	1,639,668	1,229,751	819,834	409,917	-	4,741,572	4,310,520		
3	UIC Property	223,456	167,592	111,728	55,864	-	644,336	585,760	527,184	468,608	410,032	351,456	292,880	234,304		
4	UIC Workers Compensation	43,880	39,492	35,104	30,716	26,328	21,940	17,552	13,164	8,776	4,388	-	58,740	53,400		
5	**TGS DIVISION UIC PREMIUMS**	**$ 4,371,946**	**$ 3,901,233**	**$ 3,430,520**	**$ 2,959,807**	**$ 2,489,094**	**$ 2,718,581**	**$ 2,245,156**	**$ 1,771,731**	**$ 1,298,306**	**$ 824,881**	**$ 351,456**	**$ 5,103,510**	**$ 4,607,604**		**2,774,910**
6	**Allocated to CGSA**														**46.7362%**	**1,296,887**

Footnotes:

[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.a.1_Prepayments - TGS Division Detail (CONFIDENTIAL)". Filter on "UIC" in the "Vendor" column to identify the UIC premiums contained in "WKP B-2.a.1_Prepayments - TGS Division Detail (CONFIDENTIAL)".

	A	B	C	D
1	**CORPORATE UIC PREMIUM EXPENSE ALLOCATED TO CGSA**			
2	**TEST YEAR EXPENSE JAN - DEC 31, 2023**			
3				
4				
5	**LINE NO.**	**POLICY TYPE**		**UIC Expense 2023**
6	1	UIC Auto Liability		11,333
7	2	UIC Excess Liability		1,456,516
8	3	UIC Property		114,004
9	4	UIC Workers Compensation		58,922
10	5	UIC Cyber		987,532
11	6	**CORPORATE UIC PREMIUMS**		**$ 2,628,308**
12	7	**Allocated to TGS - Distrigas Allocation**	**28.74%**	**$ 755,376**
13	8	**Allocated to CGSA**	**46.7362%**	**$ 353,034**

	A	B	C	D
1	**TGS UIC PREMIUM EXPENSE ALLOCATED TO CGSA**			
2	**TEST YEAR EXPENSE JAN - DEC 31, 2023**			
3				
4				
5	**LINE NO.**	**POLICY TYPE**		**UIC Expense 2023**
6	1	UIC Auto Liability		11,253
7	2	UIC Excess Liability		5,172,627
8	3	UIC Property		702,907
9	4	UIC Workers Compensation		64,079
10	5	**TGS UIC PREMIUMS**		**$ 5,950,866**
11	6	**Allocated to CGSA**	**46.7362%**	**$ 2,781,209**

CORPORATE ALLOCATION MANUAL

Revised /April 22, 2020
Corporate Accounting Department

The Corporate Allocation Manual provides documentation for allocation of corporate administrative costs of ONE Gas, Inc. (ONE Gas to its divisions and subsidiaries. Direct costs incurred for the direct benefit of a specific business entity of ONE Gas are not addressed in this manual because the objective and scope of this manual pertains to general charges that cannot be assigned to a single operating business entity.

ONE Gas maintains a fully distributed cost model that assigns each business entity its proportionate share of corporate administrative costs based on a reasonable and justifiable method.

Proper classification of costs is the responsibility of each employee and his or her supervisor when preparing, approving, and processing any accounting document (invoices, journal entries, etc.). The classification of costs is determined using our Classification of Accounts Manual (which includes codes for each company, cost center, natural account, expense indicator and RFU) when processing the transaction. The account coding string is the basis upon which costs are identified as costs to be allocated in our process.

Three-Step Allocation Process

Our fully distributed cost model occurs through a "three-step" process. The first step begins with the premise that costs specifically attributed to a business entity are charged directly to that business entity to the extent practical. In the second step, costs that are significant in amount and benefit multiple business entities on the basis of a causal relationship are charged to the business entities based on that causal relationship. The causal relationships are specific measurements based on the type of cost, which can be a measure of participation level, activity level, output level, or resource consumption. In the third step, any remaining costs, which are not charged directly or associated with an identifiable causal relationship, are allocated to business entities using the ONE Gas Modified Distrigas Allocation methodology (ONE Gas Distrigas).

ONE GAS Distrigas Methodology

The Distrigas Cost Allocation Methodology (Distrigas Method) is a Federal Energy Regulatory Commission (FERC) approved cost allocation methodology that is considered a reasonable and acceptable methodology for allocating costs for ratemaking purposes. ONE Gas, Inc. has used the Distrigas Method as the basis for its methodology to allocate corporate administrative costs since 1994. It is important to ONE Gas to have a common allocation methodology that is broadly accepted by our regulatory authorities and that results in a justifiable and reasonable allocation of corporate administrative costs to each of ONE Gas's business entities.

The ONE Gas Distrigas methodology uses a three factor formula comprised of the average of gross plant, net operating income and labor expenses (excluding contract labor).

To calculate the overall allocation factor for each business entity, the three allocation factor amounts are determined for each business entity and calculated as a percentage of the combined total. In cases when a business entity has an operating loss, a factor of zero is used for the operating income allocation factor. The three component allocation factors for each business entity are then combined using a simple average to derive the overall allocation factor.

ONE Gas periodically reviews its existing allocation methodologies to ensure that costs are being appropriately allocated. ONE Gas's Distrigas allocation factors are updated quarterly or when significant changes to its corporate structure occur, such as acquisitions, divestitures, or corporate restructuring.

ONE Gas uses the following methodology to allocate costs when costs cannot be charged directly or allocated using a causal relationship to a business entity. The allocation methodology allows the allocation of costs to the business entities that receive the benefit of the administrative costs. The allocation methodology is described as follows:

Methodology Name	Cost Center	Description
OGS-Distrigas	1007	Calculates allocation percentages using the respective allocation factors for the business entities of ONE Gas's business entities including Oklahoma Natural Gas, Kansas Gas Service, Texas Gas Service, and Utility Insurance Company

Appendix A provides an example calculation of ONE Gas's Distrigas methodology.

Allocated Costs

Costs to be allocated can be aggregated in the following general categories:

- Executive
- Human Resources (HR)
- Information Technology (IT)
- Finance and Accounting
- General Counsel
- Corporate Communications
- Corporate Services (includes Environmental Health & Safety, Engineering, and Resource Management)
- Customer Service
- Other

The costs allocated in these general categories are allocated in accordance with our "three step allocation methodology" described above. The following sections provide a general description of the types of costs allocated in each general category and the method in which those costs are allocated.

Executive

The executive organization provides leadership and strategic direction for ONE Gas's business activities. Examples of costs incurred in this area are related to salaries and expenses of the President and Chief Executive Officer, his or her direct reports, and corporate officers with responsibility for corporate administrative functions that are not assigned to a specific business entity. These costs are primarily allocated through the OGS-Distrigas methodology.

Human Resources

The HR organization supports our various business entities and the employees of ONE Gas by developing and administering plans and processes related to compensation, employee benefits, employee development and payroll. Typical examples of costs incurred in this area are related to:

Types of Costs	Allocation Methodology
Administrative fees for all defined plans, health & welfare and retirement plans	1. These costs are allocated using the causal

	relationship of plan participant count or employee headcount for each respective business entity. 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Health and welfare benefits for active employees	1. These costs are allocated using the causal relationship of employee headcount or plan participant count for each respective business entity. 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Retirement benefits for active and retired employees	1. These costs are allocated using the causal relationship of plan participant count for each respective business entity where the plan participant works at each measurement date or where the plan participant worked immediately prior to retirement. 2. Plan participant or retiree costs allocated to corporate departments (Executive, HR,

	Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Workforce and professional development support and training programs for all active employees	1. These costs are allocated using the causal relationship of employee headcount 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
HR administration and financial services support, including compensation, payroll and benefits accounting and IT support	1. These costs are allocated using the causal relationship of employee headcount for each respective business entity. 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.

Information Technology

The IT organization supports our various business entities by developing and administering technology solutions and information security to facilitate day-to-day business activities. Typical examples of costs incurred in this area are related to:

Types of Costs	Allocation Methodology
IT administrative functions such as administration, financial planning, accounting and reporting	Allocated through the OGS-Distrigas methodology

Disaster recovery, data backup and recovery, change management and problem management	Allocated through the OGS-Distrigas methodology.
Websites, intranet, business intelligence, legal applications, imaging and scanning, and document management technologies	Allocated through the OGS-Distrigas methodology.
ONE Gas customer billing system	Allocated using the causal relationship of customer count for each of the business entities.
Data center and general support	1. Allocated through the OGS- Distrigas methodology.
Telecommunications and Mobile Services	1. Charged directly to the business entity receiving benefit of the service. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Financial and HR systems and related systems such as fixed asset accounting, project estimation and accounting, financial reporting and HR reporting	Allocated through the OGS-Distrigas methodology.
Supporting the operational accounting systems and the measurement systems used for non-residential gas meters	1. Charged directly to the business entity that is providing service to the non- residential gas meter. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.

Support and maintenance of the corporate and operations applications such as cash management systems	1. Costs are charged directly to the business entity receiving benefit of the service. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Supporting systems related to field operations including construction and engineering	1. Charged directly to the business entity receiving benefit of the service. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.
Support of compliance and network security monitoring (cyber security)	Costs are allocated through the OGS-Distrigas methodology.
Pipeline Support Systems	Costs are allocated through the OGS-Distrigas methodology.

Finance and Accounting

The Finance and accounting organization supports our various business entities by administering processes related to corporate accounting, financial reporting, tax, credit, risk and insurance, internal audit, financial planning and business development. Typical examples of costs incurred in this area are related to payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Corporate general accounting and consolidations, corporate financial planning and business development	Allocated through the OGS-Distrigas methodology.

SEC and external reporting for ONE Gas	Allocated through the OGS- Distrigas methodology.
Accounts payable	1. Allocated using a causal relationship derived from an internally developed analysis of invoice processing volume by business entity. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Investor relations	Allocated through the OGS-Distrigas methodology.
Treasury Services	Allocated through the OGS-Distrigas methodology.
Sustainability	Allocated through the OGS-Distrigas methodology.
Federal and state income tax accounting and compliance activities, ad valorem, sales & use tax and franchise tax accounting and compliance activities	1. Taxes incurred are charged directly to the business entity incurring the tax obligation. 2. General administrative costs, including labor and benefits are charged directly to the business entity receiving benefit of the service. 3. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Maintaining long-term financing and short-term working capital	1. General administrative costs associated with our finance department are allocated through the OGS-Distrigas methodology.

Risk mitigation and insurance	1. Labor, benefits and administrative expenses associated with administration of our insurance programs are allocated to the business entities through the OGS- Distrigas methodology. 2. Costs associated with specific insurance programs are allocated as follows: a. Primary & Excess Workers' Compensation: Allocated through the OGS-Distrigas methodology. b. Excess Liability: Allocated through the OGS-Distrigas methodology. c. Directors & Officers Liability: Allocated through the OGS-Distrigas. d. Property and Terrorism: Allocated through the OGS-Distrigas methodology. e. Various others (e.g. Fiduciary Liability, Blanket Crime, Mail and Transit, etc.): Allocated through the OGS- Distrigas methodology
Internal audit services (which includes our costs related to compliance with the Sarbanes-Oxley Act of 2002)	Costs are allocated to the business entities through the OGS-Distrigas methodology.
Independent auditor fees	1. Charged directly to the business entity being audited. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.

Centralized team responsible for fixed asset accounting	1. Labor and benefits are charged directly to each business entity for which the employee has accounting responsibility. 2. General and administrative supplies and expenses are allocated based on the causal relationship of gross property, plant, and equipment values.
Centralized team responsible for accounting for the customer billing process	Allocated to the business entity based on the causal relationship of customer count.

General Counsel

The general counsel organization supports our various business entities by administering processes related to legal aspects of our day-to-day business activities. Typical examples of costs incurred in this area are related payroll and business expenses (including third party legal costs) associated with departments responsible for:

Types of Costs	Allocation Methodology
Third-party damages and workers' compensation claims	1. Charged directly to the business entity incurring the damages or workers' compensation claim. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Commercial contracts	1. Charged directly to the business entity named in the commercial contract. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.

Regulatory affairs	1. Charged directly to the business entity receiving benefits of the services provided in certain instances. 2. Costs are allocated to the business entities through the OGS-Distrigas methodology.
Human resources	1. Allocated using the causal relationship of employee headcount for each respective business entity. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Litigation	1. Charged directly to the business entity receiving benefits of the services provided. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Corporate secretary and board of directors	Allocated through the OGS- Distrigas methodology.
General legal matters, ethics and compliance and pipeline safety	1. Charged directly to the business entity receiving benefit of the legal services. 2. Costs not attributable to a specific business entity are allocated through the OGS- Distrigas methodology.

Corporate Communications

The corporate communications organization supports our various business entities by administering processes related our corporate communications efforts with employees and external stakeholders. Typical examples of costs incurred in this area are related payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Governmental affairs	1. Costs are charged directly to the business entity receiving benefit of the services provided. 2. All other costs are allocated to the business entities through the OGS-Distrigas methodology.
Corporate communications (including advertising costs, costs associated with electronic communications and costs associated with general employee communications)	1. Costs are charged directly to the business entity receiving benefit of the services provided. 2. All other costs are allocated to the business entities through the OGS-Distrigas methodology.
Corporate responsibility (includes civic donations)	Allocated through the OGS-Distrigas methodology.

<u>Corporate Services (includes Environmental Health & Safety)</u>

The corporate services organization supports our various business entities by developing and administering programs and processes that facilitate general day-to-day business activities and environmental safety and health initiatives. Typical examples of costs incurred in this area are related to payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Purchasing and materials management	1. Costs are charged directly to the business entity receiving benefit of the services provided. 2. Allocated using a causal relationship derived from miles of

	pipe in the ground for each respective business entity. 3. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Facilities and fleet management	1. Costs are charged directly to the business entity receiving benefit of the services provided. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Right-of-way management	1. Allocated using a causal relationship derived from miles of pipe in the ground for each respective business entity. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.
Business continuity planning	These costs are allocated using the causal relationship of employee headcount for each respective business entity.
Environmental management	1. Charged directly to the business entity responsible for the environmental cost incurred. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT,

	etc.) are allocated through the OGS-Distrigas methodology.
Safety programs	1. Charged directly to the business entity responsible for the cost incurred. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Records Retention	1. Charged directly to the business entity responsible for the cost incurred. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Performance Management	1. Charged directly to the business entity responsible for the cost incurred. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Enterprise Resources	1. Charged directly to the business entity responsible for the cost incurred.

	2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Aviation services	Allocated through the OGS-Distrigas methodology.
Engineering	1. Allocated using a causal relationship derived from miles of pipe in the ground for each respective business entity. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology
Resource Management (includes costs for workforce strategy and planning, contractor)	1. Allocated using a causal relationship derived from miles of pipe in the ground, employee headcount, or customer count for each respective business. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.

Customer Service

The customer service organization supports our various business entities by providing responsive, flexible, efficient service to our customers. Typical examples of costs incurred in this area are related to payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Customer Service Support	1. Allocated to the business entity based on the causal relationship of customer count.

Other

This section represents miscellaneous costs impacting multiple business entities

Types of Costs	Allocation Methodology
Incentives, short- and long-term (stock-based compensation)	1. Short-term incentive costs charged directly to the business entity for which the employee has responsibility. 2. Long-term incentive costs are allocated using the causal relationship of plan participant count for each respective business entity. 3. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Employee stock purchase program, excluding long-term incentives	1. These costs are allocated using the causal relationship of plan participant count for each respective business entity.

	2. Costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
OGS Meter Shop Expense	1. Allocated using the causal relationship of customer count for each business entity.
Payroll taxes	1. Charged directly to each employee's respective payroll organization. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Other taxes (ad valorem, franchise, etc.)	1. Charged directly to the business entity incurring the tax obligation. 2. Costs not identifiable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.

Depreciation associated with general corporate assets	Allocated through the OGS-Distrigas methodology except as follows: a. Banner Customer Information System: Allocated using the causal relationship of customer count for each business entity. b. PowerPlant Fixed Asset Accounting System: Allocated using the causal relationship of Gross PP&E value attributable to each business entity. c. Maximo: Allocated using the causal relationship of miles of pipe for each business entity. d. Concur: Allocated using the causal relationship of employee count for each business entity. e. Certain Journey costs: Allocated using the causal relationship of employee count for each business entity. Costs not identifiable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF STACEY R. BORGSTADT

BEFORE ME, the undersigned authority, on this day personally appeared Stacey R. Borgstadt who having been placed under oath by me did depose as follows:

1. "My name is Stacey R. Borgstadt. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of Rates and Regulatory for ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Stacey R. Borgstadt

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey R. Borgstadt on this 21st day of May 2024.

JOANNE C. DAVIS NOTARY #05009895 EXP. 10/25/25 PUBLIC STATE OF OKLAHOMA

Notary Public in and for the State of Oklahoma

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS	**§**	
GAS SERVICE COMPANY, A	**§**	**BEFORE THE**
DIVISION OF ONE GAS, INC., TO	**§**	
CHANGE GAS UTILITY RATES	**§**	**RAILROAD COMMISSION**
WITHIN THE UNINCORPORATED	**§**	
AREAS OF THE CENTRAL-GULF	**§**	**OF TEXAS**
SERVICE AREA	**§**	

DIRECT TESTIMONY

OF

MEGAN Z. GOUGH

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF MEGAN Z. GOUGH

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Megan Z. Gough. My business address is 15 East 5th Street, Tulsa, Oklahoma, 74103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by ONE Gas, Inc. ("ONE Gas") as the Manager of Compensation. Texas Gas Service Company ("TGS" or the "Company"), is a Division of ONE Gas which is the applicant in this case.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor's in Business Administration with an emphasis in Human Resources from Texas A&M University in 1996. I hold a Certified Compensation Professional designation from the globally recognized WorldatWork Total Rewards Association. I began my employment with ONE Gas in July 2017, as the Manager of Compensation. Prior to joining ONE Gas, I worked as a senior compensation consultant at The Williams Companies, Inc. from 2008 to 2017, specializing in executive compensation and general compensation. Prior to my employment at Williams, I worked in the semiconductor industry for DuPont Photomasks, Inc. in Round Rock, Texas, a spin-off of E.I. DuPont de Nemours & Company, as a compensation consultant from 1997 to 2003.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE RAILROAD COMMISSION OF TEXAS ("COMMISSION")?

A. No. However, I have entered testimony before the Kansas Corporation Commission in Docket No. 24-KGSG-610-RTS.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes, I sponsor the exhibits listed in the table of contents.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes the components of ONE Gas' overall market-based compensation program and supports the reasonableness and necessity of the compensation and benefits-related expenses that TGS seeks to recover in this case, including how TGS's requested compensation and benefits costs comply with the Gas Utility Regulatory Act ("GURA") § 104.060 and the Commission's decision in TGS's base rate case, Commission Docket No. OS-22-00009896 ("Docket No. 9896"). Company witnesses Stacey L. McTaggart and Stacey R. Borgstadt also address aspects of these issues in their direct testimonies.

II. ONE GAS COMPENSATION PHILOSOPHY

Q. PLEASE EXPLAIN ONE GAS' EMPLOYEE COMPENSATION PROGRAM.

A. ONE Gas' employee compensation program is designed to attract, engage, motivate and retain employees. The compensation program includes a combination of a fixed component in the form of base pay and the variable components of incentive compensation, which are comprised of Short-Term Incentives ("STI") and Long-Term Incentives ("LTI"), if applicable. When determining or setting compensation, ONE Gas' objective is to pay its employees, on average, at the 50th percentile of the market for total compensation compared to peer companies. As a result, individual pay is differentiated and may be below, at or above the 50th percentile depending on an employee's level of experience, knowledge and performance. In this way, ONE Gas aims to pay its employees at a reasonable level that is not too high or too low compared to peer companies. The compensation program is reviewed at least annually through an Annual Salary Review process to determine if changes or revisions are necessary for ONE Gas to remain competitive with the marketplace.

Q. WHY DOES ONE GAS STRUCTURE EMPLOYEE COMPENSATION INTO FIXED AND VARIABLE COMPONENTS?

A. ONE Gas structures its compensation plan to be consistent with market demands, and all companies that ONE Gas competes with for employee talent have both fixed and variable components of compensation. Variable compensation requires that both individual employees and ONE Gas meet certain performance criteria to realize an incentive award. Variable pay plans provide ONE Gas with opportunities to attract, retain, engage, reward and motivate qualified workers to operate safely and efficiently in our communities. In this way, the compensation plan incentivizes employees who work safely and productively, which benefits TGS customers, communities, employees and ONE Gas shareholders.

Q. HOW MUST REGULATORS REVIEW ONE GAS' COMPENSATION PLAN?

A. In 2019, the Texas Legislature passed GURA § 104.060 regarding the consideration of compensation and benefit expenses. Specifically, GURA § 104.060(b) provides that "when establishing a gas utility's rates, the regulatory authority shall presume that employee compensation and benefits expenses are reasonable and necessary if the expenses are consistent with market compensation studies issued not earlier than three years before the initiation of the proceeding to establish the rates." GURA § 104.060(a) defines "employee compensation and benefits" to include base salaries, wages, incentive compensation, and benefits. GURA § 104.060(a) excludes from that definition pension or other post-employment benefits and financially-based incentive compensation related to Named Executive Officers.[1]

Q. HOW DID THE COMMISSION APPLY GURA § 104.060 TO TGS'S COMPENSATION REQUEST IN DOCKET NO. 9896?

A. The Commission found that TGS provided market compensation studies issued not earlier than three years before the initiation of the proceeding in accordance with GURA § 104.060 and that TGS's total requested employee compensation expense was consistent with those market compensation studies. Based on the consistency

[1] Named Executive Officers are those employees whose compensation is required to be disclosed under 17 C.F.R. Section 229.402(a).

with market compensation studies, the Commission determined that TGS's requested compensation expense was presumed reasonable under GURA § 104.060. Moreover, the Commission determined that insufficient evidence was presented to rebut the presumption under GURA § 104.060, so TGS was entitled to full recovery of its requested employee compensation expense.[2]

Q. IS TGS PROVIDING THE SAME INFORMATION TO SUPPORT ITS REQUESTED BENEFITS AND COMPENSATION COSTS IN THIS CASE AS IT DID IN DOCKET NO. 9896?

A. Yes. We have provided market compensation studies to support our request, including updated surveys to align with the statute.

Q. HAS THE COMPANY REMOVED ALL FINANCIALLY-BASED INCENTIVE COMPENSATION RELATED TO NAMED EXECUTIVE OFFICERS?

A. Yes. This adjustment is addressed in the direct testimony of Ms. Borgstadt.

Q. IS ONE GAS' COMPENSATION APPROACH CONSISTENT WITH GURA § 104.060?

A. Yes. While I am not a lawyer, I have read and understand the statute. It is my opinion that ONE Gas' compensation approach is consistent. ONE Gas participates in national and industry-specific independent compensation studies to determine proper pay ranges and incentive pay targets for each position. These studies may be specific to the energy industry, targeted to certain segments within the energy

[2] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at Findings of Fact ("FoF") No. 65-69 (Jan. 18, 2023).

industry or from a general industry perspective. Pay information is submitted and reviewed on at least an annual basis, allowing ONE Gas to update and maintain relevant and competitive pay ranges. ONE Gas relies on the studies to establish pay ranges that are competitive with its peers. Most positions are matched to multiple studies that are conducted by independent third-party human resources compensation consulting firms.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF § 104.060 OF GURA WITH RESPECT TO TGS'S INCENTIVE COMPENSATION COST RECOVERY IN THIS FILING.

A. My understanding of the significance, based on the plain language of the statute, is that all of the compensation costs TGS seeks to recover in this case must be presumed to be reasonable and necessary because those costs are consistent with recent market compensation studies. The statute confirms ONE Gas' position that market compensation studies are an important and reasonable source for both the gas utility and regulatory authorities to rely on to determine reasonable base pay and incentive compensation amounts, as well as recovery of those costs. TGS's employee compensation and benefits expenses are consistent with these market compensation studies and must be presumed reasonable by regulators under GURA § 104.060. My understanding is consistent with the Commission's decision in Docket No. 9896 and Docket No. OS-23-00014399 ("Docket No. 14399").

Q. WHAT ARE SOME OF THE STUDIES USED TO MONITOR MARKET-BASED PAY RELATED TO ONE GAS EMPLOYEES?

A. Some of the studies used to monitor market-based pay include:

- Willis Towers Watson ("WTW") General Industry Mid-Management, Profession and Support;
- WTW Energy Services Mid-Management, Professional and Support;
- WTW Energy Services Executive Compensation;
- WTW American Gas Association Compensation;
- Mercer Energy Total Compensation; and
- Mercer Benchmark.

Several of these recent studies and study excerpts are included in my testimony exhibits.

Q. DOES ONE GAS DETERMINE AND MONITOR EXECUTIVE COMPENSATION SIMILAR TO THE MANNER IN WHICH IT DETERMINES AND MONITORS OTHER EMPLOYEE COMPENSATION?

A. Yes, ONE Gas uses a market-based pay process for both executives and other non-executive employees. The Executive Compensation Committee of ONE Gas' Board of Directors and its independent executive compensation consultant, Meridian Compensation Partners, LLC, review executive market data of ONE Gas' peers. The compensation peers are selected primarily if they are a utility company and because of additional similarities to ONE Gas, including revenue, market capitalization and number of customers. A list of peer companies included in the review is contained in ONE Gas' 2024 Proxy Statement on page 54.[3] As it does for all positions, ONE Gas strives to pay experienced executives at the median level of total compensation for peer companies. The WTW 2022 General Rate Case

[3] Schedule 14(a) 2024 Proxy Statement at https://d18rn0p25nwr6d.cloudfront.net/CIK-0001587732/2795fb95-1318-4b99-a20b-a83471bd514d.pdf.

Total Compensation Study for TGS ("Compensation Study") provided as Confidential Exhibit MZG-1 on page 6 states, "[e]xecutive positions examined are, on average, within the same +/-10% competitive range of the market median as the other ONE Gas employee groups."

Q. HOW SHOULD ONE GAS' COMPENSATION PACKAGE BE VIEWED?

A. The compensation ONE Gas offers employees should be viewed as a comprehensive compensation package. On a combined basis, considering base salaries and incentive compensation, the Company is *generally at or below* comparable energy company industry levels. The Compensation Study provided in Confidential Exhibit MZG-1 illustrates that employee groups (non-exempt, professional, etc.) at ONE Gas and TGS have salaries and incentives valued below the market median by approximately 10%. Specifically, WTW found TGS's pay competitiveness is estimated to be at the low end of the competitive market range for base salary, total cash compensation and total direct compensation. WTW's assessment included the review of small and large utility peers as well as the general industry.

Q. DOES ANY DATA DEMONSTRATE THAT ONE GAS MUST OFFER INCENTIVE COMPENSATION OPPORTUNITIES TO ATTRACT AND RETAIN EMPLOYEES?

A. Yes. The utility industry continues to provide incentive compensation to employees. This has been a consistent form of compensation to attract, engage, reward, motivate and retain employees for many years. The points below indicate that almost all public utilities rely upon some form of incentive compensation as part of their overall compensation structure:

- The WTW 2023 Long-Term Incentives Policies and Practices Survey Report U.S. excerpt - LTI Prevalence found that 69% of the 142 energy companies responding granted restricted LTI and 92% granted performance-based LTI (Confidential Exhibit MZG-2); and
- Every company in the large and small peer group studied by WTW offers STI and LTI.

Q. WHAT CONSEQUENCES WOULD ONE GAS EXPERIENCE IF IT DID NOT OFFER A COMPREHENSIVE COMPENSATION PACKAGE?

A. If ONE Gas did not offer a comprehensive compensation package, ONE Gas and TGS would expect to experience: (1) a departure of skilled employees; (2) reduced levels of service and customer satisfaction; (3) lower employee engagement; (4) increased turnover costs and (5) difficulty attracting and retaining employees. It is even more important to offer competitive compensation packages with today's tight labor market to help ensure a stable workforce to deliver safe and reliable services to our customers. Without some form of incentive compensation, highly motivated and high-performing employees will seek employment opportunities where employees with their skill sets are provided an opportunity to earn compensation beyond base pay. A comprehensive compensation package, including incentive compensation, helps to create an engaged, skilled, safe and high performing workforce.

Q. WHAT CONSEQUENCES WOULD RESULT IF ONE GAS WERE TO ELIMINATE INCENTIVE COMPENSATION AND INCREASE BASE PAY ACCORDINGLY?

A. If incentive compensation were moved to base pay, several consequences would occur. First, it would impact the Commission's and the Company's ability to determine whether employees' compensation is within a reasonable range. For instance, page 7 and 9 of the WTW study states that every company in the Large Utility and in the Small Utility peer group has a short-term at-risk and long-term at-risk compensation program.[4] ONE Gas' and TGS's peer companies use of a base and incentive compensation structure is aligned with the energy industry and is how WTW and the Company were able to determine that TGS's salaries are at the low end of the competitive market range of compensation.

Said another way, moving incentive compensation would result in confusing optics for regulatory review. Essentially, by shifting incentive compensation to base pay, all else being equal, the overall compensation level may appear to be the same. However, a shift away from our incentive compensation program would make it more difficult for the Company (and current and/or future employees) to compare the Company's compensation offering against our peers.

Moreover, having the incentive compensation component places a portion of an employee's pay at risk in an effort to encourage productive employee behavior that leads to favorable safety, operational and financial results for the benefit of customers. If the threshold objectives of this plan are not met, the incentive will not be paid. This encourages our employees to be invested in the safety and financial health of our company.

The Company's ability to attract, engage, motivate and retain highly skilled employees has a very real and direct impact to TGS customers. Not only are ONE Gas and TGS competing with other utilities for talented employees, but ONE Gas and TGS also compete with non-regulated businesses that offer incentive

[4] *See* Confidential Exhibit MZG-1 at 7, 9.

compensation. Providing employees the opportunity to earn incentive compensation in addition to base pay is an integral component of ONE Gas' compensation package.

Q. ARE TGS'S REQUESTED INCENTIVE COMPENSATION COSTS REASONABLE AND NECESSARY?

A. Yes, they are. The incentive costs TGS seeks to recover, and which are presumed reasonable and necessary under the law, include STI and LTI for TGS Direct and Division employees as well as ONE Gas employees who perform activities that are necessary for TGS to provide service to customers in the Central-Gulf Service Area ("CGSA"). It is appropriate for TGS to recover its requested incentive compensation costs because these costs are slightly below or generally at the median of the market. Furthermore, the Company's incentive compensation costs include necessary costs for employees who are involved in the day-to-day functions and operations of the Company, including field personnel who ensure the safety of customer premises, and employees whose work is critical to TGS's ability to meet required safety and regulatory requirements. All non-bargaining unit employees are eligible to earn incentive compensation through their performance.

Q. ARE THERE ANY UNIQUE ASPECTS OF ONE GAS THAT SUPPORT THE REASONABLENESS AND NECESSITY OF THE INCENTIVE COMPENSATION COSTS TGS IS REQUESTING IN THIS CASE?

A. Yes, as I stated previously, ONE Gas is a fully regulated entity and operates only regulated local distribution companies, including TGS. Due to ONE Gas' fully regulated nature, all of the work performed by ONE Gas and TGS employees is focused on serving customer interests and operating a safe and reliable system.

Because efforts from all employees are directed towards meeting customer needs, the compensation costs TGS incurs are reasonable and necessary for the provision of service.

III. COMPENSATION COMPONENTS

Q. WHAT ARE THE COMPENSATION COMPONENTS?

A. Compensation is comprised of several components, including base pay and incentive programs commonly known as STI and LTI. STI and LTI are commonly referred to as at-risk pay. STI is awarded to all employees based on first meeting specific company metrics and then meeting individual performance standards. STI provides meaningful incentives for employees to operate with an emphasis on safety and customer service along with ONE Gas' financial performance. LTI is only awarded to a select group of employees. ONE Gas also offers benefits such as health and welfare, well-being and retirement plans, which are considered part of the overall employee total rewards package.

Q. PLEASE EXPLAIN BASE PAY.

A. Base pay is designed to compensate employees based on the skills and competencies required for their position, proficiency level, experience, consistent performance level and the overall value the employee brings to the position. Other components considered when determining base pay include workforce availability in the marketplace, employer needs, location, cost of labor and economic conditions. Base pay is reviewed at least annually for all employees resulting in pay increases, if applicable, by December to remain competitive with the marketplace. This process is known as the Annual Salary Review.

Q. WHAT INCENTIVE COMPENSATION PROGRAMS DOES ONE GAS OFFER TO ITS EMPLOYEES?

A. ONE Gas has two incentive compensation programs: (1) the Annual Employee Incentive Plan and the Annual Officer Incentive Plan, which collectively are identified as ONE Gas' "STI Plan" and (2) the Equity Compensation Plan, which is identified as LTI.

Q. HOW ARE THE METRICS IN THE STI AND LTI PLANS DESIGNED?

A. ONE Gas relies on recent market studies to design the incentive plans. The metrics, explained in detail below, are designed to encourage productive employee behavior that leads to favorable safety, operational and financial results for the benefit of customers.

IV. <u>SHORT-TERM INCENTIVE PLAN</u>

Q. PLEASE EXPLAIN ONE GAS' SHORT TERM INCENTIVE PLAN.

A. The STI Plan provides an annual, lump-sum cash amount based on specific employee and ONE Gas performance criteria. All full-time employees of ONE Gas and its divisions, except for those employees affiliated with collective bargaining units, are eligible to participate in the STI Plan. STI awards are calculated using four variables: an employee's base wages earned times the employee's STI target (determined by their position and based on market studies) times the ONE Gas performance modifier times their individual performance modifier. The ONE Gas performance modifier measures multiple categories to encourage all employees to operate safely, efficiently and in a fiscally responsible manner. Before any of the five individual STI metrics contribute toward an incentive payout, ONE Gas must achieve at least the threshold performance level for the metric. Any metric for which the threshold is not achieved will not contribute toward an incentive payout. Lastly, an individual's STI award may increase or decrease based on their individual work performance.

STI provides employees with an incentive to provide the safe delivery of energy to our customers, excellent customer service and high-quality work. It is designed to engage and motivate employees to operate safely and efficiently in their day-to-day activities. The Compensation Study provided in Confidential Exhibit MZG-1, page 7, identifies that every company in the large and small utility peer groups has a short-term at-risk compensation program. The details of ONE Gas' STI Plan are set forth in Confidential Exhibits MZG-3 and MZG-4.

Q. WHAT PERFORMANCE METRICS WERE INCLUDED IN THE STI PLAN DURING THE 2023 TEST YEAR?

A. The ONE Gas performance metrics included in the STI Plan are:

1. Preventable Vehicle Incident Rate ("PVIR"),
2. Days Away, Restricted or Transferred ("DART"),
3. Emergency Response Time ("ERT"),
4. Emissions Reduction ("ER"), and
5. Diluted Earnings Per Share ("EPS").

For any of the five individual STI metrics to contribute toward an incentive payout, ONE Gas must achieve at least the threshold performance level for the metric. Any metric for which the threshold is not achieved will not contribute toward an incentive payout. Lastly, an individual's STI award may increase or decrease based on their individual work performance.

Q. DOES THE STI PLAN OFFER EMPLOYEES THE OPPORTUNITY TO EARN PAYOUTS ABOVE THE 100% TARGET?

A. Yes. As I have noted, ONE Gas designs its compensation plans to compensate employees at the median of the market and to do so in a way that is comparable to incentive opportunities at peer companies. The Compensation Study provided in Confidential Exhibit MZG-1, page 8, reflects that all peer companies offer employees the opportunity to earn STI incentives above the 100% target threshold. For this reason, offering employees payouts that range from 0% to 150% helps ONE Gas maintain compensation that is competitive with the median of the market. In fact, up to 44% of the peer companies ONE Gas competes with for employees offer a maximum incentive payout at the 200% level.

Q. WHAT CONSEQUENCES COULD RESULT IF THE ONE GAS STI PLAN DID NOT INCLUDE OPPORTUNITIES FOR EMPLOYEES TO BE AWARDED AT A LEVEL GREATER THAN THE 100% TARGET?

A. If ONE Gas did not offer the opportunity for STI awards to exceed the 100% target, it would risk losing a motivational element in the plan design. By structuring a STI Plan that offers additional compensation for exceeding performance targets, ONE Gas is able to reward employees when their own efforts exceed expectations or help ONE Gas exceed the target for the safety, operational and financial goals in the plan. Likewise, if the employee or ONE Gas does not achieve its performance targets, the payouts would be below target and/or threshold.

Q. HOW IS THE INDIVIDUAL EMPLOYEE PERFORMANCE MEASURED?

A. Employees are evaluated on job-related goals and objectives and development established at the beginning of each year. Operational employee goals may include, but are not limited to, safety, productivity, efficiency, leadership, team collaboration, quality and reliability of service and customer satisfaction.

Each employee's performance is a key factor in calculating their STI compensation. Individual performance is ranked at five levels: (a) does not meet expectations; (b) needs improvement; (c) meets expectations; (d) exceeds expectations or (e) far exceeds expectations. If an employee does not meet expectations or needs improvement, their incentive compensation will be limited or eliminated altogether. Conversely, there may be some employees who receive a larger incentive if they exceed performance expectations. This is reasonable as employees should be rewarded for the ways in which their actions exceed performance expectations related to the overall safety, operational efficiency and quality of service delivered to our customers, as well as the financial health of ONE Gas. Rewarding employees for actions that contribute to a safe environment while providing quality and efficient service to our customers and the Company, promotes positive behavior, a strong customer experience and is reasonable to recover in rates.

Q. CAN YOU PROVIDE PAYOUT EXAMPLES FOR EMPLOYEES IN THE STI PLAN?

A. Below are actual examples of employee STI payouts for a Field Technician - C&M and a Gas Tech Senior - Customer Service Field, which are employees who regularly interact with and serve customers. During the 2023 Test Year, the Field Technician - C&M in the example below had $47,000 in base wages and a 4% incentive target. The Gas Tech Senior - Customer Service Field had $50,000 in base wages and a 4% incentive target. ONE Gas performance resulted in a company modifier of 108.15%. One employee earned an individual performance modifier of 100%, while the other achieved 85%. The individual modifiers are based on the employee's performance throughout the year. The calculations are as follows:

Field Technician - C&M								
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$47,000	x	4%	x	100%	x	108.15%	=	**$2,033**
Gas Tech Senior - Customer Service Field								
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$50,000	x	4%	x	85%	x	108.15%	=	**$1,839**

As the examples demonstrate, the Field Technician - C&M and the Gas Tech Senior - Customer Service Field must meet individual performance metrics and ONE Gas must (through the company modifier) have met safety and performance goals and managed costs effectively in a given year for an employee to receive STI. These examples show that STI pay amounts are reasonable and beneficial to an employee's total cash compensation.

Q. WHAT GOAL IS ONE GAS TRYING TO ACHIEVE THROUGH THE COMBINATION OF METRICS IN THE STI PLAN?

A. Achieving the metrics in the STI Plan encourages employees to: (a) provide safe, timely and reliable service; (b) practice safe driving and operating behaviors; (c) participate in the company's commitment to emission reduction through execution of the replacement of vintage pipeline materials and (d) be good stewards of expenses by encouraging decisions that help manage the Company's costs.

The combination of these criteria is key to safely providing reliable service to our customers at reasonable rates, as well as providing a balanced approach for attracting, engaging, motivating and retaining a high-performing employee workforce appropriate for the needs and requirements of ONE Gas, TGS and its customers. In this way, the metrics in the STI Plan encourage employee actions and performance that come together to provide benefits to customers, employees and shareholders rather than creating a situation in which certain types of metrics benefit only one stakeholder group. In fact, utilizing safety metrics in the STI Plan has allowed ONE Gas to remain one of the top safety performers amongst American Gas Association peers thus benefiting ONE Gas, TGS and its customers, as discussed in the direct testimony of Company witness Alex Limón.

V. INCENTIVE COMPENSATION RELATED TO EFFORTS DURING WINTER STORM URI

Q. DOES THE COMPANY'S REQUEST INCLUDE ANY INCENTIVE COMPENSATION COSTS RELATED TO WINTER STORM URI?

A. Yes, it does. Similar to Docket No. 9896, TGS proposes recovery of (1) $153,278 for the non-Officers' STI ERT payout of 4.69%, and (2) $220,123 for the recognition award amount through the Winter Storm Uri regulatory asset. Ms. McTaggart supports the requested recovery of the Company's Winter Storm Uri regulatory asset, which includes these incentive-related costs, addressed below.

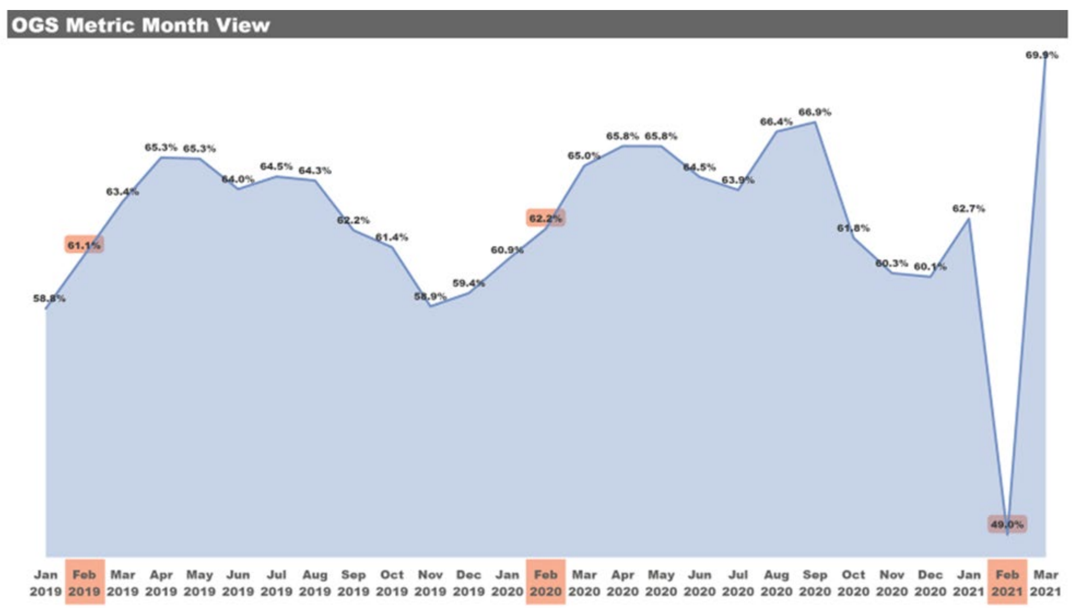
Q. PLEASE ELABORATE ON THE FACTORS ONE GAS EVALUATED RELATED TO THE 2021 STI METRICS AND 2021 AWARD AS A RESULT OF WINTER STORM URI.

A. To determine STI for 2021, ONE Gas evaluated the impact to the ERT metric performance during Winter Storm Uri, specifically the ERT performance data from February 13-22, 2021. As Mr. Limón testifies, Winter Storm Uri was an unprecedented event that impacted all of the areas TGS serves and significantly disrupted normal operations. The ERT metric is a measure of the percentage of emergency orders that are safely responded to within 30 minutes after being notified of an emergency. ONE Gas completed 5,983 emergency orders during February 13-22, 2021. Comparatively, for the same time period in 2020, ONE Gas completed 2,406 emergency orders. The ERT metric performance for the emergency orders responded to in less than 30 minutes during the 10-day period in 2021 that I mention above was 38.4%, compared to 62.5% in the same 10-day period in 2020. As Mr. Limón testifies, ONE Gas' and TGS's priority during Winter Storm Uri was maintaining service to human needs customers and providing safe and reliable service during unprecedented weather conditions. ONE Gas leadership determined that Winter Storm Uri was a significant statewide disaster that was not consistent with normal operating conditions and was a factor to consider when measuring employee performance under the ERT metric. Accordingly, ONE Gas calculated the overall ERT metric percentage for 2021, without the February 13-22, 2021, time period for all employees other than vice president level and above.

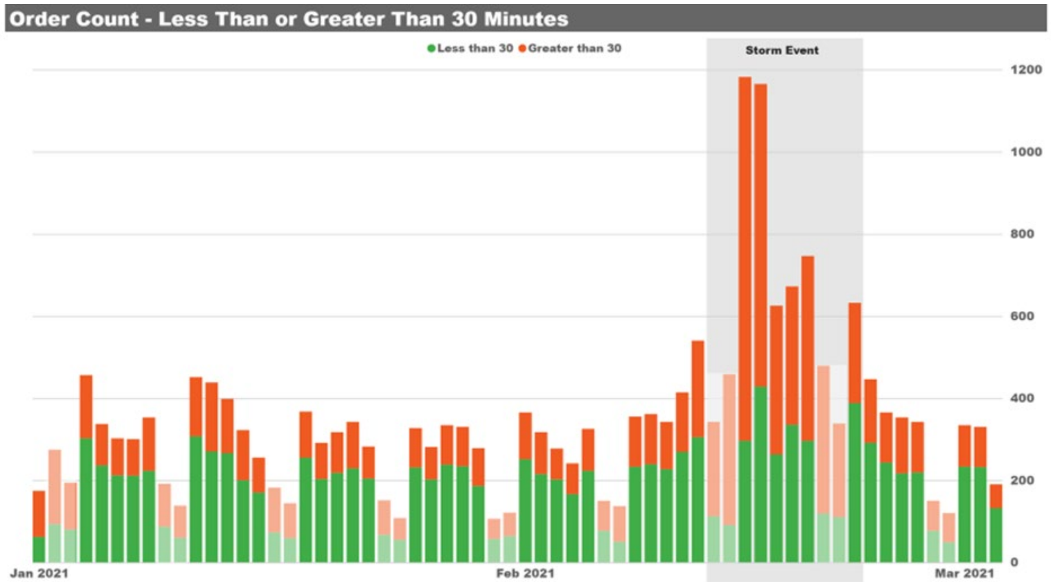
Q. CAN YOU ILLUSTRATE THE IMPACT OF THE STORM ON THE ERT METRIC?

A. Yes. The graphs below show how the 10-day severe weather event affected monthly and daily performance of the metric. Graph 1 shows the ONE Gas monthly ERT metrics from January 2019-March 2021, where a fairly consistent trend line is present until February 2021. Graph 2 tracks the order count and the emergency calls responded to in less than or greater than 30 minutes where the number of emergency calls significantly increased and affected the response time.

Graph 1



Graph 2



Q. WHAT WERE THE PERCENTAGES FOR ERT AWARDED IN 2021?

A. The achievement level for the ERT metric in 2021, was 62.7%, which fell below the threshold of 64%, resulting in an ERT payout of 0%. However, ONE Gas recognized that its employees were impacted in their response time to emergencies due to Winter Storm Uri, and ONE Gas leadership decided to exclude the 10-day period during Winter Storm Uri from its overall 2021 ERT calculation as discussed above. This adjustment resulted in an ERT payout of 4.69% of STI. Employees at the officer level (vice president) and above did not receive an ERT payout for 2021. For non-officers, by excluding the 10-day period, the ERT metric percentage met the threshold of 64%. Ms. McTaggart in her direct testimony supports the requested recovery of approximately $153,278 through a regulatory asset.

Q. PLEASE EXPLAIN AMOUNTS FOR THE ONE-TIME RECOGNITION AWARD INCLUDED IN THE WINTER STORM URI REGULATORY ASSET.

A. Recognition awards are a form of compensation designed to provide recognition to individual employees who perform one-time or short-term quality acts or service in an exceptional manner and above day-to-day responsibilities. The awards are typically low-value amounts and recognize a commitment to high performance on special tasks or situations. ONE Gas leadership approved a one-time recognition award for certain employees who directly impacted ONE Gas' ability to maintain service to customers during Winter Storm Uri. ONE Gas lost service to fewer than 900 of our 2.2 million customers during Winter Storm Uri and maintained service to 99.9% of TGS customers. The few outages that did occur lasted less than 24 hours in most cases. The employees who received the award often worked directly in the harsh winter conditions to maintain gas service to customers. For example, to ensure that critical regulator stations did not freeze, field operations employees stayed near the regulator stations in their vehicles to allow for constant monitoring of pressure levels.

Q. WHICH COMPANY EMPLOYEES WERE ELIGIBLE TO RECEIVE THE RECOGNITION AWARD?

A. Only employees involved in responding to Winter Storm Uri were eligible to receive the award. Thus, any employees that were on vacation or otherwise unable to work during Winter Storm Uri did not receive the award. Moreover, the recognition award only applied to the supervisor level and below.

Q. WHAT WAS THE AMOUNT OF THE RECOGNITION AWARD?

A. The recognition award to each employee was $2,000 or less. The portion of the company-wide award included for recovery in this case is approximately $220,123. As discussed by Ms. McTaggart, TGS is proposing to include this amount in the Winter Storm Uri regulatory asset to be amortized over six years.

Q. IS IT REASONABLE TO RECOVER THESE COSTS IN THIS RATE CASE?

A. Yes. The recognition award is directly related to compensating employees for their significant efforts to maintain and provide gas service to customers during the storm. It is reasonable to recognize, in addition to our other forms of compensation, the extraordinary efforts of employees who directly impacted the Company's ability to provide safe and reliable service to our customers during Winter Storm Uri. Further, the Commission approved a similar request in Docket No. 9896.[5]

VI. LONG-TERM INCENTIVE PLAN

Q. PLEASE EXPLAIN THE LTI PLAN.

A. ONE Gas has an LTI Plan in which two types of LTI equity awards (grants of ONE Gas stock) are available to executives and certain key employees. 127 non-officers received an LTI grant in February 2023. The payout that vested in February 2023, included 108 non-officers. ONE Gas' LTI plan is included as Confidential Exhibit MZG-5 to my testimony. LTI awards are approved and granted on an annual cycle, typically in the first quarter of each fiscal year. The ONE Gas Board of Directors Executive Compensation Committee oversees the Equity Compensation Plan,

[5] *See* Docket No. OS-22-00009896, consol., Final Order at FoF No. 46.

approves all executive LTI grants and receives information on all non-executive LTI grants.

In 2023, ONE Gas granted two forms of LTI compensation: Restricted Stock Units and Performance Stock Units. A higher ratio of Performance Stock Units to Restricted Stock Units is granted to participants with more direct ability to impact the overall performance of ONE Gas. The grant values were based on position and base salary utilizing compensation survey data. In addition to position and base salary, employee high performance, employee high potential, long-term value to ONE Gas, criticality of the job or a unique skill set and our desire to retain quality employees are considered in determining employee eligibility. LTI awards cliff vest three years after the grant to encourage long-term improvements, safe operations and financial awareness in key employees and to provide an incentive to remain employed with ONE Gas.

The Long-Term Incentives Policies and Practices Survey Report U.S. provided in Confidential Exhibit MZG-2, at pages 4-5, identifies that Performance plans are the most prevalent form of LTI, followed by Restricted Stock Units for the Energy Services sector. For that reason, these costs are presumed reasonable and necessary under GURA § 104.060.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN RESTRICTED STOCK UNITS AND PERFORMANCE STOCK UNITS.

A. Restricted Stock Units are granted for a term of three years from the date of the grant, with the participant being vested and entitled to receive one share of ONE Gas common stock for each restricted stock unit granted after three years of employment following the grant date. Restricted Stock Units are time-based equity and are <u>not</u> based on the financial performance of ONE Gas; rather, it is a form of compensation that depends entirely on an employee's tenure with ONE Gas. Restricted Stock Units are designed to encourage the retention of key employees, reducing turnover costs and retaining experienced employees who contribute to the overall success and stability of the organization.

Performance Stock Units also cliff vest three years from the date of the grant, at which time the employee is entitled to receive a percentage of the Performance Stock Units granted in shares of ONE Gas common stock. The number of shares of common stock awarded will range from 0% to 200% of the number of units granted based upon ONE Gas' performance as measured by its three-year Total Shareholder Return ("TSR") compared with a designated peer group of utility peer companies established each year by the ONE Gas Board of Directors Executive Compensation Committee over the same three-year measurement period. If the ONE Gas TSR equals the 50th percentile of the TSR earned by the peer companies over the measurement period, participants will receive 100% of the Performance Stock Units granted. A performance scale calibrates the potential number of performance stock units earned, with a 25th percentile TSR performance compared to the peer group equating to an award of 50% of the Performance Stock Units granted and a 90th percentile performance compared to the peer group equating to a payment of 200% of the Performance Stock Units granted. If the ONE Gas TSR falls below the 25th percentile TSR of the peer group, participants will not receive an award for any of the Performance Stock Units granted at the start of the measurement period. This measurement is commonly referred to as relative TSR. As I explain below, relative TSR is a common measure of long-term performance associated with utility performance plans such as the ONE Gas Performance Stock Units.

Q. WHAT IS THE PURPOSE OF OFFERING LONG-TERM INCENTIVE?

A. LTI grants, along with base pay and STI, are necessary for certain positions to allow ONE Gas to compete with peers in the market. LTI is also necessary to attract, retain, engage and motivate key employees, including executives, and encourage them to make operational decisions that create value for customers, employees and other stakeholders. Generally, participants who receive LTI are those employees who are in a position to significantly contribute to the operational and financial stability of ONE Gas.

Q. IS IT APPROPRIATE FOR PERFORMANCE STOCK UNITS TO BE LINKED TO FINANCIAL GOALS?

A. Yes, linking the award of ONE Gas Performance Stock Units to financial goals is a consistent standard across the marketplace. The most common financial metric used to evaluate company performance in an LTI plan is TSR, with 65.6% of energy companies using that metric according to the WTW 2023 Long-Term Incentives Policies and Practices Survey Report U.S. excerpt - LTI Prevalence provided in Confidential Exhibit MZG-2. The ONE Gas LTI plan design relies on TSR since it is the most common approach among the majority of peer companies, is evaluated annually to ensure that ONE Gas remains competitive with the market and ensures alignment to our shareholders' experience.

Q. WHY DOES THE LONG-TERM INCENTIVE PROGRAM OFFER PAYOUTS FOR PERFORMANCE STOCK UNITS IN EXCESS OF THE 100% TARGET FOR TSR PERFORMANCE?

A. As mentioned previously, if ONE Gas did not offer the opportunity for payouts to exceed target when ONE Gas' performance exceeds the 100% target, we would run the risk of losing a motivational and retention element in the plan design. All performance-based LTI programs within the market offer a range of opportunities, typically from 0% to 200% of target measured by relative TSR. When ONE Gas performs above its peers, a higher payout is competitive and motivates employees just like a lower or zero payout is competitive when the company performs below peers.

Q. WHAT DOES ONE GAS HOPE TO ACHIEVE THROUGH THE LTI PLAN?

A. The LTI plan enables ONE Gas to compete in the market in order to attract, engage, motivate and retain quality executives and key employees. This encourages employees to continuously improve performance, which directly benefits customers through a focus on safe, reliable and efficient service at reasonable rates. Retaining key employees also improves system and operations knowledge and reduces the need (and cost) to recruit, hire and train employees to replace employees who might leave ONE Gas or TGS if we did not compensate them competitively in the market.

VII. GENERAL BENEFITS

Q. WHAT ARE THE COMPONENTS OF ONE GAS' BENEFIT PLANS?

A. ONE Gas provides a competitive range of benefits to its employees that include: (a) medical, dental and vision insurance; (b) basic life insurance; (c) basic accidental death and dismemberment; (d) short-term and long-term disability; (e) voluntary benefits; (f) an Employee Assistance Program (EAP); (g) 401(k) plan; (h) Profit Sharing Plan or Retirement Plan and (i) an Employee Stock Purchase Plan (ESPP). These benefit programs are offered to employees, who may elect to participate in certain benefits at varying levels.

Q. HAS ONE GAS TAKEN ANY MEASURES TO HELP MANAGE ITS HEALTH BENEFIT COSTS?

A. Yes. ONE Gas' goal is to provide benefits that are competitive in the marketplace and allow ONE Gas to attract, retain, engage and motivate a quality workforce. ONE Gas compares the benefits it offers employees with that of peer companies to ensure market competitiveness and the ability to attract, engage, motivate and retain employees. Having a quality workforce is key to providing safe, reliable and efficient service to the Company's customers. ONE Gas contracts with market standard health care vendors to provide reliable service to our employees and their dependents while helping ONE Gas to control health care costs. ONE Gas has a process for auditing vendor administration fees and participant eligibility to ensure efficient administration and has performance guarantees in place to help ensure high quality vendor management. ONE Gas continues to partner with a pharmacy benefit manager to help control pharmacy cost. The Company expanded the virtual visit option for medical and mental health visits which in turn reduced cost to the plan while allowing safe and reliable health care to our participants. ONE Gas has regular governance meetings with current healthcare vendors that provide support to employees helping them to navigate and identify quality providers, review medical bills for accuracy and provide second opinions to avoid unnecessary medical procedures or identify better therapies with more favorable outcomes.

In addition, employees' dependents over age 18 are required to identify whether they use tobacco products. Those who do, pay a premium surcharge. ONE Gas also offers a tobacco cessation program for employees and dependents over age 18 who wish to stop smoking or using tobacco products. The tobacco surcharge, in turn reduces ONE Gas health claim costs. ONE Gas contracts with health carriers to provide several programs to ensure early detection of potential health concerns to produce quality outcomes and help manage health care trends.

Q. WHY IS IT IMPORTANT THAT ONE GAS' BENEFIT PROGRAMS ARE COMPARABLE WITH ITS INDUSTRY PEERS?

A. ONE Gas provides competitive benefits because it competes with other utilities and local companies and businesses for talented employees to meet its goal of providing safe, reliable service to customers at a reasonable cost. Additionally, most of our employees have transferable skills, meaning they can go work in the broader energy industry or a completely unrelated industry. We compete with the broader marketplace to attract, engage, motivate and retain employees that will support our business of providing natural gas to our customers safely and reliably. Part of that attraction, engagement, motivation and retention is that ONE Gas' pay and benefits must be competitive in the industry and local market.

Q. IN YOUR OPINION, DOES GURA § 104.060 SUPPORT THE COMPANY'S REQUEST TO RECOVER BENEFIT COSTS?

A. Yes. In addition to referring to base pay and wage issues, the statute also includes employee benefits. ONE Gas relies on and appropriately uses independent market studies that are less than three years old to analyze and decide which benefits to offer. ONE Gas' benefits are consistent with those studies, which means the benefit costs TGS is requesting are presumed reasonable and necessary. See Confidential Exhibit MZG-6 for an independent study showing the value of ONE Gas' benefits is comparable to peer companies and approximately at the median value.

Q. ARE COMPENSATION PLAN COSTS INCURRED BY ONE GAS REASONABLE AND NECESSARY?

A. Yes. The Company targets the median (50th percentile) of the local market and peer groups in the locations in which it operates to set pay and benefits. By reducing or eliminating any element of our total direct compensation, we would not be competitive in the market. Competitive pay and benefit plans are a necessary cost of doing business in order to attract, motivate and retain qualified employees, which benefits the customer and communities by ensuring the delivery of safe, reliable and efficient service.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibits MZG-1 through MZG-6 are Confidential
and will be provided pursuant to the terms of the Protective Agreement
in this proceeding or Protective Order issued in OS-24-00017471.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF MEGAN Z. GOUGH

BEFORE ME, the undersigned authority, on this day personally appeared Megan Z. Gough who having been placed under oath by me did depose as follows:

1. "My name is Megan Z. Gough. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Manager of Compensation for ONE Gas. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Megan Gough
Megan Z. Gough

SUBSCRIBED AND SWORN TO BEFORE ME by the said Megan Z. Gough on this 22 day of May 2024.

M. BETH WILLIAMS NOTARY #13002055 EXP. 03/01/25 PUBLIC STATE OF OKLAHOMA

M. Beth Williams
Notary Public in and for the State of Oklahoma

My commission expires: 3/1/2025

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

DIRECT TESTIMONY

OF

CYNDI L. KING

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF CYNDI L. KING

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cyndi L. King. My business address is 15 East Fifth Street, Tulsa, Oklahoma 74103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Director of Treasury and Finance for ONE Gas, Inc. ("ONE Gas").

Q. ON WHOSE BEHALF ARE YOU PRESENTING THIS TESTIMONY?

A. I am testifying on behalf of Texas Gas Service Company ("TGS" or the "Company"), a Division of ONE Gas, in support of its request to update rates.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science in Accounting from Oklahoma State University. I have worked for ONE Gas or its predecessor ONEOK, Inc. for 24 years in areas that include Gas Accounting and Treasury. I have been a Certified Treasury Professional since 2014, and I have served on the ONE Gas Benefits Committee, which reviews all pension activity, since 2014.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony before the Railroad Commission of Texas ("Commission") in Gas Utilities Docket ("GUD") Nos. 10739, 10766 and 10928 and Docket No. OS-23-00014399 ("Docket No. 14399").

Q. WAS THIS TESTIMONY AND ITS ACCOMPANYING EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, either I or employees under my direction prepared this testimony and the accompanying exhibit listed in the table of contents.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the Company's request to earn a return on the portion of contributions to the ONE Gas prepaid pension asset that is attributable to TGS and are part of the rates the Company is seeking approval of in this statement of intent.

II. PREPAID PENSION

Q. WHAT ARE THE TGS AND CENTRAL-GULF SERVICE AREA ("CGSA") PORTIONS OF THE PREPAID PENSION ASSET AS OF THE END OF THE TEST YEAR?

A. TGS has a total prepaid asset as of December 31, 2023, of $24.1 million and an allocated portion of the corporate prepaid asset of $19.83 million. TGS's portion of the total asset is $43.9 million and the CGSA portion is $20,530,077. These amounts are shown on Exhibit CLK-1.

Q. WHAT AMOUNT IS THE COMPANY ASKING TO BE INCLUDED IN RATE BASE?

A. The amount for the CGSA is $16.2 million as shown in Exhibit CLK-1. This reflects the prepaid asset of $20.5 million less the associated deferred taxes of $4.3 million for the total of $16.2 million.

Q. HAS THE INCLUSION OF TGS'S PREPAID PENSION ASSET IN RATE BASE BEEN PREVIOUSLY REVIEWED AND APPROVED?

A. Yes, the Commission approved the rate base treatment of TGS's portion of the ONE Gas prepaid pension asset in the Company's West Texas Service Area in GUD No. 10506 and in the West North Service Area in Docket No. OS-22-00009896 ("Docket No. 9896"). The Commission determined that the inclusion of the prepaid pension asset in rate base is just and reasonable. The Commission explained that the asset benefits ratepayers by reducing expenses more than the rate of return on the asset. The Commission also found that it avoids future additional costs and restrictions being placed on the pension plan.[1] In sum, the prepaid pension asset avoids future additional pension expense, increased variable rate Pension Benefit Guarantee Committee premiums and restrictions placed on the pension plan. The Company also proposed the same treatment of the prepaid pension asset in GUD Nos. 10488, 10526, 10656, 10739, 10766, 10928 and Docket No. 14399 all of which were resolved through settlement agreements that were approved by the Commission.[2]

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[1] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Areas (EPSA), Permian Service Area (PSA) and Dell City Service Area (DCSA)*, GUD No. 10506, consol., Final Order at Finding of Fact ("FoF") No. 61 (Sept. 27, 2016).

[2] With respect to the Commission's Final Orders in GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928 and Docket No. OS-23-00014399, the parties agreed on "black box" settlement amounts in each of those cases. However, the rate base amount agreed to in each settlement includes the Company's proposed pension plan asset. *See Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order (May 3, 2016); *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018); *Statement of Intent of Texas Gas Service, a*

Q. SINCE THE COMMISSION'S DECISIONS IN PRIOR TGS RATE CASES, HAS ONE GAS OR TGS CHANGED THE WAY IT APPROACHES THE FUNDING REQUIREMENTS FOR THE PREPAID PENSION ASSET OR THE RELATED RATE CALCULATIONS INCLUDED IN THIS STATEMENT OF INTENT?

A. No. As I explain above, ONE Gas and TGS are taking the same approach to these issues as they did in GUD No. 10506, Docket No. 9896 and other prior cases identified above.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area, GUD No. 10739, Final Order (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019); S*tatement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928, consol., Final Order (Aug. 4, 2020); and *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order (Jan. 30, 2024).

TEXAS GAS SERVICE COMPANY
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PREPAID PENSION ASSET
($ in 000s)

Line No.	Year	Corporate Prepaid Pension Asset	Distrigas %	Corporate Allocation	TGS Direct Prepaid Pension Asset	Total TGS Prepaid Asset Balance	Pension Earnings Rate	TGS Expense Reduction	Cumulative TGS Expense Reduction	CGSA Expense Reduction
	(a)	(b)	(c)	(d) = b * c	(e)	(f) = d + e	(g)	(h) = f * g	(i)	(j)
10	2019	$ 76,979.308	25.40%	$ 19,552.744	$ 33,163.628	$ 52,716.372	7.20%	3,795.579	34,204.485	1,773.909
11	2020	$ 72,824.572	25.63%	$ 18,664.938	$ 28,937.707	$ 47,602.645	7.20%	3,427.390	37,631.875	1,601.832
12	2021	$ 68,548.217	26.81%	$ 18,374.761	$ 24,965.926	$ 43,340.687	7.15%	3,098.859	40,730.734	1,448.289
13	2022	$ 67,843.246	28.07%	$ 19,043.599	$ 23,527.498	$ 42,571.097	6.40%	2,724.550	43,455.284	1,273.351
14	2023	$ 69,404.601	28.57%	$ 19,831.532	$ 24,096.037	$ 43,927.569	6.75%	2,965.111	46,420.395	1,385.780
15										
16								Allocation		
17							TGS Total	to service area	CGSA	
18					Prepaid Pension Asset		$ 43,927.569	46.7362%	$ 20,530.076	
19					Less Deferred Taxes (21%)		(9,224.789)		(4,311.316)	
20					Rate Base		$ 34,702.779		$ 16,218.760	

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF CYNDI L. KING

BEFORE ME, the undersigned authority, on this day personally appeared Cyndi L. King who having been placed under oath by me did depose as follows:

1. "My name is Cyndi L. King. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of Treasury & Finance for ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Cyndi L. King

Cyndi L. King

SUBSCRIBED AND SWORN TO BEFORE ME by the said Cyndi L. King on this 21st day of May 2024.

Valerie A. Hecht

Notary Public in and for the State of Oklahoma

VALERIE A. HECHT
NOTARY
24005915
EXP. 05/02/28
PUBLIC
STATE OF OKLAHOMA

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS	**§**	
GAS SERVICE COMPANY, A	**§**	**BEFORE THE**
DIVISION OF ONE GAS, INC., TO	**§**	
CHANGE GAS UTILITY RATES	**§**	**RAILROAD COMMISSION**
WITHIN THE UNINCORPORATED	**§**	
AREAS OF THE CENTRAL-GULF	**§**	**OF TEXAS**
SERVICE AREA	**§**	

DIRECT TESTIMONY

OF

JAIME D. SHELTON

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

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LIST OF EXHIBITS

DIRECT TESTIMONY OF JAIME D. SHELTON

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jaime D. Shelton. My business address is 15 East Fifth Street, Tulsa, Oklahoma 74103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Risk and Insurance Management for ONE Gas, Inc. ("ONE Gas").

Q. ON WHOSE BEHALF ARE YOU PRESENTING THIS TESTIMONY?

A. I am testifying on behalf of Texas Gas Service Company ("TGS" or the "Company"), a Division of ONE Gas, in support of its request to update rates.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Arts in Sociology from The University of Oklahoma. I have worked for ONE Gas since July 2023. Prior to my employment with ONE Gas, I was employed with Matrix Service Company for 14 years, where I served as Risk Manager for six of those years.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. No, I have not.

Q. WAS THIS TESTIMONY AND ITS ACCOMPANYING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, either I or employees under my direction prepared this testimony and the accompanying exhibits. The accompanying exhibits include: confidential Exhibit

JDS-1, which summarizes the Utility Insurance Company ("UIC") insurance expense charged to ONE Gas and TGS and the change in insurance cost inclusive of lower deductible limits; and Confidential Exhibits JDS-2, JDS-3, JDS-4, and JDS-5, which are copies of the policies issued by UIC to TGS. Confidential Exhibit JDS-6 is an analysis of insurance costs.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony reviews the ONE Gas insurance and risk management program and the services provided to TGS by UIC, ONE Gas' captive insurer. I also explain why the insurance rates paid by TGS to UIC are reasonable and necessary and attest to the fact that the price paid by TGS complies with the affiliate cost recovery standard, Gas Utility Regulatory Act § 104.055(b). My testimony also correlates with the direct testimony of Company witness Marie J. Michels, who also addresses the affiliate cost recovery standard, and the direct testimony of Company witness Stacey R. Borgstadt, who sponsors the schedule (*see* Exhibit SRB-2) that identifies the amount of insurance premium costs TGS is seeking to recover through rates.

II. <u>ONE GAS' INSURANCE AND RISK MANAGEMENT PROGRAM</u>

Q. WHAT IS A CAPTIVE INSURANCE COMPANY?

A. A captive insurance company, often referred to as a "captive," is a regulated insurance company that is owned and controlled by the insured organization(s). A captive allows the insured organization to have more control over the insurance coverage it receives by tailoring coverage to the organization's risk profile. Captives are regulated and must follow the insurance laws of the state in which they were incorporated and file annually with their respective insurance commissions.

Q. PLEASE BRIEFLY DESCRIBE UIC AND ITS PLACE IN ONE GAS' CORPORATE STRUCTURE.

A. UIC was chartered in Oklahoma on August 29, 2017, and was operational as of October 1, 2017. UIC is a wholly-owned subsidiary of ONE Gas and is incorporated under Oklahoma's laws and regulations. It is fully capitalized under the requirements of applicable Oklahoma law, as required by the Oklahoma Insurance Commission, and does not provide services to any entity other than ONE Gas and its divisions.

Q. HAVE THE PREMIUMS FROM UIC BEEN PREVIOUSLY APPROVED BY THE RAILROAD COMMISSION OF TEXAS?

A Yes, they have been accepted as appropriate costs in Gas Utilities Docket ("GUD") Nos. 10739, 10766, 10928, Docket Nos. OS-22-00009896 and OS-23-00014399.[1]

[1] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order at Findings of Fact ("FoF") No. 48-51 (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order at FoF No. 46-48 (Feb. 5, 2019); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928, consol., Final Order at FoF No. 59 (Aug. 4, 2020); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area,* Docket No. OS-22-00009896, consol., Final Order at FoF No. 75-78 (Jan. 18, 2023); and *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order at FoF No. 42-43 (Jan. 30, 2024).

Q. DO THE PREMIUMS CHARGED TO TGS INCLUDE INSURANCE COVERAGE FOR CORPORATE ASSETS OF ONE GAS?

A. No, not directly. Corporate is charged premiums similar to the ONE Gas divisions, on its asset and risks. The Corporate insurance expense is allocated through Distrigas to each division, including TGS, as described by Ms. Borgstadt.

Q. WHAT TYPES OF INSURANCE COVERAGE DOES UIC PROVIDE FOR ONE GAS' TGS DIVISION?

A. UIC provides the following insurance coverages for TGS:

1) property, plant and equipment, including business interruption;
2) general liability and employment practices;
3) workers' compensation and employers' liability;
4) automobile liability;
5) cyber; and
6) medical stop loss.

Copies of the policies for coverages 1 through 4 above are attached as confidential Exhibit JDS-2 through confidential Exhibit JDS-5.

Q. CAN YOU DESCRIBE THE NATURE OF THE COVERAGE PROVIDED BY UIC TO TGS?

A. Yes. TGS receives insurance coverage in the areas listed above for an amount that is equal to or in excess of $25 million per event, with a deductible from $100,000 to $300,000 per occurrence based on the type of policy for coverages 2, 4, and 5 listed above. TGS receives insurance coverage for workers' compensation of $1.9 million per occurrence. This $100,000 deductible is lower than what is commercially available in the retail insurance markets for other local distribution companies and companies the size of ONE Gas. ONE Gas' lower deductible obtained through the use of UIC ultimately results in lower costs for TGS and its customers. In addition to the cost benefits for our customers, lower deductibles also lessen distractions tied to negative financial impacts of unexpected events and allows TGS to focus on infrastructure and reliability and other customer focused priorities. Despite the benefits gained through the coverage provided by UIC, TGS's actual claims activity will ultimately impact its rates, either favorably or unfavorably, which is the same way it would work in the retail insurance marketplace. Fortunately, because ONE Gas controls UIC, it is able to avoid a situation where a retail insurer might act quickly in response to an incident to raise a deductible and premiums.

Q. HOW IS THE COST OF OBTAINING INSURANCE COVERAGE FOR ONE GAS AND ITS DIVISIONS THROUGH UIC DETERMINED?

A. UIC bases premiums on a long-term time horizon, consistent with the industry-accepted approach for captives. This approach recognizes that there will be periods when losses are less than forecasted and periods when losses are greater than forecasted. The price paid to UIC by TGS and other ONE Gas Divisions (Oklahoma Natural Gas, Kansas Gas Service and ONE Gas Corporate) is determined using several factors and based upon the advice and actuarial services of Spring Consulting. These factors are:

1) administrative fees;
2) cost of reinsurance premiums;
3) reserve requirements;
4) loss history; and
5) projected losses for all the various policies.

The administrative fees and cost of reinsurance premiums are paid by UIC directly to non-affiliated third parties and are included within the overall premium charged to TGS by UIC, at cost without mark-up.

Q. WHAT ARE SOME OF THE MAJOR DRIVERS IN SETTING THE COSTS OF THE PREMIUMS?

A. The major drivers for the cost of premiums are as follows:

1) for property insurance, the replacement value of the assets being insured, the potential business interruption or net margins of the division, division loss history;

2) for workers' compensation, the salary, job type being insured, number of employees in a division, division loss history;

3) for automotive insurance, the number of vehicles that each division is operating, division loss history; and

4) for liability insurance, division loss history, net margins, the number of customers, the value of the assets deployed, the age of the assets used and the number of employees.

All these potential risk factors are updated annually, along with loss histories for each type of coverage. Spring Consulting provides actuarial services to determine the rates just as any insurance company would do for its clients. These rates and actuarial study are then filed with the Oklahoma Insurance Commission for their review and approval.

Q. CAN YOU SHOW SAVINGS FOR THE POLICY THAT UIC HAS WRITTEN?

A. I have attached confidential Exhibit JDS-6, which shows the cost charged to all of the ONE Gas divisions, as compared to quotes in the commercial markets. Confidential Exhibit JDS-6 shows that UIC has saved ONE Gas and its customers \$9.3 million since UIC was created for liability coverage and \$1.6 million for property coverage since UIC was created. ONE Gas was not able to get an insurer to quote auto or workers compensation at this level of deductible.

Q. HOW IS THE COST OF REINSURANCE PASSED THROUGH FROM UIC TO ONE GAS AND ITS DIVISIONS?

A. Any amount of reinsurance that UIC purchases is allocated to the divisions on a risk-adjusted basis.

Q. HAS UIC PAID OUT CLAIMS ON BEHALF OF TGS?

A. Yes. During the test year period ended December 31, 2023, UIC has paid out three claims on its liability policy for TGS and medical stop loss claims related to the benefit plan as a whole. In addition, UIC has paid one property claim relating to TGS. In these cases, UIC, UIC's reinsurer and ONE Gas shareholders bore the entire cost of the claims above the deductible, while TGS only paid its premiums and deductible.

Q. ARE THE UIC COSTS PAID BY TGS REASONABLE AND NECESSARY?

A. Yes, buying appropriate levels of insurance is a necessary expense to prevent catastrophic events from negatively impacting TGS and its customers, to help keep expenses consistent and to avoid a spike or a dip from one year to the next. This is true for both TGS assets that are insured through UIC for which UIC charges TGS a premium and for UIC's coverage of ONE Gas corporate assets. Ms. Borgstadt sponsors the schedule that shows the amount of corporate costs for ONE Gas assets that TGS is seeking to recover through rates. As confidential Exhibit JDS-6 shows, ONE Gas has saved $9.3 million in liability insurance and $1.6 million in property insurance since the captive was created.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibits JDS-1 through JDS-6 are Confidential
and will be provided pursuant to the terms of the Protective Agreement
in this proceeding or Protective Order issued in OS-24-00017471.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF JAIME D. SHELTON

BEFORE ME, the undersigned authority, on this day personally appeared Jaime D. Shelton who having been placed under oath by me did depose as follows:

1. "My name is Jaime D. Shelton. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of Risk & Insurance Management for ONE Gas. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Jaime D. Shelton

Jaime D. Shelton

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jaime D. Shelton on this 21st day of May, 2024.

LISA K MCCUTCHEON
NOTARY
20009152
Expires
29 Jul 2024
PUBLIC
STATE OF OKLAHOMA

Lisa K. McCutcheon

Notary Public in and for the State of Oklahoma

LISA K. MCCUTCHEON

#20009152

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

KENNETH W. EAKENS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

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LIST OF EXHIBITS

DIRECT TESTIMONY OF KENNETH W. EAKENS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kenneth W. Eakens. My business address is 15 East 5th Street, Tulsa, Oklahoma 74103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Director, Tax Compliance and Reporting for ONE Gas, Inc. ("ONE Gas"). I joined the Company on July 18, 2022. I have responsibility for the Tax and Plant Accounting functions for ONE Gas. These responsibilities include the accounting, compliance and financial reporting as it relates to those functions for ONE Gas and its divisions, including Texas Gas Service Company ("TGS" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Business Administration from Southeast Missouri State University with an accounting major and a finance minor. For more than 30 years, I have worked in tax accounting and compliance roles. Prior to my current position, I was Manager, Tax Accounting and Reporting where I was responsible for the accounting, Securities and Exchange Commission reporting and Sarbanes Oxley tax processes for FedEx Corporation & Subsidiaries ("FEDEX"). During my tenure at FEDEX, I also served as Manager, Tax Compliance & Audit. Prior to joining FEDEX, I was a Tax Specialist at Ameren Services in St Louis, Missouri. In that role, I was the lead specialist for the tax accounting, compliance and regulatory reporting for several of the large utility subsidiaries in the Ameren group. Prior to joining Ameren, I was a Tax Auditor for the State of Missouri. In that role, I specialized in audits of Fortune 500 companies for sales, use, income and franchise taxes. I am licensed as a Certified Public Accountant in Missouri.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony on behalf of TGS in Docket No. OS-23-00014399 ("Docket No. 14399") before the Railroad Commission of Texas ("Commission").

Q. WAS THIS TESTIMONY, INCLUDING ITS EXHIBITS, PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes how the Company has complied with Accounting Order Gas Utilities Docket ("GUD") No. 10695 concerning Excess Accumulated Deferred Income Tax ("EDIT"). I am also providing testimony on two Private Letter Rulings ("PLR") from the Internal Revenue Service ("IRS"), which proscribe how the Company should return the EDIT credit to customers and address the requested modification of the Company's EDIT credit going forward.[1] I also discuss the Commission's approval of TGS's treatment of EDIT in TGS's West North Service Area rate case in Docket No. OS-22-00009896 ("Docket No. 9896") and in the Company's Rio Grande Valley Service Area rate case in Docket No. 14399, which is the same treatment TGS is requesting in this case.

[1] Exhibit KWE-1 and Exhibit KWE-2.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE DIRECT TESTIMONY OF OTHER COMPANY WITNESSES?

A. Company witness Stacey L. McTaggart proposes withdrawal of the Company's EDIT Rider and inclusion of the EDIT credit in base rates. Company witness Janet M. Simpson addresses the calculation of Accumulated Deferred Income Taxes ("ADIT") in her direct testimony.

Q. HAS THE COMPANY'S REQUESTED MODIFICATION OF THE EDIT CREDIT BEEN APPROVED BY THE COMMISSION?

A. Yes, the Commission recently found TGS's methodology to flow EDIT back to customers through base rates to be reasonable in Docket No. 9896[2] and Docket No. 14399.[3]

II. COMPLIANCE WITH ACCOUNTING ORDER IN GUD NO. 10695

Q. WHAT ISSUES DID THE COMMISSION ADDRESS IN GUD NO. 10695?

A. GUD No. 10695 was established by the Commission to address issues relating to the federal 2017 Tax Cuts and Jobs Act ("TCJA") wherein Congress lowered the corporate tax rate from 35% to 21%. As a result of the accounting order issued by the Commission in the proceeding, utilities were directed to account for certain changes in both tax expense and EDIT.

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[2] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at Findings of Fact ("FoF") No. 115 (Jan. 18, 2023).

[3] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order at FoF No. 62 (Jan. 30, 2024).

Q. WHAT DID THE ACCOUNTING ORDER ISSUED BY THE COMMISSION IN GUD NO. 10695 REQUIRE OF TGS WITH RESPECT TO EDIT?

A. The GUD No. 10695 Accounting Order includes two specific requirements related to the treatment of EDIT. These requirements are: (1) gas utilities subject to the Commission's jurisdiction are to accrue on their books, as of January 1, 2018, a regulatory liability to reflect the excess deferred reserve, including any associated gross up in taxes, caused by the reduction in the federal corporate income tax rate (Ordering Paragraph 1(C)); and (2) the amortization of the entire regulatory liability shall be consistently calculated using a methodology set forth under the TCJA (Ordering Paragraph 7).[4]

Q. DID THE COMPANY COMPLY WITH THESE REQUIREMENTS?

A. Yes, based on the information available at the time, the Company complied with the requirements of the GUD No. 10695 Accounting Order. The Company has provided the following EDIT credits to customers in the Central-Gulf Service Area ("CGSA") incorporated areas through the operation of an EDIT credit rider:

Table 1

Year	EDIT Credit
2018	$3,413,044
2019	3,195,749
2020	2,685,133
2021	3,631,834
2022	399,062
2023	500,677

[4] *Regulatory Accounting Related to Federal Income Tax Changes,* GUD No. 10695, Gas Utilities Accounting Order (Feb. 27, 2018). *See* https://portalvhdskzlfb8q9lqr9.blob.core.windows.net/media/44158/gud-10695-accounting-order-01-01-18.pdf.

Each credit was based on an annual amortization using the Average Rate Assumption Method ("ARAM") that is required by IRS tax normalization rules for "protected" EDIT and a four-year amortization of "unprotected" EDIT as stated in the EDIT credit rider TGS filed with each of the CGSA Cities in 2020. The EDIT credit is trued-up annually based on the difference between the amount of that year's EDIT credit and the amount actually credited to customers. IRS PLRs issued on August 14, 2020, and October 10, 2021, identified issues relating to how the Company has treated the Cost of Removal ("COR") portion of its depreciation expense in the Company's ARAM amortization calculations and the annual true up of the EDIT Credit ("EDIT Rider"). Both issues must be corrected and both issues are described further below.

Q. CAN THE COMPANY CONTINUE RETURNING EDIT TO CUSTOMERS IN THE SAME MANNER DESCRIBED ABOVE?

A. No, based on a different and second IRS PLR (October 22, 2021 - PLR No. 202142002) addressing a different normalization issue described below, it is my recommendation the EDIT Rider be withdrawn, and EDIT be included in base rates. This is the same change in approach TGS presented and that was approved in Docket No. 9896 and Docket No. 14399.

Q. WILL THE REMEDIATION OF THE PLR ISSUES IDENTIFIED ABOVE AFFECT THE TOTAL AMOUNT OF EDIT TO BE CREDITED TO CUSTOMERS IN THE CGSA?

A. No, customers will still receive approximately $28.5 million in total EDIT credits that were quantified following the TCJA and included within all ONE Gas EDIT Rider filings since their implementation.

III. PRIVATE LETTER RULINGS

Q. PLEASE DESCRIBE THE IRS PLR INCLUDED AS EXHIBIT KWE-1.

A. The Company has been made aware of a potential IRS normalization issue through PLR No. 202033002 that was issued on August 14, 2020, to another utility, attached to my testimony as Exhibit KWE-1. The normalization issue is related to TGS's current treatment of the COR portion of its depreciation expense, which creates a deferred tax asset and, pursuant to the new PLR, is not "protected" under the IRS normalization rules in the ARAM amortization calculation.

Q. PLEASE EXPLAIN THIS ISSUE RELATED TO COR.

A. Per the PLR, the COR portion of depreciation is not "protected" under IRS normalization rules. TGS previously treated the COR portion of depreciation as "protected" and, as such, did not separate COR from depreciation in its regulatory depreciation calculations. Importantly, TGS's prior treatment of COR benefited ratepayers because the COR portion was actually an asset and would have reduced the amount of "unprotected" EDIT returned to ratepayers through the Rider. Additionally, at the time of the TCJA, TGS did not estimate a COR component of its accumulated depreciation for purposes of determining the "protected" balance of book versus tax depreciation timing differences. Rather, the timing difference that creates a deferred tax and associated EDIT asset related to COR, was netted against the "protected" portion of its EDIT and amortized using the ARAM calculation consistent with "protected" timing differences of book versus tax depreciation. This practice was consistent with how TGS treated all "protected" EDIT. Now, to avoid a normalization violation under the new PLR, the COR portion of book versus tax depreciation timing differences needs to be separated from both the original EDIT liability and from the depreciation expense used in the ARAM calculation and included as an "unprotected" EDIT asset and amortized as such. Otherwise, the remaining "protected" EDIT may be returned too quickly under the ARAM calculation.

Q. WHAT IS TGS'S REQUEST TO ADDRESS THE IRS NORMALIZATION ISSUE RELATED TO COR?

A. TGS has estimated the amount of COR that was included as "protected" since December 31, 2017, (at the time of the TCJA), and should now be considered "unprotected." TGS requests that this amount be accounted for as a separate asset from the existing "unprotected" EDIT liability that is being amortized over four years and requests that it be amortized utilizing the same amortization period as the "protected" plant, which is consistent with depreciation-related timing differences that remain in the "protected" portion of EDIT (subject to ARAM).

Q. WHY IS IT IMPORTANT TO SEPARATELY ACCOUNT FOR THE COR PORTION OF "UNPROTECTED" EDIT AND TO UTILIZE A DIFFERENT AMORTIZATION?

A. COR in depreciation rates is deducted for tax purposes when the expenses are incurred with the disposal of an asset. As a result, the book depreciation expense being incurred prior to the tax deduction, results in a deferred tax asset. When tax rates changed in the TCJA, this deferred tax asset is remeasured based on the new tax rate and the adjustment creates an EDIT asset, meaning it is an amount that will be "collected" from customers. "Unprotected" EDIT can be credited to ratepayers over any period authorized by the regulatory authority. If the COR would have been included with the four-year amortization of "unprotected" EDIT, the EDIT credit to customers would have been significantly reduced in the short term. By continuing to utilize the ARAM period for COR, TGS will be able to continue to provide EDIT credits consistent with prior years.

Q. DOES THIS CHANGE IN TREATMENT AFFECT THE TOTAL AMOUNT OF EDIT TO BE CREDITED TO CUSTOMERS IN THE CGSA?

A. No, as mentioned previously, customers will still receive approximately $28.5 million of total EDIT credits that were quantified following the TCJA and included within all EDIT Rider filings since that date.

Q. IS THIS CHANGE RETROACTIVE?

A. No, it is not. The separation of COR into an "unprotected" asset only affects the amortization of EDIT on a going forward basis.

Q. PLEASE DESCRIBE THE IRS PLR CONTAINED IN EXHIBIT KWE-2.

A. Since the TCJA, TGS has paid estimated EDIT credits to customers based on tax years that are not consistent with the test year utilized to establish base rates. For example, in the CGSA, the 2019 Rate Case was based on a test year ending June 30, 2019, updated for known changes and conditions through September 30, 2019. However, the EDIT credit issued in 2023 was an estimated credit for the 2022 tax year ended December 31, 2022. Therefore, base rates were based on September 31, 2019, and EDIT was based on December 31, 2022. The inconsistency between base rates test year and EDIT credit tax year has existed for every year's EDIT credit. Per PLR No. 202142002 issued on October 22, 2021, attached as Exhibit KWE-2, it is a violation of normalization rules for EDIT and base rates to be based on different time periods and for EDIT from future time periods to be returned in advance of the time period being used for ADIT.

Q. HOW DOES TGS PLAN TO ADDRESS THIS POTENTIAL NORMALIZATION ISSUE?

A. In Revenue Procedure 2020-39, the IRS has provided a safe harbor for inadvertent normalization violations by indicating that corrective actions which convert a non-compliant crediting method to a compliant crediting method and are taken at the earliest available opportunity will not be considered a normalization violation. TGS believes the earliest available opportunity to take a corrective action as provided for in Revenue Procedure 2020-39 is this statement of intent filing. The only way to adequately address the disconnect between the basis for EDIT credits and base rates is to withdraw the separate EDIT Rider and include "protected" EDIT as part of base rates.

Q. AGAIN, WILL CUSTOMERS RECEIVE ANY MORE OR LESS TOTAL EDIT CREDITS?

A. No, as mentioned previously, customers in the CGSA will receive credit for the same total amount of approximately $28.5 million through EDIT credits that now will reduce the tax expense component of our cost of service.

Q. ARE TGS'S REQUESTED MODIFICATIONS BEING MADE IN A WAY THAT CAUSES THE LEAST IMPACT ON EDIT CREDITS IN THIS STATEMENT OF INTENT WHILE ENSURING MINIMAL RISK OF A NORMALIZATION VIOLATION?

A. Yes, in particular, the request to separately account for the COR asset and amortize over the same period as "protected" plant subject to ARAM as opposed to the four years applied to the current "unprotected" EDIT liability will ensure that the amounts of the ongoing credit and its impact on customer rates are consistent with previous credits.

Q. ARE THERE SERIOUS CONSEQUENCES IF THE IRS DETERMINES THAT A NORMALIZATION VIOLATION HAS OCCURRED IF THE REQUESTED MODIFICATIONS ARE NOT APPROVED?

A. Yes.

Q. WHAT IS THE POTENTIAL IMPACT OF A NORMALIZATION VIOLATION FINDING ISSUED BY THE IRS?

A. If TGS were to be found in violation of the IRS normalization rules, it could lose the ability to take accelerated depreciation credits on its annual tax returns going forward. These tax credits result in tens of millions of dollars annually in non-investor supplied capital that serves as an offset to rate base when calculating customer rates. In addition, TGS would have to pay the IRS any amounts refunded in advance of when they should have been under the normalization rules.

IV. EDIT BALANCE AND ANNUAL AMORTIZATION

Q. WHAT IS THE EDIT BALANCE FOR THE CGSA?

A. As detailed in Exhibit KWE-3, the balance of EDIT for the CGSA at December 31, 2023, is $14,634,668.

Q. HOW IS THE EDIT BALANCE AT DECEMBER 31, 2023, CALCULATED?

A. The initial EDIT balance, shown on page 1 of Exhibit KWE-3, of the CGSA was calculated by taking the difference between the ADIT balance on the day before the tax rate change and the ADIT balance calculated using the newly enacted corporate tax rate resulting from the 2017 TCJA. The December 31, 2023, EDIT balance for the CGSA is calculated by taking the initial EDIT balance and subtracting the annual amortization for the years 2018, 2019, 2020, 2021, 2022 and 2023, also shown on page 1 of Exhibit KWE-3, resulting in a December 31, 2023, balance of $14,634,668.

Q. WHAT IS THE AMOUNT OF THE ANNUAL AMORTIZATION OF THE EDIT?

A. As shown in Exhibit KWE-3, the annual amortization of EDIT for the CGSA is $500,677.

Q. HOW WAS THE ANNUAL AMORTIZATION AMOUNT OF THE EDIT BALANCE CALCULATED?

A. Exhibit KWE-3 shows the calculation of the EDIT amortization amount for the CGSA. TGS used the ARAM methodology for the calculation of the "protected" portions of EDIT. TGS used the same ARAM amortization percentage for the "unprotected" COR EDIT balance resulting from PLR No. 202033002, as previously discussed. TGS used the four-year amortization period for "unprotected" EDIT, excluding COR.

Q. HAS THIS COMMISSION APPROVED THIS RECOMMENDED TREATMENT IN OTHER TGS STATEMENT OF INTENT FILINGS?

A. Yes, this proposed treatment was approved in TGS's West North Service Area in Docket No. 9896 and most recently in the Company's Rio Grande Valley Service Area in Docket No. 14399.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Internal Revenue Service

Number: **202033002**
Release Date: 8/14/2020

Index Number: 168.24-01

In Re:

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-122510-19

Date:
March 26, 2020

LEGEND:

Taxpayer	=
Parent	=
State A	=
Commission A	=
Commission B	=
Date 1	=
Date 2	=
Date 3	=
Date 4	=
Date 5	=
Month 1	=
Month 2	=
Year 1	=

Year 2 =

Year 3 =

Year 4 =

Year 5 =

Year 6 =

Dear :

This letter responds to a request for a private letter ruling dated September 26, 2019, and submitted on behalf of Taxpayer regarding the application of the depreciation normalization rules under § 168(i)(9) of the Internal Revenue Code and § 1.167(l)-1 of the Income Tax Regulations (together, the "Normalization Rules") to certain State A state regulatory procedures which are described in this letter. The relevant facts as represented in your submission are set forth below.

FACTS

Taxpayer is an investor-owned regulated utility incorporated under the laws of State A. Taxpayer is an accrual basis taxpayer and reports on a calendar year basis.

Taxpayer is wholly owned by Parent. Parent is a State A corporation. Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent.

Taxpayer is a regulated utility engaged principally in the purchase, transmission, distribution, and sale of electric energy and the purchase, distribution, and sale of natural gas in State A. Taxpayer is subject to regulation as to rates and conditions of service by Commission A as well as Commission B. Both these regulators establish Taxpayer's rates based on its costs, including a provision for a return on the capital employed by Taxpayer in its regulated businesses.

Taxpayer has claimed accelerated depreciation on all of its public utility property (both electric and gas) to the full extent those deductions have been available. Taxpayer has normalized the federal income taxes deferred as a result of its claiming these deductions in accordance with the Normalization Rules. As a consequence, Taxpayer has a substantial balance of accumulated deferred federal income taxes (ADFIT) that is attributable to accelerated depreciation reflected on its regulated books of account for each of its divisions. In accordance with State A ratemaking practice, Taxpayer has reduced its rate base by its ADFIT balance.

Commission B has established a system to track accounts for both jurisdictional electric and gas companies. These accounts prescribe the accounting rules which are used by most large investor-owned electric and gas companies and are employed by Taxpayer’s electric and gas divisions. The applicable regulations contain several definitions relevant to Taxpayer’s inquiry including definitions for cost of removal (COR), salvage value, net salvage value, service value, and depreciation.

In general, based on these definitions, for purposes of regulatory reporting, the net positive value or net cost of disposing of an asset at the end of its life is incorporated into the annual depreciation charge. COR is, therefore, most often (but not always) a component of establishing the applicable depreciation rate. In Taxpayer’s case, due to the amount of COR it anticipates, in almost all instances its assets have negative net salvage values so that its book depreciation rate is higher than it would be were salvage value not considered. In effect, the annual depreciation charge creates a reserve for COR over the operating life of the asset. Since book depreciation expense is included in Taxpayer’s cost of service used for establishing its rates, customers pay for the COR as book depreciation is factored into their rates. This COR reserve is reflected as an addition to Taxpayer’s accumulated depreciation account. When the COR is actually incurred, the amount expended is debited to that same account, thereby reducing the balance.

For tax purposes, COR is deductible only when actually incurred. Taxpayer, therefore, reports its customer collections that fund the COR reserve as taxable income over the operating life of an asset, claiming an offsetting tax deduction only at the end of the life of that asset. Taxpayer has normalized COR since the Year 1 tax year. All references below to COR-related deferred tax accounting relate only to COR associated with assets placed in service after Year 2. Since COR is normalized in setting rates, customers are provided a tax benefit commensurate with their funding of COR. In other words, they are provided the COR tax benefit as they fund the COR reserve – prior to the time Taxpayer actually claims that benefit on its tax return.

The tax effect of the COR funding as described creates a deferred tax asset (“DTA”). This represents the future benefit to be derived from the eventual COR tax deduction. The COR-related DTA is included in Taxpayer’s overall plant-related ADFIT account that reduces Taxpayer’s ADFIT balance.

COR can (and does) impact ADFIT balances in an additional way. The COR included in depreciation expense (that is, the accrual) is an estimate prepared for an entire class of assets contained in a Commission B account. It is likely that any COR estimate will be too high or too low with respect to any individual asset with the ultimate answer remaining unknown until all vintages of each asset class are retired and removed. Any running variance from the estimate is recorded on Taxpayer’s balance sheet. Where the accrual exceeds the actual COR, it creates a net credit to the accumulated depreciation account. Where the actual COR exceeds the accrual, it creates a net debit to that account. This treatment means that Taxpayer will recover under-accruals from customers and refund over-accruals to customers through future rate adjustments. These future rate adjustments will give rise to future increases or decreases in taxable income. Under applicable accounting principles, Taxpayer must record the deferred tax consequences of these future events. An over-accrual produces a DTA (the tax benefit of a future deduction due to the refund of the excess collection) while an under-accrual produces a deferred tax liability "DTL" (the tax cost of future taxable income due to the collection of the shortfall).

For the electric distribution division, the COR book/regulatory accrual has always been included in the development of the book depreciation rate. Thus, instead of waiting for the Taxpayer to incur the tax benefit of COR, its' Customers are provided the COR tax benefit as they fund the COR reserve – prior to the time Taxpayer actually claims that benefit on its tax return. This produces a DTA as described. In addition, as of Date 1, Taxpayer has, in total, incurred more COR than it has recovered from customers and, thus, is under-accrued for COR. This has produced a DTL, also as described. Both the DTA and DTL are included within Taxpayer's overall plant-related ADFIT Account.

Prior to Month 1 Year 3, the gas distribution division accrued and collected COR as a component of the book depreciation rate. However, pursuant to order of Commission A, that collection practice was modified in Year 3. Beginning in Month 1 Year 3, the gas-only COR regulatory accrual was removed from the book depreciation rate. Rather, Taxpayer was allowed to record and recover annually (through a fixed dollar depreciation charge incremental to the normal depreciation computed via application of the depreciation rate) an amount representing an estimate of the annual COR that would be incurred in that year. At the time of this modification, the cumulative COR accrued exceeded COR actually incurred (that is, Taxpayer was over-accrued). At that time, Taxpayer had recorded a net DTA (to reflect the tax benefit of the future reduction in rates associated with refunding the excess to customers).

Since converting to this methodology in Year 3, COR actually incurred has significantly exceeded COR accrued and recovered, resulting in a DTL (the tax cost of recovering the under-accrual in the future). As of Date 1, the two components (pre-Month 1 Year 3 and post-Month 2 Year 3) combined represented a net DTL.

Effective Date 2, pursuant to an Order issued by Commission A, gas COR regulatory recovery has reverted back to a component of the book depreciation rate. The fixed dollar accrual which began in Year 3 has been eliminated.

Since Year 4, Taxpayer's tax fixed asset system has separately identified the portion of Taxpayer's book depreciation expense that relates to COR since that date. As a consequence, the system distinguishes between COR book/tax differences and depreciation method/life differences even though they are both derived from Taxpayer's book depreciation. Though the system has the capability of tracking the reversals of these differences separately, in order to set it up to do this, a significant amount of work and data manipulation would be required. It is not currently configured in a manner that would allow this.

In years prior to Year 5, Taxpayer paid income tax at a 35% rate on the recovery of the COR portion of book depreciation (and provided its customers a tax benefit at that tax rate). However, as a result of the tax rate reduction enacted as part of the Tax Cuts and Jobs Act ("TCJA"), Taxpayer will only receive a 21% benefit when the COR deduction is claimed or when any over-accrual is refunded and will pay only a 21% tax on the recovery of any COR under-accrual. In other words, in the case of COR, the tax rate reduction enacted as part of the TCJA has produced both a deferred tax shortfall as well as an excess tax reserve. Because Taxpayer will not recover the 14% "excess" tax it paid on its recovery of the COR component of book depreciation from the government when it claims its COR deduction, it must recover it from its customers. Conversely, because Taxpayer will not pay the 14% "excess" deferred tax it accrued on its obligation to refund over-accrued COR, it must restore the amount to its customers (that is, it also has COR-related excess deferred taxes).

Taxpayer's Changes in Accounting Method for Mixed Service Costs and Repairs

Prior to Taxpayer's Year 6 tax year, in capitalizing its indirect overhead costs – including its mixed service costs – Taxpayer followed the same methodology for both book and tax purposes. Effective for its Year 6 tax year, Taxpayer filed with the Internal Revenue Service an Application for Change in Accounting Method (Form 3115) in which it requested permission to depart from its book method for tax purposes. The result of the change was to recharacterize a substantial quantity of mixed service costs that Taxpayer had previously capitalized into depreciable assets as deductible costs (including additions to cost of goods sold). This resulted in Taxpayer claiming a negative adjustment under § 481(a) (that is, a deduction) to remove from the tax basis of its existing assets all such recharacterized costs to the extent Taxpayer had not previously depreciated them ("Section 481 Adjustment").

Also, prior to Taxpayer's Year 6 tax year, in identifying deductible repairs, Taxpayer followed the same methodology for both book and tax purposes. Effective for its Year 6 tax year, Taxpayer filed an Application for Change in Accounting Method (Form 3115) in which it requested permission to depart from its book method for tax purposes. In general, under its new tax method, Taxpayer elected to use larger units of property than used for book purposes. The result of the change was to characterize many projects that were capitalized for book purposes as deductible repairs for tax purposes. This resulted in Taxpayer claiming a negative § 481 Adjustment to remove from the tax basis of its existing assets all such recharacterized costs to the extent Taxpayer had not previously depreciated them.

Adjustments (additions) were made to Taxpayer's ADFIT accounts, which already reflected the deferred tax consequences of having claimed accelerated depreciation on both types of costs after they were capitalized for tax purposes for the additional deferred taxes produced by the § 481 Adjustments.

Taxpayer's Recent Commission A Proceedings

On Date 3, Taxpayer filed with Commission A to adjust both its electric and its gas rates. The parties to the proceeding reached an agreement and, on or about Date 4, Taxpayer submitted a stipulation to Commission A for its approval. Commission A approved the stipulation on Date 5.

The stipulation provides that:

1) Taxpayer will seek a private letter ruling to determine if excess deferred taxes associated with excess tax over book depreciation that is subsequently reversed by accounting method changes relating to repair deductions and the capitalization of mixed service costs are protected by the normalization rules and subject to reversal under the ARAM; and that

2) Taxpayer will seek a private letter ruling from the IRS to determine whether post-Year 1 cost of removal is protected by the normalization rules and, if so, whether it is to be treated as a separate temporary difference or part of the overall depreciation temporary difference for purposes of ARAM amortization.

RULINGS REQUESTED

Taxpayer requests the following guidance:

1) Under the circumstances described above, is Taxpayer's electric distribution COR-related net DTL "protected" by the Normalization Rules?

2) If Taxpayer's electric distribution COR-related deferred tax is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?

3) Under the circumstances described above, is Taxpayer's gas distribution COR-related net DTA accumulated through the depreciation rate prior to Month 1 of Year 3 "protected" by the Normalization Rules?

4) If Taxpayer's gas distribution COR-related deferred tax accumulated through the depreciation rate prior to Month 1 of Year 3 is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?

5) Under the circumstances described above, is Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 "protected" by the Normalization Rules?

6) If Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?

7) If Taxpayer's COR-related deferred tax shortfall is "protected," do the Normalization Rules permit Taxpayer to collect a shortfall any more rapidly than using the ARAM?

8) Do Taxpayer's depreciation-related ADFIT balances created pursuant to the Normalization Rules that are attributable to costs that were capitalized into the basis of depreciable assets prior to Taxpayer changing its method of accounting for those costs remain subject to the Normalization Rules after the change in method of accounting pursuant to which such costs were reclassified as current deductions?

LAW AND ANALYSIS

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A)(i) requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 481(a) requires those adjustments necessary to prevent amounts from being duplicated or omitted to be taken into account when a taxpayer's taxable income is computed under a method of accounting different from the method used to compute taxable income for the preceding taxable year. *See also* § 2.05(1) of Rev. Proc. 97-27, 97-27, 1997-1 C.B. 680 (the operative method change revenue procedure at the time Taxpayer filed its Form 3115, *Application for Change in Accounting Method*).

An adjustment under § 481(a) can include amounts attributable to taxable years that are closed by the period of limitation on assessment under § 6501(a). *Suzy's Zoo v. Commissioner*, 114 T.C. 1, 13 (2000), *aff'd*, 273 F.3d 875, 884 (9th Cir. 2001); *Superior Coach of Florida, Inc. v. Commissioner*, 80 T.C. 895, 912 (1983), *Weiss v. Commissioner*, 395 F.2d 500 (10th Cir. 1968), *Spang Industries, Inc. v. United States*, 6 Cl. Ct. 38, 46 (1984), *rev'd on other grounds* 791 F.2d 906 (Fed. Cir. 1986). *See also Mulholland v. United States*, 28 Fed. Cl. 320, 334 (1993) (concluding that a court has the authority to review the taxpayer's threshold selection of a method of accounting *de novo*, and must determine, *ab initio*, whether the taxpayer's reported income is clearly reflected).

Sections 481(c) and 1.481-4 provide that the adjustment required by § 481(a) may be taken into accounting in determining taxable income in the manner, and subject to the conditions, agreed to by the Service and a taxpayer. Section 1.446-1(e)(3)(i) authorizes the Service to prescribe administrative procedures setting forth the limitations, terms, and conditions deemed necessary to permit a taxpayer to obtain consent to change a method of accounting in accordance with § 446(e). *See also* § 5.02 of Rev. Proc. 97-27.

When there is a change in method of accounting to which § 481(a) is applied, § 2.05(1) of Rev. Proc. 97-27 provides that income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed, and income for the year of change and the following taxable years must be determined under the new method of accounting as if the new method had always been used.

Because of their similarity, we address requests 1, 3, and 5 together. For all of the COR-related amounts at issue in these requests, the amounts are not protected by the Normalization Rules. Generally, § 168(i)(9)(A) does not refer to COR. Moreover, there is no reference to an acceleration of taxes but only to a deferral. While COR may be a component of the calculation of the amount treated as book depreciation, it is a deduction under § 162 and has nothing to do with actual accelerated tax depreciation. While depreciation method and life differences are created and reversed solely through depreciation, such is not the case with COR. While the COR timing differences may often originate as a component of book depreciation, it reverses through the incurred COR expenditure.

Taxpayer's ruling request 8 pertains to the depreciation-related ADIT existing prior to the year of change (Year 6) for public utility property in service as of the end of the taxable year immediately preceding the year of change. Beginning with the year of change, the Year 6 Consent Agreement granted Taxpayer permission to change its (1) method of accounting for mixed service costs to recharacterize a substantial quantity of mixed service costs that Taxpayer had previously capitalized into depreciable assets as deductible costs (including additions to cost of goods sold) and (2) to depart from its book method for tax purposes electing to use for tax purposes larger units of property than used for book purposes which resulted in characterizing many projects that were capitalized for book purposes as deductible repairs for tax purposes.

When there is a change in method of accounting to which § 481(a) is applied, income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed by Taxpayer, and income for the year of change and the following taxable years must be determined under Taxpayer's new method of accounting as if the new method had always been used. *See* § 481(a); § 1.481-1(a)(1); and § 2.05(1) of Rev. Proc. 97-27. In other words: (1) Taxpayer's new method of accounting is implemented beginning in the year of change; (2) Taxpayer's old method of accounting used in the taxable years preceding the year of change is not disturbed; and (3) Taxpayer takes into account a § 481(a) adjustment in computing taxable income to offset any consequent omissions or duplications.

Accordingly, for public utility property in service as of the end of the taxable year immediately preceding the year of change (Year 6), the depreciation-related ADIT existing prior to the year of change for the changes in methods of accounting subject to the Year 6 Consent Agreement does not remain subject to the normalization method of accounting within the meaning of § 168(i)(9) after implementation of the new tax methods of accounting in the year of change and subsequent taxable years.

Based on the foregoing, we conclude that:

1) Under the circumstances described above, Taxpayer's electric distribution COR-related net DTL is not "protected" by the Normalization Rules.

3) Under the circumstances described above, Taxpayer's gas distribution COR-related net DTA accumulated through the depreciation rate prior to Month 1 of Year 3 is not "protected" by the Normalization Rules.

5) Under the circumstances described above, Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 is not "protected" by the Normalization Rules.

Because these amounts in requests 1, 3, and 5 are not protected by the Normalization Rules, requests 2, 4, 6, and 7 are moot.

8) Taxpayer's depreciation related ADFIT balances created pursuant to the Normalization Rules that are attributable to costs that were capitalized into the basis of depreciable assets prior to Taxpayer changing its method of accounting for those costs do not remain subject to the Normalization Rules after the change in method of accounting pursuant to which such costs were reclassified as current deductions.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

This ruling is based upon information and representations submitted by Taxpayer and accompanied by penalty of perjury statements executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representatives.

Sincerely,

Patrick S. Kirwan
Chief, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)

cc:

Internal Revenue Service

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Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B6
PLR-101961-21

Date:
July 26, 2021

Legend

Taxpayer	=
Corporation	=
State A	=
State B	=
Commission A	=
Commission B	=
Order	=
Date 1	=
Date 2	=
Date 3	=
Date 4	=
Date 5	=
Date 6	=
Date 7	=
Date 8	=
Year 1	=
Year 2	=
Year 3	=

Dear :

This letter responds to a request for a private letter ruling dated January 7, 2021, submitted by Taxpayer. Taxpayer requests rulings with respect to the application of § 168(i)(9) of the Internal Revenue Code, former § 167(l), and section 13001(d) of the Tax Cuts and Jobs Act, Pub. L. 115-97(the "TCJA") (together, the Normalization Rules), regarding the proper accounting and ratemaking treatment of excess deferred income taxes ("EDIT"). The relevant facts as represented in Taxpayer's submission are set forth below.

FACTS

Taxpayer is an electric and natural gas utility headquartered in State A.

Taxpayer is a wholly owned member of Corporation and Subsidiaries consolidated group. Corporation is an energy services holding company incorporated in State B. Taxpayer is included in the consolidated federal income tax return of Corporation. Taxpayer employs a calendar year reporting period and uses an accrual method of accounting. Corporation elected to be treated as a corporation for federal tax purposes. Corporation and Subsidiaries are not presently under audit by the Internal Revenue Service.

Taxpayer is engaged in the production, transmission, and distribution of electricity and the distribution of natural gas in State A. It is subject to the regulatory authority of Commission A and Commission B as to the terms and conditions of service and the rates it is permitted to charge for its service. Its rates are established or approved based on its costs of service, including a return on its capital investment (rate base).

Taxpayer's rates are established by Commission A on a "cost of service, rate-of-return" basis. Thus, Taxpayer is permitted an opportunity to recover its prudently incurred costs and earn an appropriate return on its rate base, which reflects its net invested capital. The convention employed in State A with respect to rate base is that a utility's accumulated deferred income tax balance ("ADIT") offsets gross rate base (rate base computed before reduction by ADIT). Included in Taxpayer's ADIT balance are a significant amount of deferred taxes attributable to accelerated depreciation claimed with respect to public utility property. Thus, Taxpayer's ADIT is, to a substantial extent, subject to the normalization rules contained in § 168(i)(9) and former § 167(l). Commission A uses an historical test period consisting of a 12-month period for purposes of determining Taxpayer's costs and rate base. Results of this test period are adjusted by "pro forma adjustments" to remove materially distortive items and to give effect to known and measurable changes that are not offset by other factors.

As part of this process of setting rates, Taxpayer computes its depreciation expense and its income tax expense, including both current and deferred components of income tax expense, for inclusion in its cost of service. Taxpayer also reduces its gross rate base by its ADIT balance to determine the rate base on which it is permitted to earn a return. Taxpayer's accounting treatment for depreciation expense, income tax expense, ADIT, and rate base has been consistent with the Normalization Rules.

On December 22, 2017, the TCJA was signed into law. Among other changes, the TCJA reduced the federal corporate income tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017, Taxpayer's calendar Year 1 tax year.

As a result of the tax reduction, the deferred taxes Taxpayer had accumulated at a 35 percent rate were reduced to those that would have been accumulated at a 21 percent rate had the 21 percent rate been in effect for all prior years. Because Taxpayer had a net deferred tax liability ("DTL") on December 31, 2017, the tax rate reduction resulted in EDIT, because Taxpayer now expects to pay income taxes to the Department of the Treasury at the reduced 21 percent rate, as the timing differences that gave rise to its DTL reverse. In general, Taxpayer had collected the EDIT from customers through its traditional ratemaking methodology and not on a precise dollar-for-dollar basis. The 14-percentage point reduction in the tax rate is available to reduce the tax expense that Taxpayer included in setting customer rates. It is the timing of this reduction of the EDIT that is the issue of this ruling request.

Taxpayer maintains records that include the vintage records necessary to apply the average rate assumption method ("ARAM"). The total balance of Taxpayer's EDIT is unknown. The annual amount of EDIT reversal under ARAM will vary each year, and this variance is unknown at this time. In general, this variability is caused by future events, including the time at which a vintage begins to reverse or when a vintage fully reverses. Taxpayer provides deferred taxes on plant-related timing differences whether or not those timing differences are protected by the Normalization Rules or unprotected by the Normalization Rules. Taxpayer and Commission A intend to apply ARAM to all plant-related timing differences. There is no dispute over this intent to apply ARAM. Throughout Taxpayer's general rate case ("GRC"), these balances are commonly referred to as "protected plus" or "PP" to acknowledge the fact that ARAM is being applied not only to all protected EDIT, but also unproteced plant-related EDIT.

Taxpayer has been accounting for EDIT balances in ratemaking on a consistent method since the Tax Reform Act of 1986, Pub. L. No: 99-514 ("TRA 1986"). That method has been as follows:

> Taxpayer closes its books on a monthly basis. Each resulting monthly income statement and balance sheet contains its share of book depreciation, rate base, income tax expense, and ADIT (including EDIT). Taxpayer includes the ARAM reversal of EDIT in its monthly calculation of tax expense. Its EDIT balance is included in its ADIT to ensure that rate base is reduced by the proper amount of deferred taxes. This treatment ensures that book depreciation, income tax expense, ADIT, and rate base are computed consistently.
>
> Taxpayer's rates are set periodically in a GRC using an historical test period. In a GRC, the accounting activity recorded in each month during the historical test year is the basis for setting customer rates, plus or minus any pro-forma adjustments. Once customer rates are established, they remain constant until the next GRC. At that next GRC, customer rates will be reset based on a new, different historical test year – different income and expenses (including income tax expense and book depreciation expense), different rate base, and different

ADIT. The assumption underlying the use of an historical test year is that the costs and benefits in the historical period, plus or minus any pro-forma adjustments, will be representative of future periods during which customers will pay the rates. The process is intended to ensure that customer rates will be fair, just, reasonable, and sufficient. This is so even though the actual income and incurred costs, including EDIT reversals, for the period for which the rates are set will be different than those used to set the rates during the GRC.

In its Year 2 GRC, Taxpayer used calendar year Year 1 as the historical test year. This was its first GRC following the TCJA. In its monthly accounting activity throughout Year 1, Taxpayer recorded its EDIT reversal using ARAM. Those accounting entries had the effect of reducing Taxpayer's deferred tax expense and reduced Taxpayer's EDIT balance. No other entries were made with respect to EDIT. These entries were identical to those Taxpayer made since the tax rate reduction provided by the TRA 1986 to account for the EDIT created by the TRA 1986 tax rate reduction and used to set rates since that time.

In filing its Year 2 GRC, Taxpayper included the EDIT reversals that it recorded in calendar year Year 1, consistent with the use of Year 1 as the historical test period. In addition, its ADIT balance, including the EDIT, reflected these reversals. The accounting that occurred in calendar year Year 1 formed the basis for the amounts that Taxpayer proposed in setting rates for Year 2. In other words, the Year 1 book accounting provides the basis for ratemaking in the Year 2 GRC, which was originally intended to be effective for new rates beginning in mid-Year 3.

In response to Taxpayer's Year 2 GRC filing, Commission A issued Order on Date 1. Commission A did not follow Taxpayer's requested historical treatment. Instead, Commission A ordered the approach that raises the normalization issues that are the subject of this request.

Order requires Taxpayer to separately track EDIT on a tariff rate schedule independent of its rates set in its general rate order. In one requirement, Commission A requires the schedule to be updated annually for the reversal of the EDIT for the current year as if rates were set each year. Furthermore, in another requirement, Commission A requires Taxpayer to true-up for the difference between the EDIT amounts set in the schedule and the actual amount passed back due to volumetric variances. Commission A has ordered that the schedule must produce an annual adjustment to Taxpayer's rates for ARAM amortization of EDIT without any corresponding adjustment to Taxpayer's rates for annual changes in depreciation expense, income tax expense, rate base, or ADIT (including EDIT).

Order includes Taxpayer's depreciation expense, tax expense, ADIT (including EDIT), and rate base for the test year in the computation of the primary cost of service and base rate. Order then requries an adjustment to cost of service by removing the test year ARAM amortization of EDIT and substituting for that amount, as a reduction in cost of service, the estimated EDIT amortization for the year following the test year plus the next year which includes part of the rate year (in total, a 24-month period). No other similar adjustments are made for depreciation expense, income tax expense, ADIT (including EDIT), or rate base, which were, instead, based on the historical test period (again, not including pro forma adjustments which are not a topic of this PLR).

Order was applied to Taxpayer as follows: The test year was calendar year Year 1. The original rate year was to be Date 2 through Date 3, but the start of that rate period was initially delayed due to Coronavirus to an effective date of Date 4. After some further delays, the rates became effective Date 5, for gas operations and Date 6, for electric operations. Taxpayer's originally proposed ARAM EDIT amortization was based on the test year (calendar year Year 1). The Order adjustment was based on an estimate of ARAM EDIT amortization for the two-year period Date 7 through Date 8, the total two-year amount to be passed back in one year.

Taxpayer has proposed corrective action if the Service concludes that the EDIT treatment in Order is not consistent with a normalization method of accounting. If that determination is made, Taxpayer will need to reestablish a normalization method of accounting. In that event, Commission A has agreed to immediately open a proceeding upon Taxpayer's receipt of a PLR from the Service and revisit its order to comply with the Normalization Rules. This agreement was a condition of Taxpayer dismissing its judicial appeal of Order.

Taxpayer has taken additional action to ensure a quick and complete correction if Order is found inconsistent with the Normalization Rules. Taxpayer filed an accounting petition with Commission A on Date 5 in which it requested that Commission A allow Taxpayer to track the difference between Taxpayer's approach and the approach required in Order. The difference between the two approaches will be recorded to Taxpayer's balance sheet as a monthly entry. Two accounts will be used – a tracking account and a contra account (collectively, the "PLR Tracker Accounts"). The two accounts will net to zero and thereby have no impact on Taxpayer's financial results, as doing otherwise would not be in compliance with Commission A's order. However, the accounts will provide contemporaneous documentation of the variance between the two approaches.

For gas customers, rates consistent with Order went into effect on Date 5. For electric customers, new rates went into effect on Date 6. For both gas and electric customers, the accounting petition will provide Commission A with the ability to correct any normalization infraction that the IRS identifies in its ruling.

Taxpayer anticipates that any correction will involve two elements. The first element is a new tariff rate that will comply with the Service's ruling, which will be a new base tariff. That rate would continue in effect until Taxpayer's next rate-setting event, which is expected to be a GRC. The second element is a temporary tariff rate to bring the EDIT balance back into alignment with a normalization method of accounting. This second component would have the effect of reversing the amounts that were tracked in the PLR Tracker Accounts. The recovery of these balances would likely occur over a relatively short period.

RULINGS REQUESTED

Taxpayer requests rulings whether the accounting for EDIT as required by Order of Commission A is consistent with the Normalization Rules of § 168(i)(9), former § 167(l), and section 13004(d) of the TCJA. Specifically:

(1) Whether the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA permit Taxpayer to adjust its EDIT ARAM amortization based on the test year to the EDIT ARAM amortization based on one or more subsequent years without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(2) Whether the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA permit Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(3) Whether the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA permit Taxpayer to provide a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(4) Additionally, Taxpayer asks that if we determine that any of the requirements described of Order are not consistent with the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA, Taxpayer requests that we provide in the ruling that Taxpayer will not be considered to be in violation of the normalization rules if it follows the corrective actions described in its letter.

LAW AND ANALYSIS

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A) requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule").

Taxpayer's requests relate primarily to Taxpayer's compliance with the Consistency Rule. Taxpayer asks whether the Normalization Rules permit Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense. More specifically, Taxpayer also asks whether the Normalization Rules permit Taxpayer to adjust its EDIT ARAM amortization based on the test year to the EDIT ARAM amortization based on one or more subsequent years without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense. Lastly, Taxpayer asks whether the Normalization Rules permit Taxpayer to provide a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

Therefore, the threshold question is whether the Consistency Rule applies to EDIT being accounted for under ARAM. Because these amounts were originally deferred pursuant to a normalization method of accounting, these amounts remain subject to the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA. Thus, if the EDIT being accounted for under ARAM is subject to Normalization Rules, the Consistency Rule must apply to the EDIT.

As described in § 168(i)(9)(B)(ii), the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii), does not comply with the Consistency Rule unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its EDIT ARAM amortization without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense**.** More specifically, in regard to request (1), the Normalization Rules do not allow Taxpayers to make an adjustment to cost of service by removing the test year ARAM amortization of EDIT and substituting for that amount, as a reduction in cost of service, the estimated EDIT amortization for the year following the test year plus the next year which includes part of the rate year (in total, a 24-month period) while also making no similar adjustments for depreciation, expense, income tax expense, ADIT (including EDIT), or rate base, which were based on the historical test period. In regard to request (2), the Normalization Rules do not allow Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

Additionally, in response to request (3), providing a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense likewise is not in compliance with the Consistency Rule. The true-up mechanism adjusts for volume differences only with respect to one item, EDIT amortization. This results in the use of estimated volumes in setting rates for all items other than EDIT reversal which uses actual volumes. This treatment is an inconsistent use of estimates or projects not allowed by section 168(i)(9)(B).

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By removing EDIT amortization for the test year and including the estimated EDIT amortization for the two following years, the EDIT amortization on the cost of service is higher than allowed under the ARAM limitation for the test year. This acceleration of the EDIT amortization occurs under the Order without any reduction to the EDIT balance which is taken into account in determining rate base. This provides customers not only with a lower cost of service through the acceleration of EDIT amortization but also a rate base which is artificially low because the EDIT credit balance included in rate base has not been reduced by the EDIT reversal that has been accelerated. This incorrectly provides customers with the double benefit of lower cost of service and lower rate base for the same EDIT.

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Further, Commission A has agreed to immediately open a proceeding upon receipt of Taxpayer’s receipt of a PLR from the Service and revisit its order to comply with the Normalization Rules if the Service concludes that Order results in a rate calculation that is not consistent with the Normalization rules.

Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. As noted, Taxpayer filed an accounting petition with Commission A in which it requested that Commission A allow Taxpayer to track the difference between Taxpayer’s approach and the approach required in Order. The difference between the two approaches will be recorded to Taxpayer’s balance sheet as a monthly entry identified as “the PLR Tracker Accounts.” For both gas and electric customers, the accounting petition provides

Commission A with the ability to correct any normalization infraction that the IRS identifies in this ruling.

Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because the Commission, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule for the EDIT that is a part of ADIT and calculated according to ARAM constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

CONCLUSION

Accordingly, we rule as follows:

(1) The Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA do not permit Taxpayer to adjust its EDIT ARAM amortization based on the text year to the EDIT ARAM amortization based on one or more subsequent years without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(2) The Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA do not permit Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

(3) The Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA do not permit Taxpayer to provide a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

(4) While we have determined that the described requirements of Order are not consistent with the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA, Taxpayer will not be considered to be in violation of the normalization rules if it follows the corrective actions described in its letter.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent.

This ruling is based upon information and representations submitted by Taxpayer and accompanied by penalty of perjury statements executed by an appropriate party.

While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the LB&I Policy Office.

Sincerely,

Patrick S. Kirwan
Chief, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)

cc:

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2023
ARAM Estimate for amounts attributed to the Central South Gulf Service Area

Accumulated Deferred Income Taxes for:	**Excess ADIT**	**Protected**	**Non-protected (ARAM)**	**Unprotected**	**TGS Amortization Amount**	**ONE Gas Amortization Amount**
Central South Gulf Direct Plant Assets Depreciation	($37,339,553)	($37,339,553)			($37,339,553)	
Central South Gulf Direct Plant Repairs	(10,622,000)			(10,622,000)	(10,622,000)	
Central South Gulf Cost of Removal Asset	3,375,204		3,375,204		3,375,204	
Central South Gulf Other Rate Base Items	(3,136,047)			(3,136,047)	(3,136,047)	
TGS Division Plant Assets Depreciation	(264,573)	(264,573)			(264,573)	
ONEGas Plant Assets Depreciation	(1,542,000)	(1,542,000)				(1,542,000)
Central South Gulf NOL (See NOL tab, Note 6)	21,068,802	21,068,802		-	21,068,802	
ADIT - Accumulated Deferred Income Taxes	($28,460,167)	($18,077,324)	$3,375,204	($13,758,047)	($26,918,167)	($1,542,000)
Percent Protected		64%				

CGTX

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization		
Year 1 - 2018 Actuals	3,795,203	183,881	(566,040)	566,040	3,413,044		
Year 2 - 2019 Actuals	3,690,070	164,752	(659,073)	659,073	3,195,749		
Year 3 - 2020 Actuals	3,857,074	203,852	(1,375,793)	1,375,793	2,685,133		
Year 4 - 2021 Actuals	3,788,688	256,589	(413,443)	413,443	3,631,834		
Year 5 - 2022 Actuals	492,926	175,788	(269,652)	269,652	399,062		
Year 6 - 2023 Est	811,596	129,528	(440,446)	440,446	500,677	($14,634,668)	EDIT at 12/31/23
Year 7 - 2024 Est	700,294	162,373	(427,286)	427,286	435,380		
Year 8 - 2025 Est	756,073	159,134	(447,723)	447,723	467,484		
Year 9 - 2026 Est	727,271	140,785	(435,053)	435,053	433,003		
Year 10 - 2027 Est	668,037	62,605	(413,769)	413,769	316,874		

36.81%

Accumulated Deferred Income Taxes for:	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization	2027 Amortization
Central South Gulf Direct Plant Assets Depreciation	$290,226	$164,051	$357,551	$344,255	$477,896	$780,588	$757,265	$793,485	$771,030	$733,309
Central South Gulf Direct Plant Repairs	2,655,500	2,655,500	2,655,500	2,655,500	-	-	-	-	-	-
Central South Gulf Cost of Removal Asset	-	-	-	-	-	-	(68,451)	(71,725)	(69,695)	(66,285)
Central South Gulf Other Rate Base Items	784,012	784,012	784,012	784,012	-	-	-	-	-	-
TGS Division Plant Assets Depreciation	65,465	86,507	60,011	4,921	15,030	31,007	11,480	34,313	25,936	1,014
ONEGas Plant Assets Depreciation	183,881	164,752	203,852	256,589	175,788	129,528	162,373	159,134	140,785	62,605
Central South Gulf NOL (See NOL tab, Note 6)	(566,040)	(659,073)	(1,375,793)	(413,443)	(269,652)	(440,446)	(427,286)	(447,723)	(435,053)	(413,769)
ADIT - Accumulated Deferred Income Taxes	$3,413,043	$3,195,749	$2,685,133	$3,631,834	$399,062	$500,677	$435,380	$467,484	$433,003	$316,874

	Amortization Period		ONE Gas Amortization Period	Amortization				Financial Impact		
	Protected (ARAM)	Unprotected 10 Year	Protected (ARAM)	Protected	Protected Gross Up	Unprotected	Unprotected Gross Up	Total including Gross Up	Income Tax effect	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.75%	25.00%	11.21%	355,691	94,551	3,439,512	914,301	4,804,054	(1,008,851)	3,795,203
Year 2 - 2019 Actuals	0.37%	25.00%	10.68%	250,558	66,604	3,439,512	914,301	4,670,974	(980,905)	3,690,070
Year 3 - 2020 Actuals	0.76%	25.00%	7.78%	417,562	110,998	3,439,512	914,301	4,882,372	(1,025,298)	3,857,074
Year 4 - 2021 Actuals	1.31%	25.00%	16.59%	349,176	92,819	3,439,512	914,301	4,795,807	(1,007,120)	3,788,688
Year 5 - 2022 Actuals	1.28%	0.00%	11.40%	492,926	131,031	-	-	623,957	(131,031)	492,926
Year 6 - 2023 Est	2.09%	0.00%	8.40%	811,596	215,741	-	-	1,027,336	(215,741)	811,596
Year 7 - 2024 Est	2.03%	0.00%	10.53%	768,745	204,350	(68,451)	(18,196)	886,448	(186,154)	700,294
Year 8 - 2025 Est	2.13%	0.00%	10.32%	827,798	220,047	(71,725)	(19,066)	957,054	(200,981)	756,073
Year 9 - 2026 Est	2.06%	0.00%	9.13%	796,966	211,852	(69,695)	(18,527)	920,596	(193,325)	727,271
Year 10 - 2027 Est	1.96%	0.00%	4.06%	734,323	195,200	(66,285)	(17,620)	845,617	(177,579)	668,037

	Amortization Period		Amortization				Financial Impact		
NOL	Protected (ARAM)	Unprotected 10 Year	Protected	Protected Gross Up	Unprotected	Unprotected Gross Up	Total including Gross Up	Income Tax effect	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.75%	25.00%	(566,040)	(150,466)	-	-	(716,506)	150,466	(566,040)
Year 2 - 2019 Actuals	0.37%	25.00%	(659,073)	(175,197)	-	-	(834,270)	175,197	(659,073)
Year 3 - 2020 Actuals	0.76%	25.00%	(1,375,793)	(365,717)	-	-	(1,741,510)	365,717	(1,375,793)
Year 4 - 2021 Actuals	1.31%	25.00%	(413,443)	(109,903)	-	-	(523,346)	109,903	(413,443)
Year 5 - 2022 Actuals	1.28%	0.00%	(269,652)	(71,680)	-	-	(341,332)	71,680	(269,652)
Year 6 - 2023 Est	2.09%	0.00%	(440,446)	(117,081)	-	-	(557,527)	117,081	(440,446)
Year 7 - 2024 Est	2.03%	0.00%	(427,286)	(113,582)	-	-	(540,868)	113,582	(427,286)
Year 8 - 2025 Est	2.13%	0.00%	(447,723)	(119,015)	-	-	(566,738)	119,015	(447,723)
Year 9 - 2026 Est	2.06%	0.00%	(435,053)	(115,647)	-	-	(550,700)	115,647	(435,053)
Year 10 - 2027 Est	1.96%	0.00%	(413,769)	(109,989)	-	-	(523,758)	109,989	(413,769)

	ONE Gas Amortization Period	Amortization				Financial Impact		
	Protected (ARAM)	Protected	Protected Gross Up	Unprotected	Unprotected Gross Up	Total including Gross Up	Income Tax effect	Regulatory Liability net refund
Year 1 - 2018 Actuals	11.21%	183,881	48,880	-	-	232,761	(48,880)	183,881
Year 2 - 2019 Actuals	10.68%	164,752	43,795	-	-	208,547	(43,795)	164,752
Year 3 - 2020 Actuals	7.78%	203,852	54,189	-	-	258,041	(54,189)	203,852
Year 4 - 2021 Actuals	16.59%	256,589	68,207	-	-	324,796	(68,207)	256,589
Year 5 - 2022 Actuals	11.40%	175,788	46,728	-	-	222,516	(46,728)	175,788
Year 6 - 2023 Est	8.40%	129,528	34,431	-	-	163,959	(34,431)	129,528
Year 7 - 2024 Est	10.53%	162,373	43,162	-	-	205,535	(43,162)	162,373
Year 8 - 2025 Est	10.32%	159,134	42,302	-	-	201,436	(42,302)	159,134
Year 9 - 2026 Est	9.13%	140,785	37,424	-	-	178,208	(37,424)	140,785
Year 10 - 2027 Est	4.06%	62,605	16,642	-	-	79,247	(16,642)	62,605

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF KENNETH W. EAKENS

BEFORE ME, the undersigned authority, on this day personally appeared Kenneth W. Eakens who having been placed under oath by me did depose as follows:

1. "My name is Kenneth W. Eakens. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of Tax Compliance and Financial Reporting for ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Kenneth W. Eakens

Kenneth W. Eakens

SUBSCRIBED AND SWORN TO BEFORE ME by the said Kenneth W. Eakens on this 21st day of May 2024.

Erlinda Alvarado

Notary Public in and for the State of Texas

ERLINDA ALVARADO
NOTARY PUBLIC
ID# 133935107
State of Texas
Comm. Exp. 08-29-2026

WORKPAPERS

TO

DIRECT TESTIMONY

OF

KENNETH W. EAKENS

Workpapers to the Direct Testimony of Kenneth W. Eakens are being provided in electronic format.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF TIMOTHY S. LYONS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. In 2013, I joined Sussex Economic Advisors, LLC ("Sussex"). Sussex was acquired by ScottMadden in 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL EXPERIENCE.

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE RAILROAD COMMISSION OF TEXAS ("COMMISSION")?

A. Yes. I previously sponsored testimony before this Commission as well as 28 other state regulatory commissions. Exhibit TSL-1 contains a list of regulatory proceedings in which I have sponsored testimony.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREPARED EXHIBITS SUPPORTING YOUR TESTIMONY?

A. Yes. My testimony is supported by the exhibits in the List of Exhibits. The exhibits were prepared by me or under my direction.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained by Texas Gas Service ("TGS" or the "Company") to develop a lead-lag study that determines the cash working capital ("CWC") requirement for the Company's Central-Gulf Service Area ("CGSA"). The lead-lag study summary and supporting calculations are presented, respectively, in Exhibits TSL-2 and TSL-3.

Q. PLEASE DEFINE THE TERM "CASH WORKING CAPITAL."

A. The term "cash working capital" or CWC refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in the lead-lag study include: operations and maintenance ("O&M") expenses, including labor and non-labor expenses; income taxes; and taxes other than income taxes.

Q. HOW WAS THE COMPANY'S CWC REQUIREMENT DETERMINED?

A. The Company's CWC requirement was based on the results of a lead-lag study. The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag represents the number of days from the time customers receive service to the time customers pay for service, i.e., when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations. The expense leads represent the number of days from the time the Company receives goods and services used to provide service to the time payments are made for those goods and services, i.e., when the funds are no longer available to the Company. The longer the expense leads, the less cash the Company needs to fund its day-to-day operations. Together, the revenue lag and expense leads are used to measure lead-lag days. The lead-lag days are then applied to the Company's adjusted test year expenses to derive the CWC requirement, which is included in the Company's rate base.

Q. ARE THE METHODS USED TO DEVELOP THE LEAD-LAG STUDY IN THIS PROCEEDING CONSISTENT WITH COMMISSION REQUIREMENTS?

A. Yes. The methods used to develop the lead-lag study in this proceeding are consistent with the Commission's requirements. Furthermore, the methods used to develop the lead-lag study in this proceeding are consistent with the methods approved by the Commission in the Company's most recent fully-litigated rate proceeding in Docket No. OS-22- 00009896 ("Docket No. 9896").[1]

Q. ARE THE RESULTS OF THE LEAD-LAG STUDY IN THIS PROCEEDING AN ACCURATE ASSESSMENT OF THE COMPANY'S CWC REQUIREMENT?

A. Yes, this lead-lag study is based on the Company's current billing, collection and payment practices, and thus provides an accurate assessment of the Company's CWC requirements.

III. LEAD-LAG STUDY APPROACH

Q. WHAT ARE THE RESULTS OF THE LEAD-LAG STUDY CONDUCTED FOR TGS?

A. The Company's lead-lag study is summarized in Exhibit TSL-2 and shows a CWC requirement of negative $3,364,662.

Q. WAS THE LEAD-LAG STUDY BASED ON ONE OR MORE OF THE COMPANY'S SERVICE AREAS?

A. Yes. The lead-lag study was based on data for all of TGS's service areas in Texas, including CGSA. The data includes customer billing and revenue data to determine the revenue lag, payment and financial data to determine the expense leads—as well as various other supporting documents.

The approach of developing a lead-lag study to be applicable to all of TGS's service areas in Texas is consistent with the intent of the Commission's Final Order

[1] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, OS-22-00009896, consol., Final Order at Findings of Fact ("FoF") No. 54 (Jan. 18, 2023).

in Gas Utilities Docket ("GUD") No. 10285, which states, "TGS shall include a lead-lag study to establish cash working capital with its next filed Statement of Intent proceeding involving one or more of its El Paso, Rio Grande Valley, or Austin Service Areas. The resulting lead-lag study shall be designed to be applicable to all TGS Service Areas." [2]

Q. IS THE APPROACH OF DEVELOPING A LEAD-LAG STUDY TO BE APPLICABLE TO ALL OF TGS'S SERVICE AREAS IN TEXAS CONSISTENT WITH THE COMPANY'S APPROACH IN PRIOR RATE CASE PROCEEDINGS?

A. Yes. The approach is consistent with the Company's approach in its recent rate case proceedings for Gulf Coast Service Area (GUD No. 10488)[3], West Texas Service Area (GUD No. 10506)[4], Central Texas Service Area (GUD No. 10526)[5], Rio Grande Valley Service Area (GUD No. 10656)[6], North Texas Service Area (GUD No. 10739)[7], Borger-Skellytown Service Area (GUD No. 10766)[8], Central

[2] *Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10285, Final Order at FoF No. 28 (Nov. 26, 2013).

[3] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order (May 3, 2016).

[4] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA)*, GUD No. 10506, consol., Final Order (Sept. 27, 2016).

[5] *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016).

[6] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018).

[7] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018).

[8] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019).

Texas Service Area and Gulf Coast Service Area (GUD No. 10928)[9] and Rio Grande Valley Service Area (Docket No. OS-23-00014399).[10]

Q. WHY DID YOU RELY ON THE LEAD-LAG STUDY DEVELOPED IN DOCKET NO. 9896 TO CALCULATE THE CWC REQUIREMENT FOR THE CGSA?

A. I relied on the lead-lag study developed in Docket No. 9896 for the following reasons: (1) the Company was previously directed by the Commission to develop a lead-lag study designed to be applicable to all TGS service areas in Texas; (2) the study is based on data for all of TGS's service areas in Texas; (3) the study remains relevant as an accurate measurement of the Company's CWC requirement for CGSA because the study was prepared within the past few years, and since that time there have been no significant changes in the Company's billing, collection and/or payment procedures that would have a significant impact on the overall results; and (4) the study helps to minimize rate case expenses by developing a single lead-lag study for application to all of the Texas service areas rate case proceedings.

Q. DID YOU MAKE ANY CHANGES TO THE LEAD-LAG STUDY DEVELOPED IN DOCKET NO. 9896?

A. Yes. While the overall methodology and data are the same as Docket No. 9896, there was a slight refinement in calculation of lead days for incentive compensation.

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[9] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and the Gulf Coast Service Area*, GUD No. 10928, consol., Final Order (Aug. 4, 2020).

[10] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order (Jan. 30, 2024).

The study in Docket No. 9896 is based on a single number of lead days for the Company's short-term and long-term incentive plan. The study in this case is based on distinct lead days for the Company's short-term and long-term incentive plans. Specifically, lead days for the Company's short-term incentive plan are based on the number of days from the midpoint of the performance period (i.e., the calendar year) to the payment date, generally in March for the performance period that reflects the preceding calendar year. Lead days for the Company's long-term incentive plan is zero since it reflects a non-cash item.

Q. IS THIS APPROACH CONSISTENT WITH THE COMPANY'S RECENT APPROACH IN THE LEAD-LAG STUDY IN ITS RECENT RATE PROCEEDING INVOLVING THE RIO GRANDE VALLEY SERVICE AREA?

A. Yes. I prepared the Lead-Lag Study in that case and this is the same approach applied in that filing. That case ultimately settled.[11]

Q. WHAT WAS THE APPROACH TO DEVELOP THE LEAD-LAG STUDY?

A. The lead-lag study consists of two elements: revenue lag and expense leads. The revenue lag measures from the time service is provided to customers until the time customer payments are received by the Company. Expense leads measure from the time the Company receives goods and services used to provide service to the time the Company pays for those goods and services. The expense leads are measured in days, converted to dollar-days and summarized for each cost element in the lead lag study. The difference between the revenue lag and expense lead determines if

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[11] *Id.*

there is a net revenue lag (revenue lag days are more than the expense lead days) or a net expense lead (revenue lag days are less than the expense lead days) for each cost element in the lead-lag study. The net lead-lag days are applied to adjusted test year expenses since they reflect the Company's ongoing expenses and thus best represent the Company's ongoing CWC requirements.

Q. WHAT WAS THE DATA USED TO DEVELOP THE LEAD-LAG STUDY?

A. The lead-lag study was based on the Company's customer and financial data from January 1, 2021 through December 31, 2021. The data included customer billing and collection data and payment and expense financial data.

A. Revenue Lag

Q. WHAT ARE THE COMPONENTS OF THE REVENUE LAG?

A. Revenue lag measures the number of days from the time service is provided to customers to the time payment is received from customers. The revenue lag consists of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag measures the average number of days in the service period; i.e., the number of days from the start of the billing month to the end of the billing month. Meters are read at the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that natural gas is delivered evenly over the service period.

Q. WHAT IS THE BILLING LAG?

A. The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag includes time for review and validation of billed usage and dollars.

Q. HOW WAS THE BILLING LAG MEASURED?

A. The billing lag was based on a random sample of customer bills for each of the six customer classifications (residential, commercial, industrial, public authority, transportation and irrigation), as shown on Exhibit TSL-3.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received.

Q. HOW WAS THE COLLECTION LAG MEASURED?

A. The collection lag was based on the sample of customer bills used to determine the billing lag.

Q. HOW WAS THE REVENUE LAG DETERMINED?

A. The revenue lag is based on the sum of the service lag, billing lag and collection lag—then dollar-weighted by the revenues associated with each rate class, as shown on Exhibit TSL-3.

B. Expense Leads

1. Operation and Maintenance Expenses

Q. PLEASE DESCRIBE THE DEVELOPMENT OF O&M EXPENSE LEADS.

A. O&M expense leads were measured separately for the following groups: (1) purchased gas expenses; (2) regular payroll expenses; (3) short-term incentive compensation expenses; and (4) third-party O&M expenses.

Q. HOW WERE LEAD DAYS FOR PURCHASED GAS EXPENSES DETERMINED?

A. Lead days for purchased gas expenses were based on the number of days from the midpoint of the service period (i.e., when gas was received and delivered to customers) to the payment date. The payment date occurs in the month after the gas was received and delivered to customers.

Q. HOW WERE LEAD DAYS FOR REGULAR PAYROLL EXPENSES DETERMINED?

A. Lead days for regular payroll expenses were based on the Company's salary and wages payment process, which pays employees on a bi-weekly or semi-monthly basis. Lead days for regular payroll expenses were based on the number of days from the midpoint of the pay period to the payment date.

Q. DID THE STUDY ADJUST FOR VACATION PAY?

A. Yes. The lead-lag study adjusts for vacation pay, reflecting that vacation pay is generally earned before it is taken. The adjustment is based on the regular payroll lead days and the midpoint of the year.

Q. HOW WERE THE LEAD DAYS FOR THE COMPANY'S SHORT-TERM INCENTIVE PAYMENT DETERMINED?

A. Lead days for the Company's short-term incentive payment were based on the number of days from the midpoint of the performance period (i.e., twelve-months ending December 2020) to the payment date. The annual performance bonus is paid annually in March for the performance period that reflects the preceding calendar year.

Q. HOW WERE LEAD DAYS FOR THIRD-PARTY O&M EXPENSES DETERMINED?

A. Lead days for Other O&M expenses were based on the sum of two components: (1) lead days from the service period to the invoice date; and (2) lead days from the invoice date to the payment date.

Lead days from the service period to the invoice date were based on a stratified sample of invoices paid by the Company over the period January 1, 2021 through December 31, 2021. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount then summed by invoice amounts to determine the lead days. The study relies on a sample of invoices to measure the lead days because the service periods were not readily available electronically and required detailed inspection of individual invoices.

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company over the period January 1, 2021 through December 31, 2021. Lead days were measured for each invoice as the number of days from the invoice date to the payment date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount then summed by invoice amounts to determine the lead days.

2. Current Federal Income Tax Expense

Q. HOW WERE LEAD DAYS FOR FEDERAL INCOME TAXES DETERMINED?

A. Lead days for federal income taxes were based on the number of days from the midpoint of the taxing period (i.e., the calendar year) to the payment date. The payment date reflects scheduled payment dates on April 15, June 15, September 15 and December 15. If the scheduled payment date falls on a Saturday, Sunday, or legal holiday, the payment is due on the next regular business day.

3. Taxes Other than Income Taxes

Q. WHAT TAXES ARE INCLUDED IN TAXES OTHER THAN INCOME TAXES?

A. Taxes other than income taxes include: (1) Payroll-related taxes (FICA, Federal Unemployment, and State Unemployment); (2) Revenue-related taxes (State Gross Receipts, Sales Tax, Local Franchise Tax and State Franchise Tax); (3) Ad Valorem taxes; and (4) Railroad Commission Gas Utility Tax.

Q. HOW WERE LEAD DAYS FOR EACH OF THE TAXES DETERMINED?

A. Lead days for payroll-related taxes were based on the number of days from the tax liability date to the payment date. Lead days for non-payroll-related taxes were based on the number of days from the midpoint of the taxing period to the payment date.

4. Interest on Customer Deposits

Q. HOW WERE LEAD DAYS FOR INTEREST ON CUSTOMER DEPOSITS DETERMINED?

A. Lead days for interest on customer deposits were based on the accumulated interest expense on customer deposits and the subsequent interest payment to customers.

5. Non-Cash Items

Q. DOES THE LEAD-LAG STUDY INCLUDE NON-CASH ITEMS?

A. No. Consistent with well-established Commission precedent, this study excludes non-cash items, including depreciation, amortization, deferred income taxes, long-term incentive payments and return (including return on equity and interest on long-term debt).

IV. CONCLUSION

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. The Company's lead-lag study is summarized in Exhibit TSL-2 and shows a CWC requirement of negative $3,364,662.

Q. ARE THE RESULTS OF THIS LEAD-LAG STUDY AN ACCURATE ASSESSMENT OF THE COMPANY'S CWC REQUIREMENT?

A. Yes, this lead-lag study is based on the Company's current billing, collection and payment practices and thus provides an accurate assessment of the Company's CWC requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Summary of Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before 29 U.S. and 3 Canadian regulatory agencies. Tim holds a bachelor's degree from St. Anselm College, a master's degree in economics from The Pennsylvania State University, and a master's degree in business administration from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arizona Corporation Commission			
Southwest Gas Corporation	02/24	Docket No. G-01551A-23-0341	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Summit Utilities, Inc.	01/24	Docket No. 23-079-U	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Liberty Utilities (Apple Valley Water)	01/24	Application No. 24-01-0003	Sponsored testimony supporting rate design studies for a general rate case proceeding.
Liberty Utilities (Park Water)	01/24	Application No. 24-01-0002	Sponsored testimony supporting rate design studies for a general rate case proceeding.
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California, and South Lake Tahoe jurisdictions)	8/19	Application No. 19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Colorado Public Utilities Commission			
Colorado Natural Gas (Summit Utilities)	01/24	Proceeding No. 23A-0570G	Sponsored the Fully Distributed Cost (FDC) study in support of a Cost Assignment and Allocation Manual (CAAM) application.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures, and analysis.
Delaware Public Service Commission			
Artesian Water Company	04/23	Docket No. 23-0601	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	12/23	Docket No. 23-0380	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Kentucky Public Service Commission			
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil	05/23	Docket No. 2023-00051	Sponsored testimony supporting a marginal cost study, class cost of service study, rate design and customer bill impact for a general rate case proceeding.
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
The Potomac Edison Company (FirstEnergy)	03/23	Case No. 9695	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.

Sponsor	Date	Docket No.	Subject
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/23	Docket No. U-21308	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
Liberty Utilities (Missouri Water)	03/24	Docket No. WR-2024-0104	Sponsored testimony supporting lead-lag study for a general rate case proceeding.
Liberty Utilities (Midstates Natural Gas)	02/24	Docket No. GR-2024-0106	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.

Sponsor	Date	Docket No.	Subject
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/23	Docket No. 23-09012	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
Elizabethtown Gas Company	02/24	Docket No. GR24020158	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Jersey Central Power and Light Company (FirstEnergy)	03/23	Docket No. ER23030144	Sponsored testimony supporting the class cost of service and Lead/Lag studies for a general rate case proceeding.
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
New Mexico Public Regulation Commission			
New Mexico Gas Company, Inc.	9/23	Case No. 23-00255-UT	Sponsored testimony supporting the class cost of service, rate design, bill impact and weather normalization adjustment mechanisms for a general rate case proceeding.
New York Public Service Commission			
New York Power Authority	09/04	Case No. 04-E-0572	Sponsored testimony evaluating Con Edison's class cost of service study.

Sponsor	Date	Docket No.	Subject
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Pennsylvania Public Utility Commission			
FirstEnergy Pennsylvania Electric Company	04/24	Docket No. R-2024-3047068	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
CenterPoint Energy – Texas Gas Division	10/23	Case No. 00015513	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/23	Case No. 00014399	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – West Texas, North Texas, and Borger/ Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	03/24	Docket No. 56211	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
Shenandoah Valley Electric Cooperative	01/24	Case No. PUR-2023-00207	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
American Electric Power - Appalachian Power Company	3/23	Case No. PUR-2023-00002	Sponsored testimony supporting the Lead/Lag study for the 2023 triennial review of base rates, terms, and conditions.
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
West Virginia Public Service Commission			
Monongahela Power Company and The Potomac Edison Company (FirstEnergy)	06/23	Case No. 23-0460-E-42T	Sponsored testimony supporting the class cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Ontario Energy Board			
Toronto Hydro-Electric System Limited	11/23	Docket No. EB-2023-0195	Sponsored evidence supporting Toronto Hydro's Custom Rate Framework. Prepared research and analysis evaluating the appropriateness of the Rate Framework in the context of how other electric utility ratemaking practices have responded to developments in the energy industry.
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals.
Commission of Canada Energy Regulator			
Trans-Northern Pipelines, Inc.	06/23	Docket No. RH-001-2023	Sponsored evidence related to application for approval of incentive tolls.

Texas Gas Service, A Division of One Gas, Inc.
Central Gulf Service Area
Summary of Lead-Lag Study
Cash Working Capital Requirement

Line	Description	Test Year Amount	Average Daily Amount	Revenue Lag	Ref. (*)	Expense Lag	Ref. (*)	Net (Lead)/Lag Days	Working Capital Requirement
1	Operations and Maintenance Expenses								
2	Purchased Gas Costs	$ 93,904,159	$ 257,272	45.47	A	(40.63)	B	4.84	$ 1,245,941
3	Labor - Regular Payroll Expense	30,175,452	82,672	45.47	A	(27.70)	C	17.78	1,469,528
4	Labor - STI Expense	4,795,187	13,137	45.47	A	(242.92)	C	(197.44)	(2,593,929)
5	Non-Labor - Other O&M Expense	33,052,129	90,554	45.47	A	(39.20)	C	6.28	568,243
6	Total O&M Expenses	$ 161,926,926	$ 443,635						$ 689,783
7	Federal Income Taxes								
8	Current Income Taxes	$ 13,227,540	$ 36,240	45.47	A	(37.00)	D	8.47	$ 307,024
9	Deferred Income Taxes		-	0.00		0.00		0.00	-
10	Total Federal Income Taxes	$ 13,227,540	$ 36,240						$ 307,024
11	Taxes Other Than Income Taxes								
12	FICA	$ 2,123,262	$ 5,817	45.47	A	(12.61)	E	32.87	$ 191,188
13	Federal Unemployment	16,230	44	45.47	A	(30.01)	E	15.46	687
14	State Unemployment	66,940	183	45.47	A	(113.17)	E	(67.70)	(12,415)
15	State Gross Receipts	4,283,705	11,736	45.47	A	(77.00)	E	(31.53)	(370,059)
16	Local Franchise Tax	11,356,894	31,115	45.47	A	(93.29)	E	(47.82)	(1,487,909)
17	State Franchise Tax	576,902	1,581	45.47	A	47.71	E	93.18	147,276
18	Ad Valorem	6,947,490	19,034	45.47	A	(196.17)	E	(150.70)	(2,868,409)
19	Sales Tax	5,818,131	15,940	45.47	A	(35.88)	E	9.59	152,908
20	RRC Gas Utility Tax	54,341	149	45.47	A	(86.81)	E	(41.34)	(6,155)
21	Taxes Other Than Income Taxes	$ 31,243,896	$ 85,600						$ (4,252,887)
22	Interest on Customer Deposits	$ 321,437	$ 881	45.47	A	(168.77)	F	(123.30)	$ (108,582)
23	Labor - LTI Expense	$ 935,345	$ 2,563	0.00		0.00		0.00	$ -
24	Depreciation Expense	$ 34,876,287	$ 95,551	0.00		0.00		0.00	$ -
25	Return	$ 64,093,722	$ 175,599	0.00		0.00		0.00	$ -
26	Total	$ 306,625,153	$ 840,069						$ (3,364,662)

(*) Corresponds to the spreadsheet tabs in the lead-lag study

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Revenue Collection Lag

Line	Description	Service Lag Service Period	Billing Lag Meter Read to Mail	Collection Lag Mail to Clear	Total Revenue Lag	Reference	Revenue	Dollar Days
1	Residential	15.21	6.25	26.55	48.01	WP A-1	$ 301,450,044	$ 14,472,448,316
2	Commercial	15.21	5.80	17.06	38.07	WP A-2	91,471,811	3,482,134,928
3	Industrial	15.21	6.00	18.88	40.09	WP A-3	2,851,444	114,317,331
4	Public Authority	15.21	6.93	21.47	43.61	WP A-4	19,754,626	861,431,056
5	Transportation	15.21	10.06	18.75	44.02	WP A-5	15,911,445	700,487,356
6	Irrigation	15.21	5.78	18.78	39.76	WP A-6	2,170,342	86,298,593
7	Composite Revenue Collection Days	15.21	6.32	23.94	45.47		$ 433,609,712	$ 19,717,117,581

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Purchased Gas

Line	Month	From	To	Expense	Total Days	Midpoint	Days Paid from End-of-Month	(Lead)/Lag Days	Dollar Days	Composite (Lead)/Lag Days
1	January-2021	01/01/21	01/31/21	$ 21,833,528	31.00	(15.50)	(25.55)	(41.05)	$ (896,192,218)	
2	February-2021	02/01/21	02/28/21	21,755,449	28.00	(14.00)	(25.15)	(39.15)	(851,768,097)	
3	March-2021	03/01/21	03/31/21	12,872,918	31.00	(15.50)	(25.66)	(41.16)	(529,876,292)	
4	April-2021	04/01/21	04/30/21	10,057,845	30.00	(15.00)	(24.91)	(39.91)	(401,448,820)	
5	May-2021	05/01/21	05/31/21	11,032,898	31.00	(15.50)	(24.61)	(40.11)	(442,538,966)	
6	June-2021	06/01/21	06/30/21	9,454,273	30.00	(15.00)	(25.76)	(40.76)	(385,331,884)	
7	July-2021	07/01/21	07/31/21	11,216,497	31.00	(15.50)	(24.79)	(40.29)	(451,888,156)	
8	August-2021	08/01/21	08/31/21	11,791,698	31.00	(15.50)	(24.10)	(39.60)	(466,924,747)	
9	September-2021	09/01/21	09/30/21	13,824,591	30.00	(15.00)	(22.70)	(37.70)	(521,129,751)	
10	October-2021	10/01/21	10/31/21	17,236,961	31.00	(15.50)	(27.17)	(42.67)	(735,451,851)	
11	November-2021	11/01/21	11/30/21	20,973,830	30.00	(15.00)	(27.53)	(42.53)	(892,035,434)	
12	December-2021	12/01/21	12/31/21	29,037,542	31.00	(15.50)	(25.45)	(40.95)	(1,189,155,086)	
13			Total	$ 191,088,028					$ (7,763,741,302)	(40.63)

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
O&M Expenses

Line	Description	(Lead)/Lag Days	Reference
1	Regular Payroll Expenses	(27.70)	WP C-1
2	Annual Performance Bonus Expense	(242.92)	WP C-1
3	Labor-Related - Subtotal		
4	Other O&M Expenses	(39.20)	WP C-5

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Federal Income Tax

							(Lead)/Lag Days	
Line	Quarter	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Percent of Taxes Due	Days from Midpoint to Payment Date	(Lead)/Lag Days
1	First Quarter	1/1/2021	12/31/2021	(182.50)	4/15/2021	25.00%	260.00	19.38
2	Second Quarter	1/1/2021	12/31/2021	(182.50)	6/15/2021	25.00%	199.00	4.13
3	Third Quarter	1/1/2021	12/31/2021	(182.50)	9/15/2021	25.00%	107.00	(18.88)
4	Fourth Quarter	1/1/2021	12/31/2021	(182.50)	12/15/2021	25.00%	16.00	(41.63)
5	Federal Income Tax (Lead)/Lag Days							(37.00)

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Taxes Other Than Income Tax

Line	Description	(Lead)/Lag Days	Reference
1	FICA	(12.61)	WP E-1
2	Federal Unemployment	(30.01)	WP E-2
3	State Unemployment	(113.17)	WP E-3
4	State Gross Receipts	(77.00)	WP E-4
5	Local Franchise Tax	(93.29)	WP E-5
6	State Franchise Tax	47.71	WP E-6
7	Ad Valorem	(196.17)	WP E-7
8	Sales Tax	(35.88)	WP E-8
9	RRC Gas Utility Tax	(86.81)	WP E-9

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Interest on Customer Deposits

Line	Description	Test Year Interest Expense	Monthly Interest Expense	Accrued Interest Balance	Composite (Lead)/Lag Days
1	12/1/2020			$ 53,906	
2	1/1/2021		$ 9,132	63,038	
3	2/1/2021		9,132	72,169	
4	3/1/2021		8,248	80,417	
5	4/1/2021		9,132	89,549	
6	5/1/2021		8,837	98,386	
7	6/1/2021		9,132	-	
8	7/1/2021		8,837	8,837	
9	8/1/2021		9,132	17,969	
10	9/1/2021		9,132	27,100	
11	10/1/2021		8,837	35,937	
12	11/1/2021		9,132	45,069	
13	12/1/2021		8,837	53,906	
14	Average			$ 49,714	
15	Interest Expense	$ 107,518			
16	Daily Interest Expense	$ 295			
17	Composite (Lead)/Lag Days				(168.77)

STATE OF VERMONT §
§
COUNTY OF CHITTENDEN §

AFFIDAVIT OF TIMOTHY S. LYONS

BEFORE ME, the undersigned authority, on this day personally appeared Timothy S. Lyons who having been placed under oath by me did depose as follows:

1. "My name is Timothy S. Lyons. I am over the age of eighteen (18) and fully competent to make this affidavit. I am a Partner with ScottMadden, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

LISA DUFRESNE
Notary Public, State of Vermont
Commission No. 157.0015482
My Commission Expires 01/31/2025

Timothy S. Lyons
Timothy S. Lyons

SUBSCRIBED AND SWORN TO BEFORE ME by the said Timothy S. Lyons on this 22 day of may 2024.

Lisa Dufresne
Notary Public in and for the State of Vermont

My commission expires: 1/31/2025

WORKPAPERS

TO

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

Workpapers to the Direct Testimony of Timothy S. Lyons are being provided in electronic format.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

DIRECT TESTIMONY

OF

JANET M. SIMPSON

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF JANET M. SIMPSON

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Janet M. Simpson. My business address is 5702 Beacon Drive, Austin, Texas 78734.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Managing Member of Utility Regulatory Consulting, LLC ("URC"). URC is a consulting firm specializing in utility ratemaking services.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL CREDENTIALS.

A. I am a Certified Public Accountant. I obtained my Bachelor of Business Administration in Accounting from the University of Texas in 1982. In 1983, I began employment as an analyst with the Public Utility Commission of Texas ("PUCT"). Beginning in 1987, I was employed by Southern Union Company ("SUCo") for fourteen years, during which time I held various positions including Rate Manager and Director of Economic and Market Analysis in SUCo's Rate Department. In 2003, I became a Partner in Dively and Associates, PLLC, a Public Accounting Firm, and in 2011, I became a Partner in Dively Energy Services ("DES"), an affiliated entity. In mid-2017, DES was acquired by a third party and Dively Energy Services Company ("DESC") was formed as a subsidiary of that entity. I served as Vice President of DESC through December 2019, at which time I formed URC as an independent entity. Under these entities, I have participated in a variety of projects, including utility company software implementation projects, utility accounting and tariff compliance, and development and review of utility rate requests, including development of recommendations relating to accumulated deferred income taxes.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN A UTILITY REGULATORY RATE PROCEEDING?

A. Yes. I have testified before the PUCT, the Railroad Commission of Texas ("Commission"), the Missouri Public Service Commission and the Massachusetts Department of Public Utilities. A copy of my resume identifying the various docketed proceedings in which I have testified is attached to my testimony as Exhibit JMS-1.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, it was.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents the Texas Gas Service Company ("TGS" or the "Company"), a division of ONE Gas, Inc. ("ONE Gas") Accumulated Deferred Income Tax ("ADIT") amounts that are applicable when determining rates in the Company's Central-Gulf Service Area ("CGSA"). Total CGSA ADIT is negative $79,319,324. This ADIT balance is reflected as a reduction to rate base on the CGSA Rate Case Schedules, Schedule B, line 14 and is itemized on Schedule B-9.

II. <u>BACKGROUND</u>

Q. PLEASE DEFINE ACCUMULATED DEFERRED INCOME TAXES.

A. ADIT are amounts that are recorded on the balance sheet of a company to capture and accumulate the difference between income tax expense calculated on the company's financial statement and income tax expense calculated for tax return purposes. An ADIT liability is recognized for temporary differences that will result in taxable amounts in future years, while an ADIT asset is recognized for temporary differences that will result in deductible amounts in future years. The differences between financial statement ("per Book") and tax return ("per Tax") income that result in the creation of ADIT represent temporary differences in taxable income rather than permanent differences. Over time, the same total amount of expense or revenue will be reflected in taxable income per Book and per Tax, but the year(s) in which the expense or revenue is recognized will differ. The ADIT balance represents the cumulative net amount of those deferred tax liabilities and assets at a given point in time.

Q. WHAT IS THE MAJOR SOURCE OF ADIT FOR TGS?

A. The primary source of ADIT for TGS and utility companies in general is the difference in depreciation rates and methods used on a company's financial statement (i.e., "per Book") and the depreciation rates and methods authorized by the Internal Revenue Service ("IRS") for use on the income tax return (i.e., "per Tax"). Generally speaking, the IRS depreciation rates and methods are accelerated as compared to the financial statement and rate case depreciation rates and methods. Plant assets are typically depreciated more rapidly per Tax than per Book. As a result, for any particular "vintage" (i.e., calendar year) plant additions, higher levels of depreciation expense are deducted on the tax return in early years and lower amounts are deducted in later years of that asset's life as compared to the depreciation expense recorded per Book. Having higher depreciation deductions per Tax in the early years of an asset's life results in lower taxable income and, therefore, lower income taxes in those early years as compared to per Book. This results in the Company recording an ADIT liability on its books. Conversely, in the later years of an asset's life, when depreciation is greater on the books than on the tax return for that particular asset, related income tax expense per Tax is greater than per Book. When this happens, entries are recorded on the books that reverse the ADIT liability.

Q. ARE THERE OTHER PER BOOK AND PER TAX DIFFERENCES ASSOCIATED WITH PLANT ASSETS THAT RESULT IN RECORDING ADIT FOR UTILITY COMPANIES?

A. Yes. In addition to depreciation life and method differences, there are four other major per Book and per Tax differences that impact a utility company's plant-related ADIT balance. First, for utility companies that apply mass-asset depreciation, a gain or loss is generally not recognized on the income statement when an asset is retired. Instead, the plant amount is charged against the accumulated depreciation account, resulting in any gain or loss applicable to that asset being captured in the accumulated depreciation balance. For Tax purposes, however, a taxable gain, or more commonly, a taxable loss, is recognized in the year the asset is retired. The expense recognized per Tax is equal to the undepreciated tax basis at that time. For example, if at the time of its retirement, the tax accumulated depreciation was $600 for an asset originally costing $1,000, a tax "loss" of $400 would be reflected as an expense on the tax return. The recognition of that tax loss essentially accomplishes expensing the remaining undepreciated cost of that asset in the year of retirement on the tax return.

Another event that is recognized as an expense for Tax purposes but is captured in the accumulated depreciation account per Book, is the cost of removal (net of salvage value, if any) associated with retiring or removing plant assets from service. For Tax purposes, net cost of removal is deducted as an expense in the year it is incurred, but on the Books, the net cost of removal is charged to the accumulated depreciation account. The impact on the book accumulated depreciation balance of both the retirement of an asset and the cost of removal is factored into the development and periodic recalculation of book depreciation rates. As a result, over time, the full cost of the asset, along with cost of removal, is recognized in per Book net income through book depreciation expense. Therefore, the book depreciation expense reverses the temporary differences created by recognition of tax retirement losses and cost of removal.

The third additional plant-related per Book and per Tax difference relates to the Tax treatment of certain types of construction costs as repair expense. Those amounts are capitalized to plant per Book and are depreciated but are deducted as an expense in the year incurred for Tax purposes. All three of the temporary differences described above, as well as the depreciation rate differences discussed previously, generate an ADIT credit, because the recognition of expense occurs earlier per Tax than per Book.

The final plant-related temporary difference that creates ADIT for utility companies is Contributions in Aid of Construction ("CIAC"), and it has the opposite effect on ADIT. CIAC reduces the plant balance recorded per Book, thereby lowering per Book depreciation over the life of the asset; however, for Tax purposes, CIAC is recognized as taxable revenue in the year the utility receives the

CIAC. As a result, the depreciable Tax basis of the related plant is not reduced, and higher depreciation expense is reflected per Tax than per Book over the life of the asset. Unlike the other temporary items, which result in earlier expense per Tax than per Book, CIAC results in earlier revenue per Tax than the recognition of the subsequent reduction in depreciation expense per Book.

Q. CAN YOU DETERMINE THE NET ADIT BALANCE ASSOCIATED WITH ALL OF THESE TEMPORARY PLANT-RELATED DIFFERENCES AT A SINGLE POINT IN TIME?

A. Yes. All of the temporary differences described above result in differences in the balance of Book plant as compared to Tax plant and/or differences in the balance of Book accumulated depreciation as compared to Tax accumulated depreciation. As a result, plant-related ADIT can be determined at any point in time by multiplying the income tax rate by the difference between Book Net Plant (i.e., Book gross plant minus accumulated depreciation) and Tax Net Plant (i.e., Tax gross plant minus accumulated depreciation). As explained above, typically for utility companies, that calculation yields a net ADIT credit, which reduces a utility's rate base as described below.

Q. HOW IS ADIT TREATED FOR RATEMAKING PURPOSES?

A. From a ratemaking standpoint, to the extent that a company has sufficient taxable income to make use of the net accelerated tax return deductions described above, the balance in ADIT represents interest-free funds for the company. Because ADIT does not consist of funds or capital provided by investors, ADIT, like customer-supplied funds, is used to reduce rate base. More specifically, in establishing accelerated depreciation methods for utility companies, the IRS included a provision to prohibit early year reductions in income taxes from being directly passed on to ratepayers in the form of lower income tax expense in the revenue requirement. Essentially, through the accelerated depreciation provisions, the IRS provides a loan, at no cost, to companies in the form of lower taxes payable in the early years of an asset's life. That loan gets "repaid" to the IRS in the later years of the asset's life in the form of higher taxes in those years. Therefore, the ADIT balance at any given point in time represents the outstanding amount of cost-free capital that has been provided to the company by the IRS through the tax rules. As a source of cost-free capital that supports investment, the ADIT balance is deducted from rate base, which results in a reduction in required return and a reduction in the revenue requirement.

Q. WHAT HAPPENS IF, FOR INCOME TAX RETURN PURPOSES, A COMPANY HAS MORE EXPENSE DEDUCTIONS AVAILABLE TO IT THAN TAXABLE INCOME FOR A PARTICULAR YEAR?

A. If expenses on the tax return are greater than taxable income, a company has experienced a Tax Net Operating Loss ("NOL"). Because it is not possible to reduce a tax obligation to an amount below zero, a portion of the total allowable tax return expense deductions (equal to the dollar amount of the NOL) does not provide a benefit to the company in the form of a reduced tax obligation in that year. As a result, the accelerated expense deductions reflected on the tax return have not generated cost-free capital to the extent of the amount of the NOL. The company can carry forward that NOL—i.e., the unused expense deductions—to future years and use them to reduce future taxable income and future income taxes payable. Until a company has sufficient taxable income to use those deductions to offset its income, an adjustment is made to reduce the amount of the ADIT credit that is recorded on the balance sheet and in rate base. This recognizes the tax effect of those deductions as a future benefit rather than as a current reduction in taxes payable and provision of cost-free capital.

Q. ARE THERE OTHER ELEMENTS OF ADIT THAT IT MAY BE APPROPRIATE FOR UTILITIES TO INCLUDE IN RATE BASE?

A. Yes. Book/tax temporary differences may arise because of differences in treatment of items other than plant-related items. If the company is including other items in rate base for which there is a timing difference in the treatment for book purposes and tax purposes, it may be appropriate to include the related ADIT in rate base as well. However, because those differences also impact the amount of the company's taxable income or loss, for consistency, it is necessary to take those temporary differences into account when determining if the company is in a NOL position and when calculating the related NOL ADIT balance used for rate base.

III. CALCULATION OF THE CGSA ADIT BALANCE

Q. WHAT ARE THE COMPONENTS OF THE CGSA ADIT AMOUNT OF $(79,319,324) REFERENCED PREVIOUSLY?

A. The CGSA ADIT balance consists of the following five major components:

CGSA Direct Plant-Related	$(93,912,124
CGSA Other Direct Rate Base Items	(4,661,841)
TGS Division Plant-Related	(659,027)
ONE Gas Plant-Related	(2,631,536)
CGSA NOL	22,545,204
Total CGSA ADIT	**$(79,319,324)**

Detailed calculations of each component are discussed below and shown on Exhibit JMS-2 and related workpapers.

Q. PLEASE EXPLAIN HOW YOU CALCULATED ADIT RELATING TO CGSA DIRECT PLANT ASSETS.

A. The first component of total CGSA ADIT is ADIT associated with the plant-related timing differences for plant that is physically located in the CGSA (i.e., "direct plant"). I computed ADIT applicable to the CGSA plant items as of December 31, 2023 by comparing per Book net plant for those locations as of December 31, 2023 to per Tax net plant for those locations as of December 31, 2023. Adjustments were made to the net book and net tax plant amounts consistent with the adjustments to plant and accumulated depreciation reflected in the Company's rate base schedules and workpapers.

The total difference between the adjusted net book and net tax plant amounts, multiplied by the current income tax rate of 21%, represents the CGSA direct plant-related ADIT as of December 31, 2023. Total CGSA plant-related ADIT as of December 31, 2023 equals $(93,912,124).

Q. PLEASE EXPLAIN THE SECOND COMPONENT OF CGSA ADIT THAT PERTAINS TO OTHER RATE BASE ITEMS.

A. There are several other items the Company is including in rate base for which there is a difference in the book and tax treatment, specifically:

- § 8.209 Regulatory Asset;
- Pension & Other Post Retirement Benefit ("OPEB") Deferral;
- Prepaid Pension Asset; and
- Other Regulatory Assets.

The § 8.209 Regulatory Asset, Pension & OPEB Deferral and Other Regulatory Assets items represent journal entries in which amounts that would otherwise be expensed on the books are instead charged to a deferred asset account then expensed in subsequent periods. For tax purposes, the expense is recognized in the year that it would be expensed on the books absent those amounts being deferred. As a result, for tax purposes, the deferral entry is reversed. At any given point in time, the ADIT related to this temporary difference is equal to the balance remaining in the deferred asset account multiplied by the tax rate.

The item referenced above as "Prepaid Pension Asset" is a temporary difference that pertains to the book/tax treatment of pension costs. For tax purposes, the amount deducted in a tax year is equal to the amount of funding made to the pension plan rather than the amount of expense that is recorded on the books in accordance with the requirements of Accounting Standards Codification – "ASC" 715-20 (formerly Financial Accounting Standards – "FAS" 87). Thus, the "Prepaid Pension" item reflects the temporary difference that arises because the actual deduction for tax purposes is equal to the amount by which the pension plan is funded rather than the per Book pension expense calculated in accordance with ASC 715-20.

The sum of the three temporary differences referenced above, multiplied by the tax rate of 21% represents the CGSA Other Direct Rate Base-related ADIT as of December 31, 2023, which is equal to $(4,661,841).

Q. PLEASE DESCRIBE THE NEXT TWO COMPONENTS OF THE ADIT CALCULATION.

A. The next two components of the CGSA ADIT calculation are for (1) ADIT related to an allocated portion of TGS Division plant, and (2) an allocated portion of ONE Gas corporate plant as of test-year end. These amounts were computed by comparing net book plant and net tax plant balances for TGS Division and ONE

Gas corporate plant as of December 31, 2023. The ONE Gas temporary differences were multiplied by the allocation factors that have been applied to the related plant amounts by Company witness Stacey R. Borgstadt to determine the portion of those differences applicable to TGS. Both the TGS Division plant temporary differences and the TGS portion of allocated corporate plant temporary differences were multiplied by the federal tax rate of 21%, and then allocated to the CGSA. To allocate the appropriate portions to the CGSA, both the TGS Division and the allocated ONE Gas corporate ADIT amounts were multiplied by the CGSA test-year-end customer allocation factor, consistent with the methodology used by Ms. Borgstadt to allocate shared service and corporate expenses and plant and accumulated depreciation balances. The result is $(659,027) of TGS Division plant ADIT and $(2,631,536) of ONE Gas corporate plant ADIT applicable to the CGSA.

Q. WHAT IS THE FINAL COMPONENT OF CGSA ADIT?

A. The final component is ADIT relating to the CGSA's portion of the TGS NOL.

Q. WHY IS THE TAX NOL ADIT INCLUDED IN THE ADIT CALCULATION?

A. As explained previously, a reduction to rate base for ADIT is only necessary or appropriate to the extent it represents cost-free capital. As of December 31, 2023, the Company had a cumulative Tax NOL and, as a result, has been unable to take full advantage of the temporary differences that gave rise to the entire ADIT credit balance discussed above. To the extent the Company does not have sufficient taxable income for tax purposes to realize the full benefit of the cost-free capital arising from the temporary differences between financial statement and tax return income, no reduction to rate base is warranted. As a result, when computing ADIT for rate base, the ADIT balance must be reduced to remove the portion of that balance that has yet to provide actual cost-free capital to the Company. Reduction of the ADIT credit balance has the effect of increasing rate base.

Q. WHAT IS THE TOTAL ESTIMATED TGS NOL ADIT APPLICABLE TO THE CGSA AS OF DECEMBER 31, 2023, AND HOW IS IT COMPUTED?

A. The total estimated NOL ADIT applicable to the CGSA on a stand-alone basis as of December 31, 2023 is $22,545,204. The calculation of this amount starts with cumulative 2003 through December 31, 2023 total TGS taxable income per Book. Using the cost center component of the Company's account structure, I segregated and grouped this amount into each of the Company's direct jurisdictional cost center groups, each allocable regional cost center group, and the TGS allocable division office cost center group. The TGS allocable division office cost center group includes the TGS portion of allocated corporate costs. I then made several ratemaking adjustments and tax adjustments to determine the CGSA NOL. First, an adjustment was made to align the purchased gas cost expense reflected in the CGSA and other TGS jurisdiction cost centers to equal the jurisdictional purchased gas revenue. Next, I removed amounts that are not applicable for ratemaking purposes such as legislative, charitable, merchandising and other non-utility expenses and revenues as well as unbilled revenue transactions that are not included in the development of the revenue requirement. Then, various adjustments were made to compute taxable income appropriate for use in calculating the regulatory tax NOL amount. First, to calculate the per Tax deduction applicable for meals, I removed from per Book expense 50% of the cumulative meals cost, consistent with the IRS treatment of that item as a permanent difference in prior years and also removed non-deductible parking expenses. Next, tax deductions were reflected pertaining to the Rule 8.209 Regulatory Asset and Other Regulatory Assets reversals and to reflect the Prepaid Pension Asset deduction as discussed above.

Lastly, adjustments were made to reverse the deduction of book depreciation and reflect the deduction of tax depreciation. In this context "depreciation" includes the amounts reflected for tax purposes associated with recognition of plant-related adjustments for tax purposes including tax depreciation (which is calculated on a basis that excludes CIAC amounts that are treated as taxable income for tax purposes), cost of removal expense, retirement losses and repairs adjustment. Because the actual tax depreciation expense that is reflected on the Company's tax returns includes the impact of the Company's acquisition adjustment, for purposes of the ratemaking NOL ADIT calculation, tax depreciation was recalculated excluding the impact of the acquisition adjustment. The final step was to apply the CGSA customer-based allocation factors to the resulting allocable TGS division net loss and the allocable regional net loss amounts as shown on Exhibit JMS-2. The allocated amounts applicable to the CGSA were then added to the CGSA direct net loss amounts to determine the total CGSA tax NOL.

Q. WHAT IS THE RESULTING CGSA NOL ADIT AMOUNT?

A. The result is a cumulative CGSA Tax NOL of $107,358,114 as of December 31, 2023. Multiplying this amount by the income tax rate of 21% yields the CGSA NOL ADIT of $22,545,204, which is the final component of the CGSA ADIT calculation.

Q. IS INCLUSION OF ADIT ON THE NOL CONSISTENT WITH THE COMMISSION'S PAST TREATMENT OF THIS ISSUE?

A. Yes. The Company's treatment of the NOL in this case is consistent with the Commission's Final Order in Gas Utilities Docket ("GUD") No. 10170 in which the Commission approved an increase in rate base for the ADIT associated with Atmos' NOL, as calculated on a jurisdictional stand-alone basis. As in that case, the driving force behind the Company's NOL position is the substantial plant-related tax deductions associated with its regulated operations. Because these deductions created the ADIT credit that is deducted from rate base, inclusion of the NOL ADIT debit "matches the ADIT liabilities to the ADIT NOL asset created by those deductions," which is what the Commission concluded GUD No. 10170.[1] In addition, inclusion of ADIT on the NOL in this case is consistent with the Company's methodology on this issue in several prior cases, including both settled and litigated cases in which the Commission approved the Company's request to include ADIT on the NOL.[2]

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[1] *Statement of Intent filed by Atmos Energy Corp., to Increase Gas Utility Rates Within the Unincorporated Areas Served by the Atmos Energy Corp., Mid-Tex Division*, GUD No. 10170, consol., Proposal for Decision at 92 (Nov. 13, 2012).

[2] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA)*, GUD No. 10506, consol., Final Order and Attached Schedules – Decision Summary with Schedules, Schedule B-9 at 33 of 267 (Sept. 27, 2016) corresponds to Schedule B-9 in the Company's GUD No. 10506 initial filing as well as the table in the GUD No. 10506 Direct Testimony of Janet Simpson at 9 (Mar. 30, 2016); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928, consol., Final Order (Aug. 4, 2020) (the parties agreed to settle all issues except for consolidation, which was litigated and the Commission approved.); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order (Jan. 18, 2023); and *Statement*

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area, Docket No. OS-23-00014399, consol., Final Order (Jan. 30, 2024).

JANET M. SIMPSON

CONTACT INFORMATION
5702 Beacon Drive, Austin, Tx 78734
Phone: (512) 775-3799 Email: janet@utiliregcon.com

PROFILE
Janet Simpson owns Utility Regulatory Consulting, LLC ("URC"), a consulting firm providing ratemaking and regulatory services to the utility industry. Prior to establishing URC in 2020, she served as Vice President of Dively Energy Services Company, LLC, performing similar regulatory services and Vice President of Financial Planning and Analysis for Si Energy, LP, a natural gas distribution company in Texas. She is a professional accountant with approximately forty years of experience in utility accounting and rate regulation and has participated in various accounting and regulatory projects as well as accounting information system implementations for utility companies. She has been recognized as an expert and has provided testimony in written and oral form on numerous matters and in multiple jurisdictions related to utility cost of service and rate mechanisms. In that capacity, Ms. Simpson assists clients in various financial, regulatory, and technical areas. As a specialist in utility ratemaking, she develops and reviews utility cost-of-service filings and supports her recommendations through expert testimony, issuance of and responses to requests for information, and general litigation support.

EDUCATION, CERTIFICATIONS AND DESIGNATIONS
- BBA in Accounting, University of Texas at Austin
- Certified Public Accountant, Texas

PROFESSIONAL ASSOCIATIONS
- American Institute of Certified Public Accountants
- Texas Society of Certified Public Accountants

SELECTED ENGAGEMENTS
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2024 plan year), 23-GSEP-04 (2023)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Change Gas Utility Rates within the Unincorporated Area of the Rio Grande Valley Service Area – ADIT issues – Case No. 00014399 (2023)
- *Liberty Utilities (New England Natural Gas Company)* – CY2022 Gas System Enhancement Plan Reconciliation Filing, DPU 23-GREC-04 (2023)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2023 plan year), 22-GSEP-04 (2022)
- *Liberty Utilities (New England Natural Gas Company)* – CY2021 Gas System Enhancement Plan Reconciliation Filing, DPU 22-GREC-04 (2022)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Change Gas Utility Rates within the Unincorporated Areas of the West Texas Service Area, the North Texas Service Area, and the Borger Skellytown Service Area – ADIT issues – Case No. 00009896 (2022)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2022 plan year), 21-GSEP-04 (2021)
- *Liberty Utilities (New England Natural Gas Company)* – CY2020 Gas System Enhancement Plan Reconciliation Filing, DPU 21-GREC-04 (2021)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2021 plan year), 20-GSEP-04 (2020)
- *Liberty Utilities (New England Natural Gas Company)* – CY2019 Gas System Enhancement Plan Reconciliation Filing, DPU 20-GREC-04 (2020)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2020 plan year), 19-GSEP-04 (2019)
- *Liberty Utilities (New England Natural Gas Company)* – CY2018 Gas System Enhancement Plan Reconciliation Filing, DPU 19-GREC-04 (2019)

- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Change Gas Utility Rates within the Incorporated Areas of the Central Texas Service Area, Gulf Coast Service Area and City of Beaumont – ADIT issues – GUD 10928 (2019)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2019 plan year), 18-GSEP-04 (2018)
- *Liberty Utilities (New England Natural Gas Company)* – Investigation by the Department of Public Utilities, on its own Motion, into the Effect of the Reduction in Federal Income Tax Rates on the Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15
- *Liberty Utilities (New England Natural Gas Company)* – CY2017 Gas System Enhancement Plan Reconciliation Filing, DPU 18-GREC-04 (2018)
- *SiEnergy, LP* – Statement of Intent to Increase Gas Utility Rates within the Unincorporated areas serviced by SiEnergy in Central and South Texas - GUD 10679 (2018)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company, A Division of ONE Gas, Inc., To Increase Gas Utility Rates within the Unincorporated Areas of the Borger-Skellytown Service Area – ADIT Issues (2018)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company, A Division of ONE Gas, Inc., To Increase Gas Utility Rates within the Unincorporated Areas of the North Texas Service Area – ADIT Issues (2018)
- *Texas Office of Public Utility Counsel* – Application of Southwestern Public Service Company for a Certificate of Convenience and Necessity Authorizing Construction and Operation of Wind Generation and Associated Facilities, in Hale County, Texas and Roosevelt County, New Mexico and Related Ratemaking Principles; and Approval of a Purchased Power Agreement to Obtain Wind Generated Energy - PUC Docket No. 46936.
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2018 plan year), 17-GSEP-04 (2017)
- *Liberty Utilities (New England Natural Gas Company)* – CY2016 Gas System Enhancement Plan Reconciliation Filing, DPU 17-GREC-04 (2017)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company, A Division of ONE Gas, Inc., to Increase Gas Utility Rates within the Unincorporated Areas of the Rio Grande Valley Service Area – ADIT Issues (2017)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2017 plan year), 16-GSEP-04 (2016)
- *Liberty Utilities (New England Natural Gas Company)* – CY2015 Gas System Enhancement Plan Reconciliation Filing, DPU 16-GREC-04 (2016)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2016)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates within the Unincorporated Areas of the Central Texas and South Texas Service Areas – ADIT issues – GUD 10526 (2016)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates within the Unincorporated Areas of the El Paso Service Area, Permian Service Area, and Dell City Service Area – ADIT issues – GUD 10506 (2016)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates within the Unincorporated Areas of the Galveston Service Area and the South Jefferson County Service Area – ADIT issues – GUD 10488 (2015)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2016 plan year), 15-GSEP-04 (2015)
- *Liberty Utilities (New England Natural Gas Company)* – Massachusetts Rate Case, DPU 15-75 Petition for Approval of a General Increase in Rates (2015)
- *Texas Gas Service* – El Paso Annual Rate Review – ADIT issues (2015)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2015)
- *Texas Gas Service* – Various Service Areas – Calculation of service-area-specific Net Operating Loss ADIT for annual Cost of Service Adjustment filings (2015)
- *Liberty Utilities (New England Natural Gas Company)* – CY2014 Targeted Infrastructure Recovery Factor Compliance Filing, DPU 15-54 (2015)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2015 plan year), DPU 14-133 (2014)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2014)
- *Texas Gas Service* – El Paso Annual Rate Review – ADIT issues (2014)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2014)

- *Texas Gas Service* – Various Service Areas – Development of approach and calculation of service-area-specific Net Operating Loss ADIT for annual Cost of Service Adjustment filings (2014)
- *Liberty Utilities (New England Natural Gas Company)* – CY2013 Targeted Infrastructure Recovery Factor Compliance Filing, DPU 14-82 (2014)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2013)
- *Texas Gas Service* – Rio Grande Valley Service Area – Statement of Intent to Change Rates (2013)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2013)
- *New England Gas Company*-CY2012 Targeted Infrastructure Recovery Factor Filing, DPU 13-77 (2013)
- *New England Gas Company*-Joint Petition for Approval of the Sale of New England Gas Company, DPU 13-07 (2013)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2012)
- *New England Gas Company*-Petition of New England Gas Company for the Establishment of a Regulatory Asset, DPU 12-68 (2012)
- *New England Gas Company*-CY2011 Targeted Infrastructure Recovery Factor Filing, DPU 12-37 (2012)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2012)
- *Nebraska Public Service Commission* – Gas Cost Adjustment Audit of Northwestern Energy, January 2009-April 2012; Application NG-0071 (2012)
- *New England Gas Company*-CY2010 Targeted Infrastructure Recovery Factor Compliance Filing, DPU 11-42 (2011)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2011)
- *Nebraska Public Service Commission* – Gas Cost Adjustment Audit of Black Hills Energy, January 2008-December 2010; Application NG-0066 (2011)
- *New England Gas Company* – Massachusetts Rate Case, DPU 10-114 Petition for Approval of a General Increase in Rates (2010)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2010)
- *Texas Gas Service* –El Paso Service Area - Statement of Intent to Change Rates (2009)
- *New England Gas Company* – DPU 09-131 Petition of New England Gas Company for approval of an Earnings Sharing Rate Adjustment (2009)
- *New England Gas Company* – DPU 09-83 Petition of New England Gas Company for approval by the Department of Public Utilities of its 2009 Pension Expense Factor filing (2009)
- *New England Gas Company* – DPU 08-66 Petition of New England Gas Company for approval by the Department of Public Utilities of its 2008 Pension Expense Factor filing (2008)
- *New England Gas Company* – DPU 08-64 Petition of New England Gas Company for approval of an earnings sharing rate adjustment (2008)
- *New England Gas Company* – Massachusetts Rate Case, DPU 08-35 Petition for Approval of a General Increase in Rates (2008)
- *Texas Gas Service* – Rio Grande Valley Service Area - Statement of Intent to Change Rates (2008)
- *Texas Gas Service* – Permian and Central Texas Regions - Expert services regarding revenue deficiency tax items (2008)
- *CoServ Gas, Ltd.* – G.U.D. 9670 - Petition for de Novo Review of the Reduction of the Gas Utility Rates of Atmos Energy Corp., Mid-Tex Division, by the Cities of Addison, Benbrook, Blue Ridge, et. al., and Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division to Change Rates in the Company's Statewide Gas Utility System – Analytical services to support rebuttal testimony of June M. Dively regarding proposed change in rates (2006)
- *Texas Gas Service* - Statement of Intent to Increase Rates in its Rio Grande Valley Region – Expert services regarding development of various cost-of-service components (2006)
- *CoServ Gas, Ltd.* - Statement of Intent to Increase Rates in the Environs – (2006)
- *Crosstex Energy Services, Ltd.* – Compliance reporting support for Commissions in the States of Texas, Louisiana, Mississippi and Alabama (2006, 2007, 2008)
- *Crosstex Energy Services, Ltd.* – Development of processes to support regulatory requirements in connection with conversion to PeopleSoft Accounting Systems (2006)
- *CoServ Gas, Ltd.* – Functional process analysis and support pertaining to various regulatory accounting, plant, and work order system requirements for company conversion to Oracle Accounting Systems (2005).
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas (2005)
- *Texas State Natural Gas* - Gas distribution system acquisition due diligence review (2005)

- *Texas General Land Office* - TXU Rate Case G.U.D. 9500 (2004)
- *CoServ Gas, Ltd.* - Statement of Intent to Change Rates in 25 cities in North Texas (2004)
- *Texas Gas Service* - Statement of Intent to Change Rates - South Jefferson County, TX (2003)
- *Southern Union Gas* - Statement of Intent to Change Rates - El Paso and Andrews, TX (1999)
- *Missouri Gas Energy* - Case No. GR-98-140 General rate increase (1998)
- *Missouri Gas Energy* - Case No. GR-96-285 General rate increase (1996)
- *Southern Union Company* – Functional Requirements Project Leader - development of processes to support accounting and regulatory requirements in connection with conversion to Infinium Software Accounting Systems from separate accounting systems of Rio Grande Valley Gas Company, Missouri Gas Energy, and Southern Union Gas (1994-1996)
- *Missouri Gas Energy* - Gas system acquisition by due diligence review and accounting integration (1994)
- *Rio Grande Valley* - Gas system acquisition by due diligence review and accounting integration (1993)
- *City of Nixon Gas System* - Gas system acquisition by due diligence review and accounting integration (1992)
- *Andrews Gas Company* - Gas system acquisition by due diligence review and accounting integration (1991)
- *South Texas Utilities* - Gas system acquisition by due diligence review and accounting integration (1991)
- *Gulf States Utilities Co*– PUCT Docket No. 6525 Application for Authority to Change Rates (1986)
- *San Patricio Electric Coop*– PUCT Docket No. 6620 Petition for Authority to Change Rates (1986)
- *Fayette Electric Coop* – PUCT Docket No. 6907 Petition for Authority to Change Rates (1986)
- *El Paso Electric Company* – PUCT Docket No. 6350 Application for a General Rate Case (1985)
- *Southwest Rural Electric Association* – PUCT Docket No. 6143 Application for Tariff Revisions (1985)
- *West Texas Utilities Co*– PUCT Docket No. 5764 Application for Authority to Change Rates (1984)
- *Texas-New Mexico Power Company* – PUCT Docket No. 5568 Application for Authority to Change Rates (1984)
- *San Bernard Electric Cooperative, Inc.* – PUCT Docket No. 5467 Appl. for Authority to Change Rates (1984),
- *South Texas Electric Cooperative, Inc* – PUCT Docket No. 5440 Appl. for Tariff Revisions to Reduce Fuel Factor (1984)

SUMMARY ADIT ALLOCATIONS TO CENTRAL GULF SERVICE AREA
12/31/2023

	Estimated Accumulated Deferred Income Taxes for:	ADIT at 21%
8	Central Gulf Service Area Direct Plant Repairs	(31,906,926)
9	Central Gulf Service Area Plant Assets Depreciation	(62,005,198)
10	Subtotal CGSA Direct Plant Asset Related	(93,912,124)
11	Central Gulf Service Area Other Rate Base Items	(4,661,841)
12	TGS Division Plant Assets Depreciation	(659,027)
13	ONEGAS Plant Assets Depreciation	(2,631,536)
14	Central Gulf Service Area NOL	22,545,204
16	**ADFIT - Accumulated Deferred Federal Income Taxes**	**(79,319,324)**

Accumulated Deferred Income Tax - Central Gulf Service Area Plant Related Items

	As of Dec 31, 2023	Gross Book Basis	Book Reserve	Net Book Basis	Gross Tax Basis	Tax Reserve	Net Tax Basis	Difference in Net Plant Basis	Estimated ADIT Asset/(Liability) at 21%
25	Central Gulf Service Area Direct Plant	1,079,039,213	(220,618,261)	858,420,952	758,820,361	(347,801,241)	411,019,120	447,401,832	(93,954,385)
27	Adjustments	(432,263.55)	66,366.42	(365,897.13)	(303,983.75)	139,329.32	(164,654.43)	(201,242.70)	42,260.97
29	**Adjusted Central Gulf Service Area**	**1,078,606,950**	**(220,551,895)**	**858,055,055**	**758,516,377**	**(347,661,911)**	**410,854,466**	**447,200,589**	**(93,912,124)**
31	**TGS Division (Allocated to Central Gulf Service Area)**	**5,314,762**	**(1,391,474)**	**3,923,288**	**2,164,028**	**(1,378,963)**	**785,065**	**3,138,223**	**(659,027)**
33	**ONEGas (Allocated to Central Gulf Service Area)**	**40,160,528**	**(18,484,037)**	**21,676,491**	**33,124,539**	**(23,979,171)**	**9,145,368**	**12,531,123**	**(2,631,536)**

Accumulated Deferred Income Tax Analysis For Central Gulf Service Area Other Rate Base Items

		Balance Sheet Impact per Book	Balance Sheet Impact per Tax	Difference	Estimated ADIT Asset/(Liability)
41	Pension/OPEB Expense Regulatory Deferrals	(3,315,201)	-	(3,315,201)	696,192
43	Prepaid Pension (funding in excess of FAS87 expense)	20,530,077	-	20,530,077	(4,311,316)
45	Section 8.209 Deferral	1,848,673	-	1,848,673	(388,221)
47	Regulatory Assets	3,135,695		3,135,695	(658,496)
49	Total Other Rate Base Items				(4,661,841)

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STATE OF TEXAS §
§
COUNTY OF BELL §

AFFIDAVIT OF JANET M. SIMPSON

BEFORE ME, the undersigned authority, on this day personally appeared Janet M. Simpson who having been placed under oath by me did depose as follows:

1. "My name is Janet M. Simpson. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as an Accountant and Managing Member of Utility Regulatory Consulting, LLC. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

DocuSigned by:
Janet Simpson
BB9173C99AEF476...

Janet M. Simpson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Janet M. Simpson on this 22nd day of May 2024.

Erlinda Alvarado

Notary Public in and for the State of Texas

ERLINDA ALVARADO
NOTARY PUBLIC
ID# 133935107
State of Texas
Comm. Exp. 08-29-2026

WORKPAPERS

TO

DIRECT TESTIMONY

OF

JANET M. SIMPSON

Workpapers to the Direct Testimony of Janet M. Simpson are being provided in electronic format.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

RONALD E. WHITE, Ph.D.

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

PREPARED DIRECT TESTIMONY OF RONALD E. WHITE, PH.D.

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Ronald E. White. I serve as President of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908. A summary of my education, relevant employment experience and other professional qualifications is provided in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by Texas Gas Service ("TGS"), a division of ONE Gas, Inc., to conduct a 2024 Depreciation Rate Study for gas properties located in the Central–Gulf Service Area ("CGSA"). Accompanying my testimony are the following exhibits:

a) Exhibit REW–1 contains the 2024 study conducted for CGSA.

b) Exhibit REW–2 contains depreciation rates, accruals and parameters for the TGS division (TGSD) approved in Docket No. OS-22-00009896 (Docket No. 9896).

The purpose of my testimony is to: a) sponsor and describe the CGSA study conducted by Foster Associates; and b) report approved depreciation rates and parameters for TGSD.

II. SUMMARY

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR CGSA IN THE 2024 STUDY.

A. Table 1 below provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation rates recommended for CGSA.

Function	Accrual Rates			2024 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.77%	2.89%	1.12%	$ 351,193	$ 572,830	$ 221,637
Distribution	2.27%	2.86%	0.59%	21,014,579	26,467,494	5,452,914
General Plant	6.00%	5.55%	-0.45%	7,001,257	6,480,002	(521,256)
TOTAL PLANT	2.67%	3.15%	0.48%	$ 28,367,030	$ 33,520,325	$ 5,153,296

Table 1. Central-Gulf Service Area

Primary account depreciation rates equivalent to a composite rate of 3.15% are recommended for CGSA. Depreciation expense is currently accrued at rates that composite to 2.67%. The recommended change in the composite depreciation rate is an increase of 0.48 percentage points. A continued application of current rates would produce an annualized depreciation expense of $28,367,030 compared with an annualized expense of $33,520,325 using the rates recommended in this study. The resulting 2024 expense increase is $5,153,296. The computed change in annualized accruals includes an increase of $772,304 attributable to an amortization of a $30,912,996 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2024 study. Of the 21 plant accounts included in CGSA, rate reductions are recommended for 2 accounts, rate increases for 12 accounts and no rate change for 7 accounts.

Q. PLEASE EXPLAIN THE CONTENT AND PURPOSE OF EXHIBIT REW–2.

A. Exhibit REW–2 contains depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and service life and net salvage parameters approved for TGSD in Docket No. 9896. The purpose of the exhibit is to provide the source of depreciation rates approved for TGSD and retained in this proceeding.

III. DEVELOPMENT OF DEPRECIATION RATES

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential (or future economic benefit) of an asset is the present value of future net revenue (i.e., revenue less expenses exclusive of depreciation and other noncash expenses) or cash inflows attributable to the use of that asset alone. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all property units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent such cost–based regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of an accounting measurement of earnings. While a continuation of such practices may not comport with the goals of depreciation accounting, achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon authorized levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.[1]

Q. PLEASE DESCRIBE THE PRINCIPAL ACTIVITIES UNDERTAKEN IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step is the estimation of service life statistics from an analysis of past retirement experience. The term life analysis is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about future forces of retirement to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. This step, called life estimation, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will

[1] I do not discuss, nor have I considered, whether other regulatory or public policy goals should influence or be reflected in establishing depreciation rates. Such considerations remain the prerogative of the regulatory agency responsible for determining appropriate depreciation rates.

depend upon the extent to which past retirement experience and service life indications are considered descriptive of the future.

An estimate of net salvage associated with future retirements is most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may produce different amounts of net salvage than realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the estimated projection–life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive study will also include an analysis of the adequacy (or inadequacy) of recorded depreciation reserves. The purpose of such an analysis is to compare current recorded reserve balances with balances required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between a required (or theoretical) reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish such reserve imbalances.

Although reserve records are typically maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise when depreciation rates are negotiated in settlements that shift the timing of depreciation expense to future accounting periods. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute or rebalance recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and net salvage rates. A redistribution of recorded reserves will realign reserve balances for each primary account consistent with revised estimates of net salvage and service–life statistics and establish a baseline against which future reserve comparisons can be made.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Figure 1. Elements of a Depreciation System

Finally, parameters estimated from service life and net salvage studies are entered into a formulation of accrual rates using a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Figure 1 below.

The above elements (i.e., method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

IV. 2024 DEPRECIATION STUDY

Q. PLEASE DESCRIBE THE SCOPE OF THE 2024 CGSA DEPRECIATION STUDY.

A. In the interest of consistency and to avoid re-estimating statewide parameters estimated by Foster Associates in 2022, the current CGSA study retains the statewide parameters found by the Railroad Commission of Texas ("Commission") in Docket No. 9896 to be "just and reasonable." Depreciation rates for CGSA, however, are derived from age distributions of surviving plant, recorded depreciation reserves and average net salvage rates specific to the service area on December 31, 2023.

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY TGS FOR THE CGSA.

A. Current depreciation rates for CGSA were derived in a 2019 study by combining the Central Texas Service Area (CTSA) and the Gulf Coast Service Area (GCSA). Depreciation rates for the CGSA were derived from a weighted average of accrual rates developed separately for CTSA and GCSA. Rates for each of the two Service Areas were derived from age distributions of surviving plant, recorded depreciation reserves and average net salvage rates specific to each Service Area. Current accrual rates adopted by CGSA were approved by the Railroad Commission of Texas pursuant to a Settlement Agreement in Case No. 10928 (Order dated August 4, 2020).

Q. DID TGS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2024 CGSA DEPRECIATION STUDY?

A. Yes. The database used in conducting the 2024 study was assembled by appending 2023 plant and reserve activity to the statewide database used in conducting the 2023 Rio Grande Valley Service Area (RGVSA) study. Detailed accounting entries were assigned transaction codes that describe the reported accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, gross salvage, cost of removal and other recorded accounting activity.

Age distributions on December 31, 2023 for CGSA were derived by Foster Associates in a forward–flow computation in which accounting activity was appended to the database used in conducting the 2023 RGVSA study. Derived age distributions at December 31, 2023 were reconciled to the continuing property records of TGS. Annual plant activity prior to December 31, 2023 was reconciled in the 2023 and prior depreciation rate studies.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR TGS PLANT AND EQUIPMENT?

A. Yes, in the 2022 study. As noted above, parameters (i.e., projection curves, projection lives and future net salvage rates) recommended for CGSA were estimated in a 2022 combined analysis of all (i.e., statewide) TGS Service Areas. The 2022 study (based on year–end 2021 plant and reserve balances) was filed with the Railroad Commission of Texas on June 30, 2022 and docketed as Docket No. 9896. Life analysis and estimation studies conducted in the 2022 study are described in Exhibit REW–1.

Q. DID FOSTER ASSOCIATES ESTIMATE FUTURE NET SALVAGE RATES FOR TGS PLANT AND EQUIPMENT?

A. Yes. Future net salvage rates were estimated in the 2022 study, as described in Exhibit REW–1, and retained in the 2024 CGSA study. The derivation of average net salvage rates for CGSA on December 31, 2022 is contained in Exhibit REW–1, Statement E.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES IN THE 2024 STUDY?

A. Yes. Exhibit REW–1, Statement C provides a comparison of recorded, computed and redistributed reserves on December 31, 2023. The recorded reserve for CGSA was $218,764,472 or 20.6% of the depreciable plant investment. The corresponding computed reserve is $249,677,468 or 23.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $30,912,996 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Recorded reserves for the TGS Division on December 31, 2021 were set equal to computed reserves of $2,569,342 or 24.9% of the amortizable plant investment. The equivalency between recorded and computed reserves was achieved by transferring recorded reserves in proportion to customer counts, from Account 390.10 (Structures and Improvements) from each service area in which investments were recorded in Account 390.10. The amount of reserve transferred to the TGS Division from CGSA was $220,524.

Q. DID FOSTER ASSOCIATES REBALANCE DEPRECIATION RESERVES IN THE 2024 STUDY?

A. Yes. A rebalancing of recorded reserves is consistent with the objectives of depreciation accounting and Railroad Commission precedent.[2] Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the 2024 Study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of recorded reserves for depreciable plant categories was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves to the function total calculated reserve. The sum of redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before redistribution. Depreciation reserves for amortizable categories were redistributed by setting recorded reserves for the amortization accounts equal to the theoretical reserves derived from the specified amortization periods and distributing the residual imbalances to the remaining depreciable accounts within the associated functions.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM USED TO DEVELOP CURRENT DEPRECIATION RATES FOR CGSA.

A. With the exception of selected general support asset categories for which amortization accounting has been approved, TGS is currently using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique for all depreciable rate categories in CGSA and TGSD. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (i.e., credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

[2] See, for example, GUD Nos. 9988, 10506, 10526 and Docket No. 9896.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM USED BY TGS?

A. No. Depreciation rates recommended in the 2024 Study were developed using the currently approved system. It is the opinion of Foster Associates that this system will remain appropriate for TGS, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support and distribution asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

RONALD E. WHITE, PH.D.

EDUCATION

1961 – 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated with the Service Life of Industrial Property

EMPLOYMENT

2015 – Present: Foster Associates Consultants, LLC, President

2007 – 2015 Foster Associates, Inc., Chairman

1996 – 2007 Foster Associates, Inc., Executive Vice President

1988 – 1996 Foster Associates, Inc., Senior Vice President

1979 – 1988 Foster Associates, Inc., Vice President

1978 – 1979 Northern States Power Company, Assistant Treasurer

1974 – 1978 Northern States Power Company, Manager, Corporate Economics

1972 – 1974 Northern States Power Company, Corporate Economist

1970 – 1972 Iowa State University, Graduate Student and Instructor

1968 – 1970 Northern States Power Company, Valuation Engineer

1965 – 1968 Iowa State University, Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem with AFDC is …, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

- Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.
- Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.
- Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.
- Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.
- Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.
- Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.
- Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.
- Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–16–0036, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–19–0236, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01345A–22–0144, Arizona Public Service Company; rebuttal testimony to Staff advocated treatment of net salvage accrual rates.

- Arizona Corporation Commission, Docket No. E–04204A–22–0251, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–12–0126, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–15–0322, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–01933A–19–0028, Tucson Electric Power Company; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. E–04204A–15–0142, UNS Electric, Inc.; testimony supporting proposed depreciation rates.
- Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.
- California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.
- California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.
- California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.
- California Public Utilities Commission. Application No. A.16–09–001 Southern California Edison; testimony regarding estimation of service lives and net salvage rates.
- Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.
- State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.
- State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.
- Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.
- Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.
- Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

- Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1115, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1137, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Public Service Commission of the District of Columbia, Formal Case No. 1162, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.
- Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.
- Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.
- Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.
- Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.
- Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

- Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.
- Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.
- Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.
- Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.
- Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.
- Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.
- Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.
- Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.
- Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.
- Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.
- Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.
- Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.
- Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.
- Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.
- Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.
- Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.
- Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

- Kansas Corporation Commission, Docket No. 23-EKCE-775-RTS, Evergy Kansas Central, Evergy Kansas South and Evergy Kansas Metro; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 24-KGSG-610-RTS, Kansas Gas Service, a Division of ONE Gas, Inc, testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 16-KGSG-491-RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 12-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 18-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.
- Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.
- Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.
- Kansas Corporation Commission, Docket No. 18–KGSG–560–RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.
- Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9424, Delmarva Power and Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9481, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.
- Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

- Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.
- Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 15–155, Massachusetts Electric Company/Nantucket Electric Company; testimony supporting proposed depreciation rates.
- Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.
- Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.
- Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.
- Michigan Public Service Commission, Case No. U–18150, DTE Electric Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.
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- Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.
- Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.
- Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates
- Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.
- Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.
- Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.
- Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.
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- Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.
- Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.
- Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.
- Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.
- Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.
- Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.
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- Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.
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- New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.
- New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.
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- North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.
- North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.
- North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.
- North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.
- North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.
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- Oklahoma Corporation Commission, Cause No. PUD 202100063, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.
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- Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.
- Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.
- Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.
- Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

- Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.
- Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.
- Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.
- Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.
- Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.
- Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.
- Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.
- Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.
- Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.
- Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.
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- Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

- Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.
- The Railroad Commission of Texas, GUD Docket No. 9896, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.
- The Railroad Commission of Texas, GUD Docket No. 10488, Texas Gas Service, testimony supporting recommended depreciation rates.
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- Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.
- Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

OTHER CONSULTING ENGAGEMENTS

Arbitrator in a Technical Dispute relating to classification of Capital Budget expenditures.

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

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BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

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Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

FACULTY

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September 1978.

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PROFESSIONAL ASSOCIATIONS

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee).

MODERATOR

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

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Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

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The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

SPEAKER

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Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

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Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

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Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

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Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation? American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

HONORS AND AWARDS

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

March 2024

Exhibit REW–1

2024 Depreciation Rate Study

Texas Gas Service

A Division of ONE Gas

Central Gulf Service Area

foster associates

CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2024 depreciation study conducted for gas plant owned and operated by Texas Gas Service (TGS), a division of ONE Gas, Inc., and located in the Central–Gulf Service Area (CGSA).

Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned businesses including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

At the request of TGS, the CGSA was created in a 2019 study by combining the Central Texas Service Area (CTSA) and the Gulf Coast Service Area (GCSA). Service areas combined in forming the CGSA are shown in Figure 1 below.

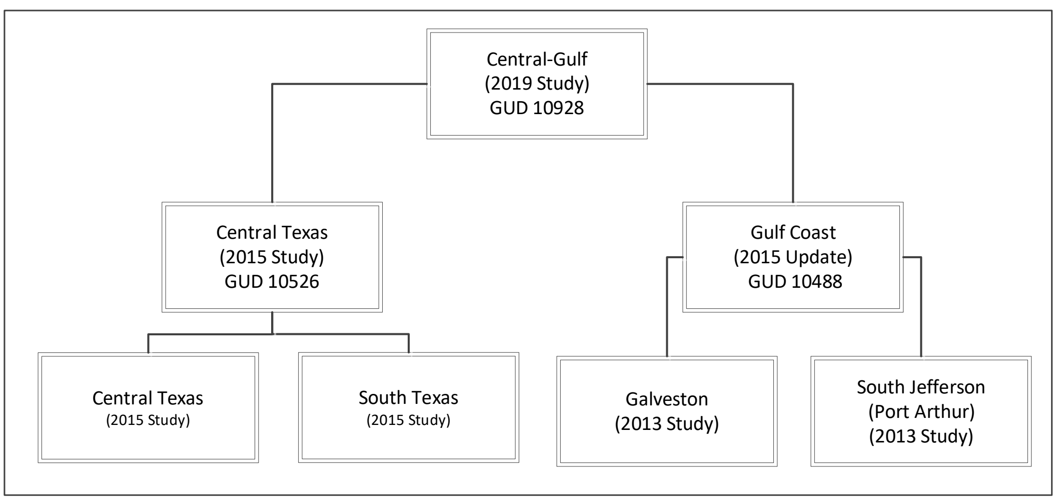


Figure 1. Central-Gulf Combined Service Areas

Recommended and approved parameters (*i.e.*, projection curves, projection lives and future net salvage rates) were estimated in the 2019 study (Docketed as Case No. 10928) from a combined analysis of all TGS Service Areas. Depreciation rates for the CGSA were derived from a weighted average of accrual rates developed separately for CTSA and GCSA. Rates for each of the two Service Areas were derived from age distributions of surviving plant, recorded depreciation reserves and average net salvage rates specific to each Service Area. Current accrual rates adopted by CGSA were approved by the Railroad Commission of Texas pursuant to a Settlement Agreement in Case No. 10928 (Order dated August 4, 2020).

Parameters (*i.e.*, projection curves, projection lives and future net salvage rates) recommended for GCSA in the current 2024 study were derived in a 2022 combined analysis of all (*i.e.*, statewide) TGS Service Areas. The 2022 study (based on year–end 2021 plant and reserve balances) was conducted for the West–North Service Area (WNSA) and filed with the Railroad Commission of Texas on June 30, 2022, docketed as Case No. 9896. A Final Order was issued on January 19, 2023 with the following Findings of Fact regarding statewide parameters and depreciation rates for West–North Texas, Fort Bliss and the TGS Division:

1. TGS's proposed depreciation rate for Account 367 - Transmission Mains based on a 60- year service life (L 1-60) is just and reasonable.
2. TGS's proposed depreciation rate for Account 376 - Distribution Mains based on a 67-year service life (R2-67) is just and reasonable.
3. TGS's proposed depreciation rate for Account 378 - M&R based on a 60-year service life (R1-60) is just and reasonable.
4. TGS's proposed depreciation rate for Account 380 - Services based on a 55-year service life (R2-55) is just and reasonable.
5. TGS's proposed depreciation rate for Account 383 - House Regulators based on a 35-year service life (R3-35) is just and reasonable.
6. TGS's proposed net salvage rates are just and reasonable.
7. TGS's proposed depreciation and amortization rates for distribution and general plant in the WNSA, as well as TGS Division plant and Fort Bliss plant depreciation rates, are just and reasonable.

Parameters estimated and approved in the 2022 WNSA study were retained in a 2023 study for the Rio Grande Valley Service Area (RGVSA) docketed as Case No. 14399. Rates requested by TGS for RGVSA were approved by the Railroad Commission of Texas in an open meeting held on January 30, 2024.

In the interest of consistency and to avoid re-estimating statewide parameters estimated by Foster Associates in 2022, the current GCSA study retains the statewide parameters found by the Commission in WNSA Case No. 9896 to be "just and reasonable." It is the opinion of Foster Associates that forces of retirement acting upon TGS plant and equipment have not changed measurably since 2022 to warrant a reexamination of statewide parameters approved in 2023. Depreciation rates for the GCSA, however, are derived from age distributions of surviving plant, recorded depreciation reserves and average net salvage rates specific to the service area on December 31, 2023. Depreciation rates for the TGS division (TGSD) are those derived in the 2022 study and approved in Case No. 9896.

The principal findings and recommendations of the 2024 CGSA study are summarized in Section IV (Statements) of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides of summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. Statement F also contains current and proposed statistics including average service lives, average remaining lives, and average net salvage rates.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to Company official records;
- Discussions with TGS plant accounting personnel;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for a plant category. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been adopted, TGS is currently using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique for all rate categories in the CGSA Service Area. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

Depreciation theory provides that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation rates recommended for CGSA.

	Accrual Rates			2024 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.77%	2.89%	1.12%	$ 351,193	$ 572,830	$ 221,637
Distribution	2.27%	2.86%	0.59%	21,014,579	26,467,494	5,452,914
General Plant	6.00%	5.55%	-0.45%	7,001,257	6,480,002	(521,256)
TOTAL PLANT	2.67%	3.15%	0.48%	$ 28,367,030	$ 33,520,325	$ 5,153,296

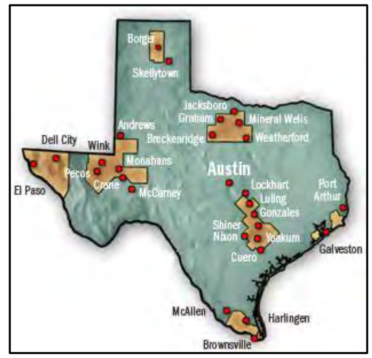
Table 1. Central-Gulf Service Area

Primary account depreciation rates equivalent to a composite rate of 3.15 percent are recommended for CGSA. Depreciation expense is currently accrued at rates that composite to 2.67 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.48 percentage points.

A continued application of current rates would provide annualized depreciation expense of $28,367,030 compared with an annualized expense of $33,520,325 using the rates developed in this study. The proposed 2024 expense increase is $5,153,296. The computed change in annualized accruals includes an increase of $772,304 attributable to an amortization of a $30,912,996 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2024 study. Of the 21 plant accounts included in the 2024 study, Foster Associates is recommending rate reductions for 2 accounts, rate increases for 12 accounts and no rate changes for 7 accounts.

COMPANY PROFILE

GENERAL



Texas Gas Service is a division of Tulsa–based ONE Gas, Inc. (NYSE: OGS), one of the largest publicly traded, 100 percent–regulated natural gas utilities in the United States. ONE Gas provides natural gas distribution services to more than 2 million customers in Oklahoma, Kansas and Texas. Headquartered in Tulsa, Oklahoma, its companies include the largest natural gas distributor in Oklahoma and Kansas, and the third largest in Texas, in terms of customers.

ONE Gas is a successor to the company founded in 1906 as Oklahoma Natural Gas Company, and became ONEOK, Inc. (NYSE: OKE) in 1980. ONEOK separated its natural gas distribution business in 2014 to create ONE Gas, Inc.

Texas Gas Service was founded in Wink, Texas in 1929 as Southern Union Gas. The Company grew to become the third largest natural gas distribution company in Texas. In January 2003, ONEOK purchased these Texas assets and named the distribution company Texas Gas Service Company.

GAS UTILITY OPERATIONS

By December 31, 2021, Texas Gas Service owned and operated approximately 10,720 miles of distribution mains and 309 miles of transmission mains. The distribution system consists of 5,343 miles of cathodically protected pipe, 463 miles of unprotected steel pipe, 24 miles of cast/wrought iron and 4,890 miles of plastic mains. All transmission mains are cathodically protected.

At the end of 2021, Texas Gas Service maintained 697,577 service lines consisting of 48,299 unprotected lines, 227,764 cathodically protected lines, 145 copper lines and 384,158 plastic lines.

The Company owns and operates 152 city gate stations serving wholesale and retail customers. A total of 20 service centers are located in Central–Gulf Texas, West–North Texas, Rio Grande Valley and Fort Bliss.

The majority of natural gas supply is provided under contracts from a number of suppliers awarded through a competitive bid process. The remainder of natural gas supply is purchased from a combination of direct wellhead production, natural gas processing plants, natural gas marketers and production companies.

CUSTOMER BASE

Texas Gas Service provides natural gas service to over 690,267 customers including residential, commercial, industrial, and transportation in more than 100 communities.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by CGSA.

SCOPE

Steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

Each of these tasks was considered in conducting the CGSA 2024 study as described below.

DATA COLLECTION

The database used in conducting the 2024 study was assembled by appending 2023 plant and reserve activity to the statewide data base used in conducting the 2023 RGVSA study. Detailed accounting entries were assigned transaction codes that describe the reported accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, gross salvage, cost of removal and other recorded accounting activity.

Age distributions on December 31, 2023 for CGSA were derived by Foster Associates in a forward–flow computation in which accounting activity was appended to the database used in conducting the 2023 RGVSA study. Derived age distributions at December 31, 2023 were reconciled to the continuing property records of TGS. Annual plant activity prior to December 31, 2023 was reconciled in the 2023 and prior depreciation rate studies.

LIFE ANALYSIS AND ESTIMATION

As noted earlier, parameters (*i.e.*, projection curves, projection lives and future net salvage rates) recommended for CGSA were estimated in a 2022 combined analysis of all (*i.e.*, statewide) TGS Service Areas. The 2022 study (based on year–end 2021 plant and reserve balances) was filed with the Railroad Commission of Texas on June 30, 2022 and docketed as Case No. OS-22–00009896. Life analysis and life estimation were described in the 2022 TGS study as follows:

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts contained in the 2022 study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2022 study are the Iowa–type curves mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second– and third–degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. Observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using the projection life derived from the polynomial hazard function) to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

The set of computer programs used in the TGS study provides multiple rolling–band and shrinking–band analyses of an account. Observation bands are defined for a "retirement era" that restricts the analysis to retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output and algorithms for calculating depreciation rates and accruals.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are viewed as "interim" retirements that will be replaced in order to maintain the integrity of the system. Plant facilities may also be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts were treated as full mortality categories in the TGS study.

NET SALVAGE ANALYSIS

Net Salvage Analyses were described in the 2022 TGS study as follows:

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the 2022 study to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as the weighting of future net salvage estimates changes from the installation of subsequent plant additions.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measurement of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor or projection curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of multiple vintages. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or anticipated changes in the parameters chosen to describe the underlying forces of retirement.

Although reserve records are commonly maintained by various account classifications, the total recorded reserve in relation to the sum of account computed reserves is the most important indicator of the adequacy (or inadequacy) of recorded reserves. When depreciation rates are derived from settlements or other Commission directives, some accounts may appear over–depreciated and other accounts may appear under–depreciated relative to calculated or theoretical reserves. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of conducting depreciation reviews.

A redistribution of recorded reserves is considered appropriate for CGSA at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

Recorded reserves were rebalanced by multiplying the calculated reserve for each primary account within a function by the ratio of the total recorded reserves to the calculated reserve. The sum of the redistributed reserves is, therefore, equal to the total recorded depreciation reserve before the redistribution. Reserves for general amortizable categories were adjusted by replacing recorded reserves with current theoretical reserves and distributing reserve imbalances to depreciable categories.

Statement C provides a comparison of recorded, computed and redistributed reserves on December 31, 2023. The recorded reserve for CGSA was $218,764,472 or 20.6 percent of the depreciable plant investment. The corresponding computed reserve is $249,677,468 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $30,912,996 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Recorded reserves for the TGS Division on December 31, 2021 were set equal to computed reserves of $2,569,342 or 24.9 percent of the amortizable plant investment. The equivalency between recorded and computed reserves was achieved by transferring recorded reserves in proportion to customer counts, from Account 390.10 (Structures and Improvements) from each service area in which investments were recorded in Account 390.10. Reserve amounts totaling $474,312 transferred from each service area are shown in Figure 1 below.

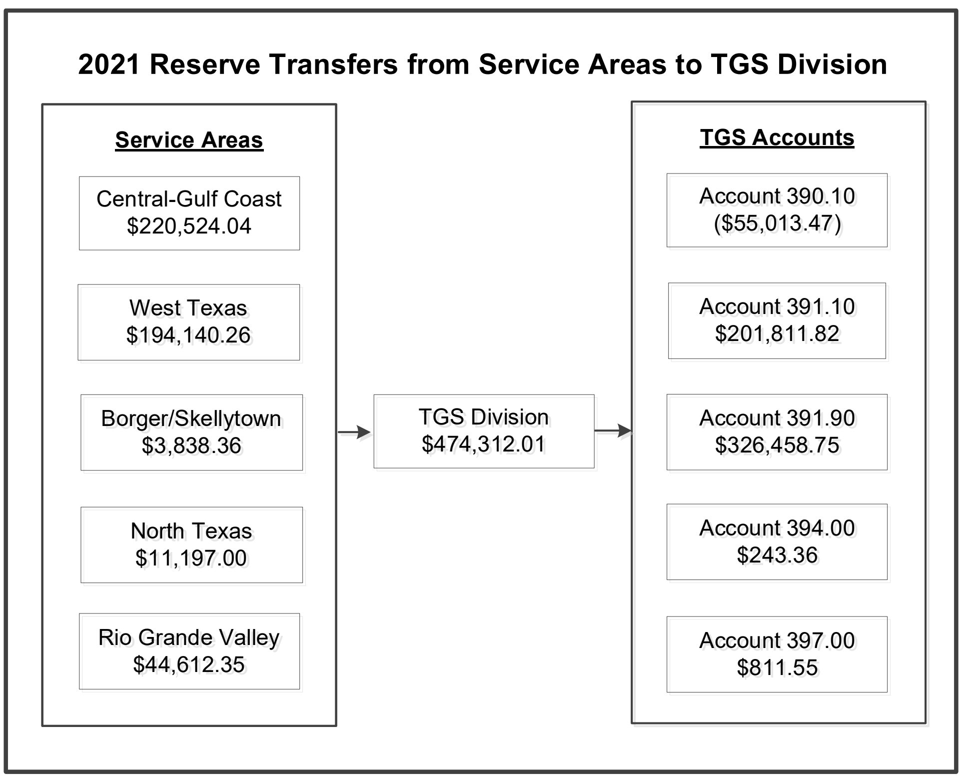


Figure 1. Reserve Transfers to TGS Division

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the CGSA 2024 study were developed using the currently approved system composed of the straight–line method, vintage group procedure and remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure and whole–life technique with amortization of reserve imbalances over the estimated composite remaining life of each rate category.

It is the opinion of Foster Associates that the vintage group procedure will remain appropriate for CGSA, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance–based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting included in this study is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for the selected general plant categories relieves TGS of the burden of maintaining detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

The treatment of amortization accounts in the current study was designed to report annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Proposed accrual rates shown in Statement A, however, are the reciprocal of amortization periods to be applied to after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period. This reporting is consistent with rates prescribed by the Commission for amortization accounts in prior proceedings.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and proposed service life and net salvage parameters recommended for CGSA plant and equipment categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2024 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2023.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of plant investments (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by CGSA for the mix of investments recorded at December 31, 2023. Similarly, proposed depreciation accruals shown on Statements B are the product of plant investments and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

TEXAS GAS SERVICE - Central-Gulf Service Area Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2023) Investment	Current Net Salvage	Current Total	Proposed (at 12/31/2023) Investment	Proposed Net Salvage	Proposed Total
A	B	C	D=B+C	E	F	G=E+F
TRANSMISSION PLANT						
367.00 Mains	1.58%	0.17%	1.75%	1.90%	0.76%	2.66%
369.00 Meas. and Reg. Station Equipment	1.66%	0.17%	1.83%	2.75%	0.68%	3.43%
Total Transmission Plant	1.60%	0.17%	1.77%	2.16%	0.74%	2.89%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	1.67%	0.03%	1.70%	2.87%	0.22%	3.09%
376.00 Mains	1.35%	0.38%	1.73%	1.53%	0.70%	2.23%
376.90 Mains - Cathodic Protection	← 15 Year Amortization →		6.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	1.63%	0.34%	1.97%	1.69%	0.44%	2.13%
379.00 Meas. and Reg. Station Equip. - City Gate	1.50%	0.20%	1.70%	1.57%	0.40%	1.97%
380.00 Services	1.51%	0.73%	2.24%	1.87%	1.29%	3.16%
381.00 Meters	3.55%	0.48%	4.03%	3.48%	0.60%	4.08%
383.00 House Regulators	2.36%	0.19%	2.55%	2.93%	0.47%	3.40%
385.00 Industrial Meas. and Reg. Station Equip.	1.48%	0.39%	1.87%	1.79%	0.59%	2.38%
386.00 Other Property on Customers' Premises	-0.12%	-0.04%	-0.16%	11.92%	-0.03%	11.89%
Total Distribution Plant	1.78%	0.49%	2.27%	2.01%	0.85%	2.86%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.35%	0.11%	2.46%	2.29%	0.23%	2.52%
392.00 Transportation Equipment	9.07%	-0.59%	8.48%	7.25%	-0.82%	6.43%
396.00 Power Operated Equipment	6.05%	-0.59%	5.46%	5.07%	-0.27%	4.80%
Total Depreciable	5.31%	-0.22%	5.09%	4.48%	-0.23%	4.25%
Amortizable						
391.10 Office Furniture and Fixtures	← 15 Year Amortization →		6.67%	← 15 Year Amortization →		6.67%
391.90 Computers and Electronic Equipment	← 7 Year Amortization →		14.29%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment	← 15 Year Amortization →		6.67%	← 15 Year Amortization →		6.67%
394.00 Tools, Shop and Garage Equipment	← 15 Year Amortization →		6.67%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	← 15 Year Amortization →		6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment	← 15 Year Amortization →		6.67%	← 15 Year Amortization →		6.67%
Total Amortizable	7.01%		7.01%	7.01%		7.01%
Total General Plant	6.11%	-0.11%	6.00%	5.67%	-0.12%	5.55%
TOTAL CENTRAL-GULF SERVICE AREA	2.25%	0.41%	2.67%	2.41%	0.74%	3.15%

TEXAS GAS SERVICE - Central-Gulf Service Area

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/23 Investment	Current 2024 Annualized Accrual Investment	Current Net Salvage	Current Total	Proposed 2024 Annualized Accrual Investment	Proposed Net Salvage	Proposed Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
TRANSMISSION PLANT								
367.00 Mains	$ 13,775,706	$ 217,656	$ 23,419	$ 241,075	$ 261,738	$ 104,695	$ 366,434	$ 125,359
369.00 Meas. and Reg. Station Equipment	6,017,387	99,889	10,230	110,118	165,478	40,918	206,396	96,278
Total Transmission Plant	$ 19,793,093	$ 317,545	$ 33,648	$ 351,193	$ 427,217	$ 145,614	$ 572,830	$ 221,637
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 47,713	$ 797	$ 14	$ 811	$ 1,369	$ 105	$ 1,474	$ 663
376.00 Mains	455,684,908	6,151,746	1,731,603	7,883,349	6,971,979	3,189,794	10,161,773	2,278,425
376.90 Mains - Cathodic Protection	28,776,037	1,919,362		1,919,362	1,919,362		1,919,362	
378.00 Meas. and Reg. Station Equip. - General	23,623,932	385,070	80,321	465,391	399,244	103,945	503,190	37,798
379.00 Meas. and Reg. Station Equip. - City Gate	7,236,737	108,551	14,473	123,025	113,617	28,947	142,564	19,539
380.00 Services	300,910,271	4,543,745	2,196,645	6,740,390	5,627,022	3,881,742	9,508,765	2,768,374
381.00 Meters	81,658,914	2,898,891	391,963	3,290,854	2,841,730	489,953	3,331,684	40,829
383.00 House Regulators	11,265,021	265,854	21,404	287,258	330,065	52,946	383,011	95,753
385.00 Industrial Meas. and Reg. Station Equip.	16,355,107	242,056	63,785	305,841	292,756	96,495	389,252	83,411
386.00 Other Property on Customers' Premises	1,063,249	(1,276)	(425)	(1,701)	126,739	(319)	126,420	128,122
Total Distribution Plant	$ 926,621,889	$ 16,514,797	$ 4,499,783	$ 21,014,579	$ 18,623,884	$ 7,843,609	$ 26,467,494	$ 5,452,914
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 33,022,712	$ 776,034	$ 36,325	$ 812,359	$ 756,220	$ 75,952	$ 832,172	$ 19,814
392.00 Transportation Equipment	25,256,473	2,290,762	(149,013)	2,141,749	1,831,094	(207,103)	1,623,991	(517,758)
396.00 Power Operated Equipment	3,532,069	213,690	(20,839)	192,851	179,076	(9,537)	169,539	(23,312)
Total Depreciable	$ 61,811,254	$ 3,280,486	$ (133,527)	$ 3,146,959	$ 2,766,390	$ (140,687)	$ 2,625,703	$ (521,256)
Amortizable								
391.10 Office Furniture and Fixtures	$ 2,464,787	$ 164,401	$ -	$ 164,401	$ 164,401		$ 164,401	$ -
391.90 Computers and Electronic Equipment	2,486,371	355,302		355,302	355,302		355,302	
393.00 Stores Equipment	123,761	8,255		8,255	8,255		8,255	
394.00 Tools, Shop and Garage Equipment	15,381,411	1,025,940		1,025,940	1,025,940		1,025,940	
397.00 Communication Equipment	34,482,407	2,299,977		2,299,977	2,299,977		2,299,977	
398.00 Miscellaneous Equipment	6,349	423		423	423		423	
Total Amortizable	$ 54,945,086	$ 3,854,299	$ -	$ 3,854,299	$ 3,854,299		$ 3,854,299	$ -
Total General Plant	$ 116,756,340	$ 7,134,785	$ (133,527)	$ 7,001,257	$ 6,620,689	$ (140,687)	$ 6,480,002	$ (521,256)
TOTAL CENTRAL-GULF SERVICE AREA	$ 1,063,171,322	$ 23,967,126	$ 4,399,904	$ 28,367,030	$ 25,671,790	$ 7,848,535	$ 33,520,325	$ 5,153,296

TEXAS GAS SERVICE - Central-Gulf Service Area
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2023

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TRANSMISSION PLANT							
367.00 Mains	$ 13,775,706	$ (264,339)	-1.92%	$ 1,418,859	10.30%	$ (26,429)	-0.19%
369.00 Meas. and Reg. Station Equipment	6,017,387	226,912	3.77%	590,450	9.81%	(10,998)	-0.18%
Total Transmission Plant	$ 19,793,093	$ (37,428)	-0.19%	$ 2,009,309	10.15%	$ (37,428)	-0.19%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 47,713	$ 35,037	73.43%	$ 37,256	78.08%	$ 31,648	66.33%
376.00 Mains	455,684,908	79,931,028	17.54%	89,869,648	19.72%	76,341,665	16.75%
376.90 Mains - Cathodic Protection	28,776,037	12,516,196	43.50%	15,581,856	54.15%	15,581,856	54.15%
378.00 Meas. and Reg. Station Equip. - General	23,623,932	4,005,437	16.95%	3,382,318	14.32%	2,873,181	12.16%
379.00 Meas. and Reg. Station Equip. - City Gate	7,236,737	1,575,780	21.77%	1,218,773	16.84%	1,035,312	14.31%
380.00 Services	300,910,271	39,926,440	13.27%	63,700,741	21.17%	54,111,936	17.98%
381.00 Meters	81,658,914	35,425,767	43.38%	29,824,946	36.52%	25,335,429	31.03%
383.00 House Regulators	11,265,021	4,880,309	43.32%	4,993,033	44.32%	4,241,437	37.65%
385.00 Industrial Meas. and Reg. Station Equip.	16,355,107	5,287,812	32.33%	4,989,243	30.51%	4,238,217	25.91%
386.00 Other Property on Customers' Premises	1,063,249	1,041,339	97.94%	982,334	92.39%	834,465	78.48%
Total Distribution Plant	$ 926,621,889	$ 184,625,145	19.92%	$ 214,580,147	23.16%	$ 184,625,145	19.92%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 33,022,712	$ 2,649,548	8.02%	$ 4,386,797	13.28%	$ 4,810,626	14.57%
392.00 Transportation Equipment	25,256,473	9,717,114	38.47%	5,935,233	23.50%	6,508,664	25.77%
396.00 Power Operated Equipment	3,532,069	1,344,081	38.05%	946,878	26.81%	1,038,360	29.40%
Total Depreciable	$ 61,811,254	$ 13,710,742	22.18%	$ 11,268,908	18.23%	$ 12,357,650	19.99%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,464,787	$ 798,899	32.41%	$ 938,718	38.09%	$ 938,718	38.09%
391.90 Computers and Electronic Equipment	2,486,371	1,097,089	44.12%	1,063,715	42.78%	1,063,715	42.78%
393.00 Stores Equipment	123,761	5,470	4.42%	9,425	7.62%	9,425	7.62%
394.00 Tools, Shop and Garage Equipment	15,381,411	4,558,334	29.64%	4,746,143	30.86%	4,746,143	30.86%
397.00 Communication Equipment	34,482,407	14,005,744	40.62%	15,059,621	43.67%	15,059,621	43.67%
398.00 Miscellaneous Equipment	6,349	476	7.50%	1,482	23.34%	1,482	23.34%
Total Amortizable	$ 54,945,086	$ 20,466,012	37.25%	$ 21,819,104	39.71%	$ 21,819,104	39.71%
Total General Plant	$ 116,756,340	$ 34,176,754	29.27%	$ 33,088,012	28.34%	$ 34,176,754	29.27%
TOTAL CENTRAL-GULF SERVICE AREA	$ 1,063,171,322	$ 218,764,472	20.58%	$ 249,677,468	23.48%	$ 218,764,472	20.58%

TEXAS GAS SERVICE - Central-Gulf Service Area
Depreciation Reserve Components
Redistributed Reserve
December 31, 2023

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
TRANSMISSION PLANT							
367.00 Mains	$ 13,775,706	$ (33,387)	-0.24%	$ 6,958	0.05%	$ (26,429)	-0.19%
369.00 Meas. and Reg. Station Equipment	6,017,387	(9,943)	-0.17%	(1,056)	-0.02%	(10,998)	-0.18%
Total Transmission Plant	$ 19,793,093	$ (43,330)	-0.22%	$ 5,902	0.03%	$ (37,428)	-0.19%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 47,713	$ 28,327	59.37%	$ 3,321	6.96%	$ 31,648	66.33%
376.00 Mains	455,684,908	69,067,963	15.16%	7,273,702	1.60%	76,341,665	16.75%
376.90 Mains - Cathodic Protection	28,776,037	15,581,856	54.15%			15,581,856	54.15%
378.00 Meas. and Reg. Station Equip. - General	23,623,932	2,453,551	10.39%	419,630	1.78%	2,873,181	12.16%
379.00 Meas. and Reg. Station Equip. - City Gate	7,236,737	849,442	11.74%	185,871	2.57%	1,035,312	14.31%
380.00 Services	300,910,271	47,722,727	15.86%	6,389,209	2.12%	54,111,936	17.98%
381.00 Meters	81,658,914	23,077,353	28.26%	2,258,075	2.77%	25,335,429	31.03%
383.00 House Regulators	11,265,021	3,763,928	33.41%	477,509	4.24%	4,241,437	37.65%
385.00 Industrial Meas. and Reg. Station Equip.	16,355,107	3,585,263	21.92%	652,954	3.99%	4,238,217	25.91%
386.00 Other Property on Customers' Premises	1,063,249	833,840	78.42%	624	0.06%	834,465	78.48%
Total Distribution Plant	$ 926,621,889	$ 166,964,250	18.02%	$ 17,660,895	1.91%	$ 184,625,145	19.92%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 33,022,712	$ 4,315,300	13.07%	$ 495,326	1.50%	$ 4,810,626	14.57%
392.00 Transportation Equipment	25,256,473	6,955,298	27.54%	(446,634)	-1.77%	6,508,664	25.77%
396.00 Power Operated Equipment	3,532,069	1,084,203	30.70%	(45,843)	-1.30%	1,038,360	29.40%
Total Depreciable	$ 61,811,254	$ 12,354,801	19.99%	$ 2,849	0.00%	$ 12,357,650	19.99%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,464,787	$ 938,718	38.09%			$ 938,718	38.09%
391.90 Computers and Electronic Equipment	2,486,371	1,063,715	42.78%			1,063,715	42.78%
393.00 Stores Equipment	123,761	9,425	7.62%			9,425	7.62%
394.00 Tools, Shop and Garage Equipment	15,381,411	4,746,143	30.86%			4,746,143	30.86%
397.00 Communication Equipment	34,482,407	15,059,621	43.67%			15,059,621	43.67%
398.00 Miscellaneous Equipment	6,349	1,482	23.34%			1,482	23.34%
Total Amortizable	$ 54,945,086	$ 21,819,104	39.71%			$ 21,819,104	39.71%
Total General Plant	$ 116,756,340	$ 34,173,905	29.27%	$ 2,849	0.00%	$ 34,176,754	29.27%
TOTAL CENTRAL-GULF SERVICE AREA	$ 1,063,171,322	$ 201,094,826	18.91%	$ 17,669,646	1.66%	$ 218,764,472	20.58%

TEXAS GAS SERVICE - Central-Gulf Service Area
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TRANSMISSION PLANT									
367.00 Mains	$ 14,255,366	$ 479,660	$ 13,775,706	-311.1%	-40.0%	$ (1,492,222)	$ (5,510,282)	$ (7,002,505)	-49.1%
369.00 Meas. and Reg. Station Equipment	6,025,854	8,467	6,017,387	-1011.0%	-25.0%	(85,601)	(1,504,347)	(1,589,948)	-26.4%
Total Transmission Plant	$ 20,281,220	$ 488,127	$ 19,793,093	-323.2%	-35.4%	$ (1,577,824)	$ (7,014,629)	$ (8,592,453)	-42.4%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 78,911	$ 31,198	$ 47,713		-10.0%	$ -	$ (4,771)	$ (4,771)	-6.0%
376.00 Mains	471,338,247	15,653,339	455,684,908	-232.5%	-40.0%	(36,394,013)	(182,273,963)	(218,667,976)	-46.4%
376.90 Mains - Cathodic Protection	41,844,553	13,068,516	28,776,037						
378.00 Meas. and Reg. Station Equip. - General	24,602,081	978,149	23,623,932	-51.9%	-25.0%	(507,659)	(5,905,983)	(6,413,642)	-26.1%
379.00 Meas. and Reg. Station Equip. - City Gate	7,424,857	188,120	7,236,737	-45.2%	-25.0%	(85,030)	(1,809,184)	(1,894,214)	-25.5%
380.00 Services	317,464,278	16,554,007	300,910,271	-265.3%	-60.0%	(43,917,781)	(180,546,163)	(224,463,943)	-70.7%
381.00 Meters	93,888,854	12,229,940	81,658,914	-35.2%	-15.0%	(4,304,939)	(12,248,837)	(16,553,776)	-17.6%
383.00 House Regulators	13,490,235	2,225,214	11,265,021	-24.1%	-15.0%	(536,277)	(1,689,753)	(2,226,030)	-16.5%
385.00 Industrial Meas. and Reg. Station Equip.	17,234,452	879,345	16,355,107	-109.8%	-30.0%	(965,521)	(4,906,532)	(5,872,053)	-34.1%
386.00 Other Property on Customers' Premises	1,311,364	248,115	1,063,249	4.8%		11,910		11,910	0.9%
Total Distribution Plant	$ 988,677,832	$ 62,055,943	$ 926,621,889	-139.7%	-42.0%	$ (86,699,310)	$ (389,385,187)	$ (476,084,497)	-48.2%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 33,827,939	$ 805,227	$ 33,022,712	-2.0%	-10.0%	$ (16,105)	$ (3,302,271)	$ (3,318,376)	-9.8%
392.00 Transportation Equipment	28,977,545	3,721,072	25,256,473	19.2%	10.0%	714,446	2,525,647	3,240,093	11.2%
396.00 Power Operated Equipment	3,827,149	295,080	3,532,069	9.5%	5.0%	28,033	176,603	204,636	5.3%
Total Depreciable	$ 66,632,633	$ 4,821,379	$ 61,811,254	15.1%	-1.0%	$ 726,374	$ (600,020)	$ 126,353	0.2%
Amortizable									
391.10 Office Furniture and Fixtures	$ 4,169,934	$ 1,705,147	$ 2,464,787						
391.90 Computers and Electronic Equipment	7,676,102	5,189,731	2,486,371						
393.00 Stores Equipment	216,263	92,502	123,761						
394.00 Tools, Shop and Garage Equipment	19,462,206	4,080,795	15,381,411						
397.00 Communication Equipment	36,977,041	2,494,634	34,482,407						
398.00 Miscellaneous Equipment	1,203,825	1,197,476	6,349						
Total Amortizable	$ 69,705,371	$ 14,760,285	$ 54,945,086						
Total General Plant	$ 136,338,004	$ 19,581,664	$ 116,756,340	3.7%	-0.5%	$ 726,374	$ (600,020)	$ 126,353	0.1%
TOTAL CENTRAL-GULF SERVICE AREA	$ 1,145,297,056	$ 82,125,734	$ 1,063,171,322	-106.6%	-37.3%	$ (87,550,760)	$ (396,999,836)	$ (484,550,596)	-42.3%

TEXAS GAS SERVICE - Central-Gulf Service Area

Current and Proposed Parameters
Vintage Group Procedure

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	Rem. Life	Avg. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2023) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION PLANT												
367.00 Mains	60.00	R1	47.57	61.58	-11.0	-10.0	60.00	L1	60.64	52.75	-49.1	-40.0
369.00 Meas. and Reg. Station Equipment	60.00	R1	58.27	60.03	-10.0	-10.0	40.00	L1	40.02	36.47	-26.4	-25.0
Total Transmission Plant									52.43	46.27	-42.4	-35.4
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	16.66	50.66	-2.9	-5.0	40.00	R4	46.96	14.14	-6.0	-10.0
376.00 Mains	65.00	R1.5	53.38	65.65	-26.7	-20.0	67.00	R2	67.31	55.30	-46.4	-40.0
376.90 Mains - Cathodic Protection	15.00	SQ	8.45	15.00			15.00	SQ	15.00	6.88		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	48.01	55.67	-20.6	-20.0	60.00	R1	60.28	52.91	-26.1	-25.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	51.24	65.67	-13.2	-10.0	65.00	R1.5	65.35	56.32	-25.5	-25.0
380.00 Services	55.00	R2	42.17	55.54	-45.2	-30.0	55.00	R2	55.33	45.00	-70.7	-60.0
381.00 Meters	25.00	R2.5	17.45	26.10	-12.9	-10.0	30.00	R2.5	30.87	20.60	-17.6	-15.0
383.00 House Regulators	35.00	R3	23.55	38.43	-7.3	-5.0	35.00	R3	37.50	22.75	-16.5	-15.0
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	42.57	56.34	-25.0	-20.0	58.00	R1.5	58.94	43.73	-34.1	-30.0
386.00 Other Property on Customers' Premises	20.00	S3	2.96	21.67	0.9		20.00	S3	23.57	1.81	0.9	
Total Distribution Plant									51.77	40.94	-48.2	-42.0
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	25.90	41.30	-4.3	-5.0	43.00	R3	43.05	37.92	-9.8	-10.0
392.00 Transportation Equipment	10.00	L0	7.93	10.62	6.3	5.0	13.00	L1	13.34	9.99	11.2	10.0
396.00 Power Operated Equipment	13.00	L2	7.51	14.68	9.8	10.0	18.00	L1.5	18.97	13.66	5.3	5.0
Total Depreciable									21.71	17.76	0.2	-1.0
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	7.34	15.00			15.00	SQ	15.00	9.29		
391.90 Computers and Electronic Equipment	7.00	SQ	1.70	7.00			7.00	SQ	7.00	4.01		
393.00 Stores Equipment	15.00	SQ	7.18	15.00			15.00	SQ	15.00	13.86		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	9.87	15.00			15.00	SQ	15.00	10.37		
397.00 Communication Equipment	15.00	SQ	9.43	15.00			15.00	SQ	15.00	8.45		
398.00 Miscellaneous Equipment	15.00	SQ	6.86	15.00			15.00	SQ	15.00	11.50		
Total Amortizable									14.26	8.60		
Total General Plant									17.43	12.49	0.1	-0.5
TOTAL CENTRAL-GULF SERVICE AREA									42.57	33.39	-42.3	-37.3

Exhibit REW–2

2022 Depreciation Rate Study

Texas Gas Service

A Division of ONE Gas

– TGS Division

foster associates

CONTENTS

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and proposed service life and net salvage parameters recommended for TGS plant and equipment categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2022 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2021.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of plant investments (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by TGS for the mix of investments recorded on December 31, 2021. Similarly, proposed depreciation accruals shown on Statements B are the product of plant investments and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement A

Account Description	Current (at 12/31/2021)			Proposed (at 12/31/2021)		
	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
TGS DIVISION						
TRANSMISSION PLANT						
367.00 Mains						
369.00 Meas. and Reg. Station Equipment						
Total Transmission Plant						
DISTRIBUTION PLANT						
375.10 Structures and Improvements						
376.00 Mains						
376.90 Mains - Cathodic Protection						
378.00 Meas. and Reg. Station Equip. - General						
379.00 Meas. and Reg. Station Equip. - City Gate						
380.00 Services						
381.00 Meters						
383.00 House Regulators						
385.00 Industrial Meas. and Reg. Station Equip.						
386.00 Other Property on Customers' Premises						
Total Distribution Plant						
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.59%		2.59%	2.33%	0.23%	2.56%
392.00 Transportation Equipment						
396.00 Power Operated Equipment						
Total Depreciable	2.59%		2.59%	2.33%	0.23%	2.56%
Amortizable						
391.10 Office Furniture and Fixtures	6.67%		6.67%	← 15 Year Amortization →		6.67%
391.90 Computers and Electronic Equipment	14.29%		14.29%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment						
394.00 Tools, Shop and Garage Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	8.97%		8.97%	8.34%		8.34%
Total General Plant	6.20%		6.20%	5.73%	0.10%	5.83%
TOTAL TGS DIVISION	6.20%		6.20%	5.73%	0.10%	5.83%

TEXAS GAS SERVICE
Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual Investment	Current Net Salvage	Current Total	Proposed 2022 Annualized Accrual Investment	Proposed Net Salvage	Proposed Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
TGS DIVISION								
TRANSMISSION PLANT								
367.00 Mains	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
369.00 Meas. and Reg. Station Equipment								
Total Transmission Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376.00 Mains								
376.90 Mains - Cathodic Protection								
378.00 Meas. and Reg. Station Equip. - General								
379.00 Meas. and Reg. Station Equip. - City Gate								
380.00 Services								
381.00 Meters								
383.00 House Regulators								
385.00 Industrial Meas. and Reg. Station Equip.								
386.00 Other Property on Customers' Premises								
Total Distribution Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 4,486,255	$ 116,194	$ -	$ 116,194	$ 104,530	$ 10,318	$ 114,848	$ (1,346)
392.00 Transportation Equipment								
396.00 Power Operated Equipment								
Total Depreciable	$ 4,486,255	$ 116,194	$ -	$ 116,194	$ 104,530	$ 10,318	$ 114,848	$ (1,346)
Amortizable								
391.10 Office Furniture and Fixtures	$ 2,691,240	$ 179,506	$ -	$ 179,506	$ 174,476		$ 174,476	$ (5,030)
391.90 Computers and Electronic Equipment	1,762,953	251,926		251,926	221,901		221,901	(30,025)
393.00 Stores Equipment								
394.00 Tools, Shop and Garage Equipment	154,325	10,293		10,293	10,288		10,288	(5)
397.00 Communication Equipment	1,243,127	82,917		82,917	81,535		81,535	(1,382)
398.00 Miscellaneous Equipment								
Total Amortizable	$ 5,851,645	$ 524,642	$ -	$ 524,642	$ 488,199		$ 488,199	$ (36,442)
Total General Plant	$ 10,337,900	$ 640,836	$ -	$ 640,836	$ 592,729	$ 10,318	$ 603,047	$ (37,788)
TOTAL TGS DIVISION	$ 10,337,900	$ 640,836	$ -	$ 640,836	$ 592,729	$ 10,318	$ 603,047	$ (37,788)

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TGS DIVISION							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains							
376.90 Mains - Cathodic Protection							
378.00 Meas. and Reg. Station Equip. - General							
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services							
381.00 Meters							
383.00 House Regulators							
385.00 Industrial Meas. and Reg. Station Equip.							
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ -	$ -		$ -		$ -	
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,486,255	$ 785,250	17.50%	$ 255,925	5.70%	$ 255,925	5.70%
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ 4,486,255	$ 785,250	17.50%	$ 255,925	5.70%	$ 255,925	5.70%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,691,240	$ 321,887	11.96%	$ 523,699	19.46%	$ 523,699	19.46%
391.90 Computers and Electronic Equipment	1,762,953	657,393	37.29%	983,852	55.81%	983,852	55.81%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	154,325	9,375	6.07%	9,618	6.23%	9,618	6.23%
397.00 Communication Equipment	1,243,127	795,436	63.99%	796,248	64.05%	796,248	64.05%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 5,851,645	$ 1,784,092	30.49%	$ 2,313,417	39.53%	$ 2,313,417	39.53%
Total General Plant	$ 10,337,900	$ 2,569,342	24.85%	$ 2,569,342	24.85%	$ 2,569,342	24.85%
TOTAL TGS DIVISION	$ 10,337,900	$ 2,569,342	24.85%	$ 2,569,342	24.85%	$ 2,569,342	24.85%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
TGS DIVISION							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains							
376.90 Mains - Cathodic Protection							
378.00 Meas. and Reg. Station Equip. - General							
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services							
381.00 Meters							
383.00 House Regulators							
385.00 Industrial Meas. and Reg. Station Equip.							
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ -	$ -		$ -		$ -	#DIV/0!
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,486,255	$ 232,659	5.19%	$ 23,266	0.52%	$ 255,925	5.70%
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ 4,486,255	$ 232,659	5.19%	$ 23,266	0.52%	$ 255,925	5.70%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,691,240	$ 523,699	19.46%			$ 523,699	19.46%
391.90 Computers and Electronic Equipment	1,762,953	983,852	55.81%			983,852	55.81%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	154,325	9,618	6.23%			9,618	6.23%
397.00 Communication Equipment	1,243,127	796,248	64.05%			796,248	64.05%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 5,851,645	$ 2,313,417	39.53%			$ 2,313,417	39.53%
Total General Plant	$ 10,337,900	$ 2,546,076	24.63%	$ 23,266	0.23%	$ 2,569,342	24.85%
TOTAL TGS DIVISION	$ 10,337,900	$ 2,546,076	24.63%	$ 23,266	0.23%	$ 2,569,342	24.85%

TEXAS GAS SERVICE
Average Net Salvage

Statement E

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TGS DIVISION									
TRANSMISSION PLANT									
367.00 Mains	$ -		$ -			$ -	$ -		
369.00 Meas. and Reg. Station Equipment									
Total Transmission Plant	$ -	$ -	$ -			$ -	$ -	$ -	
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ -	$ -	$ -				$ -	$ -	
376.00 Mains									
376.90 Mains - Cathodic Protection									
378.00 Meas. and Reg. Station Equip. - General									
379.00 Meas. and Reg. Station Equip. - City Gate									
380.00 Services									
381.00 Meters									
383.00 House Regulators									
385.00 Industrial Meas. and Reg. Station Equip.									
386.00 Other Property on Customers' Premises									
Total Distribution Plant	$ -	$ -	$ -			$ -	$ -	$ -	
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 4,505,569	$ 19,314	$ 4,486,255		-10.0%	$ -	$ (448,626)	$ (448,626)	-10.0%
392.00 Transportation Equipment									
396.00 Power Operated Equipment									
Total Depreciable	$ 4,505,569	$ 19,314	$ 4,486,255		-10.0%	$ -	$ (448,626)	$ (448,626)	-10.0%
Amortizable									
391.10 Office Furniture and Fixtures	$3,457,063	$765,823	$2,691,240						
391.90 Computers and Electronic Equipment	13,682,175	11,919,222	1,762,953						
393.00 Stores Equipment									
394.00 Tools, Shop and Garage Equipment	273,032	118,707	154,325						
397.00 Communication Equipment	1,554,769	311,642	1,243,127						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 18,967,039	$ 13,115,394	$ 5,851,645						
Total General Plant	$ 23,472,608	$ 13,134,708	$ 10,337,900		-4.3%	$ -	$ (448,626)	$ (448,626)	-1.9%
TOTAL TGS DIVISION	$ 23,472,608	$ 13,134,708	$ 10,337,900		-4.3%	$ -	$ (448,626)	$ (448,626)	-1.9%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2021) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
TGS DIVISION												
TRANSMISSION PLANT												
367.00 Mains												
369.00 Meas. and Reg. Station Equipment												
Total Transmission Plant												-39.2
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	52.56	6.15	-3.9	-5.0						
376.00 Mains	65.00	R1.5	68.39	51.57	-28.2	-20.0						
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	10.80								
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	54.99	38.69	-12.8	-20.0						
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.47	49.55	-5.3	-10.0						
380.00 Services	55.00	R2	56.12	39.62	-70.3	-30.0						
381.00 Meters	25.00	R2.5	28.18	19.93	-19.1	-10.0						
383.00 House Regulators	35.00	R3	45.72	25.10	-10.3	-5.0						
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	56.50	38.41	-17.4	-20.0						
386.00 Other Property on Customers' Premises	20.00	S3	24.98	2.56								
Total Distribution Plant												-40.7
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.07	37.39	-4.2	-5.0	43.00	R3	43.00	40.77	-10.0	-10.0
392.00 Transportation Equipment	10.00	L0	11.28	7.49	4.8	5.0						
396.00 Power Operated Equipment	13.00	L2	13.25	10.28	8.2	10.0						
Total Depreciable									43.00	40.77	-10.0	-10.0
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	12.50			15.00	SQ	15.00	12.08		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	1.67			7.00	SQ	7.00	3.09		
393.00 Stores Equipment	15.00	SQ	15.00	1.00								
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	8.69			15.00	SQ	15.00	14.07		
397.00 Communication Equipment	15.00	SQ	15.00	10.07			15.00	SQ	15.00	5.39		
398.00 Miscellaneous Equipment												
Total Amortizable									11.16	6.74		
Total General Plant									16.44	12.39	-1.9	-4.3
TOTAL TGS DIVISION									16.44	12.39	-1.9	-4.3

STATE OF FLORIDA §
§
COUNTY OF LEE §

AFFIDAVIT OF RONALD E. WHITE

BEFORE ME, the undersigned authority, on this day personally appeared Ronald E. White who having been placed under oath by me did depose as follows:

1. "My name is Ronald E. White. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as President for Foster Associates Consultants, LLC. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Ronald E. White, Ph.D.

SUBSCRIBED AND SWORN TO BEFORE ME by the said Ronald E. White on this 21st day of May 2024.

LYNNETTE A. JAY
Notary Public - State of Florida
My Comm. Expires March 7, 2025
Commission # HH75921

Lynnette A. Jay
Notary Public in and for the State of Florida

My commission expires: March 7, 2025

WORKPAPERS

TO

DIRECT TESTIMONY

OF

RONALD E. WHITE

Workpapers to the Direct Testimony of Ronald E. White are being provided in electronic format.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF SCHEDULES

DIRECT TESTIMONY OF BRUCE H. FAIRCHILD

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Bruce H. Fairchild, 3907 Red River, Austin, Texas 78751.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am a principal in Financial Concepts and Applications, Inc. ("FINCAP"), a firm engaged in financial, economic and policy consulting to business and government.

A. Qualifications

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, AND PRIOR EXPERIENCE.

A. I hold a BBA degree from Southern Methodist University and MBA and PhD degrees from the University of Texas at Austin. I am also a Certified Public Accountant. My previous employment includes working in the Controller's Department at Sears, Roebuck and Company and serving as Assistant Director of Economic Research at the Public Utility Commission of Texas ("PUCT"). I have also been on the business school faculties at the University of Colorado at Boulder and the University of Texas at Austin, where I taught undergraduate and graduate courses in finance and accounting.

Q. BRIEFLY DESCRIBE YOUR EXPERIENCE IN UTILITY-RELATED MATTERS.

A. While at the PUCT, I assisted in managing a division comprised of approximately twenty-five professionals responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems. I testified on behalf of the PUCT staff in numerous cases involving most major investor-owned and cooperative electric, telephone and water/sewer utilities in the state regarding a variety of financial, accounting and economic issues. Since forming FINCAP in 1979, I have participated in a wide range of analytical assignments involving utility-related matters on behalf of utilities, industrial consumers, municipalities and regulatory commissions. I have also prepared and presented expert testimony before a number of regulatory authorities addressing revenue requirements, cost allocation and rate design issues for gas, electric, telephone and water/sewer utilities. I have been a frequent speaker at regulatory conferences and seminars and have published research concerning various regulatory issues. A resume that contains the details of my experience and qualifications is attached as Appendix A, with Appendix B listing my prior testimony before regulatory agencies since leaving the PUCT.

B. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to recommend an overall rate of return to apply to Texas Gas Service Company's ("TGS") invested capital for its Central-Gulf Service Area ("CGSA").

Q. WHAT IS THE ROLE OF THE RATE OF RETURN IN SETTING A UTILITY'S RATES?

A. The rate of return serves to compensate investors for the use of their capital to finance the plant and equipment necessary to provide utility service to customers. Investors only commit money in anticipation of earning a return on their investment commensurate with that from other investment alternatives having comparable risks. Consistent with both sound regulatory economics and the standards specified in the U.S. Supreme Court cases of *Bluefield Water Works & Improvement Co.* (1923) and *Hope Natural Gas Co.* (1944), rates should provide the utility a reasonable opportunity to earn a rate of return sufficient to: 1) fairly compensate capital presently invested in the utility, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity.

Q. IN GENERAL, HOW HAVE YOU GONE ABOUT DEVELOPING YOUR RECOMMENDED RETURN ON EQUITY FOR TGS'S CGSA?

A. My evaluation begins with a brief review of the operations and finances of TGS and general conditions in the natural gas industry and capital markets, including a discussion of the actions the Federal Reserve Board ("Fed") is taking in response to the increases in the Consumer Price Index ("CPI"). With this background, I develop a mix of investor-supplied capital (i.e., debt and equity) to be used as weightings in calculating an overall rate of return. An average cost of debt applicable to the debt component of the capital structure is then calculated. I conduct various analyses to estimate the cost of equity, which is the rate of return equity ("ROE") investors require for the use of their money. These analyses include applications of the discounted cash flow ("DCF") model, capital asset pricing model ("CAPM"), risk premium method and comparable earnings method. Based on these analyses, I develop a cost of equity range, from which I select my recommended ROE. Finally, these components are combined to calculate my recommended overall rate of return for TGS's CGSA.

C. Summary of Conclusions

Q. WHAT IS YOUR RATE OF RETURN RECOMMENDATION?

A. As developed on Schedule BHF-1, I recommend an overall rate of return for TGS on the invested capital in its CGSA of 7.88%. This rate of return is based on capital structure ratios of 40.42% debt and 59.58% equity, a cost of debt of 4.39%, and an ROE of 10.25%.

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED CAPITAL STRUCTURE RATIOS FOR TGS'S CGSA?

A. My recommended capital structure ratios of 40.42% debt and 59.58% equity are based on the capitalization of ONE Gas, Inc. ("ONE Gas"), of which TGS is a division, at December 31, 2023, adjusted to remove securitized debt attributable to Winter Storm Uri and debt maturing in the first quarter of 2024. These adjusted ratios are consistent with the capital structure ONE Gas has maintained since it was spun off from ONEOK, Inc. ("ONEOK") into a stand-alone company in 2014 and are how the permanent assets in the CGSA will be financed when the rates in this case are in effect. They also follow ONE Gas' financial policies to maintain single-A credit metrics and a level of creditworthiness and flexibility to meet unexpected financial requirements, such as those resulting from Winter Storm Uri. ONE Gas' adjusted capital structure ratios are generally consistent with and fall within the range of those historically maintained by other natural gas local distribution companies ("LDCs") and the capital structure ratios approved by the Railroad Commission of Texas ("Commission") for the larger LDCs in Texas since 2016.

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED COST OF DEBT FOR TGS'S CGSA?

A. My recommended 4.39% cost of debt is the average cost associated with the approximately $1.9 billion of permanent long-term debt included in my recommended capital structure for ONE Gas.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ROE OF 10.25%?

A. Based on applications of the DCF, CAPM, risk premium, and comparable earnings methods to an industry group of publicly traded natural gas LDCs, I conclude that equity investors require a rate of return for the use of their money in the range of 9.75% to 10.75%, and recommend an ROE for TGS's CGSA of 10.25%, which is the mid-point of the range.

II. FUNDAMENTAL ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of TGS and ONE Gas. It also examines the natural gas distribution industry along with conditions in the capital markets and U.S. economy.

A. Texas Gas Service

Q. BRIEFLY DESCRIBE TGS.

A. TGS is the operating division of ONE Gas that distributes natural gas to approximately 695,000 sales and transport customers in 100 communities throughout Texas. In addition to its CGSA, TGS also serves the cities of Brownsville, El Paso and Mineral Wells and other areas throughout the state. In total, TGS serves approximately 13% of the natural gas customers in Texas. At

December 31, 2023, TGS had total assets of approximately $2.1 billion, with operating revenues for calendar year being approximately $567 million.

Q. BRIEFLY DESCRIBE ONE GAS.

A. ONE Gas is the largest natural gas distributor in Oklahoma and Kansas, and the third largest in Texas, serving a total of over 2.3 million customers. ONE Gas was created when ONEOK spun off its natural gas distribution operations into a separate entity on January 31, 2014. At December 31, 2023, ONE Gas had total assets of approximately $7.8 billion, with revenues during 2023 totaling some $2.4 billion. ONE Gas' common stock is traded on the New York Stock Exchange, and its debt is rated A- by Standard & Poor's Financial Services LLC ("S&P") and A3 by Moody's Investors Services, Inc. ("Moody's").

B. Natural Gas Distribution Industry

Q. PLEASE DESCRIBE THE NATURAL GAS DISTRIBUTION INDUSTRY.

A. LDCs normally transport, deliver, and sell natural gas from receipt points on inter- and intrastate pipelines to households and businesses. They often have a right to operate in a specified geographic area, with their rates and operations being subject to the jurisdiction of state or local regulatory authorities. Historically, LDCs provided only "bundled" service, which included the transportation, distribution and natural gas itself, although some now allow customers to choose their own gas supplier, with the LDC providing the delivery and service of that gas. Structural changes, which have occurred on both the demand and supply sides, have eroded the traditional monopoly status of many gas utilities, with LDCs experiencing "bypass" as large commercial and industrial customers seek to acquire gas supplies at the lowest possible prices and, in the process, abandon traditional "full-service" utility suppliers.

Q. WHAT RISKS DO LDCS FACE THAT ARE OF CONCERN TO INVESTORS?

A. LDCs face a variety of market, operating, capital-related and regulatory risks. The natural gas business is increasingly competitive and complex, with LDCs having to vie with electric companies, oil and propane suppliers, and, in some cases, energy marketers and trading companies. Moreover, the demand for natural gas is impacted by energy efficiency and technological advances adversely affecting growth over time, especially in the residential sector. The financial results of LDCs are also heavily dependent on general economic conditions, not only in terms of the overall activity of businesses, but also in the growth of households and use per customer.

With respect to operations, gas distribution inherently involves a variety of hazards and operating risks, including the need to replace aging and obsolete infrastructure, leaks, accidents and third-party damages. Many LDCs are faced with substantial known and unknown environmental costs (e.g., pipeline integrity testing) and post-retirement employee costs (e.g., pensions and medical benefits). Inflation and other increases could adversely impact an LDC's ability to control operating expenses and costs, and interruptions in gas supply, strikes, natural disasters, security breaches and terrorist activities could disrupt or shut down operations. Finally, most LDCs are involved in ongoing legal or administrative proceedings before courts and governmental bodies related to a variety of matters (e.g., general claims, taxes, environmental issues, billing, and credit and collection matters), which could result in detrimental outcomes.

Q. PLEASE ELABORATE ON THE CAPITAL AND REGULATORY RISKS FACED BY LDCS.

A. Regarding capital-related risks, virtually all LDCs are facing significant infrastructure expenditures to meet customer service requirements and improve system reliability, as well as satisfy a number of government-mandated safety initiatives. The ability of LDCs to fund these and other capital expenditures is affected by a variety of factors, including regulatory decisions, maintenance of a sufficient bond rating, capital market conditions (e.g., interest rates), and availability of credit facilities and access to capital markets. In addition, LDCs' ability to retain and attract capital is subject to changes in state and federal tax laws and accounting standards, which may adversely affect their cash flows and financial condition.

Finally, because most aspects of an LDC's operations (e.g., rates; operating terms and conditions of service; types of services offered; construction of new facilities; the integrity, safety, and security of facilities and operations; acquisition, extension, or abandonment of services or facilities; reporting and information posting requirements; maintenance of accounts and records; and relationships with affiliate companies) are subject to government oversight, investors are understandably concerned with rate, safety, and environmental regulation. Potential changes in laws, regulations, and policies, as well as the inherent uncertainty surrounding regulatory decisions, all represent significant risks to LDCs.

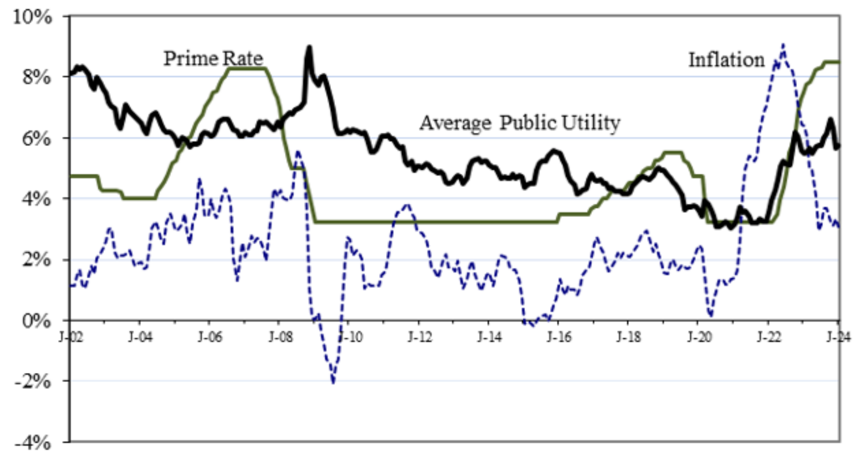
Q. IS TGS EXPOSED TO THESE INDUSTRY RISKS?

A. Yes. Attached to my testimony as Appendix C are the pages from ONE Gas' 2023 Form 10-K filed with the Securities and Exchange Commission that describe the operational risks; regulatory and legislative risks; and financial, economic, and market risks faced by ONE Gas. This discussion documents that TGS is exposed to the same risks as the LDC industry generally, as well as other risks unique to it and its service areas.

C. Capital Markets

Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE LAST TWO DECADES?

A. Average long-term public utility bond rates, the borrowing prime rate, and inflation as measured by the CPI over the last twenty years are plotted in the graph below. Beginning in 2002, the average yield on long-term public utility bonds generally fell because of monetary and fiscal policies designed to keep the economy growing. This decline ended abruptly with the 2008 financial market meltdown and global recession. Investors became exceedingly risk averse, causing interest rates on corporate bonds to spike, while government policies pushed down short-term interest rates and depressed economic conditions and lower energy prices reduced inflation. Over the next decade, various actions by the Fed to stimulate the economy through easy-money policies resulted in short- and long-term interest rates reaching record lows. These conditions were interrupted in early 2020 by the coronavirus pandemic and worldwide economic shutdown, although the impact on interest rates was moderated by extraordinary actions taken by the Fed in response. However, in late 2021, CPI inflation began to skyrocket, jumping from an average of around 2% over the prior 20 years to 7% in 2021, peaking at over 9% in June 2022, and since the third quarter of 2023 ranging between 3.0% and 3.5%:



Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED OVER THIS SAME PERIOD?

A. In the early 2000s, stock prices moved steadily higher as one of the longest bull markets in U.S. history continued unabated. In mid-2000, mounting concerns over prospects for future growth, particularly for firms in the high technology and telecommunications sectors, pushed equity prices lower, in some cases precipitously. Common stock prices generally recovered and reached record highs, buoyed in large part by widespread acquisition activity, until the capital market crisis and Great Recession occurred in 2008. Stock prices tumbled by some 40%, and while they recovered and reached all-time highs over the next decade, they crashed again in early 2020 due to the coronavirus pandemic. Since then, most stock indices reached all-time highs, but subsequently receded some 20% into bear market territory in response to inflation worries, soaring energy prices, and global events (e.g., the Russian invasion of Ukraine). They have recently fully recovered as inflation has abated and investors expect the Fed to discontinue hiking interest rates. Additionally, the stock market has become extraordinarily volatile, with share prices routinely changing more than full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 2002 (the latter two indices were scaled for comparability):

Q. WHAT IS THE CURRENT OUTLOOK FOR THE U.S. ECONOMY?

A. The U.S. economy had fully recovered from the Great Recession when the coronavirus pandemic struck in early 2020 and the world economy came to a virtual stand-still. More than 30 million U.S. jobs were lost as a result of the pandemic, and unemployment reached almost 15 percent, not counting furloughed workers, throwing the U.S. into a recession overnight. To address the crisis, the U.S. Congress provided some $4.5 trillion in aid and stimulus spending, and the Fed held short-term interest rates near zero and purchased up to $120 billion a month in Treasury debt and mortgage-backed securities to suppress long-term interest rates.

The combined effect of these fiscal and monetary policies, along with the population becoming vaccinated, is that U.S. economic activity subsequently increased to greater than prior to the coronavirus pandemic and unemployment fell to below 4%. As noted earlier, however, inflation began to increase markedly in 2021. After initially attributing the increase to supply-chain problems and then the Russian invasion of Ukraine, the Fed concluded that the dramatic rise in prices was not "transitory," and beginning in March 2022 it embarked on its most aggressive effort in more than two decades to curb inflation. This included increasing short-term interest rates, announcing that more hikes in the federal funds rate would follow, and reducing its $9 trillion inventory of Treasury debt and mortgage-backed securities up to $95 billion a month by not replacing maturing bonds. As inflation moderated in 2023, the Fed indicated that it might begin to reduce interest rates in 2024, but it has not done so because inflation has stubbornly remained above 3% and employment data continues to be strong. Whether the unprecedented actions during 2022-2023 by the Fed will reduce inflation to its target level of 2% is yet unknown. Thus far, they have been only partially successful, with the ultimate outcome remaining a significant uncertainty hanging over all segments of the U.S. economy.

Q. HOW HAVE THE FED'S ACTIONS AFFECTED THE COST OF CAPITAL?

A. Hikes in the federal funds rate by the Fed and significant reductions in its long-term bond inventory are intended to increase the cost of all borrowing, including by LDCs. As will be explained more later, higher interest rates also increase the cost of more risky equity capital. This, coupled with the greater volatility in stock prices that also increases the risk of investing in common equities, supports the conclusion that the relatively low capital cost environment that has existed for the last decade has ended. As a result, the cost of both debt and equity is expected to remain higher for the foreseeable future, and the ROEs authorized for LDCs over the last few years, including those allowed by this Commission, must be adjusted to recognize the changes in capital markets. Only an ROE that reflects the current capital market conditions faced by LDCs will fairly compensate a utility's investors, enable LDCs to attract new capital on reasonable terms, and maintain their financial integrity.

III. CAPITAL STRUCTURE

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section is to recommend capital structure ratios to use to calculate an overall rate of return for TGS.

Q. WHAT IS THE ROLE OF CAPITAL STRUCTURE IN SETTING A UTILITY'S RATE OF RETURN?

A. A utility's capital structure reflects the mix of capital—debt, preferred stock (if any), and common equity—used to finance the utility's assets. The proportions of a utility's total capitalization attributable to each source of capital are typically used to weight the cost of debt, cost of preferred stock, and ROE in calculating an overall rate of return.

Q. WHAT SOURCES OF CAPITAL ARE USED TO FINANCE TGS'S INVESTMENT IN UTILITY PLANT?

A. As an operating division of ONE Gas, TGS has no independent financing, and it relies entirely on capital supplied by ONE Gas to finance its investment in assets.

Q. WHAT PRINCIPLES UNDERLIE ONE GAS' FINANCING POLICIES AND PRACTICES?

A. When ONE Gas was spun off from ONEOK in 2014, the Registration Form 10 filed with the Securities and Exchange Commission stated:

> Our capital structure was designed to obtain investment grade credit ratings that are higher than the current credit ratings of ONEOK and similar to those of our natural gas utility peers and to provide us with the financial flexibility to maintain our current level of operations and to continue to invest in our natural gas distribution system.

Toward this objective, ONE Gas was initially financed with approximately 40% debt and 60% equity. This capital structure was instrumental in ONE Gas being rated A- by S&P, which was subsequently increased to A, and A2 by Moody's.

Q. HAS ANYTHING OCCURRED THAT ILLUSTRATES THE BENEFIT OF ONE GAS TARGETING THESE DEBT AND EQUITY RATIOS?

A. Yes. In January 2018, Moody's lowered its rating outlook for ONE Gas from "stable" to "negative" because of the adverse impact on its credit metrics resulting from the reduction of the corporate income tax rate from 35% to 21% provided for in the Tax Cuts and Jobs Act of 2017. A "negative" outlook is intended to warn investors of the potential for a bond rating downgrade. On January 29, 2019, Moody's revised its rating outlook for ONE Gas from negative to "stable," citing primarily, among other factors, "corporate actions ONE Gas has taken to strengthen its balance sheet and key financial ratios." Indeed, ONE Gas' capital structure ratios of approximately 40% debt and 60% equity were instrumental in it maintaining a solid single-A bond rating, which benefits customers by ensuring continuous access to capital markets and that ONE Gas can raise capital on favorable terms.

Q. DID ONE GAS' CAPITAL STRUCTURE PLAY A ROLE IN DEALING WITH WINTER STORM URI?

A. Yes. Because of ONE Gas' strong balance sheet, it had borrowing capacity that it would not otherwise have had if its debt ratio had been greater. As a result, during Winter Storm Uri, ONE Gas was able to obtain a $2.5 billion, two-year unsecured Term Loan Facility to finance the approximately $2.2 billion in higher natural gas purchases required to serve customers, maintain its liquidity, and meet its payment obligations. While, as noted by Moody's, this short-term borrowing doubled ONE Gas' total outstanding debt, S&P assessed ONE Gas' liquidity as adequate, in part due to its prudent risk management, which includes its capital structure policies.

Q. HAS ONE GAS ALWAYS MAINTAINED ITS TARGET CAPITAL STRUCTURE RATIOS?

A. The table below displays the capital structure ratios of ONE Gas at each year-end since it became a separate entity in 2014:

Year	Debt	Equity
2014	40.1%	59.9%
2015	39.5%	60.5%
2016	38.7%	61.3%
2017	37.8%	62.2%
2018	38.6%	61.4%
2019	37.7%	62.3%
2020	41.5%	58.5%
2021*	61.0%	39.0%
2022*	47.7%	52.3%
2023*	48.5%	51.5%

*Capital structure ratios include debt related to Winter Storm Uri.

As evidenced above, except for 2021, 2022, and 2023 when ONE Gas had outstanding all or part of $2.1 billion of temporary debt issued to finance extraordinary gas costs incurred during Winter Storm Uri, its permanent capital structure ratios have generally been in the approximately 40% debt and 60% equity vicinity since its inception.

Q. HAS ONE GAS RETURNED ITS CAPITAL STRUCTURE RATIOS TO ITS TARGET LEVELS?

A. Yes. At year-end 2023, ONE Gas had net outstanding long-term debt totaling approximately $2.650 billion, excluding $343 million of Kansas Securitized Utility Tariff Bonds, which are reported separately on ONE Gas' consolidated balance sheet to recognize that they are securitized by specific Kansas revenues. However, this total includes a $300 million issue of senior notes that matured in February 2024 and had been refinanced in December 2023, and approximately $473 million of Winter Storm Uri debt that was repaid when it matured in March 2023. Deducting this matured and repaid debt from the 2023 year-end total of $2.650 billion leaves adjusted net long-term debt outstanding, after unamortized discounts and issuance costs, of approximately $1.877 billion. As shown below, combining ONE Gas' adjusted long-term debt with 2023 year-end common equity of $2.766 billion produces capital structure ratios of 40.42% debt and 59.58% equity:

Capital Component	12/31/2023	Adjustment	Adjusted	Percent
Long-term Debt	$ 2,649,641	$(772,971)	$ 1,876,670	40.42%
Common Equity	2,765,877	--	2,765,877	59.58%
Total	$5,415,518	$(772,971)	$ 4,642,547	100.00%

Accordingly, after adjusting ONE Gas test year-end capitalization for the $733 million of long-term debt that has matured and been repaid, ONE Gas' capital structure ratios have been restored to their targets of approximately 40% long-term debt and 60% common equity.

Q. HOW DO THESE ADJUSTED CAPITAL STRUCTURE RATIOS COMPARE WITH THOSE OF OTHER LDCS?

A. Based on data published by the American Gas Association, the gas distribution industry had the following composite capital structure ratios between 2018 and 2022:

Capital Component	2022	2021	2020	2019	2018
Long-term Debt	42.8%	43.6%	42.3%	41.0%	41.9%
Preferred Stock	0.0%	0.0%	0.0%	0.9%	0.1%
Common Equity	57.2%	56.4%	57.7%	58.1%	58.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

The table above indicates that gas distribution companies have historically financed their investment in utility plant with around 42% long-term debt and 58% preferred and common equity, not appreciably different from ONE Gas' adjusted ratios.

Alternatively, Schedule BHF-2 displays the capital structure ratios at fiscal year-ends 2019 through 2023 for an industry group of other publicly traded LDCs. Beginning with the nine companies included in *The Value Line Investment Survey's* ("*Value Line*") Natural Gas Utility industry, I excluded ONE Gas, Southwest Gas Holdings, which is in the midst of a restructuring, and UGI Corp., which is not predominantly engaged in natural gas distribution. This resulted in an industry group consisting of: 1) Atmos Energy, 2) Chesapeake Utilities, 3) New Jersey Resources, 4) NiSource, Inc., 5) Northwest Natural Gas, and 6) Spire, Inc. While

ONE Gas' adjusted capital structure ratios of approximately 40% debt and 60% equity are below and above, respectively, the averages for this group over the last five years, they fall within industry bounds.

Q. WHAT CAPITAL STRUCTURE RATIOS HAS THE COMMISSION APPROVED FOR MAJOR LDCS IN TEXAS?

A. The following table lists the capital structure ratios approved by the Commission for the three largest LDCs in Texas from 2016 through the present. As shown there, with but a few exceptions, the equity ratios included in the rates of return authorized by the Commission have been approximately 60%:

Date	Docket	Utility	Debt	Equity
05/03/2016	10488	TGS – Gulf Coast	39.80%	60.20%
09/27/2016	10506	TGS – West Texas	39.90%	60.10%
11/15/2016	10526	TGS –Central Texas	39.50%	60.50%
05/23/2017	10567	CP Energy– Houston	44.85%	55.15%
12/05/2017	10640	Atmos – Dallas	41.49%	58.51%
03/20/2018	10656	TGS – RGV	38.71%	61.29%
05/22/2018	10669	CP Energy – S. Texas	45.00%	55.00%
11/13/2018	10739	TGS – NTSA	37.84%	62.16%
12/11/2018	10742	Atmos – Mid-Tex	39.82%	60.18%
12/11/2018	10743	Atmos – West Texas	39.82%	60.18%
02/05/2019	10766	TGS – BSSA	37.84%	62.16%
05/21/2019	10779	Atmos – Mid-Tex	39.82%	60.18%
04/21/2020	10900	Atmos – West Texas	39.88%	60.12%
05/21/2019	10920	CP Energy-Beaumont	43.05%	56.95%
08/04/2020	10928	TGS – CGSA	41.00%	59.00%
01/18/2023	00009896	TGS – WNSA	40.26%	59.74%
01/30/2024	00014399	TGS – RGV	40.93%	59.07%

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE USED TO CALCULATE TGS'S RATE OF RETURN?

A. I recommend that the adjusted test year-end capital structure ratios of 40.42% debt and 59.58% equity, which remove the matured and refinanced $300 million debt issue and the remaining Winter Storm Uri debt, be used to calculate the rate of return for TGS's CGSA. In addition to reflecting how the permanent assets in the CGSA will be financed when the rates in this case are in effect, my recommendation follows the Commission's practice of using the utility's capital structure ratios when they are generally consistent with and fall within the range of those maintained by other LDCs, which ONE Gas' adjusted capital structure ratios do. My recommendation is also consistent with the capital structure ratios previously approved by the Commission for TGS in previous rate cases, as well as, those approved by the Commission for the other two major LDCs in Texas – Atmos Energy and CenterPoint Energy. Finally, these capital structure ratios follow ONE Gas' financial policies and practices to maintain single-A credit metrics and a level of creditworthiness and flexibility to meet unexpected financial requirements, which is a benefit to customers both through lower debt costs and the availability of capital.

IV. COST OF DEBT

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section is to recommend a cost of debt applicable to the debt component of TGS's permanent capital structure developed above.

Q. PLEASE DESCRIBE THE LONG-TERM DEBT INCLUDED IN YOUR RECOMMENDED CAPITAL STRUCTURE FOR ONE GAS.

A. There are five issues of long-term senior notes comprising ONE Gas' adjusted December 31, 2023 capital structure, which have a total face value of $1.9 billion. One of the issues, $600 million maturing in 2044 bearing an interest rate of 4.658%, was sold in 2014 when ONE Gas was spun-off from ONEOK. ONE Gas subsequently issued $400 million in senior notes in 2019 that mature in 2048 and bear an interest rate of 4.50%, $300 million of 2.00% senior notes maturing in 2030 sold in 2020, and $300 million of 4.25% senior notes issued in 2022 that mature in 2032. Finally, as discussed above, ONE Gas issued $300 million in debt in December 2023, which carries an interest rate of 5.10%, to refinance the same amount of debt that matured in February 2024. Reducing the face amount of the senior notes at December 31, 2023 was approximately $23.3 million in unamortized issuance and discount costs and $3.4 million in unamortized costs associated with previously retired debt.

Q. WHAT IS THE AVERAGE COST OF ONE GAS' DEBT?

A. As shown below, the weighted average cost of ONE Gas' adjusted long-term debt is 4.39% (dollar amounts in 000s):

Description	Amount	Interest Rate	Annual Expense
5.10% due 2029	$ 300,000	5.100%	$ 15,300
2.0% due 2030	300,000	2.000%	6,000
4.25% due 2032	300,000	4.250%	12,750
4.658% due 2044	600,000	4.658%	27,948
4.50% due 2048	400,000	4.500%	18,000
Debt Issuance Costs Expenses	(15,778)		1,078
Debt Discounts	(7,552)		498
Debt Retirement Costs	(3,435)		723
Total	**$1,873,235**		**$82,297**
Cost of Debt		**4.39%**	

I recommend that this 4.39% cost be applied to the debt component of ONE Gas' adjusted capital structure to determine the rate of return for TGS's CGSA.

V. COST OF EQUITY ESTIMATES

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section is to develop a cost of equity range for an industry group of LDCs having similar risks to TGS. It begins by introducing the cost of equity concept, explaining the risk-return tradeoff principle fundamental to capital markets, and discussing the importance of using multiple approaches to estimate the cost of equity. The DCF model is then developed and applied to the industry group of publicly traded LDCs to estimate their current cost of equity. Next, the CAPM is described and alternative cost of equity estimates developed for the industry group using this method. Cost of equity estimates are also developed using the risk premium method based on ROEs previously authorized for other LDCs. Finally, a comparable earnings method looking at projected rates of return on book equity for other LDCs is applied.

A. Cost of Equity Concept

Q. HOW IS A RETURN ON COMMON EQUITY CUSTOMARILY DETERMINED?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital, since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment, with the "cost of equity" being the minimum rent that must be paid for the use of their money.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A. The cost of equity concept is predicated on the notion that investors are risk averse and willingly accept additional risk only if they expect to be compensated for bearing that risk. In capital markets where relatively risk-free assets are available, such as U.S. Treasury securities, investors can be induced to hold more risky assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investors' funds, riskier assets must yield a higher expected rate of return than less risky assets in order for investors to be willing to hold them.

Given this risk-return tradeoff, the minimum required rate of return (k) from an asset (i) can be generally expressed as:

$$k_i = R_f + RPi$$

where: R_f = Risk-free rate of return; and
RP_I = Risk premium required to hold more risky asset i.

Thus, the minimum required rate of return for a particular asset at any point in time is a function of: (1) the yield on risk-free assets, and (2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in certain segments of the capital markets where required rates of return can be directly inferred from market data and generally accepted measures of risk exist. For example, bond yields are reflective of investors' expected rates of return, and bond ratings are indicative of the risk of fixed income securities. The observed yields on government securities and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

To illustrate, average yields during March 2024 on 30-year U.S. Treasury bonds and public utility bonds of different ratings reported by Moody's are shown in the table below. As evidenced there, as risk increases (measured by progressively lower bond ratings), the required rate of return (measured by yields) rises accordingly. Also shown are the indicated risk premiums over long-term government securities for the additional risk associated with each bond rating category.

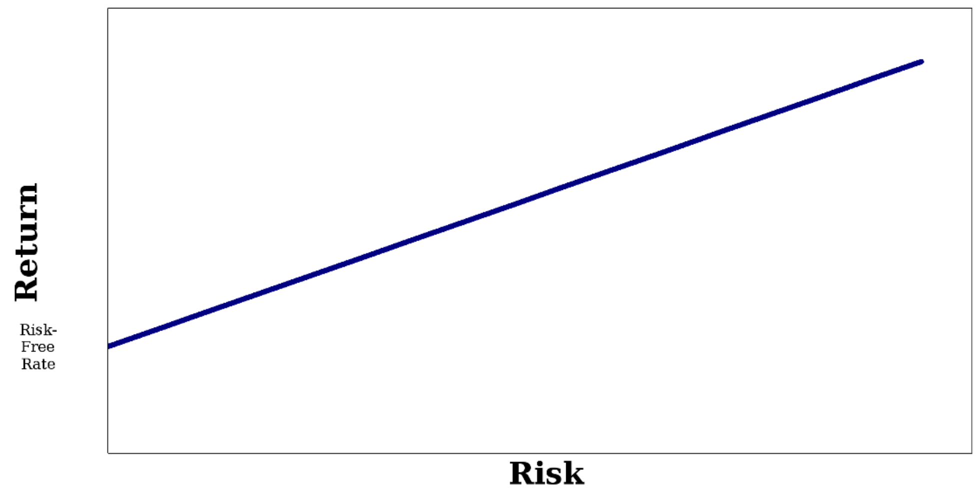
Bond and Rating	March 2024 Yield	Risk Premium Over 30-Year Treasury
U.S. Treasury		
30-Year	4.36%	--
Public Utility		
Aa	5.43%	1.07%
A	5.55%	1.19%
Baa	5.79%	1.43%

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. Documenting the risk-return tradeoff for assets other than fixed income securities is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets (e.g., common stock), required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether to hold common stocks and other assets, just as when choosing among fixed income securities. Accordingly, it is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets.

The extension of the risk-return tradeoff from assets with observable required rates of return (e.g., bonds) to other assets is represented by the concept of a "capital market line." In particular, competition between securities and among investors in the capital markets drives the prices of assets to equilibrium such that the expected rate of return from each is commensurate with its risk. Thus, the expected rate of return from any asset is a risk-free rate of return plus a corresponding risk premium. This concept of a capital market line is illustrated below. The vertical axis represents required rates of return and the horizontal axis indicates relative riskiness, with the intercept of the capital market line being the risk-free rate of return.

Capital Market Line



Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY FOR A UTILITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the utility specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, by extrapolating interest rates, or through an analysis of other financial data.

Q. DO YOU RELY ON A SINGLE METHOD TO ESTIMATE THE COST OF EQUITY?

A. No. Despite the theoretical appeal of or precedent for using a particular method to estimate the cost of equity, no single approach can be regarded as wholly reliable.

Therefore, I use multiple methods to estimate the cost of equity. Indeed, it is essential that estimates of investors' minimum required rate of return produced by one method be compared with those produced by other methods, and that all cost of equity estimates be required to pass fundamental tests of reasonableness and economic logic.

B. Discounted Cash Flow Model

Q. HOW ARE DCF MODELS USED TO ESTIMATE THE COST OF EQUITY?

A. The use of DCF models to estimate the cost of equity is essentially an attempt to replicate the market valuation process which led to the price investors are willing to pay for a share of a company's common stock. It is predicated on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each share of stock is adjusted by the market so that investors are adequately compensated for the risks to which they are exposed. Therefore, we can look to the market to determine what investors believe a share of common stock is worth, and by estimating the cash flows they expect to receive from the stock in the way of future dividends and stock price, their required rate of return can be mathematically imputed. In other words, the cash flows that investors expect from a stock are estimated, and given the stock's current market price, we can "back-into" the discount rate, or cost of equity, investors presumably used in arriving at that price.

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models are derived from a theory of valuation which posits that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+K_e)^1} + \frac{D_2}{(1+K_e)^2} + L + \frac{D_t}{(1+K_e)^t} + \frac{P_t}{(1+K_e)^t}$$

where: P_0 = Current price per share;
P_t = Future price per share in period t;
D_t = Expected dividend per share in period t;
Ke = Cost of equity.

Q. HAS THIS GENERAL FORM OF THE DCF MODEL CUSTOMARILY BEEN SIMPLIFIED FOR USE IN ESTIMATING THE COST OF EQUITY IN RATE CASES?

A. Yes. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant growth" form. In order to convert the general form of the DCF model to the constant growth DCF model, a number of assumptions must be made. These include:

- A constant growth rate for both dividends and earnings;
- A stable dividend payout ratio;
- The discount rate exceeds the growth rate;
- A constant growth rate for book value and price;
- A constant earned rate of return on book value;
- No sales of stock at a price above or below book value;
- A constant price-earnings ratio;
- A constant discount rate (i.e., no changes in risk or interest rate levels and a flat yield curve); and
- All of the above extend to infinity.

Given these assumptions, the general form of the DCF model can be reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{K_e - g}$$

where: g = Investors' long-term growth expectations.

The cost of equity ("K_e") can be isolated by rearranging terms:

$$K_e = \frac{D_1}{P_0} + g$$

The constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: (1) dividend yield (D_1/P_0), and (2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

While the constant growth form of the DCF model provides a more manageable formula to estimate the cost of equity, it is important to note that the assumptions required to convert the general form of the DCF model to the constant growth form are never strictly met in practice. In some instances, where earnings are derived solely from stable activities, and earnings, dividends, and book value track fairly closely, the constant growth form of the DCF model may be a reasonable working approximation of stock valuation. However, in other cases, where the circumstances cause the required assumptions to be severely violated, the constant growth DCF model may produce widely divergent and meaningless results. This is especially the case if the firm's earnings or dividends are unstable, or if investors are expecting the stock price to be affected by factors other than earnings and dividends.

Q. IS THERE ANYTHING ELSE THAT AFFECTS THE USE OF THE DCF MODEL TO ESTIMATE INVESTORS' REQUIRED RATE OF RETURN?

A. Yes. When the DCF model came into widespread use as a method to estimate the cost of equity in the 1960s and 1970s, it was regarded as a fair representation of investor behavior and share valuation. Investors bought and sold stocks based on their fundamental underlying value, which was tied to long-term dividend and stock price growth expectations. That is no longer the case. It is estimated that some 75% of equities bought and sold on the New York Stock Exchange are now "high frequency" or "algorithmic" trades. These trades are not investors buying stocks for the long-term, but are short-term, computer-initiated trades intended to take advantage of market discrepancies, movements, and information. Accordingly, it is not clear whether common stock prices are now based on the valuation assumed by DCF theory and upon which estimating the cost of equity using the DCF model is predicated.

Q. THESE CAVEATS NOTWITHSTANDING, HOW DID YOU ESTIMATE THE COST OF EQUITY USING THE DCF MODEL?

A. To avoid measurement error associated with applying the DCF model to a single firm, I applied the constant growth form of the DCF model to a proxy group of publicly traded LDCs. As described earlier, I began with the nine companies included in *Value Line's* Natural Gas Utility industry at February 23, 2024, and then excluded UGI Corp. because it is not predominantly engaged in natural gas distribution and Southwest Gas Holdings because it is in the midst of a major restructuring. This resulted in a proxy group consisting of the seven LDCs listed on Schedule BHF-3, which includes ONE Gas.

Q. HOW IS THE CONSTANT GROWTH FORM OF THE DCF MODEL TYPICALLY USED TO ESTIMATE THE COST OF EQUITY?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock.

Q. HOW DID YOU CALCULATE THE DIVIDEND YIELD COMPONENT OF THE CONSTANT GROWTH DCF MODEL FOR THE GAS UTILITY GROUP?

A. Because estimating the cost of equity using the DCF model is an attempt to replicate how investors arrived at an observed stock price, all of its components should be contemporaneous. Price, dividend, and growth data from different points in time, or averaged over long time periods, violate the matching principle underlying the DCF model. Therefore, dividend yield was calculated by dividing an estimate of dividends to be paid by each of the LDCs in the group over the next twelve months, obtained from the index to *Value Line's* April 5, 2024 edition, by the average closing price of each firm's stock during the month of March 2024. The expected dividends, representative price, and resulting dividend yield for each of the seven LDCs are displayed on Schedule BHF-3. As calculated there, the average dividend yield for the industry group is 3.97%. Also shown is the median for the group of 3.98%, which removes the impact of extreme low and high values on the average.

Q. EXPLAIN HOW ESTIMATES OF INVESTORS' LONG-TERM GROWTH EXPECTATIONS ARE CUSTOMARILY DEVELOPED FOR USE IN THE CONSTANT GROWTH DCF MODEL.

A. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an effort to replicate the mechanism investors used to arrive at observable stock prices. Therefore, the only "g", or growth rate, that matters in using the DCF model to estimate the cost of equity is that which investors expect and have embodied in current market prices.

Q. WHAT DRIVES INVESTORS' GROWTH EXPECTATIONS?

A. Trends in earnings, which ultimately support future dividends and share price, play a pivotal role in determining investors' long-term growth expectations. Security analysts' growth forecasts are generally regarded as the closest single measure of the expected long-term growth rate of the constant growth DCF model. While being primarily based on the outlook for a firm, they also reflect the utility's historical experience and other factors considered by investors in forming their long-term growth expectations. Moreover, various empirical studies have found that security analysts' projections are a superior source of DCF growth rates. The 5-year earnings growth projections by security analysts for each of the seven gas utilities reported by *Value Line*, LSEG's *Institutional Brokers Estimate System* ("*I/B/E/S*"), and *Zacks Investment Research* ("*Zacks*") are displayed on Schedule BHF-4, with the averages for the group being 5.9%, 7.2%, and 6.3%, respectively. Again, to eliminate the impact of extreme values, the medians for the group are also shown, which range between 5.0% and 7.4%. Also shown on Schedule BHF-4 are the 10-year and 5-year historical earnings growth rates reported by *Value Line* for each of the seven gas utilities, which average 4.8% and 6.9%, respectively, and have medians of 5.0% and 6.0%, respectively.

Q. HOW ELSE ARE INVESTOR EXPECTATIONS OF FUTURE LONG-TERM GROWTH PROSPECTS FOR A FIRM OFTEN ESTIMATED FOR USE IN THE CONSTANT GROWTH DCF MODEL?

A. In DCF theory and practice, growth in book equity comes from the reinvestment of earnings within the business and the effects of external financing. Accordingly, conventional applications of the constant growth DCF model often examine the relationships between variables that determine the "sustainable" growth attributable to these two factors.

Q. HOW IS A FIRM'S SUSTAINABLE GROWTH ESTIMATED?

A. The sustainable growth rate is calculated by the formula:

$$g = br + sv$$

where "b" is the expected earnings retention ratio (one minus the dividend payout ratio), "r" is the expected rate of return earned on book equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion ratio. The "br" term represents the growth from reinvesting earnings within the firm while the "sv" term represents the growth from external financing. This external financing growth results because existing shareholders share in a portion of any excess received from selling new shares at a price above book value.

Q. WHAT GROWTH RATE DOES THE SUSTAINABLE GROWTH METHOD SUGGEST FOR THE GAS UTILITY GROUP?

A. The sustainable growth rate for each of the seven gas utilities in the industry group based on *Value Line's* projections for 2027-2029 is developed in Schedule BHF-5. As shown there, the sustainable growth method implies an average long-term growth rate for the LDC utility group of 6.1%, and 6.3% based on the median.

Q. WHAT ARE OTHER PROJECTED AND HISTORICAL GROWTH RATES FOR THE INDUSTRY GROUP?

A. Schedule BHF-6 displays *Value Line* projected growth rates and 10- and 5-year historical growth rates in book value per share, dividends per share, and stock price for each of the seven gas utilities in the industry group. The averages for the LDC group range from a negative 3.1% (5-year historical price growth) to 9.2% (projected price growth), with the medians ranging from a negative 3.2% to 9.6%. Besides the fact that some of these growth rates, when combined with the group's approximately 4.0% dividend yield, imply implausible cost of equity estimates, the variation in these other growth rates results in their providing only limited guidance as to the prospective growth that investors expect.

Q. WHAT IS YOUR CONCLUSION AS TO THE LONG-TERM GROWTH THAT INVESTORS ARE EXPECTING FROM THE INDUSTRY GROUP?

A. After excluding clearly unreliable indicators of growth, the plausible growth rates shown on Schedules BHF-4, BHF-5, and BHF-6 indicate a range for the LDC group of between approximately 5.50% and 6.75%. Taken together, I conclude that investors expect long-term growth from the LDC group in the 5.5% to 6.5% range.

Q. WHAT CURRENT DCF COST OF EQUITY ESTIMATES DO THESE GROWTH RATE RANGES IMPLY FOR THE GAS UTILITY GROUP?

A. Summing the LDC group's average dividend yield of approximately 4.0% with my growth rate range of a 5.5% to 6.5% developed earlier indicates a current DCF cost of equity for the LDC industry group of between 9.50% and 10.50%.

C. Capital Asset Pricing Model

Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?

A. The cost of equity for the gas utility group was also estimated using the CAPM, which is a theory of market equilibrium that serves as the basis for current financial education and management. Under the CAPM, investors are assumed fully diversified, so that the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, which is measured using a "beta" coefficient. Beta reflects the tendency of a stock's price to follow changes in the market, with stocks having a beta less than 1.00 being considered less risky and stocks with a beta greater than 1.00 being regarded as more risky. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j (R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free interest rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

While the CAPM is not without controversy, it is routinely referenced in the financial literature and regulatory proceedings, and firms' beta values are widely reported.

Q. HOW DID YOU APPLY THE CAPM?

A. I applied the CAPM using two methods to determine the risk premium for the market as a whole, or the (R_m - R_f) term in the CAPM formula. The first was based on historical rates of return and the second was based on forward-looking estimates of investors' required rates of return. In both instances, the companies included in the S&P 500 index were used as a proxy for the market portfolio and the 30-year U.S. Treasury bond served as the risk-free investment.

Q. PLEASE DESCRIBE THE FIRST METHOD BASED ON HISTORICAL RATES OF RETURN.

A. Under the historical rate of return approach, equity risk premiums are calculated by first measuring the rate of return (including dividends and capital gains and losses) actually realized on an investment in common stocks over historical time periods. The historical return on bonds is then subtracted from that earned on common stocks to measure equity risk premiums. Widely used in academia, the historical rate of return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those in the past.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON HISTORICAL RATES OF RETURN?

A. Perhaps the most exhaustive study of historical rates of return, and the one most frequently cited in regulatory proceedings, is that contained in Market Results for Stocks, Bonds, Bills and Inflation, variously published by Ibbotson Associates, Morningstar, Duff & Phelps, and Kroll. The annual rate of return realized on the S&P 500 averaged 12.04% over the period 1926 through 2023 while the annual average income rate of return on 30-year Treasury bonds over this same period averaged 4.87%. Thus, the market risk premium based on historical average annual rates of return is 7.17%, as shown on Schedule BHF-7.

Q. PLEASE DESCRIBE THE SECOND METHOD BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN.

A. Consistent with the CAPM being an expectational (i.e., forward-looking) model, the second method estimated the market risk premium using current indicators of investors' required rates of return. This method is similar to how the market risk premium is calculated under the Federal Energy Regulatory Commission's May 21, 2020 *Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines* ("FERC Policy Statement"). For the market portfolio, the cost of equity was estimated by applying the DCF model to the firms in the S&P 500 paying cash dividends, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. The expected dividend yield for each firm was obtained from *Value Line*, with the expected growth rate being based on the earnings forecasts published for each firm by *Value Line*, *I/B/E/S*, and *Zacks*. As shown in footnote (b) on Schedule BHF-7, summing the 1.85% expected dividend yield for this market group, which is composed primarily of non-regulated firms, with the average of the *Value Line*, *I/B/E/S*, and *Zacks* projected growth rates of 10.10% produces a required rate of return from the market portfolio (Rm) of 11.95%.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN?

A. From the 11.95% required rate of return on the market portfolio, a market risk premium is calculated by subtracting the average yield on 30-year Treasury bonds during March 2024 of 4.36%. This produces a forward-looking market risk premium of 7.59%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CAPM?

A. Having calculated market risk premiums of 7.17% and 7.59% using historical rates of return and forward-looking rates of return, respectively, the next step is to calculate specific risk premiums for the LDC industry group. This is done by multiplying the alternative market risk premium estimates by the LDC group's average beta of 0.86, calculated using firm betas obtained from *Value Line* and shown on Schedule BHF-8, which produces LDC industry risk premiums of 6.20% and 6.56%.

Q. WHAT ARE THE RESULTING THEORETICAL CAPM COST OF EQUITY ESTIMATES FOR THE LDC GROUP?

A. Summing the industry risk premiums of 6.20% and 6.56% with a risk-free interest rate equal to the March 2024 30-year Treasury bond yield of 4.36% produces current theoretical CAPM cost of equity estimates for LDCs of 10.56% and 10.92%.

Q. ARE THESE THEORETICAL CAPM COST OF EQUITY ESTIMATES COMPLETE MEASURES OF INVESTORS' REQUIRED RATE OF RETURN FROM THE GROUP OF LDCS?

A. No. These cost of equity estimates are based on CAPM theory. However, as explained by Morningstar in its *2015 Classic Yearbook* edition of *Stocks, Bonds, Bills and Inflation*:

> One of the most remarkable discoveries of modern finance is that of a relationship between company size and return. Historically on average, small companies have higher returns than those of large ones. . . . The relationship between company size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks. (page 99, footnote omitted)

In other words, in addition to the systematic risk measured by beta, investors' required rate of return depends on a firm's relative size. To account for this, size discounts and premiums have been developed that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. This is the same conclusion reached in the FERC Policy Statement, which prescribes a size adjustment in the CAPM to improve the accuracy of the cost of equity estimate.

Q. WHAT ARE THE CURRENT CAPM COST OF EQUITY ESTIMATES FOR THE LDC GROUP ONCE SIZE EFFECTS ARE TAKEN INTO ACCOUNT?

A. A schedule of discounts and premiums to account for differences in the market capitalization of a firm's equity relative to the S&P 500 is published annually, with the most recent by Kroll being reproduced in the lower portion of Schedule BHF-8. In the far right columns of the table in the upper portion of Schedule BHF-8, the market cap of each LDC in the industry group is displayed along with its corresponding size premium, with the average size premium for the industry group being 0.93%. This means that the theoretical CAPM cost of equity estimates need to be increased by 93 basis points to account for the industry group's relatively smaller size relative to the market. As shown on Schedule BHF-7, increasing the theoretical CAPM cost of equity estimates for the LDC group by this average size premium results in current CAPM cost of equity estimates based on historical and forward-looking rates of return of 11.49% and 11.85%, respectively.

D. Risk Premium Method

Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?

A. I also estimated the cost of equity using a risk premium method based on ROEs previously authorized for LDCs by state regulatory commissions. The risk premium method to estimate investors' required rate of return is an extension of the risk-return tradeoff observed with bonds to common stocks. The cost of equity is estimated by determining the additional return investors require to forego the relative safety of a bond and bear the greater risks associated with common stock, and then adding this equity risk premium to the current yield on bonds.

Q. GENERALLY DESCRIBE THE APPLICATION OF THE RISK PREMIUM METHOD USING AUTHORIZED ROES.

A. Application of the risk premium method based on authorized ROEs is predicated on the presumption that allowed returns reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final orders. A current risk premium is estimated based on the difference between past authorized ROEs and then-prevailing interest rates. This risk premium is then added to current interest rates to estimate the cost of equity. The strength of this approach is that it is based on decades of data reflecting regulatory commissions' evaluation of ROE for LDCs under various capital market conditions. Because this risk premium method is LDC-specific, it produces cost of equity estimates judged necessary to compensate for the risks of gas distribution and the ROE required to enable an LDC to attract capital on reasonable terms under current capital market conditions.

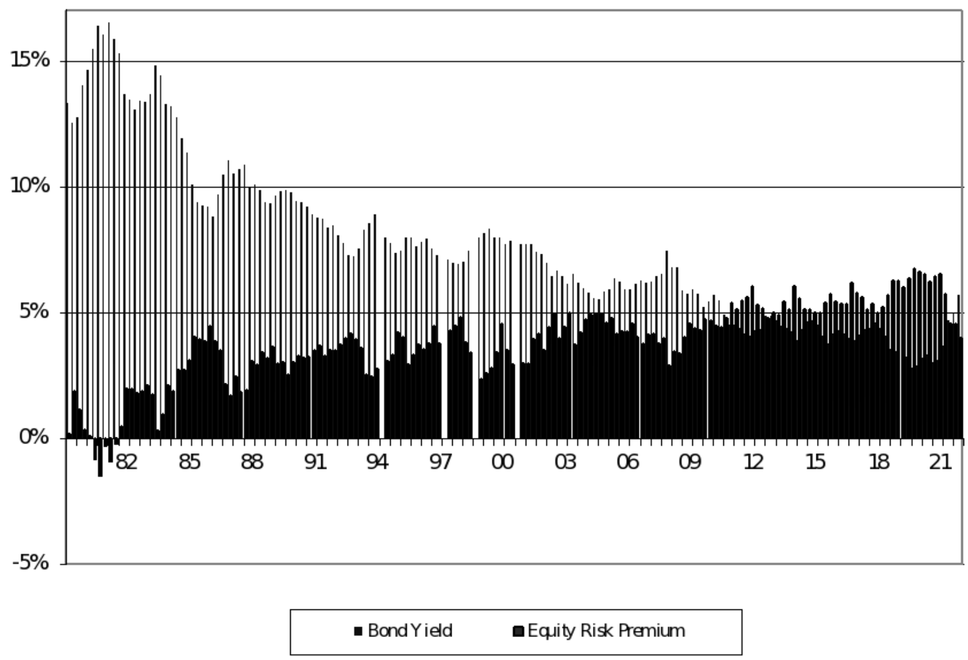
Q. WHAT WAS THE PRINCIPAL SOURCE OF THE DATA USED TO APPLY THIS RISK PREMIUM METHOD?

A. Regulatory Research Associates, Inc., ("RRA"), which is now a group within S&P Global Market Intelligence, and its predecessors have compiled the ROEs authorized for major electric and gas utilities by regulatory commissions across the U.S. The average ROE authorized for natural gas utilities published by RRA in each quarter between 1980 and 2023 are displayed in Schedule BHF-9. As shown there, the ROEs granted to LDCs over this 44-year period have averaged 11.37%, while the average utility bond yield has averaged 7.56%, resulting in an average risk premium of 3.81%.

Q. IS THIS 3.81% AVERAGE RISK PREMIUM THE RELEVANT BENCHMARK FOR ESTIMATING THE COST OF EQUITY?

A. No. It is necessary to account for the fact that authorized ROEs do not move in lockstep with interest rates. In particular, when interest rate levels are relatively high, ROEs tend to be lower (i.e., equity risk premiums narrow), and when interest rates are relatively low, authorized ROEs are greater (i.e., equity risk premiums increase). This inverse relationship can be observed in the data contained in

Schedule BHF-9, which is shown graphically below. As evident there, the higher the level of interest rates (shaded bars), the lower the equity risk premiums (the solid bars calculated as the difference between authorized ROEs and bond yields), and vice versa:



The implication of this inverse relationship is that for a one percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, one-half of a percent, respectively.

Q. HOW DID YOU ACCOUNT FOR THE INVERSE RELATIONSHIP BETWEEN EQUITY RISK PREMIUMS AND INTEREST RATES IN ESTIMATING THE COST OF EQUITY FOR THE LDC GROUP USING PAST AUTHORIZED ROES?

A. To account for the fact that equity risk premiums are lower when interest rates are high and higher when interest rates are low, I developed two regression equations relating authorized past equity risk premiums to average utility bond yields. The first was a simple linear regression between equity risk premiums and interest rates and the second equation adjusted for first order autocorrelation using the Prais-Winsten algorithm. Shown in the bottom portion of Schedule BHF-9, substituting the March 2024 yield of 5.59% on average utility bonds into the regression equations indicates that the equity risk premium at current interest rate levels is between approximately 4.72% and 4.83%.

Q. WHAT CURRENT COST OF EQUITY DOES THIS RISK PREMIUM IMPLY FOR THE GROUP OF LDCS?

A. As shown on Schedule BHF-8, the average S&P bond rating for the LDC industry group is A- and the average Moody's bond rating is A3. Adding the 4.72% and 4.83% equity risk premiums developed on Schedule BHF-9 to the March 2024 yield on single-A utility bonds of 5.55% produces a current risk premium cost of equity range of between 10.27% and 10.38%.

E. Comparable Earnings Method

Q. WHAT IS THE LAST METHOD THAT YOU USED TO ESTIMATE THE COST OF EQUITY?

A. Often referred to as the comparable earnings method, this approach looks to the rates of return that other firms of comparable risk and that compete for investors' capital are expected to earn on their book equity. Reference to the expected return on book equity of other LDCs demonstrates the level of earnings that TGS needs in order to offer investors a competitive return, be able to attract capital on reasonable terms, and maintain its financial integrity.

Q. WHAT RETURN ON BOOK EQUITY ARE OTHER LDCS EXPECTED TO EARN?

A. Schedule BHF-10 displays the return on book equity projected for each of the seven LDCs other than ONE Gas in the industry group for the 2024, 2025, and the 2027-2029 timeframes, calculated by dividing *Value Line's* projected earnings per share by average book value per share. As shown there, the average expected book ROE for this group is 9.3% in 2024 and 2025, and 10.1% for 2027-2029, with medians of 8.7%, 9.1%, and 9.9%, respectively.

VI. RECOMMENDED RETURN ON EQUITY

Q. WHAT IS YOUR CONCLUSION AS TO THE CURRENT COST OF EQUITY RANGE FOR LDCS?

A. The DCF method indicates a cost of equity range for the LDC group of between approximately 9.5% and 10.5%, and the CAPM indicates a cost of equity range of between approximately 11.5% and 11.9%, or between 10.6% and 10.9% if no size adjustment is included. Meanwhile, the risk premium method based on the authorized ROEs for LDCs and current interest rates indicates a cost of equity of between approximately 10.3% and 10.4%, and the comparable earnings method shows that other LDCs are expected to earn between 8.7% and 10.1% on their book equity. Taking into account that the DCF model may no longer reflect investor behavior and stock valuation, that the CAPM and risk premium method incorporate directly current interest rate levels on Treasury and utility bonds, respectively, and that the comparable earnings method is not market-based, I conclude that investors currently require a ROE from the LDC industry group in the 9.75% to 10.75% range.

Q. WHAT ROE DO YOU RECOMMEND FOR TGS?

A. I recommend an ROE for TGS 10.25%, which is the midpoint of my cost of equity range. This ROE is slightly above the middle of my DCF model range, below the range indicated by my CAPM analyses, both with and without the size adjustment, and at the lower end of my risk premium method range.

Q. HAVE YOU CONDUCTED ANY CHECKS OF REASONABLENESS OF YOUR RECOMMENDED ROE?

A. Yes. The reasonableness of my recommended 10.25% ROE for TGS's CGSA can be evaluated by reviewing the ROEs previously granted by the Commission. The table below lists the ROEs authorized for the three largest LDCs in Texas from 2016 through the present:

Date	Docket	Utility	ROE
05/03/2016	10488	TGS – Gulf Coast	9.50%
09/27/2016	10506	TGS – West Texas	9.50%
11/15/2016	10526	TGS – Central Texas	9.50%
05/23/2017	10567	CP Energy – Houston	9.60%
12/05/2017	10640	Atmos – Dallas	10.10%
03/20/2018	10656	TGS – RGV	9.50%
05/22/2018	10669	CP Energy – S. Texas	9.80%
11/13/2018	10739	TGS – NTSA	9.75%
12/11/2018	10742	Atmos – Mid-Tex	9.80%
12/11/2018	10743	Atmos – West Texas	9.80%
02/05/2019	10766	TGS – BSSA	9.75%
05/21/2019	10779	Atmos – Mid-Tex	9.80%
04/21/2020	10900	Atmos – West Texas	9.80%
04/21/2020	10920	CP Energy-Beaumont	9.65%
08/04/2020	10928	TGS – CGSA	9.50%
01/18/2023	00009896	TGS – WNSA	9.60%
01/30/2024	00014399	TGS – RGV	9.70%

Although the allowed ROE range of 9.50% to 10.10% is below my recommended 10.25%, all but the two most recent ROEs were determined during a period when the Fed was suppressing interest rates to stimulate the economy and recover from the COVID pandemic. Indeed, the average yield on public utility bonds between May 2016 and August 2020 was approximately 3.90%, versus 5.59% in March 2024. Because of the increase in capital costs that has already occurred, an ROE in the 9.5% to 10.1% range allowed by the Commission over the last few years is no longer sufficient to fairly compensate a utility's investors, enable it to attract new capital on reasonable terms, and maintain its financial integrity. Therefore, after adjusting the ROEs previously granted by the Commission for today's higher capital costs, as well as those that will prevail when the service rates for TGS's CGSA are in effect, my recommended 10.25% ROE is reasonable.

Q. WOULD YOU PLEASE ADDRESS THE 9.6% AND 9.7% ROES AUTHORIZED BY THE COMMISSION IN TGS'S LAST TWO CASES, DOCKET NOS. OS-22-00009896 AND OS-23-00014399?

A. Yes. In Docket No. OS-22-00009896 ("Docket No. 9896"), the Commission accepted the 9.6% ROE recommended by the Administrative Law Judge and Technical Examiners in their Proposal for Decision ("PFD"), which concluded that because current capital market conditions are reflected in stock prices, "[i]nvestors' expectations of capital market conditions are embedded in the DCF methodology, which sufficiently accounts for the potential changes in the capital markets."[1]

[1] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Amended PFD at 29 (Jan. 11, 2023).

However, the PFD's conclusion that the increased capital costs in the fall of 2022 were temporary has been shown to be wrong. Both short- and long-term interest rates remain high, and inflation continues to be well in excess of the Fed's target level and unemployment remains low. Accordingly, while the Fed has indicated that it may lower interest rates if the data warrant, any reductions are not expected to return interest rate levels to those that prevailed prior to 2021. As to Docket No. OS-23-00014399, the Commission's decision in that case reflected an agreement between the parties, with the 9.7% ROE being one of the various compromises inherent in the settlement of a rate case.

Q. HAVE YOU PERFORMED ANY OTHER TESTS OF REASONABLENESS OF YOUR RECOMMENDED 10.25% ROE?

A. Yes. In the last two TGS rate cases in which Commission Staff presented testimony, Docket No. 10928 and Docket No. 9896, Staff used essentially the same methodology in both cases to arrive at its recommended ROE. This methodology consisted of two applications of the DCF model, one based on 30-day prices and the other on 90-day prices, and a CAPM analysis. In Schedule BHF-11, I have replicated Staff's methodology using current data applied to a proxy group of LDCs that excludes NiSource, Inc. and ONE Gas, which Staff did. Also, I did not selectively exclude any companies with high growth rates or high betas, as Staff did in Docket No. 9896 but not in Docket No. 10928. The end-result of averaging the mean cost of equity estimates produced by the two DCF models and the CAPM analysis, increased by Staff's 25 basis point adjustment for market uncertainty, is an ROE of 10.17%. This is not appreciably different from, and fully supports the reasonableness of, my recommended ROE for TGS's CGSA of 10.25%.

VII. CONCLUSION

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

APPENDIX A

BRUCE H. FAIRCHILD

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.
Adjunct Assistant Professor, University of Texas at Austin (Sep. 1979 to May. 1981)	Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.
Assistant Director, Economic Research Division, Public Utility Commission of Texas (Sep. 1976 to Aug. 1979)	Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

Assistant Professor, College of Business Administration, University of Colorado at Boulder (Jan. 1977 to Dec. 1978)	Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.
Teaching Assistant, University of Texas at Austin (Jan. 1973 to Dec. 1976)	Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.
Internal Auditor, Sears, Roebuck and Company, Dallas, Texas (Nov. 1970 to Aug 1972)	Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.
Accounts Payable Clerk, Transcontinental Gas Pipeline Corp., Houston, Texas (May. 1969 to Aug. 1969)	Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics, University of Texas at Austin (Sep. 1974 to May 1980)	Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award. Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*
M.B.A., Finance and Accounting, University of Texas at Austin, (Sep. 1972 to Aug. 1974)	Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues. Professional Report: *Planning a Small Business Enterprise in Austin, Texas*
B.B.A., Accounting and Finance, Southern Methodist University, Dallas, Texas (Sep. 1967 to Dec. 1971)	Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants (Honorary).

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

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Monographs

"On the Use of Security Analysts' Growth Projections in the DCF Model," with William E. Avera, *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds., Institute for Study of Regulation (1982).

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"The Spring Thing (A) and (B)" and "Teaching Notes", with Mike E. Miles, a two-part case study in the evaluation, management, and control of risk; distributed by *Harvard's Intercollegiate Case Clearing House*; reprinted in *Strategy and Policy: Concepts and Cases*, A. A. Strickland and A. J. Thompson, Business Publications, Inc. (1978) and *Cases in Managing Financial Resources*, I. Matur and D. Loy, Reston Publishing Co., Inc. (1984).

"Energy Conservation in Existing Residences, Project Director for development of instruction manual and workshops promoting retrofitting of existing homes, *Governor's Office of Energy Resources* and *Department of Energy* (1977-1978).

"Linear Algebra," "Calculus," "Sets and Functions," and "Simulation Techniques," contributed to and edited four mathematics programmed learning texts for MBA students, *Texas Bureau of Business Research* (1975).

Articles and Notes

"How to Value Personal Service Practices," with Keith Wm. Fairchild, *The Practical Accountant* (August 1989).

"The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test," with Adrien M. McKenzie, *Public Utilities Fortnightly* (May 25, 1989).

"North Arctic Industries, Limited," with Keith Wm. Fairchild, *Case Research Journal* (Spring 1988).

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"Some Thoughts on the Rate of Return to Public Utility Companies," with William E. Avera, *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978).

"Regulatory Problems of EFTS," with Robert McLeod, *Issues in Bank Regulation* (Summer 1978) reprinted in *Illinois Banker* (January 1979).

"Regulation of EFTS as a Public Utility," with Robert McLeod, *Proceedings of the Conference on Bank Structure and Competition* (1978).

"Equity Management of REA Cooperatives," with Jerry Thomas, *Proceedings of the Southwestern Finance Association* (1978).

"Capital Costs Within a Firm," *Proceedings of the Southwestern Finance Association* (1977).

"The Cost of Capital to a Wholly-Owned Public Utility Subsidiary," *Proceedings of the Southwestern Finance Association* (1977).

Selected Papers and Presentations

"Federal Energy Regulatory Commission Audits of Common Carriers (Procedures for Audit Compliance)", Energy Transfer Accounting Employee Education, Dallas and Houston, Texas (December 2018).

"Perspectives on Texas Utility Regulation", TSCPA 2016 Energy Conference, Austin, Texas (May 16, 2016).

"Legislative Changes Affecting Texas Utilities," Texas Committee of Utility and Railroad Tax Representatives, Fall Meeting, Austin, Texas (September 1995).

"Rate of Return," "Origins of Information," Economics," and "Deferred Taxes and ITC's," New Mexico State University and National Association of Regulatory Utility Commissioners Public Utility Conferences on Regulation and the Rate-Making Process, Albuquerque, New Mexico (October 1983, 1984, 1985, 1986, 1987, 1988, 1990, 1991, 1992, 1994, and 1995, and September 1989); Pittsburgh, Pennsylvania (April 1993); and Baltimore, Maryland (May 1994 and 1995).

"Developing a Cost-of-Service Study," 1994 Texas Section American Water Works Association Annual Conference, Amarillo, Texas (March 1994).

"Financial Aspects of Cost of Capital and Common Cost Considerations," Kidder, Peabody & Co. Two-Day Rate Case Workshop for Regulated Utility Companies, New York, New York (June 1993).

"Cost-of-Service Studies and Rate Design," General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

"Rate Base and Revenue Requirements," The University of Texas Regulatory Institute Fundamentals of Utility Regulation, Austin, Texas (June 1989 and 1990).

"Determining the Cost of Capital in Today's Diversified Companies," New Mexico State University Public Utilities Course Part II, Advanced Analysis of Pricing and Utility Revenues, San Francisco, California (June 1990).

"Estimating the Cost of Equity," Oklahoma Association of Tax Representatives, Tulsa, Oklahoma (May 1990).

"Impact of Regulations," Business and the Economy, Leadership Dallas, Dallas, Texas (November 1989).

"Accounting and Finance Workshop" and "Divisional Cost of Capital," New Mexico State University Current Issues Challenging the Regulatory Process, Albuquerque, New Mexico (April 1985 and 1986) and Santa Fe, New Mexico (March 1989).

"Divisional Cost of Equity by Risk Comparability and DCF Analyses," NARUC Advanced Regulatory Studies Program, Williamsburg, Virginia (February 1988) and USTA Rate of Return Task Force, Chicago, Illinois (June 1988).

"Revenue Requirements," Revenue, Pricing, and Regulation in Texas Water Utilities, Texas Water Utilities Conference, Austin, Texas (August 1987 and May 1988).

"Rate Filing – Basic Ratemaking," Texas Gas Association Accounting Workshop, Austin, Texas (March 1988).

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"Capital Investment Analysis for Electric Utilities," The University of Texas at Dallas, Richardson, Texas (June 1980).

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"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

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"Issues in Regulated Industries – Electric Utilities," University of Texas at Dallas 4th Annual Public Utilities Conference, Dallas, Texas (July 1979).

"Investment Conditions and Strategies in Today's Markets," American Society of Women Accountants, Austin, Texas (January 1979).

"Attrition: A Practical Problem in Determining a Fair Return to Public Utility Companies," Financial Management Association, Minneapolis, Minnesota (October 1978).

"The Cost of Equity to Wholly-Owned Electric Utility Subsidiaries," with William L. Beedles, Financial Management Association, Minneapolis, Minnesota (October 1978).

"PUC Retrofitting Program," Texas Electric Cooperatives Spring Workshop, Austin, Texas (May 1978).

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"Public Utilities as Consumer Targets – Is the Pressure Justified?" University of Texas at Dallas 2nd Annual Public Utilities Conference, Dallas, Texas (July 1977).

APPENDIX B

BRUCE H. FAIRCHILD
SUMMARY OF TESTIMONY BEFORE REGULATORY AGENCIES

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
1.	Arkansas Electric Cooperative	Arkansas PSC	U-3071	Aug-80	Wholesale Rate Design
2.	East Central Oklahoma Electric Cooperative	Oklahoma CC	26925	Sep-80	Retail Rate Design
3.	Kansas Gas & Electric Company	Kansas CC	115379-U	Nov-80	PURPA Rate Design Standards
4.	Kansas Gas & Electric Company	Kansas CC	128139-U	May-81	Attrition
5.	City of Austin Electric Department	City of Austin	--	Jun-81	PURPA Rate Design Standards
6.	Tarrant County Water Control and Improvement District No. 1	Texas Water Commission	--	Oct-81	Wholesale Rate Design
7.	Owentown Gas Company	Texas RRC	2720	Jan-82	Revenue Requirements and Retail Rate Design
8.	Kansas Gas & Electric Company	Kansas CC	134792-U	Aug-82	Attrition
9.	Mississippi Power Company	Mississippi PSC	U-4190	Sep-82	Working Capital
10.	Lone Star Gas Company	Texas RRC	3757; 3794	Feb-83	Rate of Return on Equity
11.	Kansas Gas & Electric Company	Kansas CC	134792-U	Feb-83	Rate of Return on Equity
12.	Southwestern Bell Telephone Company	Oklahoma CC	28002	Oct-83	Rate of Return on Equity
13.	Morgas Company	Texas RRC	4063	Nov-83	Revenue Requirements
14.	Seagull Energy	Texas RRC	4541	Jul-84	Rate of Return
15.	Southwestern Bell Telephone Company	FCC	84-800	Nov-84	Rate of Return on Equity
16.	Kansas Gas & Electric Company, Kansas City Power & Light Company, and Kansas Electric Power Cooperatives	Kansas CC	142098-U; 142099-U; 142100-U	May-85	Nuclear Plant Capital Costs and Allowance for Funds Used During Construction
17.	Lone Star Gas Company	Texas RRC	5207	Oct-85	Overhead Cost Allocation
18.	Westar Transmission Company	Texas RRC	5787	Nov-85 Jan-86 Jul-86	Rate of Return, Rate Design, and Gas Processing Plant Economics
19.	City of Houston	Texas Water Commission	RC-022; RC-023	Nov-86	Line Losses and Known and Measurable Changes
20.	ENSTAR Natural Company	Alaska PUC	TA 50-4; R-87-2; U-87-2	Nov-86 May-87 May-87	Cost Allocation, Rate Design, and Tax Rate Changes
21.	Brazos River Authority	Texas Water Commission	RC-020	Jan-87	Revenue Requirements and Rate Design
22.	East Texas Industrial Gas Company	Texas RRC	5878	Feb-87	Revenue Requirements and Rate Design

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
23.	Seagull Energy	Texas RRC	6629	Jun-87	Revenue Requirements
24.	ENSTAR Natural Company	Alaska PUC	U-87-42	Jul-87 Sep-87 Sep-87	Cost Allocation, Rate Design, and Contracts
25.	High Plains Natural Gas Company	Texas RRC	6779	Sep-87	Rate of Return
26.	Hughes Texas Petroleum	Texas RRC	2-91,855	Jan-88	Interim Rates
27.	Cavallo Pipeline Company	Texas RRC	7086	Sep-88	Revenue Requirements
28.	Union Gas System, Inc.	Kansas CC	165591-U	Mar-89 Aug-89	Rate of Return
29.	ENSTAR Natural Gas Company	Alaska PUC	U-88-70	Mar-89	Cost Allocation and Bypass
30.	Morgas Co.	Texas RRC	7538	Aug-89	Rate of Return and Cost Allocation
31.	Corpus Christi Transmission Company	Texas RRC	7346	Sep-89	Revenue Requirements
32.	Amoco Gas Co.	Texas RRC	7550	Oct-89	Rate of Return and Cost Allocation
33.	Iowa Southern Utilities	Iowa Utilities Board	RPU-89-7	Nov-89 Mar-90	Rate of Return on Equity
34.	Southwestern Bell Telephone Company	FCC	89-624	Feb-90 Apr-90	Rate of Return on Equity
35.	Lower Colorado River Authority	Texas PUC	9427	Mar-90 Aug-90 Aug-90	Revenue Requirements
36.	Rio Grande Valley Gas Company	Texas RRC	7604	May-90	Consolidated FIT and Depreciation
37.	Southern Union Gas Company	El Paso PURB	--	Oct-90	Disallowed Expenses and FIT
38.	Iowa Southern Utilities	Iowa Utilities Board	RPU-90-8	Nov-90 Feb-91	Rate of Return on Equity
39.	East Texas Gas Systems	Texas RRC	7863	Dec-90	Revenue Requirements
40.	San Jacinto Gas Transmission	Texas RRC	7865	Dec-90	Revenue Requirements
41.	Southern Union Gas Company	Austin; Texas RRC	-- 7878	Feb-91 Feb-91	Rate of Return and Acquisition Adjustment
42.	Southern Union Gas Company	Port Arthur; Texas RRC	-- 8033	Mar-91 Aug-91 Oct-91	Rate of Return and Acquisition Adjustment
43.	Cavallo Pipeline Company	Texas RRC	8016	Jun-91	Revenue Requirements

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
44.	New Orleans Public Service Inc.	New Orleans City Council	CD-91-1	Jun-91 Mar-92	Rate of Return on Equity
45.	Houston Pipe Line Company	Texas RRC	8017	Jul-91	Rate of Return
46.	Southern Union Gas Company	El Paso PURB	--	Aug-91 Sep-91	Acquisition Adjustment
47.	Southwestern Gas Pipeline, Inc.	Texas RRC	8040	Jan-92 Feb-92	Rate Design and Settlement
48.	City of Fort Worth	Texas Water Commission	8748-A 9261-A	Mar-92 Aug-92 Dec-92 Oct-94 Nov-94	Interim Rates, Revenue Requirements, and Public Interest
49.	Southern Union Gas Company	Oklahoma Corp. Com.	--	Jun-92	Rate of Return
50.	Minnegasco	Minnesota PUC	G-008/GR-92-400	Jul-92 Dec-92	Rate of Return
51.	Guadalupe-Blanco River Authority	Texas PUC	11266	Sep-92	Cost Allocation and Bond Funds
52.	Dorchester Intra-State Gas System	Texas RRC	8111	Oct-92 Nov-92	Rate Impact of System Upgrade
53.	Corpus Christi Transmission Company GP and GPII	Texas RRC	8300 8301	Oct-92 Oct-92	Revenue Requirements
54.	East Texas Industrial Gas Company	Texas RRC	8326	Mar-93	Revenue Requirements
55.	Arkansas Louisiana Gas Company	Arkansas PSC	93-081-U	Apr-93 Oct-93	Rate of Return on Equity
56.	Texas Utilities Electric Company	Texas PUC	11735	Jun-93 Jul-93	Impact of Nuclear Plant Construction Delay
57.	Minnegasco	Minnesota PUC	G-008/GR-93-1090	Nov-93 Apr-94	Rate of Return
58.	Gulf States Utilities Company	Municipalities	--	May-94 Oct-94 Nov-94	Rate of Return on Equity
59.	Louisiana Power & Light Company	Louisiana PSC	U-20925	Aug-94 Feb-95	Rate of Return on Equity
60.	San Jacinto Gas Transmission	Texas RRC	8429	Sep-94	Revenue Requirements
61.	Cavallo Pipeline Company	Texas RRC	8465	Sep-94	Revenue Requirements
62.	Eastrans Limited Partnership	Texas RRC	8385	Oct-94	Revenue Requirements
63.	Gulf States Utilities Company	Louisiana PSC	U-19904	Oct-94	Rate of Return on Equity

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
64.	Entergy Services, Inc.	FERC	ER95-112-000	Mar-95 Nov-95	Rate of Return on Equity
65.	East Texas Gas Systems	Texas RRC	8435	Apr-95	Revenue Requirements
66.	System Energy Resources, Inc.	FERC	ER95-1042-000	May-95 Dec-95 Jan-96	Rate of Return on Equity
67.	Minnegasco	Minnesota PUC	G-008/GR-95-700	Aug-95 Dec-95	Rate of Return
68.	Entex	Louisiana PSC	U-21586	Aug-95	Rate of Return
69.	City of Fort Worth	Texas NRCC	SOAH 582-95-1084	Nov-95	Public Interest of Contract
70.	Seagull Energy Corporation	Texas RRC	8589	Nov-95	Revenue Requirements
71.	Corpus Christi Transmission Company LP	Texas RRC	8449	Feb-96	Revenue Requirements
72.	Missouri Gas Energy	Missouri PSC	GR-96-285	Apr-96 Sep-96 Oct-96	Rate of Return
73.	Entex	Mississippi PSC	96-UA-202	May-96	Rate of Return
74.	Entergy Gulf States, Inc.	Louisiana PSC	U-22084	May-96	Rate of Return on Equity (Gas)
75.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-96 Oct-96	Rate of Return on Equity
76.	American Gas Storage, L.P.	Texas RRC	8591	Sep-96	Revenue Requirements
77.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	Sep-96 Oct-96	Rate of Return on Equity
78.	Lone Star Pipeline and Gas Company	Texas RRC	8664	Oct-96 Jan-97	Rate of Return
79.	Entergy Arkansas, Inc.	Arkansas PSC	96-360-U	Oct-96 Sep-97	Rate of Return on Equity
80.	East Texas Gas Systems	Texas RRC	8658	Nov-96	Revenue Requirements
81.	Entergy Gulf States, Inc.	Texas PUC	16705	Nov-96 Jul-97	Rate of Return on Equity
82.	Eastrans Limited Partnership	Texas RRC	8657	Nov-96	Revenue Requirements
83.	Enserch Processing, Inc.	Texas RRC	8763	Nov-96	Interim Rates
84.	Entergy New Orleans, Inc.	City of New Orleans	UD-97-1	Feb-97 Mar-97 May-98	Rate of Return on Equity

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
85.	ENSTAR Natural Gas Company	Alaska PUC	U-96-108	Mar-97 Apr-97	Service Area Certificate
86.	San Jacinto Gas Transmission	Texas RRC	8741	Sep-97	Revenue Requirements
87.	Missouri Gas Energy	Missouri PSC	GR-98-140	Nov-97 Apr-98 May-98	Rate of Return
88.	Corpus Christi Transmission Company LP	Texas RRC	8762	Dec-97	Revenue Requirements
89.	Texas-New Mexico Power Company	Texas PUC	17751	Feb-98	Excess Cost Over Market
90.	Southern Union Gas Company	Texas RRC	8878	May-98	Rate of Return
91.	Entergy Louisiana, Inc.	Louisiana PSC	U-20925	May-98 Jul-98	Financial Integrity
92.	Entergy Gulf States, Inc.	Louisiana PSC	U-22092	May-98 Jul-98	Financial Integrity
93.	ACGC Gathering Company, LLC	Texas RRC	8896	Sep-98	Cost-based Rates
94.	American Gas Storage, L.P.	Texas RRC	8855	Oct-98	Revenue Requirements
95.	Duke Energy Intrastate Network	Texas RRC	8940	Jun-99	Rate of Return
96.	Aquila Energy Corporation	Texas RRC	8970	Aug-99	Revenue Requirements
97.	San Jacinto Gas Transmission	Texas RRC	8974	Sep-99	Revenue Requirements
98.	Southern Union Gas Company	El Paso PURB	--	Oct-99	Rate of Return
99.	TXU Lone Star Pipeline	Texas RRC	8976	Oct-99 Feb-00	Rate of Return
100.	Sharyland Utilities, L.P.	Texas PUC	21591	Nov-99	Rate of Return
101.	TXU Lone Star Gas Distribution	Texas RRC	9145	Apr-00 Aug-00	Rate of Return
102.	Rotherwood Eastex Gas Storage	Texas RRC	9136	May-00	Revenue Requirements
103.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9137	May-00	Revenue Requirements
104.	Eastex Gas Storage & Exchange, Inc.	Texas RRC	9138	Jul-00	Revenue Requirements
105.	East Texas Gas Systems	Texas RRC	9139	Jul-00	Revenue Requirements
106.	Eastrans Limited Partnership	Texas RRC	9140	Aug-00	Revenue Requirements
107.	Reliant Energy – Entex	City of Tyler	--	Oct-00	Rate of Return
108.	City of Fort Worth	Texas NRCC	SOAH 582-00-1092	Dec-00	CCN – Rates and Financial Ability
109.	Entergy Services, Inc.	FERC	RTO1-75	Dec-00	Rate of Return on Equity

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
110	ENSTAR Natural Gas Company	Alaska PUC	U-00-88	Jun-01 Aug-01 Nov-01 Sep-02 Dec-02	Revenue Requirements, Cost Allocation, and Rate Design
111.	TXU Gas Distribution	Texas RRC	9225	Jul-01	Rate of Return
112.	Centana Intrastate Pipeline LLC	Texas RRC	9243	Aug-01	Rate of Return
113.	Maxwell Water Supply Corp.	Texas NRCC	SOAH-582-01-0802	Oct-01 Mar-02 Apr-02	Reasonableness of Rates
114.	Reliant Energy Arkla	Arkansas PSC	01-243-U	Dec-01 Jun-01	Rate of Return
115.	Entergy Services, Inc.	FERC	ER01-2214-000	Mar-02	Rate of Return on Equity
116.	TXU Lone Star Pipeline	Texas RRC	9292	Apr-02	Rate of Return
117.	Southern Union Gas Company	El Paso PURB	--	Apr-02	Rate of Return
118.	San Jacinto Gas Transmission Co.	Texas RRC	9301	May-02	Rate of Return
119.	Duke Energy Intrastate Network	Texas RRC	9302	May-02	Rate of Return
120.	Reliant Energy Arkla	Oklahoma CC	200200166	May-02	Rate of Return
121.	TXU Gas Distribution	Texas RRC	9313	Jul-02 Sep-02	Rate of Return
122.	Entergy Mississippi, Inc.	Mississippi PSC	2002-UN-256	Aug-02	Rate of Return on Equity
123.	Aquila Storage & Transportation LP	Texas RRC	9323	Sep-02	Revenue Requirements
124.	Panther Pipeline Ltd.	Texas RRC	9291	Oct-02	Revenue Requirements
125.	SEMCO Energy	Michigan PSC	U-13575	Nov-02	Revenue Requirements
126.	CenterPoint Energy Entex	Louisiana PSC	U-26720	Jan-03	Rate of Return
127.	Crosstex CCNG Transmission Ltd.	Texas RRC	9363	May-03	Revenue Requirements
128.	TXU Gas Company	Texas RRC	9400	May-03 Jan-04	Rate of Return
129.	Eastrans Limited Partnership	Texas RRC	9386	May-03	Rate of Return
130.	CenterPoint Energy Entex	City of Houston		Jun-03	Rate of Return
131.	East Texas Gas Systems, L.P.	Texas RRC	9385	Jun-03	Rate of Return
132.	ENSTAR Natural Gas Company	Alaska RCA	U-03-084	Aug-03 Nov-03	Line Extension Surcharge
133.	CenterPoint Energy Arkla	Louisiana PSC		Nov-03	Rate of Return
134.	ENSTAR Natural Gas Company	Alaska RCA	U-03-091	Feb-04	Cost Separation and Taxes

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
135.	Sid Richardson Pipeline, Ltd.	Texas RRC	9532	Jun-04 Nov-04	Revenue Requirements
136.	ETC Katy Pipeline, Ltd.	Texas RRC	9524	Sep-04	Revenue Requirements
137.	CenterPoint Energy Entex	Mississippi PSC	03-UN-0831	Sep-04	Rate Formula
138.	Centana Intrastate Pipeline LLC	Texas RRC	9527	Sep-04	Rate of Return
139.	SEMCO Energy	Michigan PSC	U-14338	Dec-04	Revenue Requirements
140.	Atmos Energy – Energas	Texas RRC	9539	Feb-05	Regulatory Policy
141.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9613	Sep-05	Revenue Requirements
142.	SiEnergy, L.P.	Texas RRC	9604	Dec-05	Rate of Return, Income Taxes, and Cost Allocation
143.	ENSTAR Natural Gas Company	Alaska RCA	TA-140-4	Feb-06	Connection Fees
144.	SEMCO Energy	Michigan PSC	U-14984	May-06 Dec-06	Revenue Requirements
145.	Atmos Energy – Mid-Tex	Texas RRC	9676	May-06 Oct-06	Revenue Requirements
146.	EasTrans Limited Partnership	Texas RRC	9659	Jun-06	Rate of Return
147.	Kinder Morgan Texas Pipeline, L.P.	Texas RRC	9688	Jul-06	Rate of Return
148.	Crosstex CCNG Transmission Ltd.	Texas RRC	9660	Aug-06	Revenue Requirements
149.	Enbridge Pipelines (North Texas), LP	Texas RRC	9691	Oct-06	Rate of Return
150.	Panther Interstate Pipeline Energy	FERC	CP03-338-00	Mar-07	Revenue Requirements
151.	El Paso Electric Company	Texas PUC	34494	Jul-07	CCN
152.	El Paso Electric Company	NM PRC	07-00301-UT	Jul-07	CCN
153.	Atmos Energy	Kansas CC	08-ATMG-280-RTS	Sep-07 Feb-08	Rate of Return on Equity
154.	Centana Intrastate Pipeline LLC	Texas RRC	9759	Sep-07	Rate of Return
155.	Texas Gas Service Company	Texas RRC	9770	Nov-07	Rate of Return
156.	ENSTAR Natural Gas Company	Alaska RCA	U-08-25	Jun-08	Rate Class Switching
157.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-131-301	Oct-08	Rate of Return
158.	ExxonMobil Pipeline Co.	Alaska RCA	TL-140-304	Nov-08	Rate of Return
159.	Crosstex North Texas Pipeline, L.P.	Texas RRC	9843	Dec-08	Revenue Requirements
160.	Koch Alaska Pipeline Company	Alaska RCA	TL 128-308	Dec-08	Rate of Return
161.	Unocal Pipeline Company	Alaska RCA	TL 118-312	Dec-08	Rate of Return

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
162.	ETC Katy Pipeline, Ltd.	Texas RRC	9841	Dec-08	Revenue Requirements
163.	Oklahoma Natural Gas	Oklahoma CC	200800348	Jan-09	Rate of Return on Equity
164.	Entergy Mississippi, Inc.	Mississippi PSC	EC-123-0082	Mar 09	Rate of Return on Equity
165.	ENSTAR Natural Gas Company	Alaska RCA	U-09-69 U-09-70	Jun-09 Jul-09 Oct-09	Revenue Requirements, Cost Allocation, and Rate Design
166.	EasTrans, LLC	Texas RRC	9857	Jun-09	Rate of Return
167.	Oklahoma Natural Gas	Oklahoma CC	200900110	Jun-09	Rate of Return
168.	Crosstex CCNG Transmission Ltd.	Texas RRC	9858	Jun-09	Revenue Requirements
169.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul-09	Rate of Return
170.	ENSTAR Natural Gas Company	Alaska RCA	U-08-142	Jul-09	Gas Cost Adjustment
171.	Kinder Morgan Texas Pipeline, LLC	Texas RRC	9889	Jul-09	Rate of Return
172.	Koch Alaska Pipeline Company	Alaska RCA	TL 133-308	Aug-09	Rate of Return
173.	ExxonMobil Pipeline Co.	Alaska RCA	TL-147-304	Nov-09	Rate of Return
174.	Texas Gas Service Company	El Paso PURB	--	Dec-09	Rate of Return
175.	Unocal Pipeline Company	Alaska RCA	TL126-312	Dec-09	Rate of Return
176.	Kuparuk Transportation Company	Alaska RCA	P-08-05	Apr-10	Rate of Return
177.	Trans-Alaska Pipeline System	FERC	ISO9-348-000	Apr 10 Oct 10	Rate of Return
178.	Texas Gas Service	Texas RRC	9988	May 10 Aug 10	Rate of Return
179.	SEMCO Energy Gas Company	Michigan PSC	U-16169	Jun 10 Dec 10	Revenue Requirements
180.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-137-301	Jul 10	Rate of Return
181.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-308	Aug 10	Rate of Return
182.	CPS Energy	Texas PUC	36633	Sep 10 Apr 11	Rate of Return for MOU
183.	ExxonMobil Pipeline Co.	Alaska RCA	TL-151-304	Dec 10	Rate of Return
184.	Unocal Pipeline Company	Alaska RCA	TL132-312	Feb 11	Rate of Return
185.	New Mexico Gas Company	NM PRC	11-00042-UT	Mar 11	Rate of Return
186.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-143-301	May 11	Rate of Return

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
187.	Enbridge Pipelines (Southern Lights)	FERC	IS11-146-000	Jun 11 Nov 11	Rate of Return
188.	Koch Alaska Pipeline Company, LLC	Alaska RCA	TL-138-___	Jul 11	Rate of Return
189.	Unocal Pipeline Company	Alaska RCA	TL126-___	Dec 11	Rate of Return
190.	Kansas Gas Service	Kansas CC	12-KGSC-835-RTS	May 12 Oct 12	Rate of Return
191.	ExxonMobil Pipeline Co.	Alaska RCA	TL-157-304	Jun 12	Rate of Return
192.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-149-301	Jul 12	Rate of Return
193.	Seaway Crude Pipeline Company	FERC	IS12-226-000	Aug 12 Feb 13	Rate of Return
194.	Cross Texas Transmission, LLC	Texas PUC	40604	Aug 12 Oct 12 Nov 12	Revenue Requirements
195.	Wind Energy Transmission Texas	Texas PUC	40606	Aug 12 Nov 12	Revenue Requirements
196.	Lone Star Transmission LLC	Texas PUC	40798	Nov 12	Revenue Requirements
197.	West Texas Gas Company	Texas RRC	10235	Jan 13	Rate of Return
198.	Cross Texas Transmission, LLC	Texas PUC	41190	Feb 13	Revenue Requirements
199.	ExxonMobil Pipeline Co.	Alaska RCA	TL-162-304	Apr 13	Rate of Return
200.	EasTrans,LLC	Texas RRC	10276	Jul 13	Rate of Return
201.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-152-301	Jul 13	Rate of Return
202.	BP Pipelines (Alaska) Inc.	Alaska RCA	TL-143-311	Sep 13	Rate of Return
203.	Wind Energy Transmission Texas	Texas PUC	41923	Oct 13	Revenue Requirements
204.	Oliktok Pipeline Company	Alaska RCA	P-13-013	Nov 13	Rate of Return
205.	Aqua Texas Southeast Region-Gray	Texas CEQ	2013-2007-UCR	Apr 14	Revenue Requirements
206.	Entergy Mississippi	Mississippi PSC	EC-123-0082	Jun 14	Rate of Return on Equity
207.	Westlake Ethylene Pipeline	Texas RRC	10358	Jul 14 Aug 15	Rates
208.	ExxonMobil Pipeline Co.	Alaska RCA	TL-164-304	Jul 14	Rate of Return
209.	ConocoPhillips Transportation Alaska	Alaska RCA	TL-154-301	Aug 14	Rate of Return
210.	ENSTAR Natural Gas Company	Alaska RCA	TA-262-4	Sep 14 Jun 15	Revenue Requirements, Cost Allocation, and Rate Design

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
211.	Oliktok Pipeline Company	Alaska RCA	TL-44-334	Mar 15	Rate of Return
212.	Entergy Arkansas, Inc.	Arkansas PSC	15-0150U	Apr 15 Oct 15 Dec 15	Rate of Return on Equity
213.	Wind Energy Transmission Texas	Texas PUC	44746	Jun 15	Revenue Requirements
214.	Texas City	Texas RRC	10408	Jun 15 Nov 15	Pipeline Annual Assessment
215.	Oklahoma Natural Gas	Oklahoma CC	201500213	Jul 15 Nov 15	Rate of Return
216.	PTE Pipeline LLC	Alaska RCA	P-12-015	Sep 15	Rate of Return
217.	Northeast Transmission Development, LLC	FERC	ER16-453	Dec 15	Formula Rates
218.	Oncor Electric Delivery	Texas PUC	45188	Dec 15	Public Interest of Acquisition
219.	Corix Utilities (Texas)	Texas PUC	45418	Dec 15 Oct 16	Rate of Return
220.	Texas Gas Service	Texas RRC	10488	Dec 15	Rate of Return
221.	Texas Gas Service	Texas RRC	10506	Mar 16 Jun 16	Rate of Return
222.	Kansas Gas Service	Kansas CC	16-KGSG-491-RTS	May 16 Sep 16	Rate of Return on Equity
223.	ENSTAR Natural Gas Company	Alaska RCA	TA-285-4	Jun 16 Apr 17	Revenue Requirements, Cost Allocation, and Rate Design
224.	Texas Gas Service	Texas RRC	10526	Jun 16	Rate of Return
225.	West Texas LPG Pipeline	Texas RRC	10455	Aug 16 Jan 17	Rates and Rate of Return
226.	Liberty Utilities	Texas PUC	46356	Sep 16 Feb 17 Jun 17	Revenue Requirements and Rate of Return
227.	DesertLink LLC	FERC	ER17-135	Oct 16	Formula Rates
228.	Houston Pipe Line Co.	Texas RRC	10559	Nov 16	Revenue Requirements
229.	Texas Gas Service	Texas RRC	10656	Jun 17	Rate of Return
230.	Trans-Pecos Pipeline	Texas RRC	10646	Sep 17 Feb 18	Revenue Requirements
231.	Comanche Trail Pipeline	Texas RRC	10647	Sep 17 Feb 18	Revenue Requirements
232.	Alpine High Pipeline	Texas RRC	10665	Oct 17 Feb 18	Revenue Requirements

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No.	Utility Case	Agency	Docket	Date	Nature of Testimony
233.	SiEnergy, LP	Texas RRC	10679	Jan 18	Rate of Return
234.	Targa Midland Gas Pipeline LLC	Texas RRC	10690	Jan 18	Revenue Requirements
235.	ET Fuel, LP	Texas RRC	10706	Apr 18	Revenue Requirements
236.	Texas Gas Service	Texas RRC	10739	Jun 18	Rate of Return
237.	Kansas Gas Service	Kansas CC	18-KGSG-560-RTS	Jun 18 Nov 18	Rate of Return on Equity
238.	Oliktok Pipeline Company	Alaska RCA	TL46-334	Jul 18	Rate of Return
239.	Red Bluff Express, LLC	Texas RRC	10752	Jul 18	Revenue Requirements
240.	PTE Pipeline LLC	Alaska RCA	P-18-0__	Jul 18	Rate of Return
241.	Agua Blanca, LLC	Texas RRC	10761	Aug 18	Revenue Requirements
242.	Texas Gas Service	Texas RRC	10766	Aug 18	Rate of Return
243.	Republic Transmission LLC	FERC	ER19-___	Dec 18	Formula Rates
244.	Gulf Coast Express Pipeline LLC	Texas RRC	10825	Feb 19	Revenue Requirements
245.	Cook Inlet Natural Gas Storage Alaska, LLC	Alaska RCA	U-18-043	Mar 19 Apr 19	Accumulated Deferred Income Taxes and Working Capital
246.	Impulsora Pipeline LLC	Texas RRC	10829	Mar 19	Revenue Requirements
247.	SEMCO Energy Gas Co.	Michigan PSC	U-20479	May 19 Oct 19	Revenue Requirements
248.	Liberty Utilities (Fox River) LLC	AAA	01-18-0002-2510	Jul 19 Oct 19	Revenue Requirements
249.	AMP Intrastate Pipeline LLC	Texas RRC	10887	Aug 19	Revenue Requirements
250.	Corix Utilities (Texas) Inc.	Texas PUC	49923	Aug 19 Jul 20 Aug 20	TCJA Tax Expense Reduction
251.	Colonial Pipeline Company	FERC	OR18-7-003	Nov 19 Feb 20 May 20 Jul 20	Rate of Return
252.	Texas Gas Service	Texas RRC	10928	Dec 19 Apr 20	Rate of Return
253.	Mississippi Power Company	Mississippi PSC	2019-UN-219	Feb 20	Rate of Return on Equity
254.	Corix Utilities (Texas)	Texas PUC	50557	Mar 20 Mar 21	Rate of Return and Excess ADFIT
255.	SouthCross CCNG Transmission	Texas RRC	10967	May 20	Revenue Requirements
256.	Kinder Morgan Border Pipeline LLC	Texas RRC	10980	Jun 20	Revenue Requirements

257.	Monarch Utilities I LP	Texas PUC	50944	Jul 20 Nov 20	Rate of Return
258.	West Texas Gas, Inc.	Texas RRC	10998	Aug 20	Revenue Requirements, Rate of Return, and Cost of Service Study
259.	Centric Gas Services, LLC	Texas RRC		Oct 20	Rate of Return
260.	CoServ Gas, Ltd	Texas RRC	00005136	Nov 20	Rate of Return
261.	Permian Highway Pipeline LLC	Texas RRC	00005306	Dec 20	Revenue Requirements
262.	Whistler Pipeline LLC	Texas RRC	00005675	Feb 21	Revenue Requirements
263.	Oklahoma Natural Gas	Oklahoma CC	202100063	May 21 Oct 21	Rate of Return
264.	Oliktok Pipeline Company	Alaska RCA	TL47-334	Jul 21	Rate of Return
265.	Participating Gas Utilities	Texas RRC	00007061	Jul 21 Oct 21	Excess Gas Cost Securitization
266.	Texas Pipeline Webb County Lean System, LLC	Texas RRC	00008188	Nov 21	Revenue Requirements
267.	Legend Gas Pipeline LLC	Texas RRC	00008714	Jan 22	Revenue Requirements
268.	Oliktok Pipeline Company	Alaska RCA	TL48-334	Mar 22	Rate of Return
269.	Texas Gas Service	Texas RRC	00009896	Jun 22 Oct 22	Rate of Return
270.	ENSTAR Natural Gas Company	Alaska RCA	U-22-081	Aug 22 Jul 23	Income Taxes, Cost Allocation, and Rate Design
271.	Acacia Natural Gas, L.L.C.	Texas RRC	00010150	Aug 22	Revenue Requirements
272.	Corix Utilities (Texas)	Texas PUC	53815	Aug 22 Sep 23	Rate of Return, Cost Allocation, and Rate Design
273.	Oliktok Pipeline Company	Alaska RCA	TL50-334/51-334	Dec 22	Rate of Return
274.	Delaware-Permian Pipeline LLC	Texas RRC	00013058	Mar 23	Revenue Requirements
275.	SiEnergy LLC	Texas RRC	00013504	Mar 23	Rate of Return
276.	Texas Gas Service	Texas RRC	00014399	Jun 23	Rate of Return
277.	CoServ Gas, Ltd	Texas RRC	00014771	Jul 23	Rate of Return
278.	Matterhorn Express Pipeline, LLC	Texas RRC	00014719	Aug 23	Revenue Requirements
279.	TPL SouthTex Transmission Co. LP	Texas RRC	00015056	Aug 23	Revenue Requirements
280.	Kansas Gas Service	Kansas CC	24-KGSG-610-RTS	Mar 24	Rate of Return on Equity
281.	Delaware Link Ventures, LLC	Texas RRC	0000124190	Mar 24	Revenue Requirements

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2023.
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.
Commission file number 001-36108

ONE Gas, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	**46-3561936**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 East Fifth Street **Tulsa, OK**	**74103**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(918) 947-7000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of exchange on which registered
Common Stock, par value $0.01 per share	OGS	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the equity securities held by nonaffiliates based on the closing trade price of the registrant on June 30, 2023, was $4.1 billion.

On February 16, 2024, we had 56,546,006 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 23, 2024, are incorporated by reference in Part III.

No family relationship exists between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we believe we have discussed the key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including Forward-Looking Statements, which are included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

OPERATIONAL RISKS

Our business is subject to operational hazards and unforeseen interruptions that could materially and adversely affect our business and for which we may not be insured adequately.

We are subject to all the risks and hazards typically associated with the natural gas distribution business that could affect the public safety as well as the reliability of our distribution system. Operating risks include, but are not limited to, leaks, accidents, pipeline ruptures and the breakdown or failure of equipment or processes. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment or vehicles with our pipeline facilities and catastrophic events, such as severe weather events, hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, earthquakes, floods, acts of terrorism, pandemics and other health crises, or other similar events beyond our control. Climate change could cause these catastrophic events to become more severe or more frequent. It is also possible that our facilities, or those of our counterparties or service providers, could be direct targets or indirect casualties of an act of terrorism, including cyber-attacks. These issues could result in legal liability, repair and remediation costs, increased operating costs, significantly increased capital expenditures, regulatory fines and penalties and other costs and a loss of customer confidence.

Our general liability, cyber, and property insurance policies for many of these hazards and risks are subject to certain limits, deductibles, and policy exclusions. The insurance proceeds received for any loss of, or any damage to, any of our systems or facilities or to third parties may not be sufficient to restore the total loss or damage. Further, the proceeds of any such insurance may not be received in a timely manner. The occurrence of any of the foregoing could have a material adverse effect on our financial condition, results of operations and cash flows.

We may be unable to attract and retain management and professional and technical employees, or we may experience workforce disruptions due to strikes or work stoppages by our unionized employees, which could adversely impact our operations, earnings, and cash flows.

Our ability to implement our business strategy, satisfy our regulatory requirements, and serve our customers is dependent upon our ability to continue to recruit and employ a skilled, agile, diverse, and engaged workforce consisting of talented and experienced managers, professional and technical employees. The competition for talent has become increasingly intense and we may experience increased employee turnover due to a tight labor market. If we are unable to recruit and retain an appropriately qualified workforce, we could encounter operating challenges primarily due to a loss of institutional knowledge and expertise, errors due to inexperience, or the lengthy time period typically required to adequately train replacement personnel. In addition, higher costs could result from loss of productivity, increased safety compliance issues, or cost of contract labor. Additionally, approximately 18 percent of our employees are represented by collective-bargaining units under collective-bargaining agreements. Disputes over the agreements or failure to timely and effectively renegotiate new agreements upon their expiration could have a negative effect on our business, financial condition and results of operations or result in a work stoppage. Any future work stoppage could, depending on the breadth and the length of the work stoppage, have a material adverse effect on our financial condition, results of operations and cash flows.

The availability of adequate natural gas pipeline transportation and storage capacity and natural gas supply may decrease and impair our ability to meet customers' natural gas requirements and our financial condition may be adversely affected.

In order to meet customers' natural gas demands, we rely on and must obtain sufficient natural gas supplies, pipeline transportation and storage capacity from third parties. If we are unable to obtain these, our ability to meet our customers' natural gas requirements could be impaired. If a substantial disruption to or reduction in natural gas supply, pipeline capacity or storage capacity occurred due to operational failures or disruptions, legislative or regulatory actions, hurricanes, tornadoes, floods, earthquakes, extreme cold weather, acts of terrorism, or cyber-attacks or acts of war, our operations or financial results could be adversely affected.

Our business increasingly relies on technology, the failure of which may adversely affect our financial results and cash flows.

Due to technological advances, we have become more reliant on technology to effectively operate our business. We use computer programs and applications to help run our business, including an enterprise resource planning system that integrates data and reporting activities across our Company. Additionally, certain portions of our IT systems and infrastructure are provided or maintained by third-party vendors. The failure of these or other similarly important technologies, the lack of alternative technologies, or our inability to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder our operations, and adversely impact our financial condition and results of operations.

The occurrence of cyber breaches or physical security attacks on our business, or those of third parties, may disrupt or adversely affect our operations or result in the loss or misuse of confidential and proprietary information.

Any cyber breaches or physical security attacks, or threats of such attacks, that affect our IT systems, distribution facilities, customers, suppliers and third-party service providers or any financial data could disrupt normal business operations, expose sensitive information, and/or lead to physical damages that may have a material adverse effect on our business. A severe attack or security breach could adversely affect our business reputation, diminish customer confidence, disrupt operations, subject us to financial liability or increased regulation, increase our costs and expose us to material legal claims and liability which may not be fully covered by insurance, and our business, financial condition, results of operations and cash flows could be adversely affected. As cyber or physical security attacks become more frequent and sophisticated, we could be required to incur increased costs to strengthen our systems or to obtain additional insurance coverage against potential losses. Federal and state regulatory agencies, such as DHS and TSA, are increasingly focused on risks related to physical security and cybersecurity in general and have promulgated more stringent security regulations specifically for certain federal contractors and critical infrastructure sectors, including natural gas distribution. Any failure to comply with such government regulations may have a material adverse effect on our results of operations and financial condition.

We are subject to various risks associated with climate change which could increase our operating costs or restrict our opportunities in new or existing markets, adversely affecting our financial results, growth, cash flows and results of operations.

Climate change may increase the likelihood of extreme weather in our service territory, and our customers' energy use could increase or decrease depending on the duration and magnitude of any changes. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues and cash flows which are not adequately offset by our WNA mechanisms. Extreme weather conditions in general require increased system resiliency, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues and cash flows by affecting natural gas prices and the availability of our leased transportation and storage capacity. Weather impacts our operations primarily through severe weather events, including hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, snow and ice storms, earthquakes, floods, or other similar events beyond our control. To the extent the frequency of extreme weather events increases, our costs of providing service and our working capital requirements could increase.

REGULATORY AND LEGISLATIVE RISKS

We are subject to federal, state, and local regulation of the safety of our systems and operations, including pipeline safety, system integrity, and the safety of our employees and facilities that may require significant expenditures or, in the case of noncompliance, substantial fines or penalties.

We are subject to regulation under federal pipeline safety statutes promulgated by PHMSA, DOT, OSHA, and any analogous state regulations. These include safety requirements for the design, construction, operation, and maintenance of pipelines, including transmission and distribution pipelines. Additionally, the workplaces associated with our facilities are subject to the requirements of DOT and OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. Compliance with existing or new laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers or may impact materially our competitive position relative to other energy providers. The failure to comply with these laws, regulations and other requirements, or an accident or injury to employees could expose us to civil or criminal liability, enforcement actions, fines, penalties, or injunctive measures that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations, cash flows, and reputation.

We are subject to federal, state, and local laws, rules and regulations that could impact our ability to earn a reasonable rate of return on our invested capital and to fully recover our invested capital, operating costs, and natural gas costs.

We are subject to regulatory oversight from various federal, state, and local regulatory authorities, including the OCC, KCC, RRC and various municipalities in Texas. Regulatory actions from these authorities relate to allowed rates of return, rate design and construct, and purchased gas and operating cost recovery. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by regulatory authorities or third-party intervenors. Our ability to obtain timely future rate increases depends on regulatory discretion and therefore, there can be no assurance that we will be able to obtain rate increases, fully recover our costs or that our authorized rates of return will continue at the current levels, which could adversely impact our results of operations, financial condition, and cash flows.

In the normal course of business, assets are placed in service before regulatory action is taken, such as filing a rate case or seeking interim recovery under a capital tracking mechanism that could result in an adjustment of our returns. Once we make a regulatory filing, regulatory bodies have the authority to suspend implementation of the new rates while evaluating the filing. Because of this process, we may suffer the negative financial effects of having placed assets in service that do not initially earn our authorized rate of return or may not be allowed recovery on such expenditures at all.

We are subject to environmental regulations and legislation, including those intended to address climate change, which could increase our operating costs, adversely affecting our financial results, growth, cash flows and results of operations.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities, including the EPA and any analogous state agencies, relating to protection of the environment, including those that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites, and other properties associated with our operations be operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. The failure to comply with any laws, regulations, permits and other requirements, or the discovery of presently unknown environmental conditions, could expose us to civil or criminal liability, enforcement actions and regulatory fines and penalties and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to regulate greenhouse gas emissions, including carbon dioxide and methane, as a response to the threat of climate change. Various states and municipalities have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on areas such as greenhouse gas cap and trade programs, carbon taxes, reporting and tracking programs, and restrictions on emissions. Such laws or regulations could impose costs tied to carbon emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also incentivize alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates.

We are subject to federal, state, and local laws, rules and regulations that could affect our operations and financial results.

Our business and operations are subject to regulation by a number of federal agencies, including FERC, CFTC, IRS and various state agencies in Oklahoma, Kansas, and Texas, and we are subject to numerous other federal and state laws and regulations. Future changes to laws, regulations and policies may impair our ability to compete for business or recover costs and could adversely affect our cash flows, restrict our ability to make capital investments and may cause us to increase debt and take other actions to conserve cash. Any compliance failure related to these laws and regulations may result in fines, penalties or injunctive measures affecting our operating assets. The fines or penalties for noncompliance with laws and regulations may not be recoverable through our rates. Our failure to comply with applicable regulations could result in a material adverse effect on our business, financial condition, results of operations and cash flows.

FINANCIAL, ECONOMIC AND MARKET RISKS

Unfavorable economic and market conditions could adversely affect our financial condition, earnings, cash flows and limit our future growth.

Weakening economic activity in our markets and supply chain disruptions could result in a loss of existing customers, fewer new customers, especially in newly constructed homes and other buildings, or a decline in energy consumption, any of which could adversely affect our revenues or restrict our future growth. These conditions may make it more difficult for customers to pay their natural gas bills, leading to slow collections and higher-than-normal levels of accounts receivable, which in turn could increase our financing requirements and bad debt expense. Customers may also experience difficulties paying their natural gas bills in the instance of severe weather events that result in higher usage and higher natural gas prices, reducing our collections and increasing our financing requirements and bad debt expense, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity, and prospects.

Changes in supply and demand within the natural gas markets, as well as other factors, could cause an increase in the price of natural gas. Market conditions can also lead to short-term price spikes in natural gas prices, such as high demand during periods of extreme cold weather or system constraints at specific delivery locations. An increase in the price of natural gas could cause us to experience a significant increase in short-term or long-term debt because we must pay suppliers for natural gas when purchased.

We cannot predict the timing, severity, or duration of any future economic slowdowns or natural gas market disruptions. Fluctuations and uncertainties in the economy may result in higher interest rates and inflationary pressures on the costs of goods, services, and labor. This could increase our expenses and capital spending and decrease our cash flows if we are not able to recover or recover timely such increased costs from our customers. The foregoing could adversely affect our business, financial condition, results of operations and cash flows.

Our business activities are concentrated in three states.

We provide natural gas distribution services to customers in Oklahoma, Kansas, and Texas. Changes in the regional economies, politics, regulations, regulatory decisions by state and local regulatory authorities, and weather patterns of these states could adversely impact our financial condition, results of operations and cash flows.

The inability to access capital or significant increases in the cost of capital could adversely affect our results of operations, cash flows and financial condition.

Our ability to obtain adequate and cost-effective financing is dependent upon the liquidity of the financial markets, as well as our financial condition and credit ratings. Our long-term debt is currently rated as “investment grade” by both of our rating agencies. We rely upon access to both the short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions or a downgrade in our ratings outlook were to cause a significant limitation on our access to the private credit and public capital markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or a reduction in our credit ratings by one or both of our rating agencies. Such a downgrade could further limit our access to private credit and/or public capital markets and increase our costs of borrowing. Additionally, the inability to access adequate capital or an increase in the cost of capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate our dividend or other discretionary uses of cash.

Our financing arrangements subject us to various restrictions that could limit our operating flexibility, earnings, and cash flows.

The indentures governing our Senior Notes and our ONE Gas Credit Agreement contain customary covenants that restrict our ability to create or permit certain liens, to consolidate or merge, or to convey, transfer or lease substantially all of our properties and assets. Events beyond our control could impair our ability to satisfy these requirements. As long as our indebtedness remains outstanding, these restrictive covenants could impair our ability to expand or pursue our growth strategy.

In addition, the breach of any covenants or any payment obligations in any of these debt agreements will result in an event of default under the applicable debt instrument. If an event of default were to occur, the holders of the defaulted debt may have the ability to cause all amounts outstanding with respect to that debt to be due and payable, subject to applicable grace periods. This could trigger cross-defaults under our other debt agreements, including our Senior Notes. Forced repayment of some or all of our indebtedness could require us to incur new debt at a higher cost, which would have an adverse impact on our financial condition, results of operations and cash flows.

We may pursue acquisitions, divestitures, and other strategic opportunities which, if not successful, may adversely impact our results of operations, cash flows and financial condition.

As part of our strategic objectives, we may pursue acquisitions to complement or expand our business, as well as divestitures and other strategic opportunities. We may not be able to successfully negotiate, finance or receive regulatory approval for future acquisitions or integrate the acquired businesses with our existing business and services. These efforts may also distract our management and employees from day-to-day operations and require substantial commitments of time and resources. Future acquisitions could result in potentially dilutive issuances of equity securities, a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition, the incurrence of debt, contingent liabilities and amortization expenses and substantial goodwill. The effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. We may be materially and adversely affected if we are unable to successfully integrate businesses that we acquire.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

We commit significant resources to protecting and continuing to improve the security of our computer systems, software, networks, and other information or operations technology assets. Our cybersecurity efforts are designed to preserve the confidentiality, integrity, and continued availability of all information owned by, or in the care of, the Company and protect against, among other things, cybersecurity attacks by unauthorized parties attempting to obtain access to confidential information, destroy data, disrupt or degrade service, sabotage systems, or otherwise cause damage.

Governance

Our Board of Directors considers cybersecurity risk one of the significant risks to our business. As such, the Board of Directors has retained responsibility for overseeing policies and procedures related to cybersecurity and data privacy matters. The Board of Directors routinely evaluates our cybersecurity strategy to review its effectiveness. Management provides reports to the Board of Directors at least quarterly regarding cybersecurity and other information and operations technology risks.

The Company established a governance committee to provide governance and oversight of security and compliance related activities for security and IT in support of their effective and efficient management of risks, strategies, and operational imperatives for the Company. The committee is chaired by our Chief Information Officer and the membership includes a cross-functional team of executives from IT/cybersecurity, operations, customer service, commercial, risk and insurance, finance, and the legal department. The committee is structured to cultivate collaboration across the enterprise and to align and prioritize resources with our strategic plan.

Risk Management and Strategy

The cybersecurity function is centralized under the Senior Vice President and Chief Information Officer, who has over three decades of experience in information technology. The cybersecurity function is comprised of a dedicated team of professionals who work continuously to monitor risks relating to cybersecurity resilience strategy, policy, standards, architecture, and

TEXAS GAS SERVICE
A Division of ONE Gas, Inc.
Central Gulf Service Area

OVERALL RATE OF RETURN

Capital Component	Amounts	Percent of Total	Component Cost	Weighted Cost
Long-term Debt	$ 1,876,670	40.42%	4.39%	1.77%
Common Equity	2,765,877	59.58%	10.25%	6.11%
Total	**$ 4,642,547**	**100.00%**		**7.88%**

TEXAS GAS SERVICE
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Central Gulf Service Area

LDC PROXY GROUP CAPITAL STRUCTURE RATIOS

	2023 (a)		2022 (a)		2021 (a)		2020 (a)		2019 (a)	
Company	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**
Atmos Energy	37.9%	62.1%	37.9%	62.1%	38.4%	61.6%	40.0%	60.0%	38.0%	62.0%
Chesapeake Utilities	43.0%	57.0%	41.0%	59.0%	41.5%	58.5%	42.2%	57.8%	43.9%	56.1%
New Jersey Resources	58.2%	41.8%	57.8%	42.2%	57.0%	43.0%	55.1%	44.9%	49.8%	50.2%
NiSource	57.5%	42.5%	55.7%	44.3%	56.9%	43.1%	61.6%	38.4%	56.8%	43.2%
Northwest Natural Gas	54.0%	46.0%	51.5%	48.5%	52.8%	47.2%	49.2%	50.8%	48.2%	51.8%
Spire	54.9%	45.1%	51.2%	48.8%	52.5%	47.5%	49.0%	51.0%	45.0%	55.0%
LDC GROUP AVERAGE	**50.9%**	**49.1%**	**49.2%**	**50.8%**	**49.9%**	**50.2%**	**49.5%**	**50.5%**	**47.0%**	**53.1%**
Minimum	37.9%	41.8%	37.9%	42.2%	38.4%	43.0%	40.0%	38.4%	38.0%	43.2%
Maximum	58.2%	62.1%	57.8%	62.1%	57.0%	61.6%	61.6%	60.0%	56.8%	62.0%

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 23, 2024).

TEXAS GAS SERVICE
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Central Gulf Service Area

DCF MODEL -- DIVIDEND YIELD

Company	Ticker	Expected Dividend (a)	Price (b)	Dividend Yield (c)
Atmos Energy	ATO	$ 3.34	$ 115.86	2.88%
Chesapeake Utilities	CPK	$ 2.48	$ 104.24	2.38%
New Jersey Resources	NJR	$ 1.68	$ 42.23	3.98%
NiSource	NI	$ 1.06	$ 26.87	3.95%
Northwest Natural Gas	NWN	$ 1.95	$ 36.83	5.29%
ONE Gas	OGS	$ 2.65	$ 62.27	4.26%
Spire	SR	$ 3.06	$ 60.23	5.08%
AVERAGE				**3.97%**
MEDIAN				**3.98%**

(a) *The Value Line Investment Survey* "Summary & Index" (April 5, 2024).
(b) *Yahoo!* Finance (average of daily closing prices during March 2024).
(c) Expected Dividend / Price.

DCF MODEL -- EARNINGS GROWTH RATES

	Projected Growth			Historical Growth	
Company	**Value Line (a)**	**I/B/E/S LSEG (b)**	**Zacks (d)**	**10-Year (a)**	**5-Year (a)**
Atmos Energy	7.0%	7.5%	7.3%	9.5%	9.0%
Chesapeake Utilities	5.0%	7.6%	N/R	9.0%	10.0%
New Jersey Resources	5.0%	N/R	N/R	5.0%	2.5%
NiSource	9.5%	7.3%	7.2%	1.5%	15.0%
Northwest Natural Gas	6.5%	N/R	N/R	-1.0%	2.5%
ONE Gas	4.0%	N/R	5.0%	N/R	6.0%
Spire	4.5%	6.4%	5.6%	5.0%	3.0%
AVERAGE	**5.9%**	**7.2%**	**6.3%**	**4.8%**	**6.9%**
MEDIAN	**5.0%**	**7.4%**	**6.4%**	**5.0%**	**6.0%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 23, 2024).
(b) LSEG Stock Reports Plus (March 29, 2024).
(d) Zacks.com "Snapshot" (Retrieved April 1, 2024).

N/R -- None reported.

TEXAS GAS SERVICE
A Division of ONE Gas, Inc.
Central Gulf Service Area

DCF MODEL -- SUSTAINABLE GROWTH RATES

Company	Ticker	2027-2029 Projected (a) Earnings per Share	Dividends per Share	Book Value per Share	Price per Share	Shares Outstanding (a) 2023	Proj. 27-29	Earnings Retention Growth: Retention Ratio	Return on Equity	"b x r"	External Financing Growth: 2027-2029 Market-to-Book Ratio	Growth Rate in Shares	"s"	"v"	"s x v"	Sustainable Growth
Atmos Energy		$ 8.35	$ 4.25	$ 83.50	$ 137.50	148.49	175.00	49.1%	10.0%	4.9%	1.65	3.3%	5.5%	39.3%	2.2%	7.1%
Chesapeake Utilities		$ 6.50	$ 3.20	$ 66.40	$ 130.00	18.50	23.50	50.8%	9.8%	5.0%	1.96	4.9%	9.6%	48.9%	4.7%	9.7%
New Jersey Resources		$ 3.50	$ 1.95	$ 27.00	$ 60.00	97.57	100.00	44.3%	13.0%	5.7%	2.22	0.5%	1.1%	55.0%	0.6%	6.3%
NiSource		$ 2.10	$ 1.20	$ 18.75	$ 40.00	415.00	450.00	42.9%	11.2%	4.8%	2.13	1.6%	3.5%	53.1%	1.9%	6.7%
Northwest Natural Gas		$ 3.25	$ 1.98	$ 38.70	$ 65.00	37.00	42.00	39.1%	8.4%	3.3%	1.68	2.6%	4.3%	40.5%	1.7%	5.0%
ONE Gas		$ 5.00	$ 2.85	$ 60.20	$ 90.00	55.50	57.00	43.0%	8.3%	3.6%	1.50	0.5%	0.8%	33.1%	0.3%	3.8%
Spire		$ 5.50	$ 3.60	$ 66.05	$ 87.50	53.20	62.00	34.5%	8.3%	2.9%	1.32	3.1%	4.1%	24.5%	1.0%	3.9%
AVERAGE										**4.3%**					**1.8%**	**6.1%**
MEDIAN										**4.8%**					**1.7%**	**6.3%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 23, 2024).

DCF MODEL -- OTHER PROJECTED AND HISTORICAL GROWTH RATES

	Net Book Value (a)			Dividends per Share (a)			Price per Share		
	Pro-	Historical		Pro-	Historical		Pro-	Historical (b)	
Company	jected	10-Year	5-Year	jected	10-Year	5-Year	jected (a)	10-Year	5-Year
Atmos Energy	4.0%	9.5%	12.0%	7.5%	7.0%	8.5%	4.4%	9.7%	2.7%
Chesapeake Utilities	6.0%	9.5%	9.0%	8.5%	7.0%	8.5%	5.7%	9.9%	2.5%
New Jersey Resources	4.5%	7.5%	7.0%	5.0%	6.5%	6.5%	9.2%	6.2%	-3.2%
NiSource	5.0%	-3.0%	0.5%	4.5%	-0.5%	3.5%	10.5%	6.9%	-0.8%
Northwest Natural Gas	4.0%	1.0%	0.5%	0.5%	1.5%	0.5%	15.3%	-1.4%	-10.7%
ONE Gas	4.5%	N/R	4.0%	3.0%	N/R	8.0%	9.6%	N/R	-6.8%
Spire	5.5%	5.5%	3.5%	4.5%	5.0%	5.5%	9.8%	2.7%	-5.7%
AVERAGE	**4.8%**	**5.0%**	**5.2%**	**4.8%**	**4.4%**	**5.9%**	**9.2%**	**5.7%**	**-3.1%**
MEDIAN	**4.5%**	**6.5%**	**4.0%**	**4.5%**	**5.8%**	**6.5%**	**9.6%**	**6.5%**	**-3.2%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 23, 2024).
(b) *Yahoo!* Finance (Average March 2014 and 2019 closing prices to average March 2024 closing price).

N/R -- None reported.

TEXAS GAS SERVICE
A Division of ONE Gas, Inc.
Central Gulf Service Area

CAPITAL ASSET PRICING MODEL

Description	**Historical Rates of Return (a)**	**Forward-Looking Rates of Return (b)**
Market Required Rate of Return	12.04%	11.95%
Long-term Government Bond Return (a)(c)	4.87%	4.36%
Market Risk Premium (d)	7.17%	7.59%
LDC Group Beta (e)	0.86	0.86
LDC Group Risk Premium (f)	6.20%	6.56%
Risk-free Rate of Interest (c)	4.36%	4.36%
Theoretical CAPM Cost of Equity Estimate (g)	10.56%	10.92%
Size Premium (e)	0.93%	0.93%
CAPM Cost of Equity Estimates (h)	**11.49%**	**11.85%**

(a) *Kroll Cost of Capital Navigator.*
(b) Calculated by applying DCF model applied to S&P 500 firms paying dividends (February 15, 2024):

Expected Dividend Yield		1.85%
Projected Earnings Growth Rate:		
Value Line	9.33%	
I/B/E/S	10.41%	
Zacks	10.55%	
Average		10.10%
Market Required Rate of Return		11.95%

(c) March 2024 yield on 30-year U.S. Treasury bonds (Federal Reserve). 4.36%
(d) Market Required Rate of Return minus Long-term Government Bond Return.
(e) Schedule BHF-8.
(f) Market risk premium times beta.
(g) Sum of Risk Premium and Risk-free Rate of Interest.
(h) Sum of Theoretical CAPM Cost of Equity Estimate and Size Premium.

BOND RATINGS, BETA, MARKET CAPITALIZATION, AND SIZE PREMIUMS

Risk Measures

Company	Bond Rating S&P (a)	Bond Rating Moody's (b)	Beta (c)	Market Capitalization (c) (millions)	Premium(d)
Atmos Energy	A-	A1	0.85	$ 17,200	0.46%
Chesapeake Utilities	N/R	N/R	0.80	$ 1,900	1.21%
New Jersey Resources	N/R	A1	0.95	$ 4,100	0.95%
NiSource	BBB+	Baa2	0.90	$ 10,600	0.61%
Northwest Natural Gas	A+	Baa1	0.85	$ 1,300	1.39%
ONE Gas	A-	A3	0.85	$ 3,500	0.95%
Spire	A-	Baa2	0.85	$ 3,300	0.95%
LDC GROUP AVERAGE	**A-**	**A3**	**0.86**	**$ 5,986**	**0.93%**

CRSP Deciles Size Premiums (e)

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
1-Largest	$ 36,942.976	-	$ 2,662,326.048	-0.06%
2	14,910.719	-	36,391.113	0.46%
3	7,493.607	-	14,820.048	0.61%
4	4,622.261	-	7,461.284	0.64%
5	3,011.224	-	4,621.785	0.95%
6	1,864.293	-	3,010.806	1.21%
7	1,050.083	-	1,862.491	1.39%
8	555.880	-	1,046.037	1.14%
9	213.039	-	554.523	1.99%
10- Smallest	1.576	-	212.644	4.70%

(a) Moody's.com (Retreived February 19, 2024).
(b) StandardandPoors.com (Retrieved February 19, 2024).
(c) *The Value Line Investment Survey* "Ratings & Reports" (February 23, 2024).
(d) Kroll Cost of Capital Navigator (Retrieved February 19, 2024).

RISK PREMIUM METHOD

Year	Qtr.		Allowed ROE (a)	Average Utility Bond Yield (b)	Risk Premium
1980	1		13.45%	13.31%	0.14%
	2		14.38%	12.51%	1.87%
	3		13.87%	12.74%	1.13%
	4		14.35%	14.03%	0.32%
1981	1		14.69%	14.64%	0.05%
	2		14.61%	15.48%	-0.87%
	3		14.86%	16.36%	-1.50%
	4		15.70%	16.01%	-0.31%
1982	1		15.55%	16.51%	-0.96%
	2		15.62%	15.87%	-0.25%
	3		15.72%	15.27%	0.45%
	4		15.62%	13.67%	1.95%
1983	1		15.41%	13.45%	1.96%
	2		14.84%	13.07%	1.77%
	3		15.24%	13.38%	1.86%
	4		15.41%	13.33%	2.08%
1984	1		15.39%	13.64%	1.75%
	2		15.07%	14.80%	0.27%
	3		15.37%	14.42%	0.95%
	4		15.33%	13.26%	2.07%
1985	1		15.03%	13.18%	1.85%
	2		15.44%	12.74%	2.70%
	3		14.64%	11.92%	2.72%
	4		14.44%	11.33%	3.11%
1986	1		14.05%	10.05%	4.00%
	2		13.28%	9.35%	3.93%
	3		13.09%	9.25%	3.84%
	4		13.62%	9.17%	4.45%
1987	1		12.61%	8.78%	3.83%
	2		13.13%	9.66%	3.47%
	3		12.56%	10.45%	2.11%
	4		12.73%	11.04%	1.69%
1988	1		12.94%	10.50%	2.44%
	2		12.48%	10.66%	1.82%
	3		12.79%	10.87%	1.92%
	4		12.98%	9.94%	3.04%
1989	1		12.99%	10.07%	2.92%
	2		13.25%	9.85%	3.40%
	3		12.56%	9.38%	3.18%
	4		12.94%	9.34%	3.60%
1990	1		12.60%	9.62%	2.98%
	2		12.81%	9.82%	2.99%
	3		12.34%	9.84%	2.50%
	4		12.77%	9.76%	3.01%
1991	1		12.69%	9.42%	3.27%
	2		12.53%	9.34%	3.19%
	3		12.43%	9.20%	3.23%
	4		12.38%	8.89%	3.49%
1992	1		12.42%	8.76%	3.66%
	2		11.98%	8.72%	3.26%
	3		11.87%	8.37%	3.50%
	4		11.94%	8.44%	3.50%
1993	1		11.75%	8.03%	3.72%
	2		11.71%	7.74%	3.97%
	3		11.39%	7.25%	4.14%
	4		11.15%	7.21%	3.94%
1994	1		11.12%	7.53%	3.59%
	2		10.81%	8.28%	2.53%
	3		10.95%	8.51%	2.44%
	4	(c)	11.64%	8.89%	2.75%
1995	2		11.00%	7.95%	3.05%
	3		11.07%	7.74%	3.33%
	4		11.56%	7.36%	4.20%
1996	1		11.45%	7.43%	4.02%
	2		10.88%	7.98%	2.90%
	3		11.25%	7.96%	3.29%
	4		11.32%	7.61%	3.71%
1997	1		11.31%	7.80%	3.51%
	2		11.70%	7.93%	3.77%
	3		12.00%	7.53%	4.47%
	4	(c)	11.01%	7.26%	3.75%
1998	2		11.37%	7.07%	4.30%
	3		11.41%	6.94%	4.47%
	4		11.69%	6.89%	4.80%
1999	1		10.82%	7.02%	3.80%
	2	(c)	10.82%	7.43%	3.39%
	4		10.33%	7.97%	2.36%
2000	1		10.71%	8.15%	2.56%
	2		11.08%	8.30%	2.78%
	3		11.33%	7.95%	3.38%
	4		12.50%	7.97%	4.53%
2001	1		11.16%	7.68%	3.48%
	2	(c)	10.75%	7.81%	2.94%
	4		10.65%	7.70%	2.95%
2002	1		10.67%	7.71%	2.96%
	2		11.64%	7.72%	3.92%
2002	3		11.50%	7.37%	4.13%
	4		10.78%	7.31%	3.47%
2003	1		11.38%	6.95%	4.43%
	2		11.36%	6.41%	4.95%
	3		10.61%	6.64%	3.97%
	4		10.84%	6.43%	4.41%
2004	1		11.10%	6.14%	4.96%
	2		10.25%	6.53%	3.72%
	3		10.37%	6.18%	4.19%
	4		10.66%	5.95%	4.71%
2005	1		10.65%	5.77%	4.88%
	2		10.52%	5.57%	4.95%
	3		10.47%	5.51%	4.96%
	4		10.40%	5.83%	4.57%
2006	1		10.63%	5.88%	4.75%
	2		10.50%	6.35%	4.15%
	3		10.45%	6.20%	4.25%
	4		10.14%	5.89%	4.25%
2007	1		10.44%	5.92%	4.52%
	2		10.12%	6.13%	3.99%
	3		10.03%	6.27%	3.76%
	4		10.27%	6.15%	4.12%
2008	1		10.38%	6.22%	4.16%
	2		10.17%	6.41%	3.76%
	3		10.49%	6.52%	3.97%
	4		10.34%	7.46%	2.88%
2009	1		10.24%	6.78%	3.46%
	2		10.11%	6.76%	3.35%
	3		9.88%	5.86%	4.02%
	4		10.27%	5.74%	4.53%
2010	1		10.24%	5.89%	4.35%
	2		9.99%	5.73%	4.26%
	3		9.93%	5.20%	4.73%
	4		10.09%	5.43%	4.66%
2011	1		10.10%	5.66%	4.44%
	2		9.85%	5.44%	4.41%
	3		9.65%	4.91%	4.74%
	4		9.88%	4.50%	5.38%
2012	1		9.63%	4.51%	5.12%
	2		9.83%	4.39%	5.44%
	3		9.75%	4.16%	5.59%
	4		10.07%	4.04%	6.03%
2013	1		9.57%	4.27%	5.30%
	2		9.47%	4.32%	5.15%
	3		9.60%	4.84%	4.76%
	4		9.83%	4.84%	4.99%
2014	1		9.54%	4.67%	4.87%
	2		9.84%	4.44%	5.40%
	3		9.45%	4.35%	5.10%
	4		10.28%	4.24%	6.04%
2015	1		9.47%	3.90%	5.57%
	2		9.43%	4.31%	5.12%
	3		9.75%	4.62%	5.13%
	4		9.68%	4.68%	5.00%
2016	1		9.48%	4.49%	4.99%
	2		9.42%	4.05%	5.37%
	3		9.47%	3.74%	5.73%
	4		9.60%	4.17%	5.43%
2017	1		9.60%	4.26%	5.34%
	2		9.47%	4.13%	5.34%
	3		10.14%	3.97%	6.17%
	4		9.68%	3.90%	5.78%
2018	1		9.68%	4.09%	5.59%
	2		9.43%	4.32%	5.11%
	3		9.69%	4.36%	5.33%
	4		9.53%	4.57%	4.96%
2019	1		9.55%	4.37%	5.18%
	2		9.73%	4.07%	5.66%
	3		9.80%	3.53%	6.27%
	4		9.73%	3.46%	6.27%
2020	1		9.35%	3.36%	5.99%
	2		9.55%	3.21%	6.34%
	3		9.52%	2.80%	6.72%
	4		9.50%	2.89%	6.61%
2021	1		9.71%	3.18%	6.53%
	2		9.48%	3.29%	6.19%
	3		9.43%	2.99%	6.44%
	4		9.59%	3.09%	6.50%
2022	1		9.38%	3.65%	5.73%
	2		9.23%	4.68%	4.55%
	3		9.52%	4.99%	4.53%
	4		9.65%	5.66%	3.99%
2023	1		9.75%	5.33%	4.42%
	2		9.45%	5.37%	4.08%
	3		9.66%	5.72%	3.94%
	4		9.63%	5.97%	3.66%
Average			**11.37%**	**7.56%**	**3.81%**

Unadusted:

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07278	+	-0.45825	X	5.59%
RP	=	0.07278	+	-0.02562		
RP	**=**	**4.72%**				

Adjusted (Using Iterative Prais-Winsten algorithm):

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07800	+	-0.53060	X	5.59%
RP	=	0.07800	+	-0.02966		
RP	**=**	**4.83%**				

(a) S&P Global Market Intelligence (various dates and data bases), Regulatory Research Associates (January 16, 1990), and Argus UtilityScope Regulatory Service (January 1986).
(b) Mergent Public Utility Manual (2003); Mergent Bond Record (September 2005); Moody's Credit Perspectives (Various Editions).
(c) No decisions reported for following quarter.
(d) Moody's Investor Services average utility bond yield for March 2024.

COMPARABLE EARNINGS METHOD

	Projected Earned Return on Book Equity (a)		
Company	**2024**	**2025**	**2027-29**
Atmos Energy	8.8%	9.1%	10.0%
Chesapeake Utilities	9.9%	9.7%	9.8%
New Jersey Resources	13.1%	12.6%	13.0%
NiSource	8.6%	9.1%	11.2%
Northwest Natural Gas	7.7%	7.5%	8.4%
Spire	7.8%	7.8%	8.3%
LDC GROUP AVERAGE	**9.3%**	**9.3%**	**10.1%**
MEDIAN	**8.7%**	**9.1%**	**9.9%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 23, 2024).

APPLICATION OF STAFF RETURN ON EQUITY METHODOLOGY

CONSTANT GROWTH DCF 30-Day Share Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Stock Price	Annualized Dividend	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Yahoo EPS Growth	Value Line EPS Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Inc.	ATO	$110.16	$3.22	2.92%	3.03%	7.26%	7.50%	7.00%	7.25%	10.03%	10.28%	10.53%
Chesapeake Utilities	CPK	$93.24	$2.36	2.53%	2.61%	N/R	7.60%	5.00%	6.30%	7.61%	8.91%	10.21%
New Jersey Resources	NJR	$43.62	$1.68	3.85%	3.96%	N/R	6.00%	5.00%	5.50%	8.96%	9.46%	9.96%
Northwest Nat. Gas	NWN	$69.79	$1.95	2.80%	2.86%	N/R	2.80%	6.50%	4.65%	5.66%	7.51%	9.36%
Spire	SR	$82.88	$3.02	3.64%	3.74%	5.62%	6.36%	4.50%	5.49%	8.24%	9.24%	10.10%
			Mean:	3.15%	3.24%	6.44%	6.05%	5.60%	5.84%	8.10%	**9.08%**	10.03%
			Median:							8.24%	9.24%	10.10%

CONSTANT GROWTH DCF 90-Day Share Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Stock Price	Annualized Dividend	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Yahoo EPS Growth	Value Line EPS Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Atmos Energy Inc.	ATO	$114.70	$3.22	2.81%	2.91%	7.26%	7.50%	7.00%	7.25%	9.91%	10.16%	10.41%
Chesapeake Utilities	CPK	$103.24	$2.36	2.29%	2.36%	N/R	7.60%	5.00%	6.30%	7.36%	8.66%	9.96%
New Jersey Resources	NJR	$42.17	$1.68	3.98%	4.09%	N/R	6.00%	5.00%	5.50%	9.09%	9.59%	10.09%
Northwest Nat. Gas	NWN	$37.39	$1.95	5.22%	5.34%	N/R	2.80%	6.50%	4.65%	8.14%	9.99%	11.84%
Spire	SR	$59.80	$3.02	5.05%	5.19%	5.62%	6.36%	4.50%	5.49%	9.69%	10.68%	11.55%
			Mean:	3.87%	3.98%	6.44%	6.05%	5.60%	5.84%	8.84%	**9.82%**	10.77%
			Median:							9.09%	9.99%	10.41%

Ex-Ante CAPM Analysis for Comparable Companies

Company	Ticker Symbol		Beta (Value Line)	10-Yr. Treasury Yield	Market Risk Premium	CAPM k(e)
Atmos Energy Inc.	ATO		0.85	4.21%	7.74%	10.79%
Chesapeake Utilities	CPK		0.80	4.21%	7.74%	10.40%
New Jersey Resources	NJR		0.95	4.21%	7.74%	11.56%
Northwest Nat. Gas	NWN		0.85	4.21%	7.74%	10.79%
Spire	SR		0.85	4.21%	7.74%	10.79%
		Mean	0.86			**10.87%**

Risk Premium derived from average S&P total return of 11.95% - 4.21%.

Average of Mean Values of Staff DCF and CAPM Analyses

DCF (30-Day)	9.08%
DCF Mid-High Average (90-Day)	9.82%
CAPM	10.87%
Average	**9.92%**
Adjustment for Market Uncertainty	0.25%
Rate of Return on Equity	**10.17%**

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF BRUCE H. FAIRCHILD

BEFORE ME, the undersigned authority, on this day personally appeared Bruce H. Fairchild who having been placed under oath by me did depose as follows:

1. "My name is Bruce H. Fairchild. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Principal with Financial Concepts and Applications, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Bruce H. Fairchild

SUBSCRIBED AND SWORN TO BEFORE ME by the said Bruce H. Fairchild on this 21st day of May 2024.

NOTARY PUBLIC STATE OF TEXAS
BRYAN ANDERSON
NOTARY PUBLIC
STATE OF TEXAS
MY COMM. EXP. 11/02/25
NOTARY ID 12592363-3

Notary Public in and for the State of Texas

WORKPAPERS

TO

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

Workpapers to the Direct Testimony of Bruce H. Fairchild are being provided in electronic format.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS	§	
GAS SERVICE COMPANY, A	§	**BEFORE THE**
DIVISION OF ONE GAS, INC., TO	§	
CHANGE GAS UTILITY RATES	§	**RAILROAD COMMISSION**
WITHIN THE UNINCORPORATED	§	
AREAS OF THE CENTRAL-GULF	§	**OF TEXAS**
SERVICE AREA	§	

DIRECT TESTIMONY

OF

TERESA D. SERNA

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF TERESA SERNA

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Teresa D. Serna, and my business address is 1301 South Mopac Expressway, Suite 400, Austin, Texas 78746.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Rates Specialist for Texas Gas Service Company ("TGS" or the "Company"), which is a Division of ONE Gas, Inc.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Master's of Business Administration Degree from West Texas A&M University and a Bachelor's of Business Administration Degree in Finance from Texas State University. I began my career with TGS in November 2009 as a Rates Analyst II and since January 2020, I have been in the role of Rates Specialist. In my current position at TGS, my responsibilities include analyzing revenue related issues, preparing studies, reports and testimony related to cost of service and providing data to support rate design.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony on behalf of TGS in Gas Utilities Docket ("GUD") Nos. 10526, 10506, 10488, 10094, 10285, Docket Nos. OS-22-00009896 ("Docket No. 9896") and Docket No. OS-23-00014399 ("Docket No. 14399") before the Railroad Commission of Texas ("Commission").

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I prepared and sponsor the exhibits listed in the Table of Contents.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents and supports the Class Cost of Service ("CCOS") study and Class Revenue Allocation based on the CCOS study results for the Central-Gulf Service Area ("CGSA"). I support the CCOS study tabs listed in the table below in the integrated model.

Study Summary
Classified Rate Base
Classified Cost of Service
Classification Factors
Allocated Rate Base
Allocated Cost of Service
Allocation Factors
WKP Plant
WKP Admin&Gen
WKP Selected Data
903 Factors
904 Factors
Bill Determinants Summary
Customer Deposit Factors
Mains Study Summary
Meter and Regulator Factors
Odorization Summary

Peak Demand
Service Charges Summary
Service Line Factors
As Adjusted Revenues Summary
Class Revenue Allocation

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. No.

III. CLASS COST OF SERVICE STUDY

Q. WHAT IS A CLASS COST OF SERVICE STUDY?

A. A CCOS study is an analysis that fully allocates a utility's cost of service, or revenue requirement, to each customer class. The components of a utility's revenue requirement, including operating expenses, depreciation, taxes and required return, are distributed to each customer class based on cost causation principles.

Q. PLEASE EXPLAIN THE PURPOSE OF A CCOS STUDY.

A. Upon setting a utility's revenue requirement, the utility must determine how much of its revenue requirement to collect from each customer class. The CCOS study results provide a useful guide in distributing the utility's overall revenue requirement to its customer classes because interclass equity considerations support setting rates so that each customer class pays the approximate cost to serve that class, and interclass inequities can often arise over time when rates for a specific class do not reflect the actual cost of service for that class. Interclass inequities can be due to changes in customer class characteristics, adjustments to rates from interim rate filings and changes in a company's investment and expenses. In identifying both fixed and variable costs, the CCOS study also provides information that is useful in setting monthly customer charges to recover fixed costs and setting usage charges to recover variable costs for each class. Please see the direct testimony of Company witness Paul H. Raab discussing the Company's proposed rate design to recover fixed and variable costs for each class.

Q. HOW IS A CCOS STUDY PREPARED?

A. A CCOS study consists of three steps. The first step is functionalization, where elements of the cost of service are broken down according to the functions they perform. The second step is classification, which involves classifying each of the functionalized components of the cost of service into one of four classifications. The final step is the allocation step, where each of the classified rate base and cost of service components are fully assigned to customer classes based on direct assignment of costs or on application of causally related allocation factors.

Q. PLEASE DISCUSS THE FUNCTIONALIZATION STEP.

A. A gas utility CCOS study typically consists of three functions: (1) production and storage, (2) transmission and (3) distribution. The production and storage function includes the costs of gas wells, gas field lines and gas processing plants. Transmission costs involve the cost of facilities and related expenses associated with delivering gas from production and storage areas to city gates, which are the points at which the gas enters a utility's distribution system. Distribution costs refer to costs and expenses associated with delivering gas from city gates to end use customers and providing associated services such as meter reading, billing and customer service.

Q. PLEASE DISCUSS THE CLASSIFICATIONS USED IN THE CLASSIFICATION STEP.

A. There are four classifications that are used in the second step of a CCOS study. These classifications are (1) customer-related, (2) demand-related, (3) commodity-related and (4) revenue-related costs.

Customer-related costs are those costs that vary with the number of customers or customer locations served, regardless of whether any gas is used. Examples include the cost of a meter at a customer's location and the portion of the cost of distribution mains associated with reaching the customer's location. These costs do not depend on the amount of gas used over the course of the year or at peak periods, but rather are incurred to provide customer access to gas service.

Demand-related costs are defined as those costs that depend on the maximum delivery requirements of the gas system. These delivery requirements are measured by usage at the time of the system's peak. The system's peak usage is based on historically extreme winter weather conditions that relate to sizing facilities that are weather-dependent. An example of demand costs is the portion of the cost of distribution mains associated with the sizing of distribution mains to meet peak loads. Transmission costs and related expenses are another example of demand costs.

Commodity-related costs are defined as those costs that vary with the amount of gas that is delivered to customers. Odorization cost and related expenses are examples of commodity-related costs.[1]

Revenue-related costs are those costs that vary directly with the utility's gross revenue. Revenue-related taxes are examples of revenue-related expenses. In the CCOS study in this case, I have classified revenue-related elements as customer-related and allocated them based on revenues in the allocation step of the study, rather than using a separate revenue classification. The allocated cost results will be the same with this approach as with the use of the separate revenue-based classification.

Q. DO SOME OF THE COST COMPONENTS REQUIRE COMBINATIONS OF CLASSIFICATIONS?

A. Yes, while many cost of service components fall into a single classification, several components involve more than one classification category, which requires combinations of classifications. For example, the investment in Distribution Mains (Account 376) is driven by (1) the requirement to reach various customer locations and (2) the need to size the mains to meet the resulting load of these customers on the system peak. Therefore, the investment in distribution mains, as well as associated expenses, has both customer-related and demand-related costs.

As a second example, Mains and Services Expense (Account 874) is a distribution operating expense incurred to operate both mains and services.

[1] Purchased gas expense is also commodity-related, but this expense is removed in determining a company's revenue requirement and is not part of a CCOS study when the expense is separately recovered through a pass-through mechanism.

Services are classified as customer-related costs while mains have both customer-related and demand-related costs. Account 874 is classified based on the relative investment in mains and services, which results in a classification that contains both customer-related and demand-related costs.

In addition, various capital and expense costs support multiple classifications of the cost of service and are classified based on a composite of the applicable components. For example, Structures and Improvements (Account 886) is incurred to support a variety of maintenance activities. This expense is classified based on the composite classification of the maintenance expenses associated with distribution mains, measuring and regulating station equipment, services and House Regulators (Accounts 887 through 893).

Q. PLEASE DISCUSS THE ALLOCATION STEP.

A. Customer, demand, commodity and revenue allocation factors are applied in the allocation of the cost of service components. Customer-related costs are generally allocated to customer classes based on relative meter or bill counts. Weighted customer count factors are used, when necessary. For example, the investment in meters and related expenses is a customer cost, but smaller and lower cost meters are required by residential customers as compared to public authority or industrial customers. Weighted customer counts based on typical meter costs by class are used in the study to recognize the drivers of the investment in meters. Similar to meters, weighted customer factors are developed for services and house regulators in order to recognize sizing and resulting cost differences among customer classes.

Demand costs are allocated to classes based on relative class contributions to system peak usage. Commodity costs are allocated to classes based on each class's annual volumes relative to total annual volumes. Revenue-related costs are allocated to customer classes based on relative annual revenues.[2]

After functionalizing each of the cost of service components, classifying the functionalized components and allocating the classified components, the revenue requirement is entirely distributed to each of the customer classes. Each class's fully-distributed revenue requirement represents its actual cost of service.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN DIRECT ASSIGNMENT AND CAUSALLY RELATED ALLOCATION FACTORS.

A. Direct assignment ensures a more accurate reflection of cost causation. However, allocation factors must be used for the majority of the cost of service components because these components either involve joint or common costs or the data needed to make direct assignments are simply not available. For example, the allocation of distribution mains put in place to serve all classes cannot be directly assigned because the system of mains is a network that jointly provides service to all customers. Service charge revenue, customer deposits and bad debt expense allocation factors are directly assigned to the classes.

Q. HAS THE COMMISSION REVIEWED PRIOR CCOS STUDIES CONDUCTED BY THE COMPANY USING THE SAME METHODS YOU USE IN THIS CASE?

A. Yes, the Commission has reviewed prior CCOS studies conducted by the Company using the same methods I use in this case. The Commission reviewed the Company's CCOS study in Docket No. 9896 and found that the study was

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[2] Rather than using a separate revenue classification, revenue-related elements in this study were classified as customer-related and allocated based on revenues in the allocation step of the study.

"reasonable to use" and that it "classifies and allocates costs in a fair, just, and reasonable manner."[3]

Q. PLEASE DESCRIBE EXHIBIT TDS-1, WHICH IS THE CCOS STUDY IN THIS CASE.

A. The CCOS study results for CGSA are provided in Exhibit TDS-1.[4] Page 1 of Exhibit TDS-1 provides a summary of the results. Line 4 shows each class's cost of service, or revenue requirement, based on the classification and allocation methodology described in this testimony. Line 4, column (b) is the total revenue requirement shown in the Company's Schedule A. Exhibit TDS-1, page 1, lines 1 through 3 provide the customer-related, demand-related, and commodity-related costs that total to the cost of service for each class on line 4.

Q. WHAT ADDITIONAL REVENUES ARE INCLUDED IN THE REVENUE ALLOCATION?

A. To determine how much revenue must be recovered through recurring monthly customer and usage charges from each class to meet the cost of service, revenue from other sources must be credited to the cost of service. The revenue credit is comprised of revenue from service charges, special contracts, irrigation class and unmetered gas light service. Service charge revenue is directly assigned to the

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[3] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at Findings of Fact No. 92-93 (Jan. 18, 2023).

[4] In Exhibit TDS-1, the transportation cost of service results have been combined into the corresponding gas sales customer classes and are shown on line 4. Additionally, public school space heating and electrical cogeneration results have been combined into the public authority class.

customer classes.[5] Special contract revenue is associated with contract rates negotiated to keep these customers from bypassing the Company's system. Unmetered gas light service revenue is associated with providing natural gas service for gas lighting only, without the use of a metering device. Special contract revenue, irrigation revenue and unmetered gas light revenue are credited to customer classes based on each class's cost of service relative to the total cost of service. The resulting revenue credits are shown on line 5 of Exhibit TDS-1. Line 6 shows the cost of service net of these revenue credits. Line 7 shows the current revenue for each customer class, and line 8 provides the required revenue change net of these revenue credits for each class. Line 8 shows the amounts that must be collected through monthly customer and usage charges from each class in order for each class to pay its cost of service.

Q. PLEASE DESCRIBE THE COST RATIOS FOUND IN EXHIBIT TDS-1 ON PAGE 1.

A. A revenue-to-cost ratio of one indicates that a class's revenue matches the cost to serve the class. A ratio of less than one indicates that a class's revenue falls short of the cost to serve the class, and a ratio greater than one indicates that class revenue exceeds the cost to serve the class. At current revenues, the revenue-to-cost ratio of less than one for the system [line 10, column (b)] indicates that an overall revenue increase is required. The residential class currently has a revenue-to-cost ratio less than one [line 10, column (c)], indicating that the class is paying less than its cost

[5] Service charge revenue includes the additional revenue from the service charge changes proposed by TGS. This revenue is directly assigned to classes based on test year service charge revenue collections in each class.

of service today. The revenue-to-cost ratios of the non-residential classes are all greater than one [line 10, columns (d) through (g)], indicating that each class is currently paying more than its cost of service. Line 11 demonstrates that each class will pay its cost of service if the revenue changes shown on line 8 are assigned to each class.

Q. PLEASE EXPLAIN WHERE THE CLASSIFICATION STEP IS FOUND IN EXHIBIT TDS-1.

A. Pages 2 through 11 of Exhibit TDS-1 contain details on the classification step of the CCOS study, including the classification of individual plant accounts and other rate base items on pages 2 through 4. Pages 5 through 7 of Exhibit TDS-1 show the classification of the individual components of the cost of service, or revenue requirement. Pages 8 through 11 provide the classification factors used on pages 2 through 7 of Exhibit TDS-1.

Q. PLEASE EXPLAIN WHERE THE ALLOCATION STEP IS FOUND IN EXHIBIT TDS-1.

A. Pages 12 through 34 of Exhibit TDS-1 contain details on the allocation step of the study, including the allocation of the classified components of rate base on pages 12 through 17. The allocation of each of the classified components of the cost of service to customer classes is shown on pages 18 through 31 of Exhibit TDS-1. The components of the allocated cost of service before revenue credits (shown on page 31, lines 405 through 407) are carried forward to lines 1 through 3 of the Cost of Service Study Summary (page 1, Exhibit TDS-1). Pages 32 through 34 of Exhibit TDS-1 provide the customer, demand and commodity allocation factors applied in the allocation of the rate base (pages 12 through 17) and the cost of service (pages 18 through 31) components.

Q. IS YOUR CCOS METHODOLOGY CONSISTENT WITH THE APPROACH THAT WAS PERFORMED AND APPROVED IN DOCKET NOS. 14399 AND 9896 AND GUD NOS. 10656 AND 10928?

A. Yes.

IV. <u>CLASS REVENUE ALLOCATION</u>

Q. PLEASE EXPLAIN THE CONCEPT OF CLASS REVENUE ALLOCATION.

A. Class revenue allocation is the assignment of revenue to each customer class so that the total revenue assigned equals the revenue requirement. Upon assignment of revenue to each class, recurring monthly rates must be designed to collect the annual revenue assigned to the class. Conceptually, revenues should be fairly allocated to customer classes and rates should be designed to more accurately capture fixed and variable costs. Equitable class revenue allocations and rate designs are effective in attracting and retaining customers in all classes and keeping their rates reasonable. Interclass inequities that result from residential customers paying less than their cost of service could, at some point, cause non-residential customers to find gas service unattractive compared to other energy sources. If these customers switch to other energy sources, residential customers will end up paying higher rates in future rate cases in order to cover the Company's cost of service. Similarly, maintaining lower customer charges with higher usage charges could cause moderate and high-use customers to consider alternatives to gas service.

Q. HOW ARE THE CCOS STUDY RESULTS USED TO ASSIGN REVENUE TO EACH CLASS?

A. The CGSA CCOS study results that are used for the class revenue allocation are shown on page 1 of Exhibit TDS-1. For a specific class to cover its cost of service, rates for monthly service for each customer class must be designed to produce annual revenue totaling the Company's total cost of service, as shown on line 6.

Q. WHAT FACTORS DID YOU CONSIDER TO DEVELOP THE CLASS REVENUE ALLOCATION?

A. The factors I considered in developing my recommendation were class costs and the concept of gradualism. First, the Company supports basing the class revenue allocation on the actual CGSA CCOS study results so that each class pays its own cost of service. If cost-based revenue assignments are not made, a portion of the cost to serve certain classes (those paying less than the cost to serve them) are unfairly borne by other classes (those paying more than the cost of service). Implementing cost-based revenue assignments in this case requires revenue increases for the residential class and a revenue decrease for the non-residential classes.

However, it is also important to consider the impacts on each customer class that result from cost-based revenue assignments. The concept of gradualism supports that sizable bill impacts to certain classes should be mitigated, while ensuring that there is movement toward each class's cost of service. To moderate the increase to the residential class, I prepared and evaluated two revenue allocations that represent a more gradual movement for each class's cost of service in this rate case.

Q. PLEASE EXPLAIN EXHIBIT TDS-2.

A. The three class revenue allocations that I considered are shown on Exhibit TDS-2. Each class's revenue-to-cost ratio and assigned revenue change is shown along with the resulting percentage change in non-gas revenue and in total revenue associated with the assigned revenue change.[6] Additionally, Gas Reliability Infrastructure Program ("GRIP") allocation factors are listed on lines 7, 13 and 19, which the Company will apply to future GRIP filings after approval in this case.

Q. PLEASE DESCRIBE THE THREE REVENUE ALLOCATIONS CONSIDERED FOR THE CGSA.

A. Revenue Allocation One assigns revenue so that each class pays its actual cost of service. The resulting revenue change for each class is shown on line 4 of Exhibit TDS-2.

Revenue Allocation Two incorporates the principle of gradualism into the allocation process. This method assigns 20% of the cost-based required decrease to the non-residential classes. The benefit from not assigning the full cost-based decrease to the non-residential classes is assigned to the residential class. The revenue change for each class is shown on line 10 of Exhibit TDS-2. Importantly, the residential revenue increase in Revenue Allocation Two is smaller than the cost-based required increase, but there is still significant movement toward cost-based revenue assignments for each class, as shown by comparing the revenue-to-cost ratios in line 1 to those in line 9 for each customer class.

[6] The equity goal of achieving cost-based revenue assignments is reached when each class is assigned a revenue level so that its revenue-to-cost ratio equals one.

Revenue Allocation Three minimizes the impact on the residential class, however it does not improve the cost-based revenue assignments for the non-residential classes. Exhibit TDS-2 shows that this allocation results in movement toward a cost-based revenue assignment for the residential class, as shown by comparing the revenue-to-cost ratio in line 1, column (c), to the ratio in line 15, column (c). Furthermore, this revenue allocation results in no movement toward cost-based revenue assignments for the non-residential classes, as shown by comparing the revenue-to-cost ratio in line 1, column (d), (e), (f) and (g) to the ratio in line 15, in column (d), (e), (f) and (g).

Q. WHAT REVENUE ALLOCATION DO YOU RECOMMEND FOR THE CGSA?

A. While the cost-based revenue assignments of Revenue Allocation One achieve full equity in the collection of revenue among customer classes, the resulting increase to the residential class is significant. Revenue Allocation Three results in no movement towards cost-based revenue assignments for the non-residential classes. I recommend Revenue Allocation Two because it incorporates the principle of gradualism and improves the equity in the collection of revenue from all customer classes compared to today's revenue collection and is consistent with Commission precedent regarding cost-based revenue assignments.[7]

[7] In *Petition of the De Novo Review of the Denial of the Statements of Intent filed Texas Gas Service Company by the Cities of El Paso, Anthony, Clint, Horizon City, Socorro, and Village of Vinton, Texas*, GUD No. 9988, Proposal for Decision at 45 (Oct. 28, 2010), the Examiners explained that the Commission in previous dockets has expressed a policy of moving toward cost-based revenue assignments.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Costs	$ 147,270,825	$ 139,383,041	$ 7,086,829	$ 60,061	$ 736,279	$ 4,614
2	Demand Costs	$ 42,906,367	$ 29,710,869	$ 8,709,720	$ 1,296,772	$ 3,137,751	$ 51,255
3	Commodity Costs	$ 1,030,731	$ 516,218	$ 324,443	$ 88,798	$ 95,446	$ 5,826
4	Cost of Service Before Revenue Credits	$ 191,207,923	$ 169,610,129	$ 16,120,993	$ 1,445,630	$ 3,969,476	$ 61,695
5	Revenues Credited to Cost of Service (1)	$ 4,998,958	$ 4,638,075	$ 283,166	$ 20,246	$ 56,580	$ 890
6	Total Cost of Service	$ 186,208,965	$ 164,972,054	$ 15,837,826	$ 1,425,384	$ 3,912,896	$ 60,805
7	Revenue at Current Rates	$ 160,419,569	$ 128,025,477	$ 24,405,808	$ 3,033,999	$ 4,829,278	$ 125,006
8	Revenue Deficiency	$ 25,789,396	$ 36,946,576	$ (8,567,982)	$ (1,608,615)	$ (916,382)	$ (64,201)
9	Revenue-to-Cost Ratios:						
10	Current Revenue	0.8651	0.7822	1.5315	2.1127	1.2309	2.0406
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge, special contract, irrigation, and unmetered gas service revenue are used to offset each class' cost of service. Service charge revenue is directly assigned to classes and is included in the revenue credit on line 5. Allocation of the remaining revenues to be credited is based on each class' cost of service relative to the total cost of service on line 4. The components of the total revenue credit are as follows:

Service Charges	$ 2,328,662
Special Contract	$ 2,641,581
Irrigation	$ 26,751
Unmetered Gas Service	$ 1,964
	$ 4,998,958

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Intangible Plant					
1	301	Organization	NONINTPLT	$ 56,257	$ 41,233	$ 14,924	$ 100
2	302	Franchises and Consents	NONINTPLT	$ 393,474	$ 288,396	$ 104,381	$ 697
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 1,014,465	$ 743,550	$ 269,118	$ 1,797
4		Total Intangible Plant		$ 1,464,196	$ 1,073,180	$ 388,423	$ 2,593
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ —	$ —	$ —	$ —
9	367	Transmission Mains	DEM	$ 13,773,737	$ —	$ 13,773,737	$ —
10	368	Compression Station Equipment	DEM	$ —	$ —	$ —	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 5,597,704	$ —	$ 5,597,704	$ —
12	369	Odorization	COM	$ 419,683	$ —	$ —	$ 419,683
13	371	Other Equipment	DEM	$ —	$ —	$ —	$ —
14		Total Transmission Plant		$ 19,791,124	$ —	$ 19,371,441	$ 419,683
15							
16		**Distribution Plant**					
17	374	Land & Land Rights	DIS376-379	$ 231,394	$ 128,609	$ 102,567	$ 218
18	375	Structures and Improvements	DIS376-379	$ 1,761,912	$ 979,273	$ 780,979	$ 1,661
19	376	Distribution Mains	MAINS	$ 485,900,194	$ 286,924,064	$ 198,976,129	$ —
20	376	Odorization	COM	$ 144,153	$ —	$ —	$ 144,153
21	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
22	378	Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 23,056,553	$ —	$ 23,056,553	$ —
23	378	Odorization	COM	$ 688,208	$ —	$ —	$ 688,208
24	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 6,791,781	$ —	$ 6,791,781	$ —
25	379	Odorization Tank	COM	$ 486,607	$ —	$ —	$ 486,607
26	380	Services	CUS	$ 304,689,226	$ 304,689,226	$ —	$ —
27	381	Meters	CUS	$ 81,752,969	$ 81,752,969	$ —	$ —
28	382	Meter Installations	CUS	$ 7,147	$ 7,147	$ —	$ —
29	383	House Regulators	CUS	$ 11,286,787	$ 11,286,787	$ —	$ —
30	385	Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 16,308,207	$ —	$ 16,308,207	$ —
31	385	Odorization	COM	$ 47,784	$ —	$ —	$ 47,784
32	386	Other Property - Customer Premises	CUS	$ 1,063,249	$ 1,063,249	$ —	$ —
33	387	Other Equipment	DIS376-379	$ —	$ —	$ —	$ —
34		Total Distribution Plant		$ 934,216,172	$ 686,831,324	$ 246,016,216	$ 1,368,632
35							

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
36		**General Plant**					
37	389	Land & Land Rights	GENPLT	$ 8,556,713	$ 6,346,210	$ 2,198,274	$ 12,229
38	390	Structures & Improvements	GENPLT	$ 35,571,127	$ 27,224,805	$ 8,300,148	$ 46,175
39	391	Office Furniture and Equipment	GENPLT	$ 45,275,392	$ 44,061,087	$ 1,207,587	$ 6,718
40	392	Transportation Equipment	GENPLT	$ 25,015,559	$ 18,391,321	$ 6,587,590	$ 36,648
41	393	Stores Equipment	GENPLT	$ 123,761	$ 90,988	$ 32,591	$ 181
42	394	Tools, Shop & Garage	GENPLT	$ 15,487,513	$ 11,419,672	$ 4,045,336	$ 22,505
43	394	Odorization	COM	$ 19,654	$ —	$ —	$ 19,654
44	396	Major Work Equipment	GENPLT	$ 3,532,069	$ 2,596,760	$ 930,134	$ 5,175
45	397	Communication Equipment	GENPLT	$ 35,022,327	$ 25,853,651	$ 9,117,951	$ 50,725
46	398	Miscellaneous General Plant	GENPLT	$ 6,349	$ 4,668	$ 1,672	$ 9
47		Total General Plant		$ 168,610,464	$ 135,989,162	$ 32,421,282	$ 200,020
48							
49		Total Plant in Service		$ 1,124,081,957	$ 823,893,666	$ 298,197,362	$ 1,990,928
50							
51		**Depreciation & Amortization Reserve**					
52	301-303	Intangible Plant	DISPLTRES	$ (1,229,809)	$ (902,346)	$ (325,995)	$ (1,469)
53	325-371	Transmission Plant	DEM	$ 25,075	$ —	$ 25,075	$ —
54	374-387	Distribution Plant	DISPLTRES	$ (185,264,906)	$ (135,934,080)	$ (49,109,538)	$ (221,288)
55	389-398	General Plant	GENPLTRES	$ (53,957,765)	$ (44,929,505)	$ (8,974,094)	$ (54,165)
56		Total Depreciation & Amortization Reserve		$ (240,427,405)	$ (181,765,931)	$ (58,384,553)	$ (276,922)
57							
58		Net Plant in Service		$ 883,654,551	$ 642,127,735	$ 239,812,810	$ 1,714,007
59							
60		Customer Deposits	CUS	$ (6,613,930)	$ (6,613,930)	$ —	$ —
61							
62		Customer Advances	MAINS/SVCS	$ (5,170,456)	$ (3,869,152)	$ (1,301,304)	$ —
63							
64		Accumulated Deferred Income Taxes	TOTPLT	$ (79,319,324)	$ (58,136,943)	$ (21,041,894)	$ (140,487)
65							
66		Excess Deferred Income Tax	TOTPLT	$ (14,634,668)	$ (10,726,451)	$ (3,882,296)	$ (25,920)
67							
68		Materials and Supplies	TOTPLT	$ 11,709,937	$ 8,582,775	$ 3,106,421	$ 20,740
69							
70		Prepayments	OPEXP	$ 4,788,015	$ 3,898,711	$ 835,833	$ 53,471
71							
72		Pension & FAS 106 Regulatory Asset	OPEXP	$ 17,214,876	$ 14,017,464	$ 3,005,162	$ 192,250

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
73							
74		DIMP Deferrals	OPEXP	$ 1,848,673	$ 1,505,309	$ 322,719	$ 20,645
75							
76		Regulatory Assets	OPEXP	$ 3,135,695	$ 2,553,285	$ 547,391	$ 35,018
77							
78		Cash Working Capital	OPEXP	$ (3,364,662)	$ (2,739,725)	$ (587,361)	$ (37,575)
79							
80		Total Rate Base		$ 813,248,707	$ 590,599,078	$ 220,817,480	$ 1,832,149

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Transmission & Distribution Operations Exp.**					
2	814-866	Transmission Expenses	DEM	$ 1,581,149	$ —	$ 1,581,149	$ —
3	8700	Operation Supervision & Engineering	DIS871-879	$ 767,175	$ 633,067	$ 118,807	$ 15,301
4	8700	Odorization	COM	$ 67	$ —	$ —	$ 67
5	8710	Distribution Load Dispatch	COM	$ 278,346	$ —	$ —	$ 278,346
6	8740	Mains and Services Expenses	MAINS/SVCS	$ 6,942,347	$ 5,195,092	$ 1,747,255	$ —
7	8740	Odorization	COM	$ 1,475	$ —	$ —	$ 1,475
8	8750	Measuring & Reg. Stat. Exp.-Gen.	DEM	$ 336,559	$ —	$ 336,559	$ —
9	8750	Odorization	COM	$ 87,890	$ —	$ —	$ 87,890
10	8760	Meas. & Reg. Stat. Exp.- Ind.	DEM	$ 54,166	$ —	$ 54,166	$ —
11	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 23,329	$ —	$ 23,329	$ —
12	8780	Meter and House Regulator Exp.	CUS	$ 6,318,931	$ 6,318,931	$ —	$ —
13	8790	Customer Installation Expenses	CUS	$ 2,574	$ 2,574	$ —	$ —
14	8800	Other Expenses	DIS871-879	$ 1,248,595	$ 1,030,331	$ 193,361	$ 24,902
15	8800	Odorization	COM	$ 36	$ —	$ —	$ 36
16	8810	Rents	DIS871-879	$ 35,043	$ 28,917	$ 5,427	$ 699
17	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
18		Total Transmission & Distribution Oper. Exp.		$ 17,677,682	$ 13,208,912	$ 4,060,054	$ 408,716
19							
20		**Distribution Maintenance Expenses**					
21	8850	Maintenance Supervision and Engineering	DIS887-893	$ —	$ —	$ —	$ —
22	8860	Structures and Improvements	DIS887-893	$ 1,202,834	$ 662,351	$ 527,429	$ 13,054
23	8870	Maintenance of Mains	MAINS	$ 4,043,460	$ 2,387,663	$ 1,655,797	$ —
24	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 880,201	$ —	$ 880,201	$ —
25	8890	Odorization	COM	$ 80,957	$ —	$ —	$ 80,957
26	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 680,714	$ —	$ 680,714	$ —
27	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 54,194	$ —	$ 54,194	$ —
28	8920	Maintenance of Services	CUS	$ 1,719,971	$ 1,719,971	$ —	$ —
29	8930	Maintenance of Meters & House Reg.	CUS	$ —	$ —	$ —	$ —
30	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
31	8950	Clearing - Meter Shop - Small Meters	DEM	$ —	$ —	$ —	$ —
32	8960	Clearing - Meter Shop - Large Meters	DEM	$ —	$ —	$ —	$ —
33		Total Distribution Maintenance Expenses		$ 8,662,331	$ 4,769,984	$ 3,798,335	$ 94,012
34							
35		Total Operations & Maintenance Expenses		$ 26,340,013	$ 17,978,897	$ 7,858,389	$ 502,728
36							

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
37		**Customer Accounts Expenses**						
38	9010	Supervision	CUS	$ 296	$ 296	$ —	$ —	
39	9020	Meter Reading Expense	CUS	$ 773,904	$ 773,904	$ —	$ —	
40	9030	Customer Accounting	CUS	$ 3,951,897	$ 3,951,897	$ —	$ —	Gross Up
41	9040	Bad Debts (includes gross up)	CUS	$ 1,161,363	$ 1,161,363	$ —	$ —	$169,875
42	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 412,828	$ 412,828	$ —	$ —	
43		Total Customer Accounts Expenses		$ 6,300,288	$ 6,300,288	$ —	$ —	
44								
45		**Customer Information Expenses**						
46	9070	Supervision	CUS	$ —	$ —	$ —	$ —	
47	9080	Customer Assistance	CUS	$ 1,150,137	$ 1,150,137	$ —	$ —	
48	9090	Informational and Instructional Advertising	CUS	$ 77,438	$ 77,438	$ —	$ —	
49	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —	
50		Total Customer Information Expenses		$ 1,227,575	$ 1,227,575	$ —	$ —	
51								
52		**Sales and Advertising Expenses**						
53	9110	Supervision	CUS	$ —	$ —	$ —	$ —	
54	9120	Demonstrating and Selling	CUS	$ —	$ —	$ —	$ —	
55	9130	Advertising	CUS	$ 143,921	$ 143,921	$ —	$ —	
56	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —	
57	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —	
58		Total Sales and Advertising Expenses		$ 143,921	$ 143,921	$ —	$ —	
59								
60		**Administrative & General Expenses**						
61	920-940	Administrative & General Expenses	ADMINGEN	$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077	
62		Total Administrative & General Expenses		$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077	
63								
64		**Depreciation and Amortization Expense**						
65	301-303	Intangible Plant	PLT301-03	$ 41,187	$ 30,188	$ 10,926	$ 73	
66	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —	
67	366	Meas. and Reg. Station Structures	PLT366	$ —	$ —	$ —	$ —	
68	367	Transmission Mains	PLT367	$ 366,381	$ —	$ 366,381	$ —	
69	368	Compression Station Equipment	PLT368	$ —	$ —	$ —	$ —	
70	369	Measuring and Reg. Station Equipment	PLT369	$ 192,001	$ —	$ 192,001	$ —	
71	369	Odorization	COM	$ 14,395	$ —	$ —	$ 14,395	
72	371	Other Equipment	PLT371	$ —	$ —	$ —	$ —	

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
73		**Depreciation and Amort. Exp. (Cont'd)**						
74	375	Structures and Improvements	PLT375	$ 42,262	$ 23,489	$ 18,733	$ 40	
75	376	Mains	MAINS	$ 12,149,545	$ 7,174,306	$ 4,975,239	$ —	
76	376	Odorization	COM	$ 3,215	$ —	$ —	$ 3,215	
77	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —	
78	378	Meas. & Reg. Sta. Equip. - General	PLT378	$ 491,339	$ —	$ 491,339	$ —	
79	378	Odorization Tank	COM	$ 14,659	$ —	$ —	$ 14,659	
80	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 133,844	$ —	$ 133,844	$ —	
81	379	Odorization Tank	COM	$ 9,586	$ —	$ —	$ 9,586	
82	380	Services	PLT380	$ 9,665,188	$ 9,665,188	$ —	$ —	
83	381	Meters	PLT381	$ 3,335,369	$ 3,335,369	$ —	$ —	
84	382	Meter Installations	PLT382	$ 297	$ 297	$ —	$ —	
85	383	House Regulators	PLT383	$ 383,759	$ 383,759	$ —	$ —	
86	385	Meas. & Reg. Sta. Equip. - Ind.	PLT385	$ 388,137	$ —	$ 388,137	$ —	
87	385	Odorization	COM	$ 1,137	$ —	$ —	$ 1,137	
88	386	Other Property - Customer Premises	PLT386	$ 126,420	$ 126,420	$ —	$ —	
89	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —	
90	389-398	General Plant	GENDEP	$ 8,551,954	$ 7,307,740	$ 1,236,027	$ 8,186	
91	389-398	General Plant - Odorization	COM	$ 1,310	$ —	$ —	$ 1,310	
92	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ (535,021)	$ (435,649)	$ (93,397)	$ (5,975)	
93		Total Depreciation and Amortization Expense		$ 35,376,964	$ 27,611,108	$ 7,719,230	$ 46,627	
94								
95		**Taxes Other Than Income**						
96	4080	Payroll and Other	OPEXP	$ 3,127,494	$ 2,546,607	$ 545,959	$ 34,927	
97	4080	Ad Valorem - Allocated	TOTPLT	$ 6,947,490	$ 5,092,149	$ 1,843,036	$ 12,305	Gross Up
98	4080	Revenue Related (includes gross up)	CUS	$ 219,750	$ 219,750	$ —	$ —	$193,420
99		Total Taxes Other Than Income		$ 10,294,734	$ 7,858,507	$ 2,388,995	$ 47,232	
100								
101	4101	Excess Deferred Income Tax Amortization	RB	$ (500,677)	$ (363,603)	$ (135,946)	$ (1,128)	
102								
103	4310	Interest on Customer Deposits	CUS	$ 321,437	$ 321,437	$ —	$ —	
104								
105		Required Return	RB	$ 64,093,722	$ 46,546,269	$ 17,403,058	$ 144,395	
106		Income Taxes	RB	$ 13,227,540	$ 9,606,130	$ 3,591,610	$ 29,800	
107		Total Cost of Service Before Revenue Credits		$ 191,207,923	$ 147,270,825	$ 42,906,367	$ 1,030,731	

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7		DEM-COM	Demand and Commodity Factor		0.00000	0.50000	0.50000
8							
9			Total Transmission Plant	$ 19,791,124	$ —	$ 19,371,441	$ 419,683
10			Total Distribution Plant	$ 934,216,172	$ 686,831,324	$ 246,016,216	$ 1,368,632
11			Total General Plant	$ 168,610,464	$ 135,989,162	$ 32,421,282	$ 200,020
12			Total Non-Intangible Plant	$ 1,122,617,760	$ 822,820,486	$ 297,808,939	$ 1,988,335
13		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.73295	0.26528	0.00177
14							
15	376		Distribution Mains	$ 485,900,194	$ 286,924,064	$ 198,976,129	$ —
16	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
17	378		Meas. & Reg. Sta. Equip.- Gen.	$ 23,056,553	$ —	$ 23,056,553	$ —
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 7,278,389	$ —	$ 6,791,781	$ 486,607
19			Total Accounts 376-379	$ 516,235,135	$ 286,924,064	$ 228,824,463	$ 486,607
20		DIS376-379	Accounts 376-379 Factor	1.00000	0.55580	0.44326	0.00094
21							
22	376		Mains	$ 485,900,194	$ 286,924,064	$ 198,976,129	$ —
23		MAINS	Distribution Mains Allocated Factor	1.00000	0.59050	0.40950	0.00000
24							
25	376/380		Mains and Services-Allocated	$ 790,589,420	$ 591,613,291	$ 198,976,129	$ —
26		MAINS/SVCS	Mains and Services Allocated Factor	1.00000	0.74832	0.25168	0.00000
27							
28	374-87		Total Distribution Plant	$ 934,216,172	$ 686,831,324	$ 246,016,216	$ 1,368,632
29		DISPLT	Distribution Plant Factor	1.00000	0.73520	0.26334	0.00147
30							
31							
32	374		Land & Land Rights	$ (12,157)	$ (6,757)	$ (5,389)	$ (11)
33	375		Structures and Improvements	$ (165,063)	$ (91,742)	$ (73,165)	$ (156)
34	376		Distribution Mains	$ (92,558,158)	$ (54,655,592)	$ (37,902,566)	$ —
35	376		Odorization	$ (9,564)	$ —	$ —	$ (9,564)
36	378		Meas. & Reg. Sta. Equip.-Gen.	$ (3,863,368)	$ —	$ (3,863,368)	$ —
37	379		Meas. & Reg. Sta. Equip.-City Gate	$ (1,521,540)	$ —	$ (1,521,540)	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
38	378-379		Odorization Tank	$ (204,539)	$ —	$ —	$ (204,539)
39	380		Services	$ (40,260,987)	$ (40,260,987)	$ —	$ —
40	381		Meters	$ (35,453,793)	$ (35,453,793)	$ —	$ —
41	382		Meter Installations	$ (2,791)	$ (2,791)	$ —	$ —
42	383		House Regulators	$ (4,883,641)	$ (4,883,641)	$ —	$ —
43	385		Meas. & Reg. Sta. Equip.-Ind.	$ (5,281,931)	$ —	$ (5,281,931)	$ —
44	385		Odorization	$ (6,037)	$ —	$ —	$ (6,037)
45	386		Other Property-Customer Premises	$ (1,041,339)	$ (578,778)	$ (461,580)	$ (982)
46	387		Other Equipment	$ —	$ —	$ —	$ —
47			Total Distribution Plant Reserve	$ (185,264,906)	$ (135,934,080)	$ (49,109,538)	$ (221,288)
48		DISPLTRES	Distribution Plant Reserve Factor	$ 1.00000	0.73373	0.26508	0.00119
49							
50			General Plant Reserve	$ (53,957,765)	$ (44,929,505)	$ (8,974,094)	$ (54,165)
51		GENPLTRES	General Plant Reserve Factor	1.00000	0.83268	0.16632	0.00100
52							
53			Total Plant	$ 1,124,081,957	$ 823,893,666	$ 298,197,362	$ 1,990,928
54		TOTPLT	Total Plant Factor	1.00000	0.73295	0.26528	0.00177
55							
56			Total Operations and Maintenance Expenses	$ 26,340,013	$ 17,978,897	$ 7,858,389	$ 502,728
57			Total Customer Accounts Expenses	$ 6,300,288	$ 6,300,288	$ —	$ —
58			Total Customer Service Expenses	$ 1,227,575	$ 1,227,575	$ —	$ —
59			Total Sales and Advertising Expenses	$ 143,921	$ 143,921	$ —	$ —
60			Administrative and General Expenses	$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077
61			Total Operating Expenses	$ 68,394,204	$ 55,690,977	$ 11,939,421	$ 763,805
62		OPEXP	Operating Expense Factor	1.00000	0.81426	0.17457	0.01117
63							
64	8710		Distribution Load Dispatch	$ 278,346	$ —	$ —	$ 278,346
65	8740		Mains and Services Expenses	$ 6,942,347	$ 5,195,092	$ 1,747,255	$ —
66	8750		Measuring & Reg. Stat. Exp.-Gen.	$ 336,559	$ —	$ 336,559	$ —
67	8760		Meas. & Reg. Stat. Exp.- Ind.	$ 54,166	$ —	$ 54,166	$ —
68	8770		Meas. & Regulating Station Exp.- City Gate	$ 23,329	$ —	$ 23,329	$ —
69	8780		Meter and House Regulator Exp.	$ 6,318,931	$ 6,318,931	$ —	$ —
70	8790		Customer Installation Expenses	$ 2,574	$ 2,574	$ —	$ —
71			Total Accounts 871-879	$ 13,956,252	$ 11,516,597	$ 2,161,309	$ 278,346
72		DIS871-879	Accounts 871-879 Factor	1.00000	0.82519	0.15486	0.01994
73							
74	8870		Maintenance of Mains	$ 4,043,460	$ 2,387,663	$ 1,655,797	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
75	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen.	$ 961,158	$ —	$ 880,201	$ 80,957
76	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind.	$ 680,714	$ —	$ 680,714	$ —
77	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 54,194	$ —	$ 54,194	$ —
78	8920		Maintenance of Services	$ 1,719,971	$ 1,719,971	$ —	$ —
79	8930		Maintenance of Meters & House Reg.	$ —	$ —	$ —	$ —
80			Total Accounts 887-893	$ 7,459,496	$ 4,107,634	$ 3,270,905	$ 80,957
81		DIS887-893	Accounts 887-893 Factor	1.00000	0.55066	0.43849	0.01085
82							
83			Total Operations and Maintenance Expenses	$ 26,340,013	$ 17,978,897	$ 7,858,389	$ 502,728
84			Total Customer Accounts Expenses	$ 6,300,288	$ 6,300,288	$ —	$ —
85			Total Customer Service Expenses	$ 1,227,575	$ 1,227,575	$ —	$ —
86			Total Sales and Advertising Expenses	$ 143,921	$ 143,921	$ —	$ —
87			Total Operating Exp. Without A&G Expenses	$ 34,011,797	$ 25,650,681	$ 7,858,389	$ 502,728
88		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.75417	0.23105	0.01478
89							
90	920-932		Administrative and General Expenses	$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077
91		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.87371	0.11870	0.00759
92							
93	366		Meas. and Reg. Station Structures	$ —	$ —	$ —	$ —
94		PLT366	Measuring and Reg. Station Structures Factor	0.00000	0.00000	0.00000	0.00000
95							
96	367		Transmission Mains	$ 13,773,737	$ —	$ 13,773,737	$ —
97		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
98							
99	368		Compression Station Equipment	$ —	$ —	$ —	$ —
100		PLT368	Compression Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
101							
102	369		Measuring and Reg. Station Equipment	$ 5,597,704	$ —	$ 5,597,704	$ —
103		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
104							
105	371		Other Equipment	$ —	$ —	$ —	$ —
106		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
107							
108	375		Structures and Improvements	$ 1,761,912	$ 979,273	$ 780,979	$ 1,661
109		PLT375	Structures and Improvements Factor	1.00000	0.55580	0.44326	0.00094
110							
111	378		Meas. & Reg. Sta. Equip.- Gen.	$ 23,056,553	$ —	$ 23,056,553	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
112		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
113							
114	379		Meas. & Reg. Sta. Equip.- City Gate	$ 6,791,781	$ —	$ 6,791,781	$ —
115		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
116							
117	380		Services	$ 304,689,226	$ 304,689,226	$ —	$ —
118		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
119							
120	381		Meters	$ 81,752,969	$ 81,752,969	$ —	$ —
121		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
122							
123	382		Meter Installations	$ 7,147	$ 7,147	$ —	$ —
124		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000
125							
126	383		House Regulators	$ 11,286,787	$ 11,286,787	$ —	$ —
127		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
128							
129	385		Meas. & Reg. Sta. Equip. - Ind.	$ 16,308,207	$ —	$ 16,308,207	$ —
130		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
131							
132	386		Other Property - Customer Premises	$ 1,063,249	$ 1,063,249	$ —	$ —
133		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
134							
135	387		Other Equipment	$ —	$ —	$ —	$ —
136		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
137							
138	301-03		Intangible Plant	$ 1,464,196	$ 1,073,180	$ 388,423	$ 2,593
139		PLT301-03	Intangible Plant	1.00000	0.73295	0.26528	0.00177
140							
141	389-98		General Plant Depreciation Expense	$ 8,553,264	$ 7,308,860	$ 1,236,217	$ 8,188
142		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.85451	0.14453	0.00096
143							
144			Rate Base	$ 813,248,707	$ 590,599,078	$ 220,817,480	$ 1,832,149
145		RB	Rate Base Factor	1.00000	0.72622	0.27153	0.00225

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	301-303	**Intangible Plant**							
2		Customer	NONINCUS	$ 1,073,180	$ 1,024,184	$ 44,383	$ 203	$ 4,394	$ 16
3		Demand	NONINDEM	$ 388,423	$ 280,099	$ 71,500	$ 10,645	$ 25,758	$ 421
4		Commodity	COM	$ 2,593	$ 1,299	$ 816	$ 223	$ 240	$ 15
5		Total Intangible Plant		$ 1,464,196	$ 1,305,581	$ 116,699	$ 11,072	$ 30,392	$ 452
6	365-371	**Transmission Plant**							
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 19,371,441	$ 13,969,087	$ 3,565,837	$ 530,910	$ 1,284,623	$ 20,984
9		Commodity	COM	$ 419,683	$ 210,189	$ 132,104	$ 36,156	$ 38,863	$ 2,372
10		Total Transmission Plant		$ 19,791,124	$ 14,179,276	$ 3,697,941	$ 567,066	$ 1,323,486	$ 23,356
11		**Distribution Plant**							
12	374	**Land & Land Rights**							
13		Customer	CUS	$ 128,609	$ 122,738	$ 5,319	$ 24	$ 527	$ 2
14		Demand	DEM	$ 102,567	$ 73,963	$ 18,880	$ 2,811	$ 6,802	$ 111
15		Commodity	COM	$ 218	$ 109	$ 69	$ 19	$ 20	$ 1
16		Total Land & Land Rights		$ 231,394	$ 196,810	$ 24,268	$ 2,854	$ 7,348	$ 114
17	375	**Structures and Improvements**							
18		Customer	376-379CUS	$ 979,273	$ 934,564	$ 40,499	$ 185	$ 4,009	$ 15
19		Demand	DEM	$ 780,979	$ 563,177	$ 143,760	$ 21,404	$ 51,791	$ 846
20		Commodity	COM	$ 1,661	$ 832	$ 523	$ 143	$ 154	$ 9
21		Total Structures and Improvements		$ 1,761,912	$ 1,498,573	$ 184,782	$ 21,733	$ 55,954	$ 870
22	376	**Distribution Mains**							
23		Customer	CUS	$ 286,924,064	$ 273,824,552	$ 11,866,181	$ 54,351	$ 1,174,659	$ 4,321
24		Demand	DEM	$ 198,976,129	$ 143,485,187	$ 36,626,932	$ 5,453,307	$ 13,195,162	$ 215,542
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Distribution Mains		$ 485,900,194	$ 417,309,739	$ 48,493,112	$ 5,507,658	$ 14,369,821	$ 219,864
27	376	**Odorization**							
28		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM	$ 144,153	$ 72,196	$ 45,375	$ 12,419	$ 13,349	$ 815
31		Total Odorization		$ 144,153	$ 72,196	$ 45,375	$ 12,419	$ 13,349	$ 815
32	377	**Compressor Station Equipment**							
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
36		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —
37	378	**Meas. & Reg. Sta. Equip.- Gen.**							
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 23,056,553	$ 16,626,486	$ 4,244,181	$ 631,907	$ 1,529,002	$ 24,976
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Sta. Equip.- Gen.		$ 23,056,553	$ 16,626,486	$ 4,244,181	$ 631,907	$ 1,529,002	$ 24,976
42	378	**Odorization Tank**							
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ 688,208	$ 344,673	$ 216,627	$ 59,289	$ 63,729	$ 3,890
46		Total Odorization Tank		$ 688,208	$ 344,673	$ 216,627	$ 59,289	$ 63,729	$ 3,890
47	379	**Meas. & Reg. Station - City Gate**							
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 6,791,781	$ 4,897,673	$ 1,250,211	$ 186,141	$ 450,399	$ 7,357
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Equip.-City Gate		$ 6,791,781	$ 4,897,673	$ 1,250,211	$ 186,141	$ 450,399	$ 7,357
52	379	**Odorization Tank**							
53		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM	$ 486,607	$ 243,706	$ 153,169	$ 41,921	$ 45,060	$ 2,750
56		Total Odorization Tank		$ 486,607	$ 243,706	$ 153,169	$ 41,921	$ 45,060	$ 2,750
57	380	**Services**							
58		Customer	SERCUS	$ 304,689,226	$ 288,586,355	$ 14,430,315	$ 85,739	$ 1,580,299	$ 6,519
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Services		$ 304,689,226	$ 288,586,355	$ 14,430,315	$ 85,739	$ 1,580,299	$ 6,519
62	381	**Meters**							
63		Customer	METCUS	$ 81,752,969	$ 75,145,213	$ 5,777,039	$ 83,943	$ 738,927	$ 7,847
64		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meters		$ 81,752,969	$ 75,145,213	$ 5,777,039	$ 83,943	$ 738,927	$ 7,847
67	382	**Meter Installations**							
68		Customer	METCUS	$ 7,147	$ 6,570	$ 505	$ 7	$ 65	$ 1

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
71		Total Meter Installations		$ 7,147	$ 6,570	$ 505	$ 7	$ 65	$ 1
72	383	**House Regulators**							
73		Customer	REGCUS	$ 11,286,787	$ 9,860,317	$ 1,190,936	$ 34,941	$ 197,167	$ 3,426
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
76		Total House Regulators		$ 11,286,787	$ 9,860,317	$ 1,190,936	$ 34,941	$ 197,167	$ 3,426
77	385	**Meas. & Reg. Sta. Equip. - Ind.**							
78		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	NRDEM	$ 16,308,207	$ —	$ 10,764,272	$ 1,602,670	$ 3,877,920	$ 63,346
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Meas. & Reg. Sta. Equip.- Ind.		$ 16,308,207	$ —	$ 10,764,272	$ 1,602,670	$ 3,877,920	$ 63,346
82	385	**Odorization**							
83		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ 47,784	$ 23,932	$ 15,041	$ 4,117	$ 4,425	$ 270
86		Total Odorization		$ 47,784	$ 23,932	$ 15,041	$ 4,117	$ 4,425	$ 270
87	386	**Other Prop.-Customer Premises**							
88		Customer	CUS	$ 1,063,249	$ 1,014,706	$ 43,972	$ 201	$ 4,353	$ 16
89		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Other Prop.- Cust. Premises		$ 1,063,249	$ 1,014,706	$ 43,972	$ 201	$ 4,353	$ 16
92	387	**Other Equipment**							
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
97		**Total Distribution Plant**							
98		Customer		$ 686,831,324	$ 649,495,014	$ 33,354,767	$ 259,392	$ 3,700,004	$ 22,147
99		Demand		$ 246,016,216	$ 165,646,486	$ 53,048,236	$ 7,898,240	$ 19,111,076	$ 312,178
100		Commodity		$ 1,368,632	$ 685,448	$ 430,804	$ 117,908	$ 126,736	$ 7,736
101		Total Distribution Plant		$ 934,216,172	$ 815,826,949	$ 86,833,806	$ 8,275,540	$ 22,937,816	$ 342,061
102		**Total General Plant**							
103		Customer	CUS	$ 135,989,162	$ 129,780,580	$ 5,624,039	$ 25,760	$ 556,736	$ 2,048

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
104		Demand	DEM	$ 32,421,282	$ 23,379,557	$ 5,968,013	$ 888,565	$ 2,150,027	$ 35,121
105		Commodity	COM	$ 200,020	$ 100,175	$ 62,960	$ 17,232	$ 18,522	$ 1,131
106		Total General Plant		$ 168,610,464	$ 153,260,312	$ 11,655,011	$ 931,556	$ 2,725,285	$ 38,299
107		**Total Plant in Service**							
108		Customer		$ 823,893,666	$ 780,299,778	$ 39,023,188	$ 285,355	$ 4,261,134	$ 24,211
109		Demand		$ 298,197,362	$ 203,275,228	$ 62,653,585	$ 9,328,360	$ 22,571,484	$ 368,704
110		Commodity		$ 1,990,928	$ 997,111	$ 626,684	$ 171,519	$ 184,361	$ 11,253
111		Total Plant in Service		$ 1,124,081,957	$ 984,572,117	$ 102,303,457	$ 9,785,235	$ 27,016,979	$ 404,168
112		**Depreciation & Amort. Reserve**							
113		**Intangible Plant**							
114		Customer	CUS	$ (902,346)	$ (861,149)	$ (37,318)	$ (171)	$ (3,694)	$ (14)
115		Demand	DEM	$ (325,995)	$ (235,080)	$ (60,008)	$ (8,934)	$ (21,618)	$ (353)
116		Commodity	COM	$ (1,469)	$ (736)	$ (462)	$ (127)	$ (136)	$ (8)
117		Total Intangible Plant		$ (1,229,809)	$ (1,096,965)	$ (97,788)	$ (9,232)	$ (25,449)	$ (375)
118		**Transmission Plant**							
119		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
120		Demand	DEM	$ 25,075	$ 18,082	$ 4,616	$ 687	$ 1,663	$ 27
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Transmission Plant		$ 25,075	$ 18,082	$ 4,616	$ 687	$ 1,663	$ 27
123		**Distribution Plant**							
124		Customer	DISPLTCUS	$ (135,934,080)	$ (128,544,672)	$ (6,601,402)	$ (51,338)	$ (732,286)	$ (4,383)
125		Demand	DISPLTDEM	$ (49,109,538)	$ (33,066,204)	$ (10,589,442)	$ (1,576,640)	$ (3,814,936)	$ (62,317)
126		Commodity	COM	$ (221,288)	$ (110,827)	$ (69,655)	$ (19,064)	$ (20,491)	$ (1,251)
127		Total Distribution Plant		$ (185,264,906)	$ (161,721,703)	$ (17,260,498)	$ (1,647,041)	$ (4,567,713)	$ (67,951)
128		**General Plant**							
129		Customer	GENPTCUS	$ (44,929,505)	$ (42,617,919)	$ (2,073,646)	$ (14,140)	$ (222,610)	$ (1,191)
130		Demand	DISPLTDEM	$ (8,974,094)	$ (6,042,395)	$ (1,935,075)	$ (288,109)	$ (697,127)	$ (11,388)
131		Commodity	COM	$ (54,165)	$ (27,127)	$ (17,049)	$ (4,666)	$ (5,016)	$ (306)
132		Total General Plant		$ (53,957,765)	$ (48,687,442)	$ (4,025,770)	$ (306,916)	$ (924,753)	$ (12,884)
133		**Total Depr. & Amort. Reserve**							
134		Customer		$ (181,765,931)	$ (172,023,740)	$ (8,712,365)	$ (65,649)	$ (958,590)	$ (5,587)
135		Demand		$ (58,384,553)	$ (39,325,598)	$ (12,579,909)	$ (1,872,996)	$ (4,532,019)	$ (74,030)
136		Commodity		$ (276,922)	$ (138,690)	$ (87,167)	$ (23,857)	$ (25,643)	$ (1,565)
137		Total Depr. & Amortization Reserve		$ (240,427,405)	$ (211,488,028)	$ (21,379,441)	$ (1,962,502)	$ (5,516,252)	$ (81,183)
138		**Net Plant in Service**							
139		Customer		$ 642,127,735	$ 608,276,038	$ 30,310,823	$ 219,707	$ 3,302,544	$ 18,624

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
140		Demand		$ 239,812,810	$ 163,949,630	$ 50,073,676	$ 7,455,364	$ 18,039,466	$ 294,673
141		Commodity		$ 1,714,007	$ 858,421	$ 539,517	$ 147,662	$ 158,718	$ 9,688
142		Total Net Plant in Service		$ 883,654,551	$ 773,084,089	$ 80,924,016	$ 7,822,733	$ 21,500,728	$ 322,985
143		**Customer Deposits**							
144		Customer	DEPCUS	$ (6,613,930)	$ (3,223,171)	$ (3,345,736)	$ (35,898)	$ (9,126)	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —
147		Total Customer Deposits		$ (6,613,930)	$ (3,223,171)	$ (3,345,736)	$ (35,898)	$ (9,126)	$ —
148		**Customer Advances**							
149		Customer	MSCUS	$ (3,869,152)	$ (3,678,168)	$ (171,979)	$ (916)	$ (18,017)	$ (71)
150		Demand	DEM	$ (1,301,304)	$ (938,393)	$ (239,540)	$ (35,665)	$ (86,296)	$ (1,410)
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Customer Advances		$ (5,170,456)	$ (4,616,562)	$ (411,519)	$ (36,581)	$ (104,314)	$ (1,481)
153		**Accum. Deferred Income Taxes**							
154		Customer	TPLTCUS	$ (58,136,943)	$ (55,060,799)	$ (2,753,619)	$ (20,136)	$ (300,681)	$ (1,708)
155		Demand	TPLTDEM	$ (21,041,894)	$ (14,343,842)	$ (4,421,066)	$ (658,243)	$ (1,592,726)	$ (26,017)
156		Commodity	COM	$ (140,487)	$ (70,360)	$ (44,221)	$ (12,103)	$ (13,009)	$ (794)
157		Total Accum. Deferred Inc. Taxes		$ (79,319,324)	$ (69,475,000)	$ (7,218,905)	$ (690,482)	$ (1,906,417)	$ (28,520)
158		**Excess Deferred Income Taxes**							
159		Customer	TPLTCUS	$ (10,726,451)	$ (10,158,893)	$ (508,051)	$ (3,715)	$ (55,477)	$ (315)
160		Demand	TPLTDEM	$ (3,882,296)	$ (2,646,484)	$ (815,701)	$ (121,448)	$ (293,863)	$ (4,800)
161		Commodity	COM	$ (25,920)	$ (12,982)	$ (8,159)	$ (2,233)	$ (2,400)	$ (147)
162		**Total Excess Deferred Income Taxes**		$ (14,634,668)	$ (12,818,359)	$ (1,331,911)	$ (127,396)	$ (351,740)	$ (5,262)
163		**Materials and Supplies**							
164		Customer	TPLTCUS	$ 8,582,775	$ 8,128,643	$ 406,518	$ 2,973	$ 44,390	$ 252
165		Demand	TPLTDEM	$ 3,106,421	$ 2,117,586	$ 652,683	$ 97,177	$ 235,135	$ 3,841
166		Commodity	COM	$ 20,740	$ 10,387	$ 6,528	$ 1,787	$ 1,921	$ 117
167		Total Materials and Supplies		$ 11,709,937	$ 10,256,616	$ 1,065,729	$ 101,936	$ 281,445	$ 4,210
168		**Prepayments**							
169		Customer	OPEXPCUS	$ 3,898,711	$ 3,676,739	$ 198,028	$ 1,992	$ 21,789	$ 163
170		Demand	OPEXPDEM	$ 835,833	$ 551,864	$ 187,434	$ 27,907	$ 67,525	$ 1,103
171		Commodity	COM	$ 53,471	$ 26,780	$ 16,831	$ 4,607	$ 4,951	$ 302
172		Total Prepayments		$ 4,788,015	$ 4,255,383	$ 402,293	$ 34,505	$ 94,265	$ 1,568
173		**Pension & FAS 106 Reg. Asset**							
174		Customer	OPEXPCUS	$ 14,017,464	$ 13,219,384	$ 711,992	$ 7,161	$ 78,341	$ 586
175		Demand	OPEXPDEM	$ 3,005,162	$ 1,984,179	$ 673,902	$ 100,336	$ 242,779	$ 3,966

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
176		Commodity	COM	$ 192,250	$ 96,284	$ 60,515	$ 16,562	$ 17,803	$ 1,087
177		Total Pen. & FAS 106 Reg. Asset		$ 17,214,876	$ 15,299,847	$ 1,446,409	$ 124,059	$ 338,922	$ 5,639
178		**DIMP Deferrals**							
179		Customer	TPLTCUS	$ 1,505,309	$ 1,425,660	$ 71,298	$ 521	$ 7,785	$ 44
180		Demand	TPLTDEM	$ 322,719	$ 219,991	$ 67,806	$ 10,095	$ 24,428	$ 399
181		Commodity	COM	$ 20,645	$ 10,340	$ 6,499	$ 1,779	$ 1,912	$ 117
182		Total DIMP Deferrals		$ 1,848,673	$ 1,655,990	$ 145,602	$ 12,395	$ 34,125	$ 560
183		**Regulatory Assets**							
184		Customer	TPLTCUS	$ 2,553,285	$ 2,418,186	$ 120,935	$ 884	$ 13,205	$ 75
185		Demand	TPLTDEM	$ 547,391	$ 373,146	$ 115,011	$ 17,124	$ 41,434	$ 677
186		Commodity	COM	$ 35,018	$ 17,538	$ 11,023	$ 3,017	$ 3,243	$ 198
187		**Total Regulatory Assets**		$ 3,135,695	$ 2,808,870	$ 246,969	$ 21,025	$ 57,882	$ 950
188		**Cash Working Capital**							
189		Customer	OPEXPCUS	$ (2,739,725)	$ (2,583,740)	$ (139,159)	$ (1,400)	$ (15,312)	$ (115)
190		Demand	OPEXPDEM	$ (587,361)	$ (387,809)	$ (131,715)	$ (19,611)	$ (47,451)	$ (775)
191		Commodity	COM	$ (37,575)	$ (18,819)	$ (11,828)	$ (3,237)	$ (3,480)	$ (212)
192		Total Cash Working Capital		$ (3,364,662)	$ (2,990,368)	$ (282,702)	$ (24,248)	$ (66,243)	$ (1,102)
193		**Total Rate Base**							
194		Customer		$ 590,599,078	$ 562,439,879	$ 24,901,049	$ 171,174	$ 3,069,441	$ 17,535
195		Demand		$ 220,817,480	$ 150,879,867	$ 46,162,491	$ 6,873,036	$ 16,630,428	$ 271,657
196		Commodity		$ 1,832,149	$ 917,590	$ 576,705	$ 157,840	$ 169,658	$ 10,356
197		Total Rate Base		$ 813,248,707	$ 714,237,336	$ 71,640,245	$ 7,202,050	$ 19,869,528	$ 299,548

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1		**Transmission and Distribution Operating Expense**							
2	814-866	**Transmission Expenses**							
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 1,581,149	$ 1,140,195	$ 291,053	$ 43,334	$ 104,854	$ 1,713
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 1,581,149	$ 1,140,195	$ 291,053	$ 43,334	$ 104,854	$ 1,713
7	8700	**Operation Supervision & Engineering**							
8		Customer	871-879CUS	$ 633,067	$ 587,987	$ 39,465	$ 556	$ 5,007	$ 52
9		Demand	DEM	$ 118,807	$ 85,674	$ 21,870	$ 3,256	$ 7,879	$ 129
10		Commodity	COM	$ 15,301	$ 7,663	$ 4,816	$ 1,318	$ 1,417	$ 86
11		Total Supervision & Engineering		$ 767,175	$ 681,324	$ 66,151	$ 5,130	$ 14,302	$ 267
12	8700	**Odorization**							
13		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
14		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
15		Commodity	COM	$ 67	$ 34	$ 21	$ 6	$ 6	$ 0
16		Total Odorization		$ 67	$ 34	$ 21	$ 6	$ 6	$ 0
17	8710	**Distribution Load Dispatch**							
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 278,346	$ 139,403	$ 87,615	$ 23,980	$ 25,775	$ 1,573
21		Total Distribution Load Dispatch		$ 278,346	$ 139,403	$ 87,615	$ 23,980	$ 25,775	$ 1,573
22	8740	**Mains and Services Expenses**							
23		Customer	MSCUS	$ 5,195,092	$ 4,938,659	$ 230,916	$ 1,230	$ 24,192	$ 95
24		Demand	DEM	$ 1,747,255	$ 1,259,976	$ 321,629	$ 47,887	$ 115,870	$ 1,893
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services		$ 6,942,347	$ 6,198,635	$ 552,545	$ 49,117	$ 140,062	$ 1,988
27	8740	**Odorization**							
28		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM	$ 1,475	$ 739	$ 464	$ 127	$ 137	$ 8
31		Total Odorization		$ 1,475	$ 739	$ 464	$ 127	$ 137	$ 8

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
32	8750	**Meas. & Reg. Station - Gen.**							
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ 336,559	$ 242,699	$ 61,953	$ 9,224	$ 22,319	$ 365
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
36		Total Meas. & Reg. Station - Gen.		$ 336,559	$ 242,699	$ 61,953	$ 9,224	$ 22,319	$ 365
37	8750	**Odorization**							
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
40		Commodity	COM	$ 87,890	$ 44,018	$ 27,665	$ 7,572	$ 8,139	$ 497
41		Total Odorization		$ 87,890	$ 44,018	$ 27,665	$ 7,572	$ 8,139	$ 497
42	8760	**Meas. & Reg. Stat. - Ind.**							
43		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	NRDEM	$ 54,166	$ —	$ 35,752	$ 5,323	$ 12,880	$ 210
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Stat. - Ind.		$ 54,166	$ —	$ 35,752	$ 5,323	$ 12,880	$ 210
47	8770	**Meas. & Reg. Stat.- City Gate**							
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 23,329	$ 16,823	$ 4,294	$ 639	$ 1,547	$ 25
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Stat. - City Gate		$ 23,329	$ 16,823	$ 4,294	$ 639	$ 1,547	$ 25
52	8780	**Meter & House Reg. Exp.**							
53		Customer	MTRGCUS	$ 6,318,931	$ 5,755,497	$ 486,840	$ 8,882	$ 66,866	$ 847
54		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meter & House Reg. Exp.		$ 6,318,931	$ 5,755,497	$ 486,840	$ 8,882	$ 66,866	$ 847
57	8790	**Customer Installation Expense**							
58		Customer	METCUS	$ 2,574	$ 2,366	$ 182	$ 3	$ 23	$ 0
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Customer Install. Expense		$ 2,574	$ 2,366	$ 182	$ 3	$ 23	$ 0
62	8800	**Other Expenses**							

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
63		Customer	871-879CUS	$ 1,030,331	$ 956,963	$ 64,230	$ 905	$ 8,149	$ 84
64		Demand	DEM	$ 193,361	$ 139,436	$ 35,593	$ 5,299	$ 12,823	$ 209
65		Commodity	COM	$ 24,902	$ 12,472	$ 7,838	$ 2,145	$ 2,306	$ 141
66		Total Other Expenses		$ 1,248,595	$ 1,108,871	$ 107,662	$ 8,350	$ 23,277	$ 434
67	8800	**Odorization**							
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 36	$ 18	$ 11	$ 3	$ 3	$ 0
71		Total Odorization		$ 36	$ 18	$ 11	$ 3	$ 3	$ 0
72	8810	**Rents**							
73		Customer	871-879CUS	$ 28,917	$ 26,858	$ 1,803	$ 25	$ 229	$ 2
74		Demand	DEM	$ 5,427	$ 3,913	$ 999	$ 149	$ 360	$ 6
75		Commodity	COM	$ 699	$ 350	$ 220	$ 60	$ 65	$ 4
76		Total Rents		$ 35,043	$ 31,122	$ 3,022	$ 234	$ 653	$ 12
77	8820	Corporate & Div. Exp.							
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —
82		**Total Distr. & Trans. Op. Expense**							
83		Customer		$ 13,208,912	$ 12,268,331	$ 823,435	$ 11,601	$ 104,465	$ 1,080
84		Demand		$ 4,060,054	$ 2,888,716	$ 773,144	$ 115,112	$ 278,532	$ 4,550
85		Commodity		$ 408,716	$ 204,696	$ 128,651	$ 35,211	$ 37,847	$ 2,310
86		Total Distr. & Trans. Operations Exp.		$ 17,677,682	$ 15,361,743	$ 1,725,231	$ 161,923	$ 420,844	$ 7,940
87		**Distribution Maintenance Expenses**							
88	8850	**Maintenance Supervision and Engineering**							
89		Customer	887-893CUS	$ —	$ —	$ —	$ —	$ —	$ —
90		Demand	887-893DEM	$ —	$ —	$ —	$ —	$ —	$ —
91		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
92		Total Supervision and Engineering		$ —	$ —	$ —	$ —	$ —	$ —
93	8860	**Structures and Improvements**							

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
94		Customer	887-893CUS	$ 662,351	$ 630,116	$ 29,058	$ 151	$ 3,015	$ 12
95		Demand	887-893DEM	$ 527,429	$ 301,186	$ 149,333	$ 22,234	$ 53,798	$ 879
96		Commodity	COM	$ 13,054	$ 6,538	$ 4,109	$ 1,125	$ 1,209	$ 74
97		Total Structures and Improvements		$ 1,202,834	$ 937,839	$ 182,500	$ 23,509	$ 58,022	$ 964
98	8870	**Maintenance of Mains**							
99		Customer	CUS	$ 2,387,663	$ 2,278,654	$ 98,745	$ 452	$ 9,775	$ 36
100		Demand	DEM	$ 1,655,797	$ 1,194,024	$ 304,794	$ 45,380	$ 109,805	$ 1,794
101		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
102		Total Mains		$ 4,043,460	$ 3,472,678	$ 403,540	$ 45,832	$ 119,580	$ 1,830
103	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen.**							
104		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
105		Demand	DEM	$ 880,201	$ 634,728	$ 162,025	$ 24,124	$ 58,371	$ 953
106		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
107		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 880,201	$ 634,728	$ 162,025	$ 24,124	$ 58,371	$ 953
108	8890	**Odorization**							
109		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
110		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
111		Commodity	COM	$ 80,957	$ 40,546	$ 25,483	$ 6,974	$ 7,497	$ 458
112		Total Odorization		$ 80,957	$ 40,546	$ 25,483	$ 6,974	$ 7,497	$ 458
113	8900	**Meas. & Reg. Sta. Equip. - Ind.**							
114		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
115		Demand	NRDEM	$ 680,714	$ —	$ 449,307	$ 66,896	$ 161,867	$ 2,644
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Meas. & Reg. Sta. Eq.- Ind.		$ 680,714	$ —	$ 449,307	$ 66,896	$ 161,867	$ 2,644
118	8910	**Meas. & Reg. Sta. Eq.- City Gate**							
119		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
120		Demand	DEM	$ 54,194	$ 39,080	$ 9,976	$ 1,485	$ 3,594	$ 59
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Meas. & Reg. Sta. Eq.- City Gate		$ 54,194	$ 39,080	$ 9,976	$ 1,485	$ 3,594	$ 59
123	8920	**Services**							
124		Customer	SERCUS	$ 1,719,971	$ 1,629,070	$ 81,459	$ 484	$ 8,921	$ 37

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
125		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Services		$ 1,719,971	$ 1,629,070	$ 81,459	$ 484	$ 8,921	$ 37
128	8930	**Maintenance of Meters & House Regulators**							
129		Customer	MTRGCUS	$ —	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Meters & House Regulators		$ —	$ —	$ —	$ —	$ —	$ —
133	8940	**Maintenance of Other Equipment**							
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
137		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
138	8950	Clearing - Meter Shop - Small Meters							
139		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
141		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
142		**Total Clearing-Meter-Shop-Small Meters**		$ —	$ —	$ —	$ —	$ —	$ —
143	8960	Clearing - Meter Shop - Large Meters							
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
147		**Total Clearing-Meter Shop-Large Meters**		$ —	$ —	$ —	$ —	$ —	$ —
148		**Total Distr. Maintenance Expense**							
149		Customer		$ 4,769,984	$ 4,537,840	$ 209,262	$ 1,087	$ 21,710	$ 84
150		Demand		$ 3,798,335	$ 2,169,018	$ 1,075,434	$ 160,119	$ 387,434	$ 6,329
151		Commodity		$ 94,012	$ 47,084	$ 29,592	$ 8,099	$ 8,706	$ 531
152		Total Distr. Maintenance Expense		$ 8,662,331	$ 6,753,942	$ 1,314,289	$ 169,306	$ 417,850	$ 6,945
153		**Total Oper. & Maint. Expense**							
154		Customer		$ 17,978,897	$ 16,806,171	$ 1,032,698	$ 12,688	$ 126,175	$ 1,165
155		Demand		$ 7,858,389	$ 5,057,735	$ 1,848,578	$ 275,231	$ 665,966	$ 10,879

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
156		Commodity		$ 502,728	$ 251,780	$ 158,243	$ 43,310	$ 46,553	$ 2,842
157		Total Operations & Maint. Expense		$ 26,340,013	$ 22,115,685	$ 3,039,519	$ 331,229	$ 838,694	$ 14,885
158		**Customer Accounts Expense**							
159	901	Supervision							
160		Customer	902-904CUS	$ 296	$ 283	$ 12	$ 0	$ 1	$ 0
161		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
162		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
163		Total Supervision		$ 296	$ 283	$ 12	$ 0	$ 1	$ 0
164	902	**Meter Reading Expense**							
165		Customer	METCUS	$ 773,904	$ 711,353	$ 54,688	$ 795	$ 6,995	$ 74
166		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
167		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
168		Total Meter Reading Expense		$ 773,904	$ 711,353	$ 54,688	$ 795	$ 6,995	$ 74
169	903	**Customer Accounting**							
170		Customer	903CUS	$ 3,951,897	$ 3,840,746	$ 104,627	$ 283	$ 6,221	$ 20
171		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
172		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
173		Total Customer Accounting		$ 3,951,897	$ 3,840,746	$ 104,627	$ 283	$ 6,221	$ 20
174	904	**Bad Debt Expense**							
175		Customer	904CUS	$ 1,161,363	$ 1,076,852	$ 82,281	$ 2,023	$ 206	$ —
176		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Bad Debt Expense		$ 1,161,363	$ 1,076,852	$ 82,281	$ 2,023	$ 206	$ —
179	905	**Miscellaneous Customer Accounts**							
180		Customer	902-904CUS	$ 412,828	$ 394,721	$ 16,942	$ 217	$ 941	$ 7
181		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
182		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
183		Total Misc. Customer Accounts		$ 412,828	$ 394,721	$ 16,942	$ 217	$ 941	$ 7
184	907-910	**Customer Information Expense**							
185		Customer	CUS	$ 1,227,575	$ 1,171,530	$ 50,768	$ 233	$ 5,026	$ 18
186		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
187		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
188		Total Customer Information Expense		$ 1,227,575	$ 1,171,530	$ 50,768	$ 233	$ 5,026	$ 18
189		**Sales and Advertising Expense**							
190	911	Supervision							
191		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
192		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
193		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
194		**Total Supervision Expense**		$ —	$ —	$ —	$ —	$ —	$ —
195	912	**Demonstrating and Selling**							
196		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
197		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
198		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
199		Total Demon. and Selling Expense		$ —	$ —	$ —	$ —	$ —	$ —
200	913	**Advertising**							
201		Customer	CUS	$ 143,921	$ 137,351	$ 5,952	$ 27	$ 589	$ 2
202		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
203		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
204		Total Advertising		$ 143,921	$ 137,351	$ 5,952	$ 27	$ 589	$ 2
205	914	Employee Sales Referrals							
206		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
207		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
208		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
209		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —
210		Misc. Gas Sales Expense							
211	916	Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
212		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
213		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
214		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —
215		**Administrative & General Exp.**							
216	920-940	**Administrative & General Expenses**							
217		Customer	OPEXPCUS	$ 30,040,296	$ 28,329,962	$ 1,525,842	$ 15,347	$ 167,889	$ 1,256

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
218		Demand	OPEXPDEM	$ 4,081,032	$ 2,694,530	$ 915,164	$ 136,257	$ 329,696	$ 5,386
219		Commodity	COM	$ 261,077	$ 130,755	$ 82,179	$ 22,492	$ 24,176	$ 1,476
220		Total Administrative & General Exp.		$ 34,382,406	$ 31,155,246	$ 2,523,186	$ 174,095	$ 521,761	$ 8,118
221		**Depreciation & Amortization Expense**							
222	301-303	**Intangible Plant**							
223		Customer	CUS	$ 30,188	$ 28,810	$ 1,248	$ 6	$ 124	$ 0
224		Demand	DEM	$ 10,926	$ 7,879	$ 2,011	$ 299	$ 725	$ 12
225		Commodity	COM	$ 73	$ 37	$ 23	$ 6	$ 7	$ 0
226		Total Intangible Plant		$ 41,187	$ 36,726	$ 3,283	$ 311	$ 855	$ 13
227	365	**Land and Land Rights**							
228		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
229		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
230		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
231		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —
232	366	**Meas. and Reg. Station Structures**							
233		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
234		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
235		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
236		Total Measuring and Reg. Stat. Struct.		$ —	$ —	$ —	$ —	$ —	$ —
237	367	**Transmission Mains**							
238		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
239		Demand	DEM	$ 366,381	$ 264,204	$ 67,442	$ 10,041	$ 24,297	$ 397
240		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
241		Total Transmission Mains		$ 366,381	$ 264,204	$ 67,442	$ 10,041	$ 24,297	$ 397
242	368	**Compression Station Equipment**							
243		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
244		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
245		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
246		Total Compression Sta. Equipment		$ —	$ —	$ —	$ —	$ —	$ —
247	369	**Meas. & Reg. Station Equipment**							
248		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
249		Demand	DEM	$ 192,001	$ 138,455	$ 35,343	$ 5,262	$ 12,733	$ 208
250		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
251		Total Meas. & Reg. Stat. Equipment		$ 192,001	$ 138,455	$ 35,343	$ 5,262	$ 12,733	$ 208
252	369	**Odorization**							
253		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
254		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
255		Commodity	COM	$ 14,395	$ 7,209	$ 4,531	$ 1,240	$ 1,333	$ 81
256		Total Odorization		$ 14,395	$ 7,209	$ 4,531	$ 1,240	$ 1,333	$ 81
257	371	**Other Equipment**							
258		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
259		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
260		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
261		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
262	375	**Structures and Improvements**							
263		Customer	376-379CUS	$ 23,489	$ 22,417	$ 971	$ 4	$ 96	$ 0
264		Demand	DEM	$ 18,733	$ 13,509	$ 3,448	$ 513	$ 1,242	$ 20
265		Commodity	COM	$ 40	$ 20	$ 13	$ 3	$ 4	$ 0
266		Total Structures and Improvements		$ 42,262	$ 35,945	$ 4,432	$ 521	$ 1,342	$ 21
267	376	**Distribution Mains**							
268		Customer	CUS	$ 7,174,306	$ 6,846,763	$ 296,704	$ 1,359	$ 29,371	$ 108
269		Demand	DEM	$ 4,975,239	$ 3,587,732	$ 915,827	$ 136,356	$ 329,934	$ 5,389
270		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
271		Total Distribution Mains		$ 12,149,545	$ 10,434,495	$ 1,212,531	$ 137,715	$ 359,306	$ 5,498
272	376	**Odorization**							
273		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
274		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
275		Commodity	COM	$ 3,215	$ 1,610	$ 1,012	$ 277	$ 298	$ 18
276		Total Odorization		$ 3,215	$ 1,610	$ 1,012	$ 277	$ 298	$ 18
277	377	**Compressor Station Equipment**							
278		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
279		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
280		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
281		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —
282	378	**Meas. & Reg. Sta. Equip. - Gen.**							
283		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM	$ 491,339	$ 354,313	$ 90,444	$ 13,466	$ 32,583	$ 532
285		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Meas. & Reg. Sta. Eq.- Gen.		$ 491,339	$ 354,313	$ 90,444	$ 13,466	$ 32,583	$ 532
287	378	**Odorization Tank**							
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ 14,659	$ 7,342	$ 4,614	$ 1,263	$ 1,357	$ 83
291		Total Odorization Tank		$ 14,659	$ 7,342	$ 4,614	$ 1,263	$ 1,357	$ 83
292	379	**Meas.& Reg. Sta. Equip.- City Gate**							
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 133,844	$ 96,517	$ 24,638	$ 3,668	$ 8,876	$ 145
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Meas. & Reg. Sta. Eq.- City Gate		$ 133,844	$ 96,517	$ 24,638	$ 3,668	$ 8,876	$ 145
297	379	**Odorization Tank**							
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
300		Commodity	COM	$ 9,586	$ 4,801	$ 3,017	$ 826	$ 888	$ 54
301		Total Odorization Tank		$ 9,586	$ 4,801	$ 3,017	$ 826	$ 888	$ 54
302	380	**Services**							
303		Customer	SERCUS	$ 9,665,188	$ 9,154,382	$ 457,751	$ 2,720	$ 50,129	$ 207
304		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
306		Total Services		$ 9,665,188	$ 9,154,382	$ 457,751	$ 2,720	$ 50,129	$ 207
307	381	**Meters**							
308		Customer	METCUS	$ 3,335,369	$ 3,065,785	$ 235,692	$ 3,425	$ 30,147	$ 320
309		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
311		Total Meters		$ 3,335,369	$ 3,065,785	$ 235,692	$ 3,425	$ 30,147	$ 320
312	382	**Meter Installations**							
313		Customer	METCUS	$ 297	$ 273	$ 21	$ 0	$ 3	$ 0
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
316		Total Meter Installations		$ 297	$ 273	$ 21	$ 0	$ 3	$ 0
317	383	**House Regulators**							
318		Customer	REGCUS	$ 383,759	$ 335,258	$ 40,493	$ 1,188	$ 6,704	$ 116
319		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
321		Total House Regulators		$ 383,759	$ 335,258	$ 40,493	$ 1,188	$ 6,704	$ 116
322	385	**Meas. & Reg. Sta. Equip. - Ind.**							
323		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
324		Demand	NRDEM	$ 388,137	$ —	$ 256,191	$ 38,144	$ 92,295	$ 1,508
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Meas. & Reg. Stat. Eq.- Ind.		$ 388,137	$ —	$ 256,191	$ 38,144	$ 92,295	$ 1,508
327	385	**Odorization**							
328		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
329		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
330		Commodity	COM	$ 1,137	$ 570	$ 358	$ 98	$ 105	$ 6
331		Total Odorization		$ 1,137	$ 570	$ 358	$ 98	$ 105	$ 6
332	386	**Other Prop.- Customer Premises**							
333		Customer	CUS	$ 126,420	$ 120,649	$ 5,228	$ 24	$ 518	$ 2
334		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
336		Total Other Prop. - Customer Premises		$ 126,420	$ 120,649	$ 5,228	$ 24	$ 518	$ 2
337	387	**Other Equipment**							
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
341		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
342	389-398	**General Plant**							
343		Customer	GENPTCUS	$ 7,307,740	$ 6,931,763	$ 337,276	$ 2,300	$ 36,207	$ 194
344		Demand	DISPLTDEM	$ 1,236,027	$ 832,236	$ 266,523	$ 39,682	$ 96,017	$ 1,568
345		Commodity	COM	$ 8,186	$ 4,100	$ 2,577	$ 705	$ 758	$ 46
346		Total General Plant		$ 8,551,954	$ 7,768,099	$ 606,377	$ 42,687	$ 132,983	$ 1,808
347	389-398	**General Plant - Odorization**							
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 1,310	$ 656	$ 412	$ 113	$ 121	$ 7
351		Total General Plant - Odorization		$ 1,310	$ 656	$ 412	$ 113	$ 121	$ 7
352	40730	**Pension & FAS 106 Amort. Expense**							
353		Customer	CUS	$ (435,649)	$ (415,759)	$ (18,017)	$ (83)	$ (1,784)	$ (7)
354		Demand	DEM	$ (93,397)	$ (67,351)	$ (17,192)	$ (2,560)	$ (6,194)	$ (101)
355		Commodity	COM	$ (5,975)	$ (2,992)	$ (1,881)	$ (515)	$ (553)	$ (34)
356		Total Pension & FAS 106 Amort. Exp.		$ (535,021)	$ (486,102)	$ (37,090)	$ (3,157)	$ (8,530)	$ (142)
357		**Total Depreciation & Amort. Exp.**							
358		Customer		$ 27,611,108	$ 26,090,339	$ 1,357,369	$ 10,943	$ 151,515	$ 941
359		Demand		$ 7,719,230	$ 5,227,495	$ 1,644,675	$ 244,872	$ 592,508	$ 9,679
360		Commodity		$ 46,627	$ 23,352	$ 14,677	$ 4,017	$ 4,318	$ 264
361		Total Depreciation & Amort. Expense		$ 35,376,964	$ 31,341,186	$ 3,016,721	$ 259,832	$ 748,341	$ 10,883
362		**Taxes Other Than Income**							
363	4081	**Payroll and Other Taxes**							
364		Customer	OPEXPCUS	$ 2,546,607	$ 2,401,617	$ 129,350	$ 1,301	$ 14,232	$ 107
365		Demand	OPEXPDEM	$ 545,959	$ 360,473	$ 122,430	$ 18,228	$ 44,107	$ 720
366		Commodity	COM	$ 34,927	$ 17,492	$ 10,994	$ 3,009	$ 3,234	$ 197
367		Total Payroll and Other Taxes		$ 3,127,494	$ 2,779,583	$ 262,775	$ 22,538	$ 61,573	$ 1,024
368	4081	**Ad Valorem Taxes**							
369		Customer	CUS	$ 5,092,149	$ 4,859,667	$ 210,594	$ 965	$ 20,847	$ 77
370		Demand	DEM	$ 1,843,036	$ 1,329,045	$ 339,261	$ 50,512	$ 122,221	$ 1,996
371		Commodity	COM	$ 12,305	$ 6,163	$ 3,873	$ 1,060	$ 1,139	$ 70
372		Total Ad Valorem Taxes		$ 6,947,490	$ 6,194,875	$ 553,727	$ 52,536	$ 144,208	$ 2,143

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
373		**Revenue Related Taxes**							
374		Customer	TOTREVCUS	$ 219,750	$ 164,043	$ 45,874	$ 2,926	$ 6,800	$ 107
375		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
376		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
377		Total Revenue Related Taxes		$ 219,750	$ 164,043	$ 45,874	$ 2,926	$ 6,800	$ 107
378		**Total Taxes Other Than Income**							
379		Customer		$ 7,858,507	$ 7,425,327	$ 385,818	$ 5,192	$ 41,880	$ 290
380		Demand		$ 2,388,995	$ 1,689,519	$ 461,691	$ 68,740	$ 166,328	$ 2,717
381		Commodity		$ 47,232	$ 23,655	$ 14,867	$ 4,069	$ 4,374	$ 267
382		Total Taxes Other Than Income		$ 10,294,734	$ 9,138,501	$ 862,376	$ 78,001	$ 212,582	$ 3,274
383		**Excess Deferred Income Tax Amortization**							
384		Customer	CUS	$ (363,603)	$ (347,003)	$ (15,037)	$ (69)	$ (1,489)	$ (5)
385		Demand	DEM	$ (135,946)	$ (98,033)	$ (25,025)	$ (3,726)	$ (9,015)	$ (147)
386		Commodity	COM	$ (1,128)	$ (565)	$ (355)	$ (97)	$ (104)	$ (6)
387		**Total Excess Def. Income Tax Amortization**		$ (500,677)	$ (445,601)	$ (40,417)	$ (3,892)	$ (10,608)	$ (159)
388		**Interest on Customer Deposits**							
389		Customer	DEPCUS	$ 321,437	$ 156,646	$ 162,603	$ 1,745	$ 444	$ —
390		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
391		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
392		Total Interest on Cust. Deposits		$ 321,437	$ 156,646	$ 162,603	$ 1,745	$ 444	$ —
393		**Required Return**							
394		Customer	CUS	$ 46,546,269	$ 44,421,200	$ 1,924,992	$ 8,817	$ 190,559	$ 701
395		Demand	DEM	$ 17,403,058	$ 12,549,651	$ 3,203,503	$ 476,963	$ 1,154,089	$ 18,852
396		Commodity	COM	$ 144,395	$ 72,317	$ 45,451	$ 12,440	$ 13,371	$ 816
397		Tot. Req. Return		$ 64,093,722	$ 57,043,168	$ 5,173,946	$ 498,220	$ 1,358,019	$ 20,369
398		**Income Taxes**							
399		Customer	CUS	$ 9,606,130	$ 9,167,563	$ 397,276	$ 1,820	$ 39,327	$ 145
400		Demand	DEM	$ 3,591,610	$ 2,589,973	$ 661,133	$ 98,435	$ 238,179	$ 3,891
401		Commodity	COM	$ 29,800	$ 14,925	$ 9,380	$ 2,567	$ 2,760	$ 168
402		Total Income Taxes		$ 13,227,540	$ 11,772,460	$ 1,067,789	$ 102,822	$ 280,265	$ 4,204
403		**Total Cost of Service Before**							

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
404		**Revenue Credits**							
405		Customer		$ 147,270,825	$ 139,383,041	$ 7,086,829	$ 60,061	$ 736,279	$ 4,614
406		Demand		$ 42,906,367	$ 29,710,869	$ 8,709,720	$ 1,296,772	$ 3,137,751	$ 51,255
407		Commodity		$ 1,030,731	$ 516,218	$ 324,443	$ 88,798	$ 95,446	$ 5,826
408		**Total Cost of Service Before Revenue Credits**		$ 191,207,923	$ 169,610,129	$ 16,120,993	$ 1,445,630	$ 3,969,476	$ 61,695

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Cost Allocation Factors							
2								
3	Total Customers		326,442	311,538	13,500	62	1,336	5
4	**Total Customers Factor (CUS)**	CUS	1.00000	0.95435	0.04136	0.00019	0.00409	0.00002
5								
6	Services - Allocated Weighting			1.00000	1.15388	1.49682	1.27651	1.43131
7	Weighted Customers		328,921	311,538	15,578	93	1,706	7
8	**Weighted Services Customer Factor (SERCUS)**	SERCUS	1.00000	0.94715	0.04736	0.00028	0.00519	0.00002
9								
10	Meters - Allocated Weighting			1.00000	1.77405	5.62795	2.29224	6.61687
11	Weighted Customers		338,932	311,538	23,951	348	3,063	33
12	**Weighted Meters Customer Factor (METCUS)**	METCUS	1.00000	0.91917	0.07066	0.00103	0.00904	0.00010
13								
14	Regulators - Allocated Weighting			1.00000	2.78714	17.85294	4.66126	22.01461
15	Weighted Customers		356,607	311,538	37,628	1,104	6,230	108
16	**Weighted Regulators Customer Factor (REGCUS)**	REGCUS	1.00000	0.87362	0.10552	0.00310	0.01747	0.00030
17								
18	Meters and Regulators - Allocated Weighting			1.00000	1.95193	7.77448	2.70821	9.32049
19	Weighted Customers		342,036	311,538	26,352	481	3,619	46
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	MTRGCUS	1.00000	0.91083	0.07704	0.00141	0.01058	0.00013
21								
22	Non-Residential Customers		14,904	0	13,500	62	1,336	5
23	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.90585	0.00415	0.08967	0.00033
24								
25	Customer Cost Allocation Factors							
26								
27	Distribution Plant Customer Costs		$ 686,831,324	$ 649,495,014	$ 33,354,767	$ 259,392	$ 3,700,004	$ 22,147
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.94564	0.04856	0.00038	0.00539	0.00003
29								
30	Account 376-379 Customer Costs		$ 286,924,064	$ 273,824,552	$ 11,866,181	$ 54,351	$ 1,174,659	$ 4,321
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.95435	0.04136	0.00019	0.00409	0.00002
32								
33	Total Revenue (inc. cost of gas)		$ 257,245,398	$ 192,033,343	$ 53,701,147	$ 3,425,419	$ 7,960,482	$ 125,006
34	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.74650	0.20875	0.01332	0.03095	0.00049
35								

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
36	Mains - Customer Cost Factor		0.48499	0.46284	0.02006	0.00009	0.00199	0.00001
37	Services - Customer Cost Factor		0.51501	0.48780	0.02439	0.00014	0.00267	0.00001
38	**Mains & Svcs. Cust. Factor (MSCUS)**	MSCUS	1.00000	0.95064	0.04445	0.00024	0.00466	0.00002
39								
40	Total Plant Customer		$ 823,893,666	$ 780,299,778	$ 39,023,188	$ 285,355	$ 4,261,134	$ 24,211
41	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.94709	0.04736	0.00035	0.00517	0.00003
42								
43	Non-Intangible Plant Customer							
44	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 822,820,486	$ 785,254,634	$ 34,028,992	$ 155,863	$ 3,368,604	$ 12,393
45		NONINCUS	1.00000	0.95435	0.04136	0.00019	0.00409	0.00002
46								
47	Account 871-879 Customer Costs		$ 11,516,597	$ 10,696,522	$ 717,937	$ 10,114	$ 91,081	$ 942
48	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.92879	0.06234	0.00088	0.00791	0.00008
49								
50	Account 887-893 Customer Costs		$ 4,107,634	$ 3,907,724	$ 180,205	$ 936	$ 18,696	$ 73
51	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.95133	0.04387	0.00023	0.00455	0.00002
52								
53	Account 903 Customer		$ 3,951,897	$ 3,840,746	$ 104,627	$ 283	$ 6,221	$ 20
54	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.97187	0.02648	0.00007	0.00157	0.00001
55								
56	Customer Cost Allocation Factors							
57								
58	Account 904 Customer		$ 1,161,363	$ 1,076,852	$ 82,281	$ 2,023	$ 206	$ —
59	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.92723	0.07085	0.00174	0.00018	0.00000
60								
61	Accounts 902-904 Customer		$ 5,887,164	$ 5,628,951	$ 241,596	$ 3,101	$ 13,422	$ 94
62	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.95614	0.04104	0.00053	0.00228	0.00002
63								
64	Operating Expense Customer		$ 53,261,789	$ 50,229,346	$ 2,705,336	$ 27,210	$ 297,669	$ 2,228
65	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.94307	0.05079	0.00051	0.00559	0.00004
66								
67	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 90,514,165	$ 85,593,794	$ 4,395,663	$ 34,184	$ 487,606	$ 2,919
68	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 45,474,997	$ 43,398,837	$ 1,880,688	$ 8,614	$ 186,173	$ 685
69	Total General Plant Customer Costs		$ 135,989,162	$ 128,992,631	$ 6,276,350	$ 42,798	$ 673,779	$ 3,604
70	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.94855	0.04615	0.00031	0.00495	0.00003
71								

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
72	Customer Deposits		$ (6,613,930)	$ (3,223,171)	$ (3,345,736)	$ (35,898)	$ (9,126)	$ —
73	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.48733	0.50586	0.00543	0.00138	0.00000
74								
75	Demand Cost Allocation Factors							
76								
77	System Demand							
78	**System Demand Factor (DEM)**	DEM	1.00000	0.72112	0.18408	0.02741	0.06632	0.00108
79								
80	Non-Residential Demand							
81	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.66005	0.09827	0.23779	0.00388
82								
83	Distribution Plant Demand		$ 246,016,216	$ 165,646,486	$ 53,048,236	$ 7,898,240	$ 19,111,076	$ 312,178
84	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.67332	0.21563	0.03210	0.07768	0.00127
85								
86	Demand Cost Allocation Factors							
87								
88	Non-Intangible Plant Demand		$ 297,808,939	$ 214,755,265	$ 54,819,780	$ 8,162,002	$ 19,749,290	$ 322,603
89	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.72112	0.18408	0.02741	0.06632	0.00108
90								
91	Total Plant Demand		$ 298,197,362	$ 203,275,228	$ 62,653,585	$ 9,328,360	$ 22,571,484	$ 368,704
92	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.68168	0.21011	0.03128	0.07569	0.00124
93								
94	Operating Expense Demand		$ 15,577,618	$ 10,285,230	$ 3,493,254	$ 520,103	$ 1,258,474	$ 20,557
95	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.66026	0.22425	0.03339	0.08079	0.00132
96								
97	Acct. 887-893 Demand		$ 3,270,905	$ 1,867,833	$ 926,102	$ 137,885	$ 333,636	$ 5,450
98	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.57104	0.28313	0.04216	0.10200	0.00167
99								
100	Rate Base Demand		$ 220,817,480	$ 150,879,867	$ 46,162,491	$ 6,873,036	$ 16,630,428	$ 271,657
101	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.68328	0.20905	0.03113	0.07531	0.00123
102								
103	Commodity Cost Allocation Factors							
104								
105	Annual Distribution Volumes (Ccf)		200,820,622	100,576,461	63,212,213	17,300,748	18,596,127	1,135,073
106	**Distribution Commodity Factor (COM)**	COM	1.00000	0.50083	0.31477	0.08615	0.09260	0.00565

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Current Revenue-to-Cost Ratio (1)	0.8651	0.7822	1.5315	2.1127	1.2309	2.0406
2	Revenue Allocation One - Cost of Service Study Required Revenue Changes						
3	Revenue-to-Cost Ratio	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
4	Rate Design Revenue Change	$ 25,789,396	$ 36,946,576	$ (8,567,982)	$ (1,608,615)	$ (916,382)	$ (64,201)
5	% Increase - Non-Gas Revenue (2)	15.59%	27.85%	-34.70%	-52.67%	-18.76%	-51.00%
6	% Increase - Total Revenue (3)	9.83%	18.79%	-15.87%	-46.69%	-11.43%	-51.00%
7	% Total Revenue (for GRIP)	100.00 %	88.60 %	8.51 %	0.77 %	2.10 %	0.03 %
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)						
9	Revenue-to-Cost Ratio	1.0000	0.9474	1.4252	1.8902	1.1847	1.8325
10	Rate Design Revenue Change	$ 25,789,396	$ 28,020,832	$ (1,713,596)	$ (321,723)	$ (183,276)	$ (12,840)
11	% Increase - Non-Gas Revenue (2)	15.59%	21.12%	-6.94%	-10.53%	-3.75%	-10.20%
12	% Increase - Total Revenue (3)	9.83%	14.25%	-3.17%	-9.34%	-2.29%	-10.20%
13	% Total Revenue (for GRIP)	100.00 %	83.80 %	12.19 %	1.46 %	2.50 %	0.06 %
14	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)						
15	Revenue-to-Cost Ratio	1.0000	0.9342	1.5315	2.1127	1.2309	2.0406
16	Rate Design Revenue Change	$ 25,789,396	$ 25,789,396	$ —	$ —	$ —	$ —
17	% Increase - Non-Gas Revenue (2)	15.59%	19.44%	0.00%	0.00%	0.00%	0.00%
18	% Increase - Total Revenue (3)	9.83%	13.11%	0.00%	0.00%	0.00%	0.00%
19	% Total Revenue (for GRIP)	100.00 %	82.60 %	13.11 %	1.63 %	2.59 %	0.07 %

(1) Revenue-to-cost ratios are the ratios of each class' non-gas revenue (including revenue credits) to the cost of service.

(2) Non-gas revenue is the sum of as adjusted test year base revenue (i.e., revenue from recurring monthly charges resulting from as adjusted billing determinants), service charge revenue, special contract revenue, and other revenue credited to the cost of service for each class.

(3) Total revenue is the sum of non-gas revenue (see Note 2) and as adjusted gas costs. As adjusted gas costs are calculated by multiplying the test year average cost of gas (i.e., test year gas cost revenue divided by unadjusted sales service volumes) by as adjusted sales service volumes.

(4) For each class with a cost of service required revenue decrease, 20 percent of the required decrease is implemented. The benefit of implementing less than the required decrease is assigned to the residential class.

(5) No revenue change assigned to a class for which the cost of service required revenue change calls for a decrease. The resulting benefit from not implementing the required decease is assigned to the residential class.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF TERESA D. SERNA

BEFORE ME, the undersigned authority, on this day personally appeared Teresa D. Serna who having been placed under oath by me did depose as follows:

1. "My name is . I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Rate Specialist for Texas Gas Service Company, a division of ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Teresa D. Serna

Teresa D. Serna

SUBSCRIBED AND SWORN TO BEFORE ME by the said Teresa D. Serna on this 21ST day of MAY 2024.

Erlinda Alvarado

Notary Public in and for the State of Texas

ERLINDA ALVARADO
NOTARY PUBLIC
ID# 133935107
State of Texas
Comm. Exp. 08-29-2026

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

ZANE M. DRUMMOND

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

DIRECT TESTIMONY OF ZANE M. DRUMMOND

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Zane M. Drummond, and my business address is 1301 South Mopac Expressway, Suite 400, Austin, Texas 78746.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Rates Analyst I for Texas Gas Service Company ("TGS" or the "Company"), which is a Division of ONE Gas, Inc.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science Degree in Accountancy and Finance from the University of Wisconsin - La Crosse in May 2021. I began my career with TGS in September 2021 as a Rates Analyst I.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents and supports the revenue adjustments used to develop the revenue requirement for TGS's Central-Gulf Service Area ("CGSA").

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I am sponsoring Schedules G-1 through G-3.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. <u>REVENUE ADJUSTMENTS</u>

Q. WHAT ADJUSTMENTS TO REVENUE ARE YOU SPONSORING?

A. I am sponsoring the adjustments to Gas Sales and Transportation Revenue listed on Schedules G-1, G-2 and G-3. Schedule G-1 presents the cost of gas expense and the cost of gas revenues that are removed from the Company's per books test year expenses and revenues. These adjustments are necessary because gas costs are recovered via the Cost of Gas Clause ("CGC") rather than through base rates. Schedule G-2 shows the derivation of the test year base sales revenue through the removal of the cost of gas revenue from total per book revenues. Schedule G-2 also contains the various adjustments to test year base revenue attributable to Gas Sales customers that are necessary to make test year revenues representative of expected annual revenues for purposes of setting rates in this filing. Finally, Schedule G-3 contains adjustments to base revenue attributable to transportation customers and other utility revenue that are required to normalize test year revenue in this filing.

Q. PLEASE EXPLAIN THE ADJUSTMENTS ON SCHEDULE G-1.

A. Gas costs are recovered through the Company's CGC instead of through base rates because: (1) the Company does not make a profit on gas costs and (2) fluctuations in the cost of gas are outside the control of the Company. Therefore, it is necessary to remove gas costs and revenues from the test year cost of service. Line 1 of Schedule G-1 is the cost of gas revenue collected via the CGC, which is removed from Base Sales Revenue on Schedule G-2. Line 2 is the test year cost of gas expense that is removed from this filing as shown on Schedule G. Schedule G is sponsored by Company witnesses Marie J. Michels and Stacey Borgstadt.

Q. WHAT INFORMATION IS SHOWN ON LINES 1-3 OF SCHEDULE G-2?

A. The per book Gas Sales Revenue for the twelve months ending December 31, 2023, is shown on line 1 of Schedule G-2. This total includes revenue derived from: (1) charges for the cost of gas and (2) charges for sales service. Line 2 is the total per book revenue attributable to recovery of the cost of gas. The revenue on line 2 is subtracted from the revenue on line 1 to remove all revenue associated with gas costs from the total per book revenues to yield Base Sales Revenue as shown on line 3.

Q. PLEASE EXPLAIN THE WEATHER NORMALIZATION ADJUSTMENT ("WNA") ON LINE 4 OF SCHEDULE G-2.

A. TGS currently has WNAs in effect for the CGSA. Revenue collected or refunded through the WNA is adjusted each month to offset the impacts of abnormal weather on customers' bills and Company revenues. The Company's test year cost of service calculation includes an adjustment to reflect revenues that would have been expected if weather had been normal. In effect, this causes the WNA to be counted twice in the calculation of the Company's revenue requirement. To avoid this redundancy, it is necessary to remove the revenue recognized through the WNA during the test year. This is accomplished through the adjustment of $(2,602,511) on line 4 of Schedule G-2.

Q. PLEASE EXPLAIN A HEATING DEGREE DAY ("HDD").

A. A HDD is defined as the number of degrees that a day's average temperature is below 65 degrees Fahrenheit. A HDD is calculated by comparing the average of the high and low temperature on a given day with 65 degrees, the outside temperature above which a building needs no heating. If the average for that day is less than 65 degrees, the resulting HDD for the given day is the difference between the average temperature and 65. Thus, if the high temperature on Day X was 70 and the low temperature was 56, then the average temperature would be 63 ((70+56)/2) and would result in two HDDs on Day X. If the average was equal to or greater than 65, there would be no HDDs for that day. HDDs are used in determining the demand for gas that is based on the weather and to adjust actual gas usage to normal weather.

Q. HOW IS "NORMAL" WEATHER DEFINED?

A. Weather varies seasonally and daily. Seasonal weather patterns generally result in an expected temperature range. Within each season, there are daily variations within the expected, or "normal," range. The goal of normalizing weather is to capture the average of these variations in a way that reflects the most relevant weather experienced over a period that is sufficiently long to smooth out variations caused by extreme or unusual weather in a year. TGS uses an average of daily weather calculated over a ten-year period to derive normal HDDs. In this case, "normal" weather is calculated by averaging daily HDDs over a ten-year period ending December 31, 2023.

Q. WHY WAS A PERIOD OF TEN YEARS SELECTED?

A. A ten-year period is consistent with what has been approved in the Company's other service areas pursuant to Railroad Commission of Texas ("Commission") orders issued in Docket No. OS-22-00009896 ("Docket No. 9896") and Gas Utilities Docket ("GUD") No. 10506, which were fully litigated, and GUD Nos. 9988, 10928, 10488, 10526, 10656, 10739, 10766 and Docket No. OS-23-00014399 ("Docket No. 14399"), pursuant to settlement. It is also consistent with the practice of other Texas gas utilities and Commission decisions[1] and has been found reasonable and precluded from further litigation in prior proceedings.[2]

Q. PLEASE EXPLAIN HOW THE WNA SHOWN ON LINE 5 OF SCHEDULE G-2 WAS DEVELOPED.

A. The adjustment on line 5 of Schedule G-2 is required to weather normalize revenues. The analysis was developed based on data from the four weather stations used in the CGSA, Austin Camp Mabry (KATT), Beaumont/Port Arthur Southeast Regional Airport (KBPT), Scholes International Airport/Galveston (KGLS) and San Antonio International Airport (KSAT). A separate analysis is conducted for each customer class to reflect usage patterns and to price adjustments at the appropriate tariff rates. By analyzing the relationship between monthly average usage per customer for a class and actual HDDs for the month using regression analysis, an estimated usage per customer per HDD was developed for each class.

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[1] *See, e.g.*, *Statement of Intent filed by TXU Gas Company to Change Rates in the Company's Statewide Gas Utility System*, GUD No. 9400, Final Order (May 25, 2004).

[2] *See, e.g.*, *Statement of Intent filed by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas to Increase Rates on a Division Wide Basis in the Beaumont/East Texas Division*, GUD No. 10182, consol., Examiners' Letter 18 (Sept. 17, 2012) ("The company's use of the last 10 years to establish normal weather for purposes of normalizing revenues and billing determinants [sic] not be relitigated in this proceeding.").

This value was then used to develop the weather adjustment for each billing cycle by multiplying the estimated usage per customer per HDD by the difference between normal HDDs and actual HDDs. The result was then multiplied by the number of customers in the billing cycle to yield the total adjustment to volumes. The resulting volumes were used to normalize usage in each billing cycle of the test year. This analysis is consistent with that used by TGS in prior rate cases.[3] This volume adjustment was then priced at the test year tariff rates to yield the revenue adjustment, a $1,141,969 increase to test year base sales revenues, as shown on line 5 of Schedule G-2. This adjustment increases base sales revenues in recognition of the fact that the volumes and resulting revenues were abnormally low because temperatures in the test year period were warmer than normal. By adjusting sales volumes upward to reflect normal weather conditions in the CGSA and applying

[3] This methodology was utilized in the Company's Rio Grande Valley Service Area in *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order (Jan. 30, 2024); West-North Service Area in *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order (Jan. 18, 2023); Central-Gulf Service Area in Central Gulf Service Area in *Statement of Intent of Texas Gas Services Company, a Division of ONE Gas, Inc. to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928, consol., Final Order (Aug. 4, 2020); Gulf Coast Service Area in *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order (May 3, 2016); West Texas Service Area in *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA)*, GUD No. 10506 consol., Final Order (Sept. 27, 2016); Central Texas Service Area in *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016); Rio Grande Valley Service Area in *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018); North Texas Service Area in *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018); and the Borger-Skellytown Service Area in *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018).

these volumes to existing rates, the resulting adjusted revenue reflects the level of revenues reasonably anticipated to be collected under normal weather conditions. The weather normalized sales volumes are also used by Company witness Paul H. Raab to develop proposed rates that are reasonably anticipated to collect the proposed revenue requirement.

Q. PLEASE DESCRIBE THE CUSTOMER GROWTH (LOSS) ADJUSTMENT ON LINE 6 OF SCHEDULE G-2.

A. To account for customer growth or loss, the Company includes an adjustment to quantify customer growth or loss patterns and adjusts customer counts accordingly. For each customer class within the CGSA, this adjustment annualizes the growth or loss in customers that occurred during the twelve months ended December 31, 2023, by adjusting bill counts and volumes in each month of the test year to reflect the levels observed at the end of the test year. This adjustment is necessary to ensure that test year revenues accurately reflect the number of customers served when new rates take effect.

Q. HOW IS THE CUSTOMER GROWTH (LOSS) ADJUSTMENT CALCULATED?

A. The adjustment is calculated by multiplying the change in customer bill counts by the normal monthly per customer usage for each class to yield the adjustment volumes. This volume adjustment and the changes to bill counts were then priced at the test year tariff rates for each customer class to yield the revenue adjustment. The change in customers as of December 31, 2023, was calculated by comparing the number of active customers at December 31, 2022, to the number of active customers at December 31, 2023. The adjustment shown on line 6 on Schedule G-

2 annualizes the customer growth, an $890,498 increase to test year base sales revenue.

Q. PLEASE EXPLAIN LINE 7 OF SCHEDULE G-2.

A. The adjustment shown on line 7 removes revenue collected through a Gas Reliability Infrastructure Program ("GRIP") adjustment during the twelve months ended December 31, 2023. This adjustment is necessary because the Company's test year cost of service calculation already includes a GRIP annualization.

Q. PLEASE EXPLAIN THE GRIP ANNUALIZATION ADJUSTMENT ON LINE 8 OF SCHEDULE G-2.

A. TGS has filed four GRIP adjustments for the CGSA since GUD No. 10928. The annualization of this revenue impact over the entire test year based upon the rates requested in those filings results in a $42,911,678 increase to base sales revenues. The adjustment is derived by taking the difference between revenues calculated based on current rates and revenues generated during the test year period ending December 31, 2023.

Q. WHAT IS THE NET IMPACT OF THE PREVIOUSLY DISCUSSED ADJUSTMENTS TO GAS SALES REVENUES?

A. The total adjustment to base revenues attributable to Gas Sales revenues is an increase of $16,080,231, as shown on line 9 of Schedule G-2. This results in a total Base Sales Revenue amount, as adjusted, of $151,701,685, as shown on line 10 of Schedule G-2.

Q. PLEASE EXPLAIN TRANSPORTATION REVENUE AS SHOWN ON LINE 1 OF SCHEDULE G-3.

A. The revenue on line 1 reflects the per books revenue collected from transportation customers during the test year.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 2 OF SCHEDULE G-3.

A. Line 2 reflects a revenue adjustment of $(529,628) to remove GRIP revenue collected in the CGSA during the twelve months ended December 31, 2023. As previously described, this adjustment is necessary because the Company's test year cost of service calculation already includes a GRIP annualization.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 3 OF SCHEDULE G-3.

A. As previously described, TGS has filed four GRIP adjustments for the CGSA. The annualization of this revenue impact over the entire test year results in a $974,705 increase to transportation revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 4 OF SCHEDULE G-3.

A. Transportation customers are not billed until shortly after the billing system closes for the month. As a result, transportation revenue must be estimated each month and those estimates are reversed out in the following month when actual revenue is recorded on the Company's books. Removing these estimates restores transportation revenues to the actual amount billed during the test year, which increases transportation revenues by $67,676.

Q. WHAT IS THE NET IMPACT OF THE ADJUSTMENTS TO TRANSPORTATION REVENUES ON SCHEDULE G-3?

A. The total adjustment to transportation revenues is an increase of $512,753, as shown on line 5 of Schedule G-3.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO SERVICE FEES ON LINE 8 OF SCHEDULE G-3.

A. Ms. Michels presents the proposed changes to service fees. Line 8 of Schedule G-3 contains the adjustment to annualize the changes in service fees. These changes will have the effect of increasing the revenues the Company would otherwise recover under its existing service fees. To account for these changes, an increase of $304,384 to test year revenues is included on line 8 of Schedule G-3.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO OTHER UTILITY REVENUE ON LINE 11 OF SCHEDULE G-3.

A. Interest on storage gas is recovered through a gas cost recovery mechanism rather than via base rates. Therefore, it is not part of the Company's revenue requirement and is removed from this filing. This results in a $806,701 decrease to revenues.

Q. WHAT IS THE TOTAL TRANSPORTATION REVENUE, SERVICE FEE REVENUE AND OTHER UTILITY REVENUE AS ADJUSTED?

A. As shown on line 13 of Schedule G-3, the total amount as adjusted is $13,716,843.

III. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF ZANE M. DRUMMOND

BEFORE ME, the undersigned authority, on this day personally appeared Zane M. Drummond who having been placed under oath by me did depose as follows:

1. "My name is Zane M. Drummond. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Rates Analyst I for Texas Gas Service Company, a division of ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Zane Drummond
Zane M. Drummond

SUBSCRIBED AND SWORN TO BEFORE ME by the said Zane M. Drummond on this 21st day of May 2024.

Erlinda Alvarado
Notary Public in and for the State of Texas

ERLINDA ALVARADO
NOTARY PUBLIC
ID# 133935107
State of Texas
Comm. Exp. 08-29-2026

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., TO CHANGE GAS UTILITY RATES WITHIN THE UNINCORPORATED AREAS OF THE CENTRAL-GULF SERVICE AREA	§ § § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

DIRECT TESTIMONY

OF

PAUL H. RAAB

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 3, 2024

TABLE OF CONTENTS

LIST OF EXHIBITS

DIRECT TESTIMONY OF PAUL H. RAAB

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Paul H. Raab, and my business address is 5313 Portsmouth Road, Bethesda, Maryland 20816. I am an independent economic consultant.

Q. ON WHOSE BEHALF ARE YOU APPEARING TODAY?

A. I am appearing on behalf of Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS" or "the Company").

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I have a B.A. in Economics from Rutgers University and an M.A. from the State University of New York at Binghamton with a concentration in Econometrics. While attending Rutgers, I studied as a Henry Rutgers Scholar.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have been providing consulting services to the utility industry for over 45 years, having assisted electric, gas, telephone and water utilities; Commissions; and intervenor clients in a variety of areas. I am trained as a quantitative economist so most of this assistance has been in the form of mathematical and economic analysis and information systems development. My areas of focus are planning issues, costing and rate design analysis and depreciation and life analysis. I began my career with the professional services firm that is now known as Ernst & Young, where I was employed for ten years.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE RAILROAD COMMISSION OF TEXAS ("COMMISSION") IN REGULATORY PROCEEDINGS?

A. Yes. I have previously provided expert testimony before this Commission and numerous state regulatory authorities, as well as the Federal Energy Regulatory Commission, the Michigan House Economic Development and Energy Committee, the Pennsylvania House Consumer Affairs Committee, the Province of Saskatchewan and the United States Tax Court. Details on the subject matter of the testimony presented are provided in Exhibit PHR-1.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I prepared and sponsor the exhibits listed in the table of contents.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents and supports the rate designs I developed for the Central-Gulf Service Area ("CGSA") based on the CGSA class cost of service study ("CCOSS") results sponsored by Company witness Teresa D. Serna.

II. RATE DESIGN

A. Overview

Q. PLEASE PROVIDE AN OVERVIEW OF THE RATE DESIGN PRESENTATION IN YOUR TESTIMONY.

A. As I have previously indicated, my testimony develops rates for the CGSA. For most classes, the Company is proposing to maintain the existing two-part (customer charges and usage charges) rate structures, adjusted to meet the revenue levels associated with its current cost of providing service to these customers. In the case of rates for service to residential and commercial sales customers, the Company is proposing to maintain a two-part rate structure, but applied to different usage levels with each class. Accordingly, this section of my testimony begins with a discussion of the specific rates being proposed, followed by a discussion of how the specific tariffs for the CGSA satisfy the Company's rate design objectives.

Q. PLEASE DESCRIBE THE NEW RESIDENTIAL AND COMMERCIAL RATE STRUCTURES BEING PROPOSED.

A. To minimize the bill impacts associated with rate eliminations and rate level increases, to encourage customer choice, and to more appropriately reflect the Company's costs of providing service, the Company is proposing to split the existing residential class into two sub-classes: a "large" residential sub-class composed of residential customers who annually consume more than the average amount of the combined class and a "small" residential sub-class composed of residential customers who annually consume less than the average amount of the combined class. The Company is proposing the same small/large rate distinction for commercial customers. This same "two-tiered" rate structure was recently approved by the Commission for TGS residential customers in the Company's Rio Grande Valley and West North Service Areas.[1] The Commission also approved two-tiered rates for TGS commercial customers in the Company's Rio Grande Valley Service Area.[2]

Q. WHAT EXHIBITS HAVE YOU PROVIDED TO SUPPORT THE PROPOSED RATE DESIGNS FOR EACH CUSTOMER CLASS?

A. I have developed seven exhibits, Exhibit PHR-2 through Exhibit PHR-8, to assist in the presentation of these rate designs. This presentation focuses on three areas: (1) the rates themselves and how they compare to existing rates; (2) the customer bill impacts when moving from existing rates to the new rates; and (3) how effectively the new rate structures recover Commission-approved levels of revenues in this case.

Exhibit PHR-2 begins with a summary of Current and Recommended Rates. Bill impacts are documented in Exhibits PHR-3 through PHR-7. These latter exhibits examine how the proposed rate designs minimize bill impact issues associated with proposed rate levels and changes in rate structures. Finally, Exhibit PHR-8 contains a proof of revenues that demonstrates that the new rate structures recover Company-proposed levels of revenues in this case.

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[1] *See Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896, consol., Final Order at Finding of Fact No. 103 (Jan. 18, 2023) ("TGS's two tiered-rate proposal for residential customers based upon a large residential class, consisting of customers that annually consume more than the average amount of the combined class, and a small residential class that consumes less than the average amount of the combined class is just and reasonable."); Docket No. OS-22-00009896, consol., Final Order, Attachment 1, Tariffs and Schedules Rate Schedule 10 and 15.

[2] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, Docket No. OS-23-00014399, consol., Final Order, Attachment 1, Schedules, Rate Schedule 20 and 25 (Jan. 30, 2024).

B. Current Rates

Q. PLEASE DESCRIBE THE CURRENT RESIDENTIAL RATES.

A. Current residential rate structures consist of a fixed customer charge and usage charges, as shown in Exhibit PHR-2. The residential customer charge is $25.47/customer/month. Residential usage is priced at a single per Ccf rate of $0.32626.

Q. PLEASE DESCRIBE THE CURRENT COMMERCIAL RATES.

A. Also as shown in Exhibit PHR-2, current customer charges for commercial sales customers are $96.08/customer/month. Commercial usage is priced at $0.12679/Ccf. Customer charges for commercial transportation customers of $308.08/customer/month reflect the higher metering and administrative costs associated with providing service to these customers relative to sales customers.

Q. PLEASE DESCRIBE THE CURRENT INDUSTRIAL RATES.

A. Current industrial rate structures are also summarized in Exhibit PHR-2. As shown there, current customer charges for industrial sales customers are $1,005.41/customer/month. Usage for these customers is priced at a single per Ccf rate of $0.12707/Ccf.

Customer charges for industrial transportation customers are $1,205.41/customer/month and the usage charge for these customers is $0.12707/Ccf. These rates again reflect the higher metering and administrative costs associated with providing service to transportation customers relative to sales customers.

Q. PLEASE DESCRIBE THE CURRENT PUBLIC AUTHORITY RATES.

A. For public authority sales customers, the current customer charge is $160.70/customer/month. The customer charge for public authority transportation customers is $183.70/customer/month. Both public authority sales and public authority transportation usage is priced at a per Ccf rate of $0.12549. In addition, the Company has one unmetered gas light customer which is served at the public authority usage rate.

Q. PLEASE DESCRIBE THE CURRENT PUBLIC SCHOOLS SPACE HEAT RATES.

A. Public schools space heat sales customers are served under rates with a customer charge of $213.70/customer/month. Public schools space heat transport customers are served under rates with a customer charge of $313.70/customer/month. The current usage charge for both public schools space heat sales customers and public schools space heat transport customers is $0.10012/Ccf.

Q. PLEASE DESCRIBE THE ELECTRIC COGENERATION RATES.

A. There are currently no electric cogeneration sales customers and, in the absence of billing determinants for these customers, the rates for electric cogeneration sales customers are set equal to rates for electric cogeneration transportation customers. Those rates are a customer charge of $183.70/customer/month and a declining block rate structure for usage charges. The first 5,000 Ccf per month is priced at $0.07720/Ccf. Usage greater than 5,000 Ccf/month but less than or equal to 35,000 Ccf/month is priced at $0.06850/Ccf. Usage greater than 35,000 Ccf/month but less than or equal to 60,000 Ccf/month is priced at $0.05524/Ccf. Finally, all usage greater than 100,000 Ccf per month is priced at a rate of $0.04016/Ccf.

Q. PLEASE DESCRIBE THE CURRENT COMPRESSED NATURAL GAS RATES.

A. Compressed natural gas sales and transportation customers are served under the same usage rate, $0.06684/Ccf. The current customer charge for compressed natural gas sales customers is $812.71/customer/month. The current customer charge for compressed natural gas transportation customers is $837.71/customer/month.

C. Proposed Rates

Q. HOW DID YOU DESIGN THE PROPOSED RATE RECOMMENDATIONS?

A. I began with class revenue recommendations developed by Ms. Serna. As described more fully by Ms. Serna in her direct testimony in this proceeding, those recommendations are the result of applying class Revenue Allocation Two, under which the revenue excess of those classes that are indicated to be contributing revenues in excess of their full cost of service are reduced by 20% and credited to the required revenue of the residential class, which is contributing revenues less than its full cost of service. This approach relies on the concept of gradualism to adjust rates so that each class is served under rates that are closer to the class' actual cost of service. Furthermore, to ensure rate continuity, I generally relied on the current rate structures for each class as the starting point in designing the recommended consolidated rates in this case. The concept of rate continuity supports using current rate structures to form the basis for recommended rates.

Q. IN DESIGNING THE PROPOSED RATES, DID YOU ALSO CONSIDER PAST COMMISSION GUIDANCE?

A. Yes. In its final order in the Company's last rate change application in the Central Texas Service Area and Gulf Cost Service Area Gas Utilities Docket No. 10928, the Commission issued the following Finding of Fact:

> 51. It is reasonable that the TGS will prepare a study of tiered residential rates for the next rate case filing.

In this case, the Company is proposing to implement such a rate for residential and commercial customers, the development of and associated rationale for these rate designs serve to satisfy this portion of the referenced Commission order. Development of these rates first considers intraclass equity, which relates to the fairness in the collection of revenue from customers within a class who use different amounts of gas. For each customer class, rates should be designed so that fixed costs are recovered through the fixed monthly customer charge, and variable costs are recovered through the volumetric charges. If a class's customer charge is too low to fully recover fixed costs, moderate-and high-use customers unfairly pay part of the cost to serve lower use customers. Likewise, if the volumetric charge is too low to fully recover variable costs, relatively low-use customers unfairly pay part of the cost to serve moderate-and high-use customers.

The rate proposals also assess average monthly bill impacts for each customer class. Furthermore, because the Company is proposing rate structures for the residential and commercial classes that are different from the rates under which these customers are currently served, I present a more detailed analysis of rate impacts in which the bill impacts by annual consumption level are examined. In considering bill impacts, it is important to recognize that no matter how rates are designed, there will be a disparity in customer bill impacts, some of which could be large.

Q. HAVE YOU IDENTIFIED ANY OTHER CHALLENGES IN DESIGNING RATES?

A. Yes. For all classes, current customer charges are below the fixed cost per bill indicated by the CCOSS. This means that moderate and high-use customers within each class are paying a disproportionate amount of the class costs.

Q. WHAT ARE YOUR RECOMMENDED RESIDENTIAL CUSTOMER AND USAGE CHARGES?

A. For "Small" Residential customers whose weather normalized consumption is less than or equal to 352 Ccf per year, I recommend the following charges:

Customer charge:	$25.50/customer/month
Volumetric Charge:	$0.69448/Ccf

For "Large" Residential customers in the proposed CGSA whose weather normalized consumption is greater than 352 Ccf per year, I recommend the following charges:

Customer charge:	$39.00/customer/month
Volumetric Charge:	$0.23425/Ccf

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THESE CHARGES.

A. As stated above, I began with the Company's CCOSS and developed a benchmark single, two-part (a customer charge and a volumetric charge) rate for all affected customers. Ms. Serna calculates that a customer charge of $45.23 most accurately captures the customer-related and demand-related costs by class identified in the Company's CCOSS. This customer charge results from the development of a so-called "Straight Fixed-Variable" or SFV rate. These types of rates are particularly appropriate for natural gas local distribution companies ("LDCs") because they operate in competitive end-use markets for every residential customer they serve. In other words, there is not one end-user an LDC serves that cannot also be served by a competing energy source (electricity, propane, fuel oil, wood, etc.). Because of this, it is extremely important that the rates reflect the costs of providing that service, or customers could make energy-consumption decisions that do not maximize economic welfare. This is particularly true on an intraclass basis, where higher volume residential users of natural gas are predominantly heating customers and lower volume users are non-heating customers. SFV rates help to ensure that the individual end-use markets in which these two types of customers participate are not distorted.

Q. WHY ARE YOU NOT SIMPLY PROPOSING THE STRAIGHT FIXED-VARIABLE RATE DESIGN YOU JUST DESCRIBED FOR ALL CUSTOMERS?

A. Because that rate structure, when applied to typical residential class bills, results in significant bill increases for lower usage customers relative to the Company's current rate structures. Thus, while the rate structure just described would best match the costs of service identified by the Company, it would not avoid a potentially significant rate shock for those customers. Because of this, I adopted an approach that fits the circumstances of both low-use and high-use customers.

Q. HOW DID YOU DO THIS?

A. Recognizing that lower usage customers would experience the biggest shock from a rate design with a higher customer charge that more closely reflects the cost of service, I propose to set the customer charges for lower usage customers equal to $25.50/customer/month, a level approximating the current residential customer charge. I also propose that, because higher usage level customers will not face rate shock issues because of implementation of rates with higher customer charges that more closely reflect the cost of service, they should be billed a customer charge that reflects the full cost of service to the extent possible. I calculate this level to be $39.00/customer/month.

Q. WHAT DID YOU DO NEXT?

A. Because the rates applied to the volumes of the lower usage customers do not fully collect the cost of service, the more customers that are billed on the lower usage level rates, the more revenues need to be made up by other customers on the system. In other words, the lower usage customers are being subsidized. Thus, I had to determine the amount of the subsidy and which customers were going to pay for that subsidy.

Q. IS THE FACT THAT LOWER USE CUSTOMERS WOULD NOT COVER THEIR RESPECTIVE COST OF SERVICE UNDER PROPOSED RATES UNUSUAL?

A. Not at all. This reality exists in virtually any rate design proposal. The term used to describe this inherent reality is "intraclass subsidy."

Q. HOW DID YOU ACCOUNT FOR THE INTRACLASS SUBSIDY IN YOUR PROPOSED RATE DESIGN?

A. I recover the intraclass subsidy through an equal, additional charge applied to the usage charges of both new residential rate classes so that all residential customers are contributing to make up the shortfall. This not only makes up the revenue shortfall relative to the identified cost of service of the lower usage customers but also minimizes the rate impacts of moving to a new rate design. Thus, the new rate design moves the Company's rates closer to its underlying cost of service and avoids the significant rate shock associated with immediate implementation of a full cost of service-based rate for lower usage customers.

Q. CAN THIS RATE STRUCTURE BE EASILY IMPLEMENTED?

A. Yes. Since both rates contain a two-part structure (customer charges and volumetric charges), they can be implemented very simply and in a way that is transparent to customers.

Q. HOW WILL THE PROPOSED RATE DESIGN AFFECT CUSTOMERS WITH AVERAGE USAGE?

A. It is anticipated that customers with average usage will not be overly affected regardless of the sub-class to which they are assigned, so the Company does not expect significant migration of customers from one sub-class to the other. This can be seen by comparing the annual bills for two customers near the breakpoint between sub-classes. Consider a residential customer who uses exactly 352 Ccfs per year. A Small Residential Customer's annual bill is $550.46, the same amount as a Large Residential Customer, subject to rounding. If the customer reduces usage by 10%, to 317 Ccfs per year, there is only a small difference in the annual bill between the customer's most economical rate schedule (Small Residential) and the alternative ($526.01 versus $542.21, or $1.35 per month). A similar result occurs if usage increases by 10%. Thus, at the margin, it makes little difference in the customer's annual bill what rate schedule the customer is on but makes a much more significant difference for the relatively small number of very low- or very high-use customers, who can take service under the rate schedule that best fits their needs. As a result, most customers will not be much affected, and the Company's revenues will not change radically because of these proposed rate changes.

Q. HOW WILL THE COMPANY DETERMINE WHICH RATE TO APPLY TO CUSTOMERS INITIALLY?

A. Similar to the process that the Company followed when it implemented tiered rates its West North and Rio Grande Valley service areas, each residential customer will initially be assigned to the rate schedule that appears to be the most economical for them based on their historical usage, and then customers may choose a different rate schedule if the customer believes the other rate will better suit them due to changed circumstances or personal preferences, subject to the restriction that they would only be allowed to switch once per year.

Q. HAS THE COMPANY PREVIOUSLY RELIED ON THIS SAME INITIAL ASSIGNMENT PROCESS?

A. Yes. The Company or an affiliate currently serves well over one million residential and commercial customers in Oklahoma and Texas and has relied on this same process as it rolled out rates for those customers. To my knowledge, there have been no problems related to the initial implementation of rate structure in any service territory where the rate structure was introduced.

Q. WHAT ARE YOUR RECOMMENDED COMMERCIAL CUSTOMER AND USAGE CHARGES FOR THE PROPOSED CGSA?

A. For "Small" Commercial customers whose weather normalized consumption is less than or equal to 3,640 Ccf per year, I recommend the following charges:

Customer charge:	$85.00/customer/month
Volumetric Charge:	$0.15710/Ccf

For "Large" Commercial customers in the proposed CGSA whose weather normalized consumption is greater than 3,640 Ccf per year, I recommend the following charges:

Customer charge:	$100.00/customer/month
Volumetric Charge:	$0.10765/Ccf

Q. WERE THESE COMMERCIAL CUSTOMER RATES DEVELOPED IN THE SAME MANNER AND DOES THEIR DEVELOPMENT INVOLVE THE SAME CONSIDERATIONS AS THE RESIDENTIAL RATES DESCRIBED ABOVE?

A. Yes. For the proposed Commercial rates, I again began with Ms. Serna's CCOSS result and developed a benchmark single, two-part rate for all affected customers. Ms. Serna calculates that a customer charge of $97.51 most accurately captures the customer-related and demand-related costs for the Commercial class. To develop the Commercial rate, I set the customer charge for lower usage customers equal to $85.00/customer/month, a level approximating the current commercial customer charges, and set the customer charge for higher usage customers equal to $100.00/customer/month, a level approximating the full cost of service for commercial customers.

As with the development of the residential rates above, I next developed the additional charge needed to recover the intraclass subsidy thereby recovering the revenue shortfall relative to the identified cost of service and minimizing the rate impacts of moving to a new rate design.

Q. HOW DID YOU DESIGN COMMERCIAL TRANSPORTATION RATES?

A. As a general rule, I developed all transportation rates by maintaining: (1) the same customer charge differential between sales and equivalent transportation customers under two-part rates and (2) the current usage rates, which are equal between sales customers and their counterpart transportation customers. Thus, I only needed to develop a hypothetical two-part customer charge for sales customers that recovers the target revenues while maintaining the two relationships enumerated above, and all rate components are defined. Target revenues for these customers were developed by applying the ratio of proposed revenues for all commercial customers to current test year revenues for all commercial customers to current test year revenues for transportation customers. This same approach was used to develop target revenues for commercial sales customers so that both commercial sales and commercial transportation customers receive the same percentage decrease, about 7%.

The resulting rates for commercial transportation customers are customer charges of $297.51/customer/month and volumetric charges of $0.12679/Ccf.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE CGSA INDUSTRIAL SALES AND TRANSPORT CLASSES.

A. For the industrial classes, I recommend the same two-part, single-block rate structure that is currently in place. To develop rates for these customers, I first set the usage charge for each rate equal to the current usage charge, $0.12707/Ccf. I then adjusted the customer charges for these classes, considering the current sales/transportation customer charge differential and the cost to serve these customers as determined within Ms. Serna's CCOSS. The resulting rates are shown in Exhibit PHR-2 for all customers.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE CGSA PUBLIC AUTHORITY SALES AND TRANSPORT CLASSES.

A. The Company's CCOSS includes Public Authority, Public Schools and Electric Cogeneration sales and transport customers as well as an Unmetered Gas Light customer within the Public Authority class, and establishes a cost of service for all of these classes as a group. In order to develop rates for the individual classes, I first develop class revenue targets by allocating the CCOSS revenue target to the classes using current revenues to develop an allocation factor. In this proceeding, the Company is proposing to eliminate the Public Schools rate class and serve these customers under new Public Authority rates, for which I recommend the same two-part, single-block rate structure that is currently in place. To develop rates for these classes, I set usage charges for each rate equal to the current usage charges. When adjusting the customer charges for these classes, I considered the current sales/transportation customer charge differential and the cost to serve these customers as determined by my allocated cost estimate from Ms. Serna's CCOSS. The assigned revenue for these classes, less the revenue recovered from the recommended usage charges, is the revenue that must be recovered through customer charges for each class.

For Electrical Cogeneration customers, I reduced all charges by approximately 4%, consistent with Ms. Serna's CCOSS and my allocation of her identified deficiency. The resulting rates are shown in Exhibit PHR-2 for all customers.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE CGSA COMPRESSED NATURAL GAS SALES AND TRANSPORT CLASSES.

A. For the compressed natural gas classes, I also recommend the same two-part, single-block rate structure that is currently in place. To develop rates for these customers, I again set the usage charge for each rate equal to the current usage charge, \$0.06684/Ccf. I then adjusted the customer charges for these classes, considering the current sales/transportation customer charge differential and the cost to serve these customers as determined within Ms. Serna's CCOSS. The resulting rates are shown in Exhibit PHR-2 for all customers.

Q. IN YOUR OPINION, IS YOUR RATE DESIGN JUST AND REASONABLE?

A. Yes.

III. <u>CUSTOMER BILL IMPACTS</u>

Q. HAVE YOU CALCULATED CUSTOMER BILL IMPACTS RESULTING FROM YOUR RECOMMENDED CGSA RATES?

A. Yes. Exhibit PHR-3 provides proposed customer bill impacts for each service offering for average monthly usage. The bill amounts for each of the service offerings are based on current and recommended rates and include the test year average cost of gas.

Q. PLEASE DESCRIBE HOW THE NEW RESIDENTIAL USAGE SUBCLASSES AVOID SIGNIFICANT RATE SHOCK FOR RESIDENTIAL CUSTOMERS.

A. This can be demonstrated in two ways. First, the rate impacts from implementation of this rate design for the range of weather-normalized consumption observed for residential customers can be calculated. These calculations are shown in Exhibit PHR-4.

However, these bill impacts show the combined effect of the required revenue increase and the change from traditional two-part rates to the proposed Residential rates. A better way to show the impact of the rate design change is to compare the proposed rates to the Company's traditional rates, adjusted to collect the requested revenues in this case, thereby developing an "apples-to-apples" comparison. This comparison is provided as Exhibit PHR-5 and shows that the rate design change is mitigating the rate increase by reducing bills for many customers below levels that they would be if the traditional rate design were continued. As can be seen, the rate structure particularly benefits the highest and lowest usage customers on the system.

Q. PLEASE DESCRIBE HOW THE NEW COMMERCIAL HIGH AND LOW USAGE RATES AVOID RATE SHOCK.

A. The proposed usage rates for Commercial customers exhibit the same advantages as the Residential rates discussed above. Shown on Exhibit PHR-6 and Exhibit PHR-7, the calculated rate impacts from implementation of this rate design also show that the rate design change is mitigating the rate increase by reducing bills for many customers below levels that they would be if the traditional rate design were continued. As above, Exhibit PHR-7 demonstrates that the rate structure particularly benefits the highest and lowest usage customers on the system.

IV. PROOF OF REVENUE

Q. HAVE YOU PREPARED A PROOF OF REVENUE TO SHOW THAT THE CGSA RECOMMENDED RATES PRODUCE THE REVENUE ASSOCIATED WITH MS. SERNA'S PROPOSED CLASS ALLOCATION?

A. Yes. An arithmetical demonstration that the recommended proposed rates produce the assigned revenue for each class and for the entire service area is provided in Exhibit PHR-8. As a result of usage charges being limited to five digits in designing rates, there are small rounding differences for the various customer classes, as shown in the Exhibit PHR-8.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

PAUL H. RAAB

Mr. Raab's consulting focus is on the regulated public utility industry. His experience includes mathematical and economic analyses and system development and his areas of expertise include regulatory change management, load forecasting, supply-side and demand-side planning, management audits, mergers and acquisitions, costing and rate design, and depreciation and life analysis.

PROFESSIONAL EXPERIENCE

Mr. Raab has directed or has had a key role in numerous engagements in the areas listed above. Representative clients are provided for each of these areas in the subsections below.

Regulatory Change Management. Mr. Raab has recently been assisting both electric and natural gas utilities as they prepare to operate in an environment that is significantly different from the one they operate in today. This work has involved the development of unbundled cost of service studies; the development of strategies that will allow companies to prosper in a restructured industry; retail access program development, implementation, and evaluation; and the development of innovative ratemaking approaches to accompany changes in the regulatory structure. Representative clients for whom he has performed such work include:

- Texas Gas Service
- Virginia Natural Gas
- UGI Utilities, Inc. – Gas Division, UGI Penn Natural Gas, Inc., and UGI Central Penn Gas, Inc.
- The Peoples Natural Gas Company d/b/a Dominion Peoples
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania, Inc.
- Aquila
- Kansas Corporation Commission
- Atmos Energy Corporation
- Electric Cooperatives' Association
- Cleco
- Washington Gas
- Western Resources
- Kansas Gas Service
- Mid Continent Market Center.

Load Forecasting. Mr. Raab has broad experience in the review and development of forecasts of sales forecasts for electric and natural gas utilities. This work has also included the development of elasticity of demand measures that have been used for attrition adjustments and revenue requirement reconciliations. Representative clients for whom he has performed such work include:

- Washington Gas Energy Services
- Central Louisiana Electric Company
- Washington Gas
- Saskatchewan Public Utilities Review Commission
- Union Gas Limited
- Nova Scotia Power Corporation
- Cajun Electric Power Cooperative
- Cincinnati Gas & Electric
- Commonwealth Edison Company
- Cleveland Electric Illuminating
- Public Service of Indiana
- Atlantic City Electric Company
- Detroit Edison Company
- Sierra Pacific Power
- Connecticut Natural Gas Corporation
- Appalachian Power Company
- Missouri Public Service Company
- Empire District Electric Company
- Public Service Company of Oklahoma
- Wisconsin Electric Power Company
- Northern States Power Company
- Iowa State Commerce Commission
- Missouri Public Service Commission.

Supply Side Planning. Mr. Raab has assisted clients to determine the most appropriate supply-side resources to meet future demands. This assistance has included the determination of optimal sizes and types of capacity to install, determination of production costs including and excluding the resource, and an assessment of system reliability changes because of different resource additions. Much of this work for the following clients has been done in conjunction with litigation:

- Enstar Natural Gas
- AGL Resources
- Washington Gas
- Soyland Electric Cooperative
- Houston Lighting and Power
- City of Farmington, New Mexico
- Big Rivers Electric Cooperative
- City of Redding, California
- Brown & Root
- Kentucky Joint Committee on Electric Power Planning Coordination
- Sierra Pacific Power.

Demand Side Planning. Demand Side Planning involves the forecasting of future demands; the design, development, implementation, and evaluation of demand side management programs; the determination of future supply side costs; and the integration of cost-effective demand side management programs into an Integrated Least Cost Resource Plan. Mr. Raab has performed such work for the following clients:

- UGI Utilities
- Dominion Peoples Gas
- National Fuel Gas Distribution Corporation
- Columbia Gas of Pennsylvania
- Kansas Gas Service
- Atmos Energy Corporation
- Black Hills Gas Company
- Oklahoma Natural Gas Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- Montana-Dakota Utilities.

Management Audits. Mr. Raab has been involved in several management audits. Consistent with his other experience, the focus of his efforts has been in the areas of load forecasting, demand- and supply-side planning, integrated resource planning, sales and marketing, and rates. Representative commission/utility clients are as follows:

- Arizona Corporation Commission/Arizona Public Service Company
- Public Utilities Commission of Ohio/East Ohio Gas
- Kentucky Public Service Commission/Louisville Gas & Electric
- New Hampshire Public Service Commission/Public Service Company of New Hampshire
- New Mexico Public Service Commission/Public Service of New Mexico
- New York Public Service Commission/New York State Electric & Gas
- Missouri Public Service Commission/Laclede Gas Company
- New Jersey Board of Public Utilities/Jersey Central Power & Light
- New Jersey Board of Public Utilities/New Jersey Natural Gas
- Pennsylvania Public Utilities Commission/ Pennsylvania Power & Light
- California Public Utilities Commission/San Diego Gas & Electric Company.

Mergers and Acquisitions. Mr. Raab has been involved in several merger and acquisition studies throughout his career. Many of these were conducted as confidential studies and cannot be listed. Those in which his involvement was publicly known are:

- ONEOK, Inc./Southwest Gas Corporation
- Western Resources
- Constellation.

Costing and Rate Design Analysis. Mr. Raab has prepared generic rate design studies for the National Governor's Conference, the Electricity Consumer's Resource Council, the Tennessee Valley Industrial Committee, the State Electricity Commission of

Western Australia, and the State Electricity Commission of Victoria. These generic studies addressed advantages and disadvantages of alternative costing approaches in the electric utility industry; the strengths and weaknesses of commonly encountered costing methodologies; future tariff policies to promote equity, efficiency, and fairness criteria; and the advisability of changing tariff policies. Mr. Raab has performed specific costing and rate design studies for the following companies:

- New Mexico Gas
- SEMCO Gas
- Enstar Natural Gas
- Atmos Energy Corporation
- Southern Maryland Electric Cooperative, Inc.
- Comcast Cable Communications, Inc.
- Cable Television Association of Georgia
- Devon Energy
- Aquila
- Oklahoma Natural Gas
- Semco Energy Gas Company
- Laclede Gas
- Western Resources
- Kansas Gas Service Company
- Central Louisiana Electric Company
- Washington Gas Light Company
- Piedmont Natural Gas Company
- Chesapeake Utilities
- Pennsylvania & Southern Gas
- KPL Gas Service Company
- Allegheny Power Systems
- Northern States Power
- Interstate Power Company
- Iowa-Illinois Gas & Electric Company
- Arkansas Power and Light
- Iowa Power & Light
- Iowa Public Service Company
- Southern California Edison
- Pacific Gas & Electric
- New York State Electric & Gas
- Middle South Utilities
- Missouri Public Service Company
- Empire District Electric Company
- Sierra Pacific Power
- Commonwealth Edison Company
- South Carolina Electric & Gas
- State Electricity Commission of Western Australia
- State Electricity Commission of Victoria, Australia
- Public Service Company of New Mexico

- Tennessee Valley Authority.

Depreciation and Life Analysis. Mr. Raab has extensive experience in depreciation and life analysis studies for the electric, gas, rail, and telephone industries and has taught a course on depreciation at George Washington University, Washington, DC. Representative clients in this area include:

- Champaign Telephone Company
- Plains Generation & Transmission Cooperative
- CSX Corporation (Includes work for Seaboard Coast Line, Louisville & Nashville, Baltimore & Ohio, Chesapeake & Ohio, and Western Maryland Railroads)
- Lea County Electric Cooperative, Inc.
- North Carolina Electric Membership Cooperative
- Alberta Gas Trunk Lines (NOVA)
- Federal Communications Commission.

TESTIMONY

The following table summarizes Mr. Raab's testimony experience.

Jurisdiction	Docket Number	Subject
Alaska	U-09-069, U-09-070	Rate Design
	U-14-010	Rate Design
Colorado	14AL-0300G	Costing/Rate Design
	17AL-0363G	Costing/Rate Design
	19AL-0309G	Costing/Rate Design
	22AL-0046G	Costing/Rate Design
District of Columbia	834	Demand Side Planning
	905	Costing/Rate Design
	917	Costing/Rate Design
	921	Demand Side Planning
	922	Rate Design
	934	Rate Design
	989	Rate Design
	1016	Rate Design
	1053	Costing/Rate Design
	1054	Costing/Rate Design
	1079	Rate Design
	1093	Costing/Rate Design
	1137	Costing/Rate Design
	1162	Costing/Rate Design
	1169	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Georgia	18300-U	Costing/Rate Design
Indiana	36818	Capacity Planning
Iowa	RPU-05-2	Costing/Rate Design
Kansas	174,155-U	Retail Competition
	176,716-U	Costing/Rate Design
	98-KGSG-822-TAR	Rate Design
	99-KGSG-705-GIG	Restructuring
	01-KGSG-229-TAR	Rate Design
	02-KGSG-018-TAR	Rate Design
	02-WSRE-301-RTS	Cost of Service
	03-KGSG-602-RTS	Cost of Service/Rate Design
	03-AQLG-1076-TAR	Rate Design
	05-AQLG-367-RTS	Cost of Service/Rate Design
	06-KGSG-1209-RTS	Cost of Service/Rate Design
	07-AQLG-431-RTS	Rate Design
	08-WSEE-1041-RTS	Cost of Service
	10-KCPE-415-RTS	Cost of Service/Rate Design
	10-KGSG-421-TAR	Demand Side Planning
	10-KCPE-795-TAR	Demand Side Planning
	12-WSEE-112-RTS	Cost of Service/Rate Design
	12-KGSG-835-RTS	Cost of Service/Rate Design
	12-GIMX-337-GIV	Demand Side Planning
	12-KG&E-718-CON	Cost of Service
	13-KG&E-451-CON	Cost of Service
	13-WSEE-629-RTS	Cost of Service/Rate Design
	14-ATMG-320-RTS	Cost of Service/Rate Design
	15-WSEE-181-TAR	Demand Side Planning
	15-KCPE-116-RTS	Cost of Service/Rate Design
	16-ATMG-079-RTS	Cost of Service/Rate Design
	16-KGSG-491-RTS	Cost of Service/Rate Design
	16-KCPE-446-TAR	Demand Side Planning
	18-KCPE-480-RTS	Cost of Service/Rate Design
	18-KGSG-560-RTS	Cost of Service/Rate Design
	19-ATMG-525-RTS	Cost of Service/Rate Design
	22-EKME-254-TAR	Demand Side Planning
	23-ATMG-359-RTS	Cost of Service/Rate Design
	23-EKCE-775-RTS	Cost of Service/Rate Design

Jurisdiction	Docket Number	Subject
Kentucky	9613	Capacity Planning
	97-083	Management Audit
	2009-00354	Cost of Service
	2013-00148	Cost of Service
	2015-00343	Cost of Service
	2017-00349	Cost of Service
	2018-00281	Cost of Service
	2021-00214	Cost of Service
Louisiana	U-21453	Restructuring/Market Power
Maryland	8251	Costing/Rate Design
	8259	Demand Side Planning
	8315	Costing/Rate Design
	8720	Demand Side Planning
	8791	Costing/Rate Design
	8920	Costing/Rate Design
	8959	Costing/Rate Design
	9092	Costing/Rate Design
	9104	Costing/Rate Design
	9106	Costing/Rate Design
	9180	Capacity Planning
	9267	Costing/Rate Design
	9433	Capacity Planning
	9481	Costing
	9651	Costing/Rate Design
	9704	Costing/Rate Design
Michigan	U-6949	Load Forecasting
	U-13575	Costing/Rate Design
	U-16169	Costing/Rate Design
	U-20479	Costing/Rate Design
Missouri	GR-2002-356	Rate Design
Montana	D2005.4.48	Costing/Rate Design
Nebraska	NG-0001, NG-0002, NG-0003	Rate Design
	NG-0041	Rate Design
Nevada	81-660	Load Forecasting
New Jersey	OAL# PUC 1876-82	Load Forecasting

Jurisdiction	BPU# 822-0116 Docket Number	Subject
New Mexico	2087	Capacity Planning
	11-00042-UT	Rate Design
New York	27546	Costing/Rate Design
Ohio	81-1378-EL-AIR	Load Forecasting
Oklahoma	27068	Load Forecasting
	PUD 200400610	Costing/Rate Design
	PUD 200700449	Demand Side Planning
	PUD 200800348	Costing/Rate Design
	PUD 200900110	Costing/Rate Design
	PUD 201000143	Demand Side Planning
	PUD 201100170	Demand Side Planning
	PUD 201200029	Demand Side Planning
	PUD 201300007	Demand Side Planning
	PUD 201300032	Demand Side Planning
	PUD 201400069	Demand Side Planning
	PUD 201500138	Demand Side Planning
	PUD 201500213	Costing/Rate Design
	PUD 201600132	Demand Side Planning
	PUD 201700079	Demand Side Planning
	PUD 201800028	Demand Side Planning
	PUD 201900018	Demand Side Planning
	PUD 201900021	Demand Side Planning
	PUD 202000022	Demand Side Planning
	PUD 202100062	Demand Side Planning
	PUD 202100063	Costing/Rate Design
	PUD 202200023	Demand Side Planning
	PUD 202200036	Demand Side Planning
	PUD 202300012	Demand Side Planning

Jurisdiction	Docket Number	Subject
Pennsylvania	R-0061346	Costing/Rate Design
	M-2009-2092222, M-2009-2112952, M-2009-2112956	Demand Side Planning
	M-2009-2093216	Demand Side Planning
	M-2009-2093217	Demand Side Planning
	M-2009-2093218	Demand Side Planning
	M-2010-2210316	Demand Side Planning
	R-2010-2214415	Demand Side Planning
	M-2012-2334387, M-2012-2334392, M-2012-2334398	Demand Side Planning
	M-2012-2334388	Demand Side Planning
	M-2015-2177174	Demand Side Planning
Tennessee	PURPA Hearings	Costing/Rate Design
US Tax Court	4870	Life Analysis
	4875	Life Analysis
Texas	GUD No. 9762	Costing/Rate Design
	GUD No. 10170	Costing/Rate Design
	GUD No. 10174	Costing/Rate Design
	GUD No. 10506	Demand Side Planning
	GUD No. 10526	Demand Side Planning
	GUD No. 10779	Costing/Rate Design
	GUD No. 10928	Costing/Rate Design
	OS-22-00009896	Costing/Rate Design
	Case No.00014399	Costing/Rate Design

Jurisdiction	Docket Number	Subject
Virginia	PUE900013	Demand Side Planning
	PUE920041	Costing/Rate Design
	PUE940030	Costing/Rate Design
	PUE940031	Costing/Rate Design
	PUE950131	Capacity Planning
	PUE980813	Costing/Rate Design
	PUE-2002-00364	Costing/Rate Design
	PUE-2003-00603	Costing/Rate Design
	PUE-2006-00059	Costing/Rate Design
	PUE-2008-00060	Demand Side Planning
	PUE-2009-00064	Demand Side Planning
	PUE-2012-00118	Demand Side Planning
	PUE-2015-00132	Demand Side Planning
	PUE-2015-00138	Demand Side Planning
	PUE-2016-00001	Capacity Planning
	PUR-2018-00080	Capacity Planning
	PUR-2018-00193	Demand Side Planning
	PUR-2021-00288	Demand Side Planning
	PUR-2022-00054	Costing/Rate Design
West Virginia	79-140-E-42T	Capacity Planning
	90-046-E-PC	Demand Side Planning
Wisconsin	05-EP-2	Capacity Planning

In addition, Mr. Raab has presented expert testimony before the Federal Energy Regulatory Commission, the Pennsylvania House Consumer Affairs Committee, the Michigan House Economic Development and Energy Committee and the Province of Saskatchewan. He has also served on the Advisory Board of the Expert Evidence Report, published by The Bureau of National Affairs, Inc.

EDUCATION

Mr. Raab holds a B.A. (with high distinction) in Economics from Rutgers University and an M.A. from SUNY at Binghamton with a concentration in Econometrics. While attending Rutgers, he studied as a Henry Rutgers Scholar.

PUBLICATIONS AND PRESENTATIONS

Mr. Raab has published in several professional journals and spoken at several industry conferences. His publications/ presentations include:

- "Natural Gas as an Electric DSM Tool," American Gas Association Membership Services Committee Meeting, Williamsburg, VA, September 15, 2009.

- "Electric-to-Gas Fuel Switching," NARUC Summer Meeting, Seattle, WA, July 20, 2009.

- "The Future of Fuel in Virginia: Natural Gas," The Twenty-Seventh National Regulatory Conference, Williamsburg, VA, May 19, 2009.

- "Revenue Decoupling for Natural Gas Utilities," Energy Bar Association Midwest Energy Conference, Chicago, IL, March 6, 2008.

- "Responses to Arrearage Problems from High Natural Gas Bills," American Gas Association Rate and Regulatory Issues Seminar, Phoenix, AZ, April 8, 2004.

- "Factors Influencing Cooperative Power Supply," National Rural Utilities Cooperative Finance Corporation Independent Borrower's Conference, Boston, MA, July 3, 1997.

- "Current Status of LDC Unbundling," American Gas Association Unbundling Conference: Regulatory and Competitive Issues, Arlington, VA, June 19, 1997.

- "Balancing, Capacity Assignment, and Stranded Costs," American Gas Association Rate and Strategic Planning Committee Spring Meeting, Phoenix, AZ, March 26, 1997.

- "Gas Industry Restructuring and Changes: The Relationship of Economics and Marketing" (with Jed Smith), National Association of Business Economists, 38th Annual Meeting, Boston, MA September 10, 1996.

- "Improving Corporate Performance By Better Forecasting," 1996 Peak Day Demand and Supply Planning Seminar, San Francisco, CA, April 11, 1996.

- "Natural Gas Price Elasticity Estimation," AGA Forecasting Review, Vol. 6, No. 1, November 1995.

- "Assessing Price Competitiveness," Competitive Analysis & Benchmarking for Power Companies, Washington, DC, November 13, 1995.

- "Avoided Cost Concepts and Management Considerations," Workshop on Avoided Costs in a Post 636 Gas Industry: Is It Time to Unbundle Avoided Cost? Sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, Milwaukee, WI, June 29, 1994.

- "Estimating Implied Long- and Short-Run Price Elasticities of Natural Gas Consumption," Atlantic Economic Conference, Philadelphia, PA, October 10, 1993.

- "Program Evaluation and Marginal Cost," The Natural Gas Least Cost Planning Conference, Washington, DC, April 7, 1992.

- "The New Environmentalism & Least Cost Planning," Institute for Environmental Negotiation, University of Virginia, May 15, 1991.

- "Development of Conditional Demand Estimates of Gas Appliances," AGA Forecasting Review, Vol. 1, No. 1, October 1988.

- "The Feasibility Study: Forecasting and Sensitivities," Municipal Wastewater Treatment Facilities, The Energy Bureau, Inc., November 18, 1985.

- "The Development of a Gas Sales End-Use Forecasting Model," Third International Forecasting Symposium, The International Institute of Forecasting, July 1984.

- "New Forecasting Guidelines for REC's - A Seminar," (Chairman), Kansas City, Missouri, June 1984.

- "A Method and Application of Estimating Long Run Marginal Cost for an Electric Utility," Advances in Microeconomics, Volume II, 1983.

- "Forecasting Under Public Scrutiny," Forecasting Energy and Demand Requirements, University of Wisconsin - Extension, October 25, 1982.

- "Forecasting Public Utilities," The Journal of Business Forecasting, Vol. 1, No. 4, Summer, 1982.

- "Are Utilities Underforecasting," Electric Ratemaking, Vol. 1. No. 1, February 1982.

- "A Polynomial Spline Function Technique for Defining and Forecasting Electric Utility Load Duration Curves," First International Forecasting Symposium, Montreal, Canada, May 1981.

- "Time-of-Use Rates and Marginal Costs," ELCON Legal Seminar, March 20, l980.

- "The Ernst & Whinney Forecasting Model," Forecasting Energy & Demand Requirements, University of Wisconsin - Extension, October 8, l979.

- "Marginal Cost in Electric Utilities - A Multi-Technology Multi-Period Analysis" (with Frederick McCoy), ORSA/Tims Joint National Meeting, Los Angeles, California, November 13-15, 1978.

The native versions of Exhibits PHR-2 through PHR-8 are contained in the CGSA Integrated Rate Case Model provided with the filing.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CURRENT AND RECOMMENDED RATES

Description		CGSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c)	(d)
Residential			Small	Large
Customer Charge		$25.47	$25.50	$39.00
Usage Rates	All Ccf	$0.32626	$0.69448	$0.23425
Commercial				
Customer Charge - Sales		$96.08	$85.00	$100.00
Usage Rates		$0.12679	$0.15710	$0.10765
Customer Charge - Transportation		$308.08	$297.51	
Usage Rates	All Ccf	$0.12679	$0.12679	
Industrial				
Customer Charge - Sales		$1,005.41	$572.02	
Usage Rates	All Ccf	$0.12707	$0.12707	
Customer Charge - Transportation		$1,205.41	$772.02	
Usage Rates	All Ccf	$0.12707	$0.12707	
Public Authority				
Customer Charge - Sales		$160.70	$156.05	
Usage Rates	All Ccf	$0.12549	$0.12549	
Customer Charge - Transportation		$183.70	$179.05	
Usage Rates	All Ccf	$0.12549	$0.12549	
Public Schools Space Heat - WITHDRAW				
Customer Charge - Sales		$213.70	$156.05	
Usage Rates	All Ccf	$0.10012	$0.12549	
Customer Charge - Transportation		$313.70	$179.05	
Usage Rates	All Ccf	$0.10012	$0.12549	
Electrical Generation				
Customer Charge - Sales		$183.70	$175.98	
Usage Rates	First 5,000 Ccf/Month	$0.07720	$0.07427	
	Next 35,000 Ccf/Month	$0.06850	$0.06590	
	Next 60,000 Ccf/Month	$0.05524	$0.05314	
	All Over 100,000 Ccf/Month	$0.04016	$0.03864	
Customer Charge - Transportation		$183.70	$175.98	
Usage Rates	First 5,000 Ccf/Month	$0.07720	$0.07427	
	Next 35,000 Ccf/Month	$0.06850	$0.06590	
	Next 60,000 Ccf/Month	$0.05524	$0.05314	
	All Over 100,000 Ccf/Month	$0.04016	$0.03864	
Compressed Natural Gas				
Customer Charge - Sales		$812.71	$594.88	
Usage Rates	All Ccf	$0.06684	$0.06684	
Customer Charge - Transportation		$837.71	$619.88	
Usage Rates	All Ccf	$0.06684	$0.06684	
Unmetered Gas Light				
Usage Rates	All Ccf	$0.12549	$0.12549	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small (3)				
Incorporated	$41.76	$48.02	$6.26	15.0%
Environs	$41.76	$48.02	$6.26	15.0%
Residential - Large (3)				
Incorporated	$67.28	$76.81	$9.53	14.2%
Environs	$67.28	$76.81	$9.53	14.2%
Commercial - Small (3)				
Incorporated	$143.11	$133.90	-$9.21	-6.4%
Environs	$143.11	$133.90	-$9.21	-6.4%
Commercial - Large (3)				
Incorporated	$833.61	$819.03	-$14.58	-1.7%
Environs	$833.61	$819.03	-$14.58	-1.7%
Industrial				
Incorporated	$2,597.27	$2,163.88	-$433.39	-16.7%
Environs	$2,597.27	$2,163.88	-$433.39	-16.7%
Public Authority				
Incorporated	$533.27	$528.62	-$4.65	-0.9%
Environs	$533.27	$528.62	-$4.65	-0.9%
Public Schools Space Heating (4)				
Incorporated	$1,238.21	$1,215.85	-$22.36	-1.8%
Environs	$1,238.21	$1,215.85	-$22.36	-1.8%
Compressed Natural Gas				
Incorporated	$812.71	$594.88	-$217.83	-26.8%
Environs	$812.71	$594.88	-$217.83	-26.8%
Unmetered Gas Light				
Incorporated	$993.52	$993.52	$0.00	0.0%
Transportation Service: (5)				
Commercial Transportation				
Incorporated	$3,536.39	$3,525.82	-$10.57	-0.3%
Environs	$3,536.39	$3,525.82	-$10.57	-0.3%
Industrial Transportation				
Incorporated	$28,514.60	$28,081.21	-$433.39	-1.5%
Environs	$28,514.60	$28,081.21	-$433.39	-1.5%
Public Authority Transportation				
Incorporated	$1,360.59	$1,355.94	-$4.65	-0.3%
Environs	$1,360.59	$1,355.94	-$4.65	-0.3%
Public Schools Space Heating Transportation (4)				
Incorporated	$966.26	$855.10	-$111.16	-11.5%
Environs	$966.26	$855.10	-$111.16	-11.5%
Electrical Cogeneration Transportation				
Incorporated	$219,905.95	$219,305.49	-$600.46	-0.3%
Environs	$219,905.95	$219,305.49	-$600.46	-0.3%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Compressed Natural Gas Transportation				
Incorporated	$16,715.00	$16,497.17	-$217.83	-1.3%
Environs	$16,715.00	$16,497.17	-$217.83	-1.3%

(1) Bill impacts are shown for those schedules with customers during the test year. The test year cost of gas is included in the bill calculations. Bills under current and recommended rates do not include revenue-related taxes. These taxes vary across different locations in the service area.

(2) Bills are based on the following average usage levels:

	Year-Round
Residential - Small	17
Residential - Large	43
Commercial - Small	62
Commercial - Large	966
Industrial	2,085
Public Authority	489
Public Schools Space Heat	1,391
Compressed Natural Gas	0

(3) Calculations for residential and commerical are based on usage at the Small and Large amounts shown in Note 2 (Residential: 17 Ccf for Small and 43 Ccf for Large/Commercial: 62 Ccf for Small and 966 for Large). See the individual rate design tabs for the source of these values.

(4) The gas sales and transportation Public School Space Heating tariffs will be discontinued. Customers will be consolidated into the Public Authority class.

(5) Transportation customers secure their own gas. While the Company has no way of knowing the customer's cost of gas, these bill comparisons assume that customers obtain their gas at a cost that is five percent less than the Company's gas cost. These transportation bill comparisons are only illustrations of the level of total bills and the percentage changes in those bills. Bills are based on the following average usage levels:

	Year-Round
Commercial Transportation	4,414
Industrial Transportation	37,325
Public Authority Transportation	1,612
Public Schools Space Heat Transportation	926
Electrical Cogeneration Transportation	337,558
Compressed Natural Gas Transportation	23,647

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Small/Large Rate Relative to Existing Rates

								$ 25.50	$ 1.33089	$ 1.33089	Small					
			$ 25.47	$ 0.96267	$ 0.96267			$ 39.00	$ 0.87066	$ 0.87066	Large					
Consumption					Current Charges					Proposed Charges			Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	22	446	$ 305.64	$ —	$ 21.18	$ 305.64	$ 326.82	$ 306.00	$ —	$ 29.28	$ 306.00	$ 335.28	$ 0.03	$ 0.71	0%	3%
23	44	2,443	$ 305.64	$ 22.14	$ 42.36	$ 327.78	$ 348.00	$ 306.00	$ 30.61	$ 58.56	$ 336.61	$ 364.56	$ 0.74	$ 1.38	3%	5%
45	66	3,907	$ 305.64	$ 43.32	$ 63.54	$ 348.96	$ 369.18	$ 306.00	$ 59.89	$ 87.84	$ 365.89	$ 393.84	$ 1.41	$ 2.06	5%	7%
67	88	5,587	$ 305.64	$ 64.50	$ 84.71	$ 370.14	$ 390.35	$ 306.00	$ 89.17	$ 117.12	$ 395.17	$ 423.12	$ 2.09	$ 2.73	7%	8%
89	110	7,416	$ 305.64	$ 85.68	$ 105.89	$ 391.32	$ 411.53	$ 306.00	$ 118.45	$ 146.40	$ 424.45	$ 452.40	$ 2.76	$ 3.41	8%	10%
111	132	9,800	$ 305.64	$ 106.86	$ 127.07	$ 412.50	$ 432.71	$ 306.00	$ 147.73	$ 175.68	$ 453.73	$ 481.68	$ 3.44	$ 4.08	10%	11%
133	154	12,107	$ 305.64	$ 128.04	$ 148.25	$ 433.68	$ 453.89	$ 306.00	$ 177.01	$ 204.96	$ 483.01	$ 510.96	$ 4.11	$ 4.76	11%	13%
155	176	14,455	$ 305.64	$ 149.21	$ 169.43	$ 454.85	$ 475.07	$ 306.00	$ 206.29	$ 234.24	$ 512.29	$ 540.24	$ 4.79	$ 5.43	13%	14%
177	198	16,250	$ 305.64	$ 170.39	$ 190.61	$ 476.03	$ 496.25	$ 306.00	$ 235.57	$ 263.52	$ 541.57	$ 569.52	$ 5.46	$ 6.11	14%	15%
199	220	17,733	$ 305.64	$ 191.57	$ 211.79	$ 497.21	$ 517.43	$ 306.00	$ 264.85	$ 292.80	$ 570.85	$ 598.80	$ 6.14	$ 6.78	15%	16%
221	242	18,510	$ 305.64	$ 212.75	$ 232.97	$ 518.39	$ 538.61	$ 306.00	$ 294.13	$ 322.08	$ 600.13	$ 628.08	$ 6.81	$ 7.46	16%	17%
243	264	18,621	$ 305.64	$ 233.93	$ 254.14	$ 539.57	$ 559.78	$ 306.00	$ 323.41	$ 351.35	$ 629.41	$ 657.35	$ 7.49	$ 8.13	17%	17%
265	286	18,350	$ 305.64	$ 255.11	$ 275.32	$ 560.75	$ 580.96	$ 306.00	$ 352.69	$ 380.63	$ 658.69	$ 686.63	$ 8.16	$ 8.81	17%	18%
287	308	17,299	$ 305.64	$ 276.29	$ 296.50	$ 581.93	$ 602.14	$ 306.00	$ 381.97	$ 409.91	$ 687.97	$ 715.91	$ 8.84	$ 9.48	18%	19%
309	330	16,441	$ 305.64	$ 297.47	$ 317.68	$ 603.11	$ 623.32	$ 306.00	$ 411.25	$ 439.19	$ 717.25	$ 745.19	$ 9.51	$ 10.16	19%	20%
331	352	14,865	$ 305.64	$ 318.64	$ 338.86	$ 624.28	$ 644.50	$ 306.00	$ 440.52	$ 468.47	$ 746.52	$ 774.47	$ 10.19	$ 10.83	20%	20%
353	852	107,054	$ 305.64	$ 339.82	$ 820.19	$ 645.46	$ 1,125.83	$ 468.00	$ 307.34	$ 741.80	$ 775.34	$ 1,209.80	$ 10.82	$ 7.00	20%	7%
853	1352	7,616	$ 305.64	$ 821.16	$ 1,301.53	$ 1,126.80	$ 1,607.17	$ 468.00	$ 742.67	$ 1,177.13	$ 1,210.67	$ 1,645.13	$ 6.99	$ 3.16	7%	2%
1,353	1852	1,530	$ 305.64	$ 1,302.49	$ 1,782.86	$ 1,608.13	$ 2,088.50	$ 468.00	$ 1,178.00	$ 1,612.46	$ 1,646.00	$ 2,080.46	$ 3.16	$ (0.67)	2%	-0%
1,853	2352	516	$ 305.64	$ 1,783.83	$ 2,264.20	$ 2,089.47	$ 2,569.84	$ 468.00	$ 1,613.33	$ 2,047.79	$ 2,081.33	$ 2,515.79	$ (0.68)	$ (4.50)	-0%	-2%
2,353	2852	230	$ 305.64	$ 2,265.16	$ 2,745.53	$ 2,570.80	$ 3,051.17	$ 468.00	$ 2,048.66	$ 2,483.12	$ 2,516.66	$ 2,951.12	$ (4.51)	$ (8.34)	-2%	-3%
2,853	3352	102	$ 305.64	$ 2,746.50	$ 3,226.87	$ 3,052.14	$ 3,532.51	$ 468.00	$ 2,483.99	$ 2,918.45	$ 2,951.99	$ 3,386.45	$ (8.35)	$ (12.17)	-3%	-4%
3,353	3852	87	$ 305.64	$ 3,227.83	$ 3,708.20	$ 3,533.47	$ 4,013.84	$ 468.00	$ 2,919.32	$ 3,353.78	$ 3,387.32	$ 3,821.78	$ (12.18)	$ (16.01)	-4%	-5%
3,853	4352	47	$ 305.64	$ 3,709.17	$ 4,189.54	$ 4,014.81	$ 4,495.18	$ 468.00	$ 3,354.65	$ 3,789.11	$ 3,822.65	$ 4,257.11	$ (16.01)	$ (19.84)	-5%	-5%
4,353	4852	25	$ 305.64	$ 4,190.50	$ 4,670.87	$ 4,496.14	$ 4,976.51	$ 468.00	$ 3,789.98	$ 4,224.44	$ 4,257.98	$ 4,692.44	$ (19.85)	$ (23.67)	-5%	-6%
4,853	5352	24	$ 305.64	$ 4,671.84	$ 5,152.21	$ 4,977.48	$ 5,457.85	$ 468.00	$ 4,225.31	$ 4,659.77	$ 4,693.31	$ 5,127.77	$ (23.68)	$ (27.51)	-6%	-6%
5,353	5852	16	$ 305.64	$ 5,153.17	$ 5,633.54	$ 5,458.81	$ 5,939.18	$ 468.00	$ 4,660.64	$ 5,095.10	$ 5,128.64	$ 5,563.10	$ (27.51)	$ (31.34)	-6%	-6%
5,853	6352	8	$ 305.64	$ 5,634.51	$ 6,114.88	$ 5,940.15	$ 6,420.52	$ 468.00	$ 5,095.97	$ 5,530.43	$ 5,563.97	$ 5,998.43	$ (31.35)	$ (35.17)	-6%	-7%
6,353	6852	11	$ 305.64	$ 6,115.84	$ 6,596.21	$ 6,421.48	$ 6,901.85	$ 468.00	$ 5,531.30	$ 5,965.76	$ 5,999.30	$ 6,433.76	$ (35.18)	$ (39.01)	-7%	-7%
6,853	7352	6	$ 305.64	$ 6,597.18	$ 7,077.55	$ 6,902.82	$ 7,383.19	$ 468.00	$ 5,966.63	$ 6,401.09	$ 6,434.63	$ 6,869.09	$ (39.02)	$ (42.84)	-7%	-7%
7,353	42342	36	$ 305.64	$ 7,078.51	$ 40,761.37	$ 7,384.15	$ 41,067.01	$ 468.00	$ 6,401.96	$ 36,865.49	$ 6,869.96	$ 37,333.49	$ (42.85)	$ (311.13)	-7%	-9%

Exhibit PHR-5
Residential Bill Impacts New Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO TRADITIONAL RATE STRUCTURE

Annual Residential Bill Impacts of Small/Large Rate Structure Compared to Traditional Rate Structure

Consumption			Current Charges					Proposed Charges					Absolute Change		Percentage Change	
								$ 25.50	$ 1.33089	$ 1.33089 Small						
			$ 41.61	$ 0.64116	$ 0.64116			$ 39.00	$ 0.87066	$ 0.87066 Large						
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	22	446	$ 499.32	$ —	$ 14.11	$ 499.32	$ 513.43	$ 306.00	$ —	$ 29.28	$ 306.00	$ 335.28	$ (16.11)	$ (14.85)	-39%	-35%
23	44	2,443	$ 499.32	$ 14.75	$ 28.21	$ 514.07	$ 527.53	$ 306.00	$ 30.61	$ 58.56	$ 336.61	$ 364.56	$ (14.79)	$ (13.58)	-35%	-31%
45	66	3,907	$ 499.32	$ 28.85	$ 42.32	$ 528.17	$ 541.64	$ 306.00	$ 59.89	$ 87.84	$ 365.89	$ 393.84	$ (13.52)	$ (12.32)	-31%	-27%
67	88	5,587	$ 499.32	$ 42.96	$ 56.42	$ 542.28	$ 555.74	$ 306.00	$ 89.17	$ 117.12	$ 395.17	$ 423.12	$ (12.26)	$ (11.05)	-27%	-24%
89	110	7,416	$ 499.32	$ 57.06	$ 70.53	$ 556.38	$ 569.85	$ 306.00	$ 118.45	$ 146.40	$ 424.45	$ 452.40	$ (10.99)	$ (9.79)	-24%	-21%
111	132	9,800	$ 499.32	$ 71.17	$ 84.63	$ 570.49	$ 583.95	$ 306.00	$ 147.73	$ 175.68	$ 453.73	$ 481.68	$ (9.73)	$ (8.52)	-20%	-18%
133	154	12,107	$ 499.32	$ 85.27	$ 98.74	$ 584.59	$ 598.06	$ 306.00	$ 177.01	$ 204.96	$ 483.01	$ 510.96	$ (8.47)	$ (7.26)	-17%	-15%
155	176	14,455	$ 499.32	$ 99.38	$ 112.84	$ 598.70	$ 612.16	$ 306.00	$ 206.29	$ 234.24	$ 512.29	$ 540.24	$ (7.20)	$ (5.99)	-14%	-12%
177	198	16,250	$ 499.32	$ 113.49	$ 126.95	$ 612.81	$ 626.27	$ 306.00	$ 235.57	$ 263.52	$ 541.57	$ 569.52	$ (5.94)	$ (4.73)	-12%	-9%
199	220	17,733	$ 499.32	$ 127.59	$ 141.06	$ 626.91	$ 640.38	$ 306.00	$ 264.85	$ 292.80	$ 570.85	$ 598.80	$ (4.67)	$ (3.46)	-9%	-6%
221	242	18,510	$ 499.32	$ 141.70	$ 155.16	$ 641.02	$ 654.48	$ 306.00	$ 294.13	$ 322.08	$ 600.13	$ 628.08	$ (3.41)	$ (2.20)	-6%	-4%
243	264	18,621	$ 499.32	$ 155.80	$ 169.27	$ 655.12	$ 668.59	$ 306.00	$ 323.41	$ 351.35	$ 629.41	$ 657.35	$ (2.14)	$ (0.94)	-4%	-2%
265	286	18,350	$ 499.32	$ 169.91	$ 183.37	$ 669.23	$ 682.69	$ 306.00	$ 352.69	$ 380.63	$ 658.69	$ 686.63	$ (0.88)	$ 0.33	-2%	1%
287	308	17,299	$ 499.32	$ 184.01	$ 197.48	$ 683.33	$ 696.80	$ 306.00	$ 381.97	$ 409.91	$ 687.97	$ 715.91	$ 0.39	$ 1.59	1%	3%
309	330	16,441	$ 499.32	$ 198.12	$ 211.58	$ 697.44	$ 710.90	$ 306.00	$ 411.25	$ 439.19	$ 717.25	$ 745.19	$ 1.65	$ 2.86	3%	5%
331	352	14,865	$ 499.32	$ 212.22	$ 225.69	$ 711.54	$ 725.01	$ 306.00	$ 440.52	$ 468.47	$ 746.52	$ 774.47	$ 2.92	$ 4.12	5%	7%
353	852	107,054	$ 499.32	$ 226.33	$ 546.27	$ 725.65	$ 1,045.59	$ 468.00	$ 307.34	$ 741.80	$ 775.34	$ 1,209.80	$ 4.14	$ 13.68	7%	16%
853	1352	7,616	$ 499.32	$ 546.91	$ 866.85	$ 1,046.23	$ 1,366.17	$ 468.00	$ 742.67	$ 1,177.13	$ 1,210.67	$ 1,645.13	$ 13.70	$ 23.25	16%	20%
1,353	1852	1,530	$ 499.32	$ 867.49	$ 1,187.43	$ 1,366.81	$ 1,686.75	$ 468.00	$ 1,178.00	$ 1,612.46	$ 1,646.00	$ 2,080.46	$ 23.27	$ 32.81	20%	23%
1,853	2352	516	$ 499.32	$ 1,188.07	$ 1,508.01	$ 1,687.39	$ 2,007.33	$ 468.00	$ 1,613.33	$ 2,047.79	$ 2,081.33	$ 2,515.79	$ 32.83	$ 42.37	23%	25%
2,353	2852	230	$ 499.32	$ 1,508.65	$ 1,828.59	$ 2,007.97	$ 2,327.91	$ 468.00	$ 2,048.66	$ 2,483.12	$ 2,516.66	$ 2,951.12	$ 42.39	$ 51.93	25%	27%
2,853	3352	102	$ 499.32	$ 1,829.23	$ 2,149.17	$ 2,328.55	$ 2,648.49	$ 468.00	$ 2,483.99	$ 2,918.45	$ 2,951.99	$ 3,386.45	$ 51.95	$ 61.50	27%	28%
3,353	3852	87	$ 499.32	$ 2,149.81	$ 2,469.75	$ 2,649.13	$ 2,969.07	$ 468.00	$ 2,919.32	$ 3,353.78	$ 3,387.32	$ 3,821.78	$ 61.52	$ 71.06	28%	29%
3,853	4352	47	$ 499.32	$ 2,470.39	$ 2,790.33	$ 2,969.71	$ 3,289.65	$ 468.00	$ 3,354.65	$ 3,789.11	$ 3,822.65	$ 4,257.11	$ 71.08	$ 80.62	29%	29%
4,353	4852	25	$ 499.32	$ 2,790.97	$ 3,110.91	$ 3,290.29	$ 3,610.23	$ 468.00	$ 3,789.98	$ 4,224.44	$ 4,257.98	$ 4,692.44	$ 80.64	$ 90.18	29%	30%
4,853	5352	24	$ 499.32	$ 3,111.55	$ 3,431.49	$ 3,610.87	$ 3,930.81	$ 468.00	$ 4,225.31	$ 4,659.77	$ 4,693.31	$ 5,127.77	$ 90.20	$ 99.75	30%	30%
5,353	5852	16	$ 499.32	$ 3,432.13	$ 3,752.07	$ 3,931.45	$ 4,251.39	$ 468.00	$ 4,660.64	$ 5,095.10	$ 5,128.64	$ 5,563.10	$ 99.77	$ 109.31	30%	31%
5,853	6352	8	$ 499.32	$ 3,752.71	$ 4,072.65	$ 4,252.03	$ 4,571.97	$ 468.00	$ 5,095.97	$ 5,530.43	$ 5,563.97	$ 5,998.43	$ 109.33	$ 118.87	31%	31%
6,353	6852	11	$ 499.32	$ 4,073.29	$ 4,393.23	$ 4,572.61	$ 4,892.55	$ 468.00	$ 5,531.30	$ 5,965.76	$ 5,999.30	$ 6,433.76	$ 118.89	$ 128.43	31%	32%
6,853	7352	6	$ 499.32	$ 4,393.87	$ 4,713.81	$ 4,893.19	$ 5,213.13	$ 468.00	$ 5,966.63	$ 6,401.09	$ 6,434.63	$ 6,869.09	$ 128.45	$ 138.00	32%	32%
7,353	42342	36	$ 499.32	$ 4,714.45	$ 27,148.00	$ 5,213.77	$ 27,647.32	$ 468.00	$ 6,401.96	$ 36,865.49	$ 6,869.96	$ 37,333.49	$ 138.02	$ 807.18	32%	35%

Exhibit PHR-6
Commercial Bill Impacts Existing Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Bill Impacts of Small/Large Commercial Rate Relative to Existing Rates

								85.00	0.79351	0.79351 Small						
			96.08	0.76320	0.76320			100.00	0.74406	0.74406 Large						
Consumption					Current Charges					Proposed Charges			Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	228	3,421	1,152.96	—	174.01	1,152.96	1,326.97	1,020.00	—	180.92	1,020.00	1,200.92	(11.08)	(10.50)	-12%	-9%
229	455	1,808	1,152.96	174.77	347.26	1,327.73	1,500.22	1,020.00	181.71	361.05	1,201.71	1,381.05	(10.50)	(9.93)	-9%	-8%
456	683	1,072	1,152.96	348.02	521.27	1,500.98	1,674.23	1,020.00	361.84	541.97	1,381.84	1,561.97	(9.93)	(9.35)	-8%	-7%
684	910	677	1,152.96	522.03	694.51	1,674.99	1,847.47	1,020.00	542.76	722.09	1,562.76	1,742.09	(9.35)	(8.78)	-7%	-6%
911	1138	538	1,152.96	695.28	868.52	1,848.24	2,021.48	1,020.00	722.89	903.01	1,742.89	1,923.01	(8.78)	(8.21)	-6%	-5%
1,139	1365	354	1,152.96	869.28	1,041.77	2,022.24	2,194.73	1,020.00	903.81	1,083.14	1,923.81	2,103.14	(8.20)	(7.63)	-5%	-4%
1,366	1593	323	1,152.96	1,042.53	1,215.78	2,195.49	2,368.74	1,020.00	1,083.93	1,264.06	2,103.93	2,284.06	(7.63)	(7.06)	-4%	-4%
1,594	1820	238	1,152.96	1,216.54	1,389.02	2,369.50	2,541.98	1,020.00	1,264.85	1,444.19	2,284.85	2,464.19	(7.05)	(6.48)	-4%	-3%
1,821	2048	248	1,152.96	1,389.79	1,563.03	2,542.75	2,715.99	1,020.00	1,444.98	1,625.11	2,464.98	2,645.11	(6.48)	(5.91)	-3%	-3%
2,049	2275	237	1,152.96	1,563.80	1,736.28	2,716.76	2,889.24	1,020.00	1,625.90	1,805.24	2,645.90	2,825.24	(5.90)	(5.33)	-3%	-2%
2,276	2503	197	1,152.96	1,737.04	1,910.29	2,890.00	3,063.25	1,020.00	1,806.03	1,986.16	2,826.03	3,006.16	(5.33)	(4.76)	-2%	-2%
2,504	2730	157	1,152.96	1,911.05	2,083.54	3,064.01	3,236.50	1,020.00	1,986.95	2,166.28	3,006.95	3,186.28	(4.76)	(4.18)	-2%	-2%
2,731	2958	148	1,152.96	2,084.30	2,257.55	3,237.26	3,410.51	1,020.00	2,167.08	2,347.20	3,187.08	3,367.20	(4.18)	(3.61)	-2%	-1%
2,959	3185	147	1,152.96	2,258.31	2,430.79	3,411.27	3,583.75	1,020.00	2,348.00	2,527.33	3,368.00	3,547.33	(3.61)	(3.04)	-1%	-1%
3,186	3413	138	1,152.96	2,431.56	2,604.80	3,584.52	3,757.76	1,020.00	2,528.12	2,708.25	3,548.12	3,728.25	(3.03)	(2.46)	-1%	-1%
3,414	3640	130	1,152.96	2,605.56	2,778.05	3,758.52	3,931.01	1,020.00	2,709.04	2,888.38	3,729.04	3,908.38	(2.46)	(1.89)	-1%	-1%
3,641	4640	530	1,152.96	2,778.81	3,541.25	3,931.77	4,694.21	1,200.00	2,709.12	3,452.44	3,909.12	4,652.44	(1.89)	(3.48)	-1%	-1%
4,641	5640	425	1,152.96	3,542.01	4,304.45	4,694.97	5,457.41	1,200.00	3,453.18	4,196.50	4,653.18	5,396.50	(3.48)	(5.08)	-1%	-1%
5,641	6640	354	1,152.96	4,305.21	5,067.65	5,458.17	6,220.61	1,200.00	4,197.24	4,940.56	5,397.24	6,140.56	(5.08)	(6.67)	-1%	-1%
6,641	7640	289	1,152.96	5,068.41	5,830.85	6,221.37	6,983.81	1,200.00	4,941.30	5,684.62	6,141.30	6,884.62	(6.67)	(8.27)	-1%	-1%
7,641	8640	252	1,152.96	5,831.61	6,594.05	6,984.57	7,747.01	1,200.00	5,685.36	6,428.68	6,885.36	7,628.68	(8.27)	(9.86)	-1%	-2%
8,641	9640	198	1,152.96	6,594.81	7,357.25	7,747.77	8,510.21	1,200.00	6,429.42	7,172.74	7,629.42	8,372.74	(9.86)	(11.46)	-2%	-2%
9,641	10640	144	1,152.96	7,358.01	8,120.45	8,510.97	9,273.41	1,200.00	7,173.48	7,916.80	8,373.48	9,116.80	(11.46)	(13.05)	-2%	-2%
10,641	11640	129	1,152.96	8,121.21	8,883.65	9,274.17	10,036.61	1,200.00	7,917.54	8,660.86	9,117.54	9,860.86	(13.05)	(14.65)	-2%	-2%
11,641	12640	129	1,152.96	8,884.41	9,646.85	10,037.37	10,799.81	1,200.00	8,661.60	9,404.92	9,861.60	10,604.92	(14.65)	(16.24)	-2%	-2%
12,641	13640	110	1,152.96	9,647.61	10,410.05	10,800.57	11,563.01	1,200.00	9,405.66	10,148.98	10,605.66	11,348.98	(16.24)	(17.84)	-2%	-2%
13,641	14640	96	1,152.96	10,410.81	11,173.25	11,563.77	12,326.21	1,200.00	10,149.72	10,893.04	11,349.72	12,093.04	(17.84)	(19.43)	-2%	-2%
14,641	15640	58	1,152.96	11,174.01	11,936.45	12,326.97	13,089.41	1,200.00	10,893.78	11,637.10	12,093.78	12,837.10	(19.43)	(21.03)	-2%	-2%
15,641	16640	70	1,152.96	11,937.21	12,699.65	13,090.17	13,852.61	1,200.00	11,637.84	12,381.16	12,837.84	13,581.16	(21.03)	(22.62)	-2%	-2%
16,641	17640	50	1,152.96	12,700.41	13,462.85	13,853.37	14,615.81	1,200.00	12,381.90	13,125.22	13,581.90	14,325.22	(22.62)	(24.22)	-2%	-2%
17,641	772618	506	1,152.96	13,463.61	589,662.06	14,616.57	590,815.02	1,200.00	13,125.96	574,874.15	14,325.96	576,074.15	(24.22)	(1,228.41)	-2%	-2%

Exhibit PHR-7
Commercial Bill Impacts New Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO NEW RATES

Annual Bill Impacts of Small/Large Commercial Rate Relative to Traditional Rate Structure

								$ 85.00	$ 0.79351	$ 0.79351 Small						
			$ 85.51	$ 0.76320	$ 0.76320			$ 100.00	$ 0.74406	$ 0.74406 Large						
Consumption					Current Charges					Proposed Charges			Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	228	3,421	1,026.12	—	174.01	1,026.12	1,200.13	1,020.00	—	180.92	1,020.00	1,200.92	(0.51)	0.07	-1%	0%
229	455	1,808	1,026.12	174.77	347.26	1,200.89	1,373.38	1,020.00	181.71	361.05	1,201.71	1,381.05	0.07	0.64	0%	1%
456	683	1,072	1,026.12	348.02	521.27	1,374.14	1,547.39	1,020.00	361.84	541.97	1,381.84	1,561.97	0.64	1.22	1%	1%
684	910	677	1,026.12	522.03	694.51	1,548.15	1,720.63	1,020.00	542.76	722.09	1,562.76	1,742.09	1.22	1.79	1%	1%
911	1138	538	1,026.12	695.28	868.52	1,721.40	1,894.64	1,020.00	722.89	903.01	1,742.89	1,923.01	1.79	2.36	1%	1%
1,139	1365	354	1,026.12	869.28	1,041.77	1,895.40	2,067.89	1,020.00	903.81	1,083.14	1,923.81	2,103.14	2.37	2.94	1%	2%
1,366	1593	323	1,026.12	1,042.53	1,215.78	2,068.65	2,241.90	1,020.00	1,083.93	1,264.06	2,103.93	2,284.06	2.94	3.51	2%	2%
1,594	1820	238	1,026.12	1,216.54	1,389.02	2,242.66	2,415.14	1,020.00	1,264.85	1,444.19	2,284.85	2,464.19	3.52	4.09	2%	2%
1,821	2048	248	1,026.12	1,389.79	1,563.03	2,415.91	2,589.15	1,020.00	1,444.98	1,625.11	2,464.98	2,645.11	4.09	4.66	2%	2%
2,049	2275	237	1,026.12	1,563.80	1,736.28	2,589.92	2,762.40	1,020.00	1,625.90	1,805.24	2,645.90	2,825.24	4.67	5.24	2%	2%
2,276	2503	197	1,026.12	1,737.04	1,910.29	2,763.16	2,936.41	1,020.00	1,806.03	1,986.16	2,826.03	3,006.16	5.24	5.81	2%	2%
2,504	2730	157	1,026.12	1,911.05	2,083.54	2,937.17	3,109.66	1,020.00	1,986.95	2,166.28	3,006.95	3,186.28	5.81	6.39	2%	2%
2,731	2958	148	1,026.12	2,084.30	2,257.55	3,110.42	3,283.67	1,020.00	2,167.08	2,347.20	3,187.08	3,367.20	6.39	6.96	2%	3%
2,959	3185	147	1,026.12	2,258.31	2,430.79	3,284.43	3,456.91	1,020.00	2,348.00	2,527.33	3,368.00	3,547.33	6.96	7.53	3%	3%
3,186	3413	138	1,026.12	2,431.56	2,604.80	3,457.68	3,630.92	1,020.00	2,528.12	2,708.25	3,548.12	3,728.25	7.54	8.11	3%	3%
3,414	3640	130	1,026.12	2,605.56	2,778.05	3,631.68	3,804.17	1,020.00	2,709.04	2,888.38	3,729.04	3,908.38	8.11	8.68	3%	3%
3,641	4640	530	1,026.12	2,778.81	3,541.25	3,804.93	4,567.37	1,200.00	2,709.12	3,452.44	3,909.12	4,652.44	8.68	7.09	3%	2%
4,641	5640	425	1,026.12	3,542.01	4,304.45	4,568.13	5,330.57	1,200.00	3,453.18	4,196.50	4,653.18	5,396.50	7.09	5.49	2%	1%
5,641	6640	354	1,026.12	4,305.21	5,067.65	5,331.33	6,093.77	1,200.00	4,197.24	4,940.56	5,397.24	6,140.56	5.49	3.90	1%	1%
6,641	7640	289	1,026.12	5,068.41	5,830.85	6,094.53	6,856.97	1,200.00	4,941.30	5,684.62	6,141.30	6,884.62	3.90	2.30	1%	0%
7,641	8640	252	1,026.12	5,831.61	6,594.05	6,857.73	7,620.17	1,200.00	5,685.36	6,428.68	6,885.36	7,628.68	2.30	0.71	0%	0%
8,641	9640	198	1,026.12	6,594.81	7,357.25	7,620.93	8,383.37	1,200.00	6,429.42	7,172.74	7,629.42	8,372.74	0.71	(0.89)	0%	-0%
9,641	10640	144	1,026.12	7,358.01	8,120.45	8,384.13	9,146.57	1,200.00	7,173.48	7,916.80	8,373.48	9,116.80	(0.89)	(2.48)	-0%	-0%
10,641	11640	129	1,026.12	8,121.21	8,883.65	9,147.33	9,909.77	1,200.00	7,917.54	8,660.86	9,117.54	9,860.86	(2.48)	(4.08)	-0%	-0%
11,641	12640	129	1,026.12	8,884.41	9,646.85	9,910.53	10,672.97	1,200.00	8,661.60	9,404.92	9,861.60	10,604.92	(4.08)	(5.67)	-0%	-1%
12,641	13640	110	1,026.12	9,647.61	10,410.05	10,673.73	11,436.17	1,200.00	9,405.66	10,148.98	10,605.66	11,348.98	(5.67)	(7.27)	-1%	-1%
13,641	14640	96	1,026.12	10,410.81	11,173.25	11,436.93	12,199.37	1,200.00	10,149.72	10,893.04	11,349.72	12,093.04	(7.27)	(8.86)	-1%	-1%
14,641	15640	58	1,026.12	11,174.01	11,936.45	12,200.13	12,962.57	1,200.00	10,893.78	11,637.10	12,093.78	12,837.10	(8.86)	(10.46)	-1%	-1%
15,641	16640	70	1,026.12	11,937.21	12,699.65	12,963.33	13,725.77	1,200.00	11,637.84	12,381.16	12,837.84	13,581.16	(10.46)	(12.05)	-1%	-1%
16,641	17640	50	1,026.12	12,700.41	13,462.85	13,726.53	14,488.97	1,200.00	12,381.90	13,125.22	13,581.90	14,325.22	(12.05)	(13.65)	-1%	-1%
17,641	772618	506	1,026.12	13,463.61	589,662.06	14,489.73	590,688.18	1,200.00	13,125.96	574,874.15	14,325.96	576,074.15	(13.65)	(1,217.84)	-1%	-2%

Exhibit PHR-8
Proof of Revenue

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROOF OF REVENUE

Line No.	Description	Bills	Volumes		Recommended Rates: Customer Charge	Recommended Rates: Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.	GRIP Allocation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential - Small	2,330,758			$ 25.50		$ 59,434,329				
2			All Ccf	39,439,549		0.69448	$ 27,389,978				
3	Residential - Large	1,407,697			$ 39.00		$ 54,900,183				
4			All Ccf	61,136,913		0.23425	$ 14,321,322				
5	Residential Total							$ 156,045,812	$ 156,046,309	$ (497)	83.80 %
6											
7	Commercial - Small	118,004			$ 85.00		$ 10,030,340				
8			All Ccf	7,271,449		0.15710	$ 1,142,345				
9	Commercial - Large	40,110			$ 100.00		$ 4,011,000				
10			All Ccf	38,760,730		0.10765	$ 4,172,593	$ 19,356,277			
11											
12	Commercial - Transport	3,892			297.51		$ 1,157,864				
13			All Ccf	17,180,034		0.12679	$ 2,178,256	$ 3,336,120			
14	Commercial Total							$ 22,692,397	$ 22,692,212	$ 185	12.19 %
15											
16	Industrial	295			$ 572.02		$ 168,746				
17			All Ccf	615,043		0.12707	$ 78,153	$ 246,899			
18											
19	Industrial - Transport	447			$ 772.02		$ 345,122				
20			All Ccf	16,685,705		0.12707	$ 2,120,253	$ 2,465,374			
21	Industrial Total							$ 2,712,274	$ 2,712,276	$ (2)	1.46 %
22											
23	Public Authority	10,055			$ 156.05		$ 1,569,109				
24			All Ccf	4,920,106		0.12549	$ 617,424	$ 2,186,533			
25											
26	Public Authority - Transport	5,970			$ 179.05		$ 1,068,955				
27			All Ccf	9,625,326		0.12549	$ 1,207,882	$ 2,276,837			
28	Public Authority Total							$ 4,463,370			
29											
30	Electric Cogeneration- Transport	12			$ 175.98		$ 2,112				
31			First 5,000 Ccf	60,000		0.07427	$ 4,456				
32			Next 35,000 Ccf	420,000		0.06590	$ 27,678				
33			Next 60,000 Ccf	720,000		0.05314	$ 38,261				
34			All over 100,000 Ccf	2,850,695		0.03864	$ 110,151				
35	Electric Cogeneration Total							$ 182,658	$ 4,646,002	$ 26	2.50 %
36											
37	Compressed Natural Gas	11			$ 594.88		$ 6,544				
38			All Ccf	0		0.06684	$ —	$ 6,544			
39											
40	Compressed Natural Gas - Transport	48			$ 619.88		$ 29,754				
41			All Ccf	1,135,073		0.06684	$ 75,868	$ 105,623			
42	Compressed Natural Gas Total							$ 112,166	$ 112,166		
43											
44	Total Revenue - All Classes										
45											
46	Recommended Rate Revenue							$ 186,208,676	$ 186,208,965		
47	Current Rate Revenue							$ 160,419,569	$ 160,419,569		
48	Revenue Change							$ 25,789,107	$ 25,789,396		
49											
50	Schedule A - Revenue Deficiency								$ 25,789,395		
									$ (0)		

STATE OF MARYLAND §
§
COUNTY OF MONTGOMERY §

AFFIDAVIT OF PAUL H. RAAB

BEFORE ME, the undersigned authority, on this day personally appeared Paul H. Raab who having been placed under oath by me did depose as follows:

1. "My name is Paul H. Raab. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as an Economic Consultant. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Paul H. Raab

SUBSCRIBED AND SWORN TO BEFORE ME by the said Paul H. Raab on this 21 day of May 2024.

Notary Public in and for the State of Maryland

DAVID KIM
Notary Public - State of Maryland
Montgomery County
My Commission Expires May 1, 2027

WORKPAPERS

TO

DIRECT TESTIMONY

OF

PAUL H. RAAB

Workpapers to the Direct Testimony of Paul H. Raab are being provided in electronic format.

PUBLIC NOTICE OF PROPOSED RATE CHANGE
NATURAL GAS UTILITY RATES

On June 3, 2024, Texas Gas Service Company, a Division of ONE Gas, Inc. (“TGS” or the “Company”), filed a Statement of Intent to Change Rates (“Statement of Intent”) in the Central-Gulf Service Area ("CGSA") with the Railroad Commission of Texas (“Commission”) and with the Cities of Austin, Bayou Vista, Beaumont, Bee Cave, Cedar Park, Cuero, Dripping Springs, Galveston, Georgetown, Gonzales, Groves, Hutto, Jamaica Beach, Kyle, Lakeway, Lockhart, Luling, Marble Falls, Mustang Ridge, Nederland, Nixon, Pflugerville, Port Arthur, Port Neches, Rollingwood, Shiner, Sunset Valley, West Lake Hills and Yoakum, Texas for the gas utility rates charged by the Company to customers. The proposed change in rates will affect all residential, commercial, commercial transportation, industrial, industrial transportation, public authority, public authority transportation, public school space heating, public school space heating transportation, electrical cogeneration, electrical cogeneration transportation, compressed natural gas, compressed natural gas transportation and unmetered gas light customers within the cities listed above and the unincorporated areas of the CGSA. The proposed effective date of the requested rate changes is July 8, 2024.

The proposed rates and tariffs are expected to increase the Company’s annual system-wide revenues within the CGSA by approximately $25.8 million or 9.83% including gas cost or 15.59% excluding gas cost. The proposed change in rates does constitute a “major change” as that term is defined by Section 104.101 of the Texas Utilities Code because the proposed rates will increase the total aggregate revenues of the Company in the CGSA by more than two and one-half percent. The proposed change in rates will not become effective until similar changes have become effective within the nearest incorporated city.

The Company proposes to implement the rates included in Table 1 below:

TABLE 1 – Proposed Rate Changes for Incorporated and Unincorporated/Environs Customers

	Current Rates Incorporated and Unincorporated/Environs		
Customer Class	CGSA Incorporated Rates	CGSA Environs Rates	Proposed CGSA Rates
Residential			
No. of Customers Affected	281,253	30,284	
Customer Charge	$25.47	$25.47	
Volumetric Charge (per Ccf)	$0.32626	$0.32626	
Small Customer Charge			$25.50
Small Volumetric Charge (per Ccf)			$0.69448
Large Customer Charge			$39.00
Large Volumetric Charge (per Ccf)			$0.23425
Commercial			
No. of Customers Affected	12,743	433	
Customer Charge	$96.08	$96.08	
Volumetric Charge (per Ccf)	$0.12679	$0.12679	
Small Customer Charge			$85.00
Small Volumetric Charge (per Ccf)			$0.15710
Large Customer Charge			$100.00
Large Volumetric Charge (per Ccf)			$0.10765

Commercial Transportation			
No. of Customers Affected	313	11	
Customer Charge	$308.08	$308.08	$297.51
Volumetric Charge (per Ccf)	$0.12679	$0.12679	$0.12679
Industrial			
No. of Customers Affected	25	0	
Customer Charge	$1,005.41	$1,005.41	$572.02
Volumetric Charge (per Ccf)	$0.12707	$0.12707	$0.12707
Industrial Transportation			
No. of Customers Affected	28	9	
Customer Charge	$1,205.41	$1,205.41	$772.02
Volumetric Charge (per Ccf)	$0.12707	$0.12707	$0.12707
Public Authority			
No. of Customers Affected	777	54	
Customer Charge	$160.70	$160.70	$156.05
Volumetric Charge (per Ccf)	$0.12549	$0.12549	$0.12549
Public Authority Transportation			
No. of Customers Affected	412	8	
Customer Charge	$183.70	$183.70	$179.05
Volumetric Charge (per Ccf)	$0.12549	$0.12549	$0.12549
Public School Space Heating (Reclassed to Public Authority)			
No. of Customers Affected	6	1	
Customer Charge	$213.70	$213.70	$156.05
Volumetric Charge (per Ccf)	$0.10012	$0.10012	$0.12549
Public School Space Heating Transportation (Reclassed to Public Authority Transportation)			
No. of Customers Affected	76	2	
Customer Charge	$313.70	$313.70	$179.05
Volumetric Charge (per Ccf)	$0.10012	$0.10012	$0.12549
Electric Generation (Previously Known as Electric Cogeneration)			
No. of Customers Affected	0	0	
Customer Charge	$183.70	$183.70	$175.98
Volumetric Charge (per Ccf)			
First 5,000 Ccf/Month	$0.07720	$0.07720	$0.07427
Next 35,000 Ccf/Month	$0.06850	$0.06850	$0.06590
Next 60,000 Ccf/Month	$0.05524	$0.05524	$0.05314
All Over 100,000 Ccf/Month	$0.04016	$0.04016	$0.03864

Electric Generation Transportation (Previously Known as Electric Cogeneration Transportation)			
No. of Customers Affected	1	0	
Customer Charge	$183.70	$183.70	$175.98
Volumetric Charge (per Ccf)			
First 5,000 Ccf/Month	$0.07720	$0.07720	$0.07427
Next 35,000 Ccf/Month	$0.06850	$0.06850	$0.06590
Next 60,000 Ccf/Month	$0.05524	$0.05524	$0.05314
All Over 100,000 Ccf/Month	$0.04016	$0.04016	$0.03864
Compressed Natural Gas			
No. of Customers Affected	1	0	
Customer Charge	$812.71	$812.71	$594.88
Volumetric Charge (per Ccf)	$0.06684	$0.06684	$0.06684
Compressed Natural Gas Transportation			
No. of Customers Affected	3	1	
Customer Charge	$837.71	$837.71	$619.88
Volumetric Charge (per Ccf)	$0.06684	$0.06684	$0.06684
Unmetered Gas Light			
No. of Customers Affected	1	0	
Customer Charge	$0.00	$0.00	$0.00
Public Authority Volumetric Charge (per Ccf)	$0.12549	$0.12549	$0.12549
Residential Volumetric Charge (per Ccf)	$0.69448	$0.69448	$0.69448
Commercial Volumetric Charge (per Ccf)	$0.15710	$0.15710	$0.15710
Industrial Volumetric Charge (per Ccf)	$0.12707	$0.12707	$0.12707

TABLE 2 – Impact on Average Bill

Customer Class CGSA (Average Usage)	**Current Average Monthly Bill Including Cost of Gas**	**Proposed Average Monthly Bill Including Cost of Gas**	**Proposed Monthly Dollar Change**	**Proposed Percentage Change with Gas Cost**	**Proposed Percentage Change without Gas Cost**
Sales Service					
Residential - Small (17 Ccf)					
Incorporated	$41.76	$48.02	$6.26	14.99%	20.09%
Environs	$41.76	$48.02	$6.26	14.99%	20.09%
Residential - Large (43 Ccf)					
Incorporated	$67.28	$76.81	$9.53	14.16%	23.93%
Environs	$67.28	$76.81	$9.53	14.16%	23.93%
Commercial - Small (62 Ccf)					
Incorporated	$143.11	$133.90	$(9.21)	(6.44)%	(8.93)%
Environs	$143.11	$133.90	$(9.21)	(6.44)%	(8.93)%
Commercial - Large (966 Ccf)					
Incorporated	$833.61	$819.03	$(14.58)	(1.75)%	(6.59)%
Environs	$833.61	$819.03	$(14.58)	(1.75)%	(6.59)%

Customer Class CGSA (Average Usage)	Current Average Monthly Bill Including Cost of Gas	Proposed Average Monthly Bill Including Cost of Gas	Proposed Monthly Dollar Change	Proposed Percentage Change with Gas Cost	Proposed Percentage Change without Gas Cost
Industrial (2,085 Ccf)					
Incorporated	$2,597.27	$2,163.88	$(433.39)	(16.69)%	(34.11)%
Environs	$2,597.27	$2,163.88	$(433.39)	(16.69)%	(34.11)%
Public Authority (489 Ccf)					
Incorporated	$533.27	$528.62	$(4.65)	(0.87)%	(2.11)%
Environs	$533.27	$528.62	$(4.65)	(0.87)%	(2.11)%
Public Schools Space Heating (Withdrawing/Proposed Reclass to Public Authority) (1,391 Ccf)					
Incorporated	$1,238.21	$1,215.85	$(22.36)	(1.81)%	(6.35)%
Environs	$1,238.21	$1,215.85	$(22.36)	(1.81)%	(6.35)%
Compressed Natural Gas (0 Ccf)					
Incorporated	$812.71	$594.88	$(217.83)	(26.80)%	(26.77)%
Environs	$812.71	$594.88	$(217.83)	(26.80)%	(26.77)%
Electric Generation (Previously Known as Electric Cogeneration)					
Incorporated	NA	NA	$0.00	0.00%	0.00%
Environs	NA	NA	$0.00	0.00%	0.00%
Unmetered Gas Light (1,304 Ccf)					
Incorporated	$993.52	$993.52	$0.00	0.00%	0.00%
Environs	NA	NA	$0.00	0.00%	0.00%
Transportation Service					
Commercial Transportation (4,414 Ccf)					
Incorporated	$3,536.39	$3,525.82	$(10.57)	(0.30)%	(1.22)%
Environs	$3,536.39	$3,525.82	$(10.57)	(0.30)%	(1.22)%
Industrial Transportation (37,325 Ccf)					
Incorporated	$28,514.60	$28,081.21	$(433.39)	(1.52)%	(7.29)%
Environs	$28,514.60	$28,081.21	$(433.39)	(1.52)%	(7.29)%
Public Authority Transportation (1,612 Ccf)					
Incorporated	$1,360.59	$1,355.94	$(4.65)	(0.34)%	(1.22)%
Environs	$1,360.59	$1,355.94	$(4.65)	(0.34)%	(1.22)%
Public Schools Space Heating Transportation (Withdrawing/Proposed Reclass to Public Authority Transportation) (926 Ccf)					
Incorporated	$966.26	$855.10	$(111.16)	(11.50)%	(27.35)%
Environs	$966.26	$855.10	$(111.16)	(11.50)%	(27.35)%
Electric Generation Transportation (Previously Known as Electric Cogeneration Transportation) (337,558 Ccf)					
Incorporated	$219,905.95	$219,305.49	$(600.46)	(0.27)%	(3.81)%
Environs	$219,905.95	$219,305.49	$(600.46)	(0.27)%	(3.81)%
Compressed Natural Gas Transportation (23,647 Ccf)					
Incorporated	$16,715.00	$16,497.17	$(217.83)	(1.30)%	(9.01)%
Environs	$16,715.00	$16,497.17	$(217.83)	(1.30)%	(9.01)%

Table 2 calculations are based on a $0.64 cost of gas and do not include revenue-related taxes.

The Company also proposes changes to Miscellaneous Service Charges included in Table 3 below.

Table 3 – Miscellaneous Service Charges

Incorporated/Environs	CGSA	
Service Fees and Deposits	Current Fee	Proposed Fee
Connect	$35.00	$38.00
Reconnect Fee	$35.00	$38.00
Read-In (Connect Fee - Read Only)	$15.00	$18.00
Special Handling	$15.00	$18.00
Expedited Service/Overtime/After Hours	$60.00	$70.00
Regular Labor Rate	$45.00	$50.00
No Access Fee (Door Tag)	$15.00	$18.00
Meter Test Up to 1500 CFH	$150.00	$150.00
Meter Test Over 1500 CFH	$200.00	$225.00
Orifice Meters	$200.00	$200.00
Payment Re-processing Fee (Returned Check Fee)	$25.00	$25.00
Collection Fee (All Classes)	$15.00	$18.00
Special Read	$15.00	$20.00
Meter Exchange without ERT (Customer Request)	$150.00	Discontinue
Meter Exchange (Customer Request)	$150.00	$180.00
Unauthorized Consumption (Plus Expenses)	$30.00	$30.00
Meter Removal Fee	$25.00	$25.00
Account Research per hour Fee	$20.00	$20.00
Excess Flow Valve Installation Fee	$400.00	$400.00
Minimum Deposit Residential	$75.00	$75.00
Minimum Non Residential Deposit	$250.00	$250.00
Meter Tampering (Residential)	$150.00	$180.00

The proposed changes in Table 3 reflect a net increase of $304,384 in revenues.

In addition to requesting new rates in the CGSA, TGS is requesting: (1) Commission approval of new depreciation rates for Direct and Division distribution and general plant within the CGSA; (2) a finding from the Commission that expenses for Winter Storm Uri and COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (3) a prudence determination for capital investment made in the CGSA through December 31, 2023, including capital investment in the Company's Interim Rate Adjustment ("IRA") filings made since the last rate cases in the CGSA pursuant to Texas Utilities Code § 104.301; (4) approval to include Excess Deferred Income Taxes ("EDIT") in base rates, with discontinuance of the EDIT Rider, to return EDIT to customers; and (5) approval to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law.

The Company also proposes revisions to CGSA rate schedules and tariffs that contain the proposed rates in Table 1. For all proposed incorporated and environs Rate Schedules for General Sales and Transportation Customers, TGS proposes to: include revisions to the "Applicability" section to include additional cities and their respective environs; revise the "Other Adjustments" section to remove references to Rate Schedule EDIT-Rider and Rate Schedule HARV-Rider; add references to Rate Schedules RCE and PSF; revise the "Cost of Service Rate" section to clarify the Company's delivery charge; revise the "Territory" section in General Sales rate schedules; and revise the "Availability" section in the Transportation rate schedule for consistency with other Company service areas. For Residential Rate Schedules 10, 15, 1Y and 1Z, TGS proposes to: add residential builders to the "Applicability" sections: designate 10 and 1Z as Small Residential; and, add new 15 and 1Y Large Residential rate schedules. For Commercial Rate Schedules 20, 25, 2Y and 2Z, TGS proposes to designate 20 and 2Z as Small Commercial and add new 25 and 2Y Large Commercial rate schedules. For Electric Generation (previously known as Electric Cogeneration) Rate Schedules C-1 and C-1-ENV, TGS proposes revisions to the "Applicability" section that provide a mechanism to provide natural gas service to non-residential customers for the purpose of electric generation. For Transportation Rate Schedules T-1, T-1-ENV and T-TERMS, TGS proposes to remove rates for Public School Space Heating; to revise section 1.2 with the addition of definitions for "Agreement," "Firm Service" and "Force Majeure" to provide clarity for Customer and Company rights and responsibilities during a curtailment event; to add a definition for "Electric Generation Service" to align with Commission Rule §7.455 to include distributed generation and backup power systems that are registered with the applicable balancing authorities; to revise sections 1.4 and 1.6 to clarify Qualified Supplier and Company responsibilities for designating receipt points; to add clarifying language to section 1.5(g) for Customer's responsibility to provide written notice to the Company; to revise the "Applicability," "Availability," "Additional Charges," and "Subject To" sections in T-1 and T-1-ENV and sections 1.1, 1.2, 1.4, 1.5, 1.6 and 1.7 in T-TERMS for consistency with other Company service areas; and to add sections 1.3 and 1.8 for consistency with other Company service areas. For the Cost of Gas Clauses 1-INC and 1-ENV, TGS proposes to expand language in section B.3 to include other renewable sources of natural gas and Environmental Attributes associated with the purchase of RNG to make the language consistent with approved Cost of Gas clauses in Docket No. OS-22-00009896 ("Docket No. 9896"); and to add clarifying language for the use of financial instruments in sections B.3, B.7, and B.10 to make consistent with the recently approved Cost of Gas clauses in Docket No. 9896 and Docket No. OS-23-00014399 ("Docket No. 14399"). Rate Schedule RNG is a new rate schedule for which the Company is requesting approval that allows for the inclusion of a designated amount of RNG credits in the Cost of Gas Clause and establishment of a RNG Credits Program tariff, Rate Schedule RNG Credits Program, through which interested customers can opt to offset a portion of their gas usage with RNG Credits. For Rate Schedule WNA, TGS proposes revisions to the "Applicability" section to reference new Rate Schedules for Large Residential and Large Commercial; updated weather factors for each class consistent with weather normalization calculation in this case; and revisions to the "Applicability" and "Filing with the Cities and the Railroad Commission of Texas (RRC)" sections for additional cities and their respective environs included in the service area. For Rate Schedules Pit and PIT rider, TGS proposes revisions to the "Territory" section for additional cities and their respective environs included in the service area. For Rate Schedules RCE and RCE-ENV, TGS proposes a mechanism to recover all reasonable rate case expenses incurred by the Company and cities in connection with the Statement of Intent filings that have been made with the cities and the Commission. For Rate Schedule RNG, TGS proposes establishing an RNG Credits Program. For the Rules of Service, TGS proposes revisions for consistency with the Commission's Quality of Service Rules and the approved Rules of Service in Docket Nos. 9896 and 14399. In addition the Company proposes: updating the Company's contact information on page 1 for customer inquiries; updating § 1.3, Definitions, to include all definitions of terminology in the Rules of Service consistent with approved Rules of Service in Docket Nos. 9896 and 14399 as well as add definitions for "Firm Service" and "Force Majeure" to provide clarity for Customer and Company rights and responsibilities during a curtailment event, add definition for "Master Meter," while revising "Electrical Cogeneration Service" to "Electric Generation Service" and "Excess Flow Valve" to expand the definitions and include distributed generation and backup power systems that are registered with the applicable balancing authorities; revisions to § 3 and § 4.5 to include language for the availability of rate schedules on the Company's website; revisions to § 4.4 to remove a reference to the Company's previous filed curtailment plan and § 4.4(iv) to include curtailment language consistent with the new Commission Rule §7.455; the addition of § 4.7 to clarify the process for customer complaints; revisions to § 4.8 to add language regarding force majeure situations to the limitation of liability provision; revisions to § 4.6, § 7.4, § 7.7, § 9.1 and § 9.6 to provide for electronic billing and notice; revisions to § 5 to move Refusal of Service to § 6; revisions to § 9.9 (previously § 20.1) to update the language to reflect the current plan description for Average Payment Plan; making an administrative correction to § 12.9; revisions to § 8 and § 11 (previously § 10 and § 8, respectively) to include language consistent with Commission Rule §7.458 and to clarify security deposits and requirements for customer-owned facilities; revisions to § 15 (previously § 21), Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas; and withdraw the rules of service addenda CGSA-Env 7-45 and CGSA-Env 7-46, as these provisions have been included within the proposed CGSA Rules of Service in Sections 7.7 and 8.3(e). Finally, TGS proposes to withdraw the Public School Space Heating (48 and 4H) Rate Schedules and Rate Schedule EDIT-Rider.

Persons with specific questions or desiring additional information about this filing may contact TGS at 1-800-700-2443. Complete copies of the filed Statement of Intent, including all proposed rates and schedule changes, are available for inspection on the Company's website at https://www.texasgasservice.com/RateInformation/centralgulf. Any affected person may file written comments or a protest concerning the proposed rate change with the Docket Services Section of the Office of the Hearings Division, Railroad Commission of Texas, P.O. Box 12967, Austin, Texas 78711-2967, at any time within 30 days following the date on which this change would or has become effective, or August 7, 2024. Please reference Docket No. OS-24-00017471. Any affected person within an incorporated area may contact their city council.

Este aviso tiene como fin informarle a los clientes de Texas Gas Service Company, una Division de ONE Gas, Inc. ("TGS" o la "Compañía") de el área Golfo Central que la Compañía ha presentado una solicitud para aumentar las tarifas del servicio público de gas. Esta solicitud afecta a todos los clientes residenciales, comerciales, transporte comercial, industrial, transporte industrial, autoridad pública, transporte de autoridad pública, calefacción de espacios de escuelas públicas, transporte de calefacción de espacios de escuelas públicas, cogeneración eléctrica, transporte de cogeneración eléctrica, gas natural comprimido, transporte de gas natural comprimido y clientes de luz de gas sin medidor. Las personas que deseen hacer preguntas específicas o recibir más información sobre esta solicitud pueden comunicarse con la Compañía llamando al 1-800-700-2443 o envié un mensaje de correo electrónico a la dirección ODCInformationCenterWebTeam@onegas.com. Cualquier persona afectada puede presentar por escrito comentarios o una protesta sobre el cambio de tarifas propuesto a la Sección de Servicios de la Oficina de la División de Audiencias, Comisión Ferroviaria de Texas, P.O. Box 12967, Austin, Texas 78711-2967, en cualquier momento dentro de los 30 días siguientes a la fecha en que este cambio entraría en vigencia o el 7 de agosto el 2024. Por favor, haga referencia a Docket No. OS-24-00017471. Cualquier persona afectada dentro de un área incorporada puede contactar a su Consejo Municipal.

CASE NO. 00017471

STATEMENT OF INTENT OF TEXAS	**§**	
GAS SERVICE COMPANY, A	**§**	**BEFORE THE**
DIVISION OF ONE GAS, INC., TO	**§**	
CHANGE GAS UTILITY RATES	**§**	**RAILROAD COMMISSION**
WITHIN THE UNINCORPORATED	**§**	
AREAS OF THE CENTRAL-GULF	**§**	**OF TEXAS**
SERVICE AREA	**§**	

PROTECTIVE ORDER

This Protective Order shall govern the use of all information deemed confidential or highly sensitive confidential information by a party providing information to the Railroad Commission of Texas ("Commission") or responding to discovery requests, including information whose confidentiality may be under dispute in this docket and all dockets consolidated herewith. This order may be modified by the Examiner *sua sponte*, or on advice of the Open Records Coordinator, Office of General Counsel, and the Railroad Commission of Texas.

1. Designation of Protected Materials

Any party or person producing or filing a document, including, but not limited to, records stored or encoded on a computer disk or other similar electronic storage medium, in this proceeding may designate that document, or any portion of it, as confidential by typing or stamping on its face **"PROTECTED MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER ISSUED IN CASE NO. 00017471"** (hereinafter referred to as "protected materials"). The documents shall be consecutively Bates Stamped when necessary.

2. Materials Excluded from Protected Materials Designation

Protected materials shall not include any information or document contained in the public files of the Commission or any other federal or state agency, court, or local government authority subject to the Public Information Act or under the Federal Freedom of Information Act provided however, that any party or person may assert any privilege or exception available under these Acts. Protected materials also shall not include materials that at the time of or prior to disclosure in these proceedings, is or was publicly disclosed, on a non-confidential basis. The disclosure of materials to a party, its customers, or their respective employees, agents, consultants, or counsel in the normal course of business shall not preclude a claim that such materials are protected materials hereunder. Protected materials disclosed by someone other than an employee, agent, or consultant of the originating party in violation of this Protective Order shall not lose their status as protected material as a result of such disclosure.

3. Definition of "reviewing party."

A "reviewing party" is defined for purposes of this Protective Order as a party expressly admitted or that has had a Motion to Intervene granted in Case No. 00017471.

4. Definition of "producing party."

A "producing party" is defined for purposes of this Protective Order as a party expressly admitted or that has had a Motion to Intervene granted in Case No. 00017471, which has had discovery propounded upon it in any form as provided by applicable law.

5. Access to Protected Materials

A reviewing party shall be permitted access to protected materials only through its authorized representatives. "Authorized representatives" of a party include its counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by the party and directly engaged in these proceedings, provided that such person has signed the certification required by Paragraph 8.

6. Designation of Highly Sensitive Protected Materials

The term "highly sensitive protected materials" is a subset of "protected materials." The term refers to, but is not limited to, documents and information, the provision of which to the reviewing party or its authorized representatives would: (1) expose the producing party or any of its affiliates to an unreasonable risk of harm, or (2) would result in disclosure of information that would be subject to a privilege against disclosure, a contractual confidentiality agreement or other Protective Agreement or agreement. Highly sensitive protected materials further include, but are not limited to, business operations or financial information that is commercially sensitive. Documents so classified by a producing party shall bear the designation "HIGHLY SENSITIVE PROTECTED MATERIALS PROVIDED PURSUANT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. 00017471."

7. Restrictions on Copies and Inspection of Highly Sensitive Protected Materials

Highly sensitive protected materials shall be made available for inspection only at the address specified pursuant to Paragraph 9. Additionally, only one copy of highly sensitive protected materials shall be provided to counsel of any party to Case No. 00017471 upon written request following completion of the certifications required by Paragraph 8 herein. A party may make one additional copy of reproduced highly sensitive protected materials for use in this proceeding pursuant to this Protective Order. No additional copies of such highly sensitive protected materials may be made, except that additional copies may be made in order to have sufficient copies for introduction of the material into the evidentiary record if the material is to be offered for admission into the record. A record of any copies that are made of highly sensitive protected material shall be kept and a copy of the record shall be sent to the producing party upon request. The record shall include information on the location and the person in possession of the copy. The authorized representatives for the purpose of access to highly sensitive protected materials must be persons who are: (1) counsel for the reviewing party, (2) consultants for the reviewing party working under the direction of the reviewing party's counsel, (3) permanent non-elected employees of municipalities that are parties in Case No. 00017471, who have primary responsibility for utility regulation. The authorized representatives for the Commission's Director of Gas Services or the State of Texas for the purpose of access to these materials shall consist of its respective counsel of record in this docket and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by those agencies and directly engaged in this docket. Limited notes may be made of highly sensitive protected materials, and such notes shall themselves be treated as highly sensitive protected material unless such notes are restricted to a description of the document and a general characterization of its subject matter in a manner that does not include any substantive information contained in such highly sensitive protected materials.

8. Required Certification

Each person who inspects the protected materials shall, before such inspection, agree in writing to follow certification set forth in Exhibit A to this Order:

> I certify my understanding that the protected materials are provided to me pursuant to the terms and restrictions of the Protective Order in Case No. 00017471, and that I have been given a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the protected materials, any notes, memoranda, or any other form of information regarding or derived from the protected materials shall not be disclosed to anyone other than in accordance with the Protective Order and shall be used only for the purpose of the proceeding in Case No. 00017471. I acknowledge that the obligations imposed by this certification are pursuant to a ruling issued by the Examiners in this docket. However, if the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this docket, the understanding stated herein shall not apply.

In addition, reviewing parties who are permitted access to highly sensitive protected material under the terms of this ruling shall, before inspection of such materials, agree in writing to the following certification set forth in Exhibit A to this Protective Order:

> I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Order in Case No. 00017471.

A copy of each signed certification shall be provided to counsel for the party asserting confidentiality. Except for highly sensitive protected materials, any authorized representative may disclose protected materials to any other person who is an authorized representative, provided that, if the person to whom disclosure is to be made has not executed and provided for delivery of a signed certification to the party asserting confidentiality, that certification shall be executed prior to any disclosure. An authorized representative may disclose highly sensitive protected material to other reviewing representatives who are permitted access to such materials and have executed the additional certification required for persons who receive access to highly sensitive protected material. In the event that any authorized representative to whom protected materials are disclosed ceases to be engaged in these proceedings, access to protected materials by that person shall be terminated and all notes or memoranda or other information derived from the protected material shall be returned to the party on whose behalf that person was acting. Any person who has agreed to either or both of the foregoing certifications shall continue to be bound by the provisions of this Protective Order, even if no longer engaged in these proceedings. Parties who assert confidentiality shall maintain a list of persons who sign a certification pursuant to this Paragraph.

9. Voluminous Materials

(a) Voluminous protected materials which exceed eight linear feet shall be made available for inspections in its normal repository between the hours of 9:30 a.m. and 5:00 p.m., Monday through Friday (except holidays) in accordance with the Texas Rules of Civil Procedure. A party shall notify the other parties of the address at which the voluminous data will be produced simultaneously with the production of such data. For purposes of this Protective Order voluminous materials or data shall mean responses to a particular question or subpart that consist of one hundred pages or more in the aggregate.

(b) Except for highly sensitive protected materials as provided for in Paragraph 7, and for protected materials that are voluminous, the party asserting confidentiality shall provide a party one copy of the protected materials upon receipt of the signed certifications described in Paragraph 8. Except as provided above for highly sensitive protected materials, parties may take notes regarding the information contained in protected materials made available for inspection pursuant to Paragraph 9(a). Only one copy of such protected materials shall be reproduced for each party. Parties shall make a diligent, good-faith effort to limit the amount of copying requested to only that which is appropriate for purposes of this proceeding. Notwithstanding the foregoing provisions of this Paragraph 9(b), a party may make further copies of reproduced protected materials for use in this proceeding pursuant to this Protective Order, but a record shall be maintained as to the documents produced and the number of copies made, and upon request, the party shall provide the party asserting confidentiality with a copy of that record.

10. Availability for Purposes of this Filing

All protected materials shall be made available to the parties solely for the purposes of this proceeding. Protected materials, as well as a party's notes, memoranda, or other information regarding, or derived from the protected materials are to be treated confidentially by the parties and shall not be disclosed or used by the party except as permitted and provided in this Protective Order. Information derived from or describing the protected materials shall be maintained in a secure place and shall not be placed in the public or general files of the party except in accordance with the provisions of this Protective Order. A party must take all reasonable precautions to ensure that the protected materials, including notes and analysis made from protected materials, are not viewed or taken by any person other than an authorized representative of the party.

All non-voluminous protected materials may be reviewed only during the "reviewing period," which period shall commence upon issuance of this Protective Order and continue until conclusion of the plenary jurisdiction of the Commission in this proceeding. The "reviewing period" shall reopen if the Commission regains jurisdiction due to a remand as provided by law. Protected materials that are admitted into the evidentiary record or accompanying the evidentiary record as offers of proof, may be reviewed while this proceeding or any appeals hereof are pending.

11. Treatment of Protected Materials

(a) If a party tenders for filing any written testimony, exhibit, brief, or other submission that quotes from protected materials or discloses the confidential content of protected materials, the confidential portion of such testimony, exhibit, brief, or other submission shall be sealed and shall be filed and served in accordance with the appropriate procedures utilized by the

Commission. The Examiners may subsequently, on their own motion or on motion of a party, issue a ruling respecting whether or not the inclusion, incorporation, or reference to protected materials is such that the written testimony, exhibit, brief, or other submission should remain under seal.

(b) Any party or person giving testimony in this proceeding may designate those portions of his or her testimony deemed to be confidential materials in accordance with Paragraph 1 of this Protective Order by advising the Examiner of such fact. In that event, the Examiner shall, on a case-by-case basis, devise procedures which are fair to all parties without unduly burdening the record in this docket.

(c) All protected materials filed with the Commission, the Examiner, any other judicial or administrative body in support of or as part of a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers.

12. Changes to Protective Order

Nothing herein restricts the party seeking protected material and the party producing the protected material from agreeing to other procedures/methods for handling of protected material, including highly sensitive protected material. In addition, each party shall have the right to seek changes in this Protective Order as appropriate from the Examiners, the Commission, or the courts. Nothing herein shall prevent any party from opposing efforts to seek changes to this ruling.

13. Judicial Findings

In the event that the Examiner at any time in the course of this proceeding finds that all or part of the protected materials are not confidential, by finding, for example, that such materials have entered the public domain, those materials shall nevertheless be subject to the protection afforded by this ruling for three full working days, unless otherwise ordered, from the latest of (i) the date of receipt by the party asserting confidentiality of the Examiner's order, or (ii) the date of a final and appealable Commission order denying an appeal filed within the three full working day period from the Examiner's order; or (iii) approval of such order by operation of law following the filing of such an appeal. Neither the party asserting confidentiality, nor any reviewing party waives its right to seek additional administrative or judicial remedies after the Commission's denial of any appeal.

14. Disclosure of Protected Materials

(a) During the pendency of Case No. 00017471 at the Commission, in the event that a party wishes to disclose protected materials to any person to whom disclosure is not authorized by this Protective Order, or wishes to have changed the designation of certain information or material as protected materials by alleging, for example, that such information or material has entered the public domain, such party shall first file and serve on all parties written notice of such proposed disclosure or request for change in designation, identifying with particularity each of such protected materials. In the event that the party asserting confidentiality wishes to contest such proposed disclosure or request for change in designation, that party shall file with the Commission its objection to such proposal, with supporting sworn affidavits, if any, within five working days after receiving such notice of proposed disclosure or request for change in designation. Failure of that party to file such an objection within this period shall be deemed a waiver of objection to the proposed disclosure or request for change in designation. Upon the request of either the producing party or reviewing party or upon the Examiner's own initiative, the Examiner may conduct a prehearing conference. If either the producing or reviewing party wishes to submit materials in question for an in camera inspection, it shall do so at the time of filing its written notice or objection to disclosure. Responses to such an objection, with supporting affidavits, if any, shall be filed within five working days after receipt of the objection. The Examiner will determine whether the proposed disclosure or change in designation is appropriate. The burden is on the party asserting confidentiality to show that such proposed disclosure or change in designation should not be made. If the Examiner determines that such proposed disclosure or change in designation should be made, disclosure shall not take place earlier than three full working days after such determination unless otherwise ordered. No party waives any right to seek additional administrative or judicial remedies concerning such Examiner's ruling. As long as the periods set out in this Protective Order for filing the pleadings described above for consideration by the Examiner and for challenging the determination of the Examiner or the Commission have not expired and while a challenge is pending, the protected materials shall maintain the confidential treatment and status provided for in this Protective Order.

(b) All protected materials shall be afforded the confidential treatment and status provided for in this Protective Order during the period an appeal on an Examiner's ruling is pending before the Commission and during the periods for challenging the various orders.

(c) All notices, applications, responses, or other correspondence shall be made in a manner that protects protected materials from unauthorized disclosure.

15. Objection to Protected Materials

Nothing in this ruling shall be construed as precluding any party from objecting to the use of protected materials on grounds other than confidentiality, including the lack of required relevance. Nothing in this ruling shall be construed as an agreement by any party that the protected materials are entitled to confidential classification.

16. Acts upon Conclusion of Proceeding

Following the conclusion of these proceedings, each party must, no later than thirty days following receipt of the notice described below, destroy or return to the party asserting confidentiality all copies of the protected materials provided by that party pursuant to this Protective Order and all copies reproduced by a reviewing party, and counsel for each party must provide to the party asserting confidentiality a verified certification that, to the best of his or her knowledge, information, and belief, all copies of notes, memorandum, and other documents regarding or derived from the protected materials (including copies of protected materials) that have not been so returned, if any, have been destroyed, other than notes, memoranda, or other documents which contain information in a form which, if made public, would not cause disclosure of protected materials. Promptly following the conclusion of this proceeding, counsel for the party asserting confidentiality will send a written notice to all parties, reminding them of their obligations under this Paragraph. Nothing in this Paragraph shall prohibit counsel for each party from retaining two copies of any filed testimony, exhibit, brief, application for rehearing, or other pleading which refers to protected materials provided that any such protected materials retained by counsel shall remain subject to the provisions of this ruling. As used in this Paragraph, "conclusion of this proceeding" refers to the exhaustion of available appeals, or the running of the time for making of such appeals, as provided by applicable law. If, following any appeal, the Commission conducts a remand proceeding, then "the conclusion of these proceedings" is extended by the remand to the exhaustion of available appeals, or the running of the time for the making of such appeals, as provided by applicable law. If, following any appeal, the Commission conducts a remand proceeding, then the "conclusion of this proceeding" is extended by the remand to the exhaustion of available appeals of the remand or the running of time for making such appeals of the remand, as provided by applicable law.

17. Compliance with Legal Requirements

This Protective Order is subject to the requirements of the Public Information Act, the Open Meetings Act, and any other applicable law, provided that parties subject to those acts will give the party asserting confidentiality notice, if possible, under those acts, prior to disclosure pursuant to those acts.

18. Effect of Court Order

If required by order of a government or judicial body, the party may release to such body the confidential information required by such order, provided, however, the party agrees that prior to such disclosure, it shall promptly notify the party asserting confidentiality of the order and allow such party sufficient time to contest release of the confidential information; provided, further, the party shall use its best efforts to prevent such confidential information from being disclosed.

The term "best efforts" as used in the preceding paragraph requires that the party's attempt to ensure that disclosure is not made by its employees or authorized representatives unless such disclosure is pursuant to a final order of a governmental or judicial body or written opinion of the Attorney General which was sought in compliance with V.T.C.A., Government Code §552.301 (Public Information). The party is not required to delay compliance with a lawful order to disclose such information but is simply required to timely notify the party asserting confidentiality, or its counsel, that it has received a challenge to the confidentiality of the information and that the reviewing party will either proceed under the provisions of § 552.301 of the Texas Government Code or intends to comply with the final governmental or court order.

19. Effect of Violation of Court Order

In the event of a breach of the provisions contained in Paragraph 18, the party asserting confidentiality will not have an adequate remedy in money or damages, and accordingly, shall in addition to any other available legal or equitable remedies, be entitled to an injunction against such breach. The producing party shall not be relieved of proof of any element required to establish the right to injunctive relief.

Signed this _______ day of _______ 2024.

____

____
Administrative Law Judge

EXHIBIT A

CERTIFICATIONS

<u>Certification for protected materials only:</u>

I certify my understanding that the protected materials are provided to me pursuant to the terms and restrictions of the Protective Order in Case No. 00017471, and that I have been given a copy of it and have read the Protective Order and agree to be bound by it. I understand that the contents of the protected materials, any notes, memoranda, or any other form of information regarding or derived from the protected materials shall not be disclosed to anyone other than in accordance with the Protective Order and shall be used only for the purpose of the proceeding in Case No. 00017471. I acknowledge that the obligations imposed by this certification are pursuant to a ruling issued by the Examiners in this docket. However, if the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this docket, the understanding stated herein shall not apply.

Signature	Party Represented
Printed Name	Date

<u>Additional certification for highly sensitive protected materials:</u>

I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Order in Case No. 00017471.

Signature	Party Represented
Printed Name	Date

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUMMARY OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$833,181,714	$(19,933,007)	$813,248,707
2	Rate of Return	E	7.8812%	7.8812%	7.8812%
3	Required Return		$65,664,681	$(1,570,959)	$64,093,722
4	Cost of Gas	G	93,904,159	(93,904,159)	0
5	Depreciation and Amortization Expense	G	28,535,214	6,341,073	34,876,287
6	Taxes Other Than Income Taxes	G	8,723,616	1,377,697	10,101,313
7	Interest on Customer Deposits	G	92,616	228,821	321,437
8	Transmission and High-Pressure Distribution Expense	G	1,379,809	201,340	1,581,149.48
9	Distribution Expense	G	24,076,286	682,577	24,758,864
10	Customer Accounts Expense	G	7,061,900	440,009	7,501,909
11	Administrative and General Expense	G	36,382,309	(1,999,903)	34,382,406
12	Federal Income Tax	F	13,551,108	(323,568)	13,227,540
13	Revenue Requirement before Gross-up		$279,371,699	$(88,527,071)	$190,844,628
14	Test Year Adjusted Revenue	G	243,232,019	(77,813,492)	165,418,527
15	Revenue Deficiency		$36,139,679	$(10,713,579)	$25,426,100
	Gross-up for Revenue Related Expenses:	Factors:			
16	Uncollectible Expense	0.0065870			
17	Texas Franchise Tax	0.0075000			
18	Gross-Up Percentage	0.0140870	516,374	(153,079)	363,295
19	Total Revenue Deficiency		$36,656,053	$(10,866,658)	$25,789,395
20	Total Revenue Requirement (Line 13 + Line 18)		$279,888,072	$(88,680,150)	$191,207,923

WKP A.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

PROOF OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	AMOUNT	AMOUNT
		(a)	(b)
1	Total Revenue Requirement		$191,207,923
	Less:		
2	Depreciation	$34,876,287	
3	Taxes	10,101,313	
4	Interest on Deposits	321,437	
5	Transmission Expense	1,581,149	
6	Distribution Expense	24,758,864	
7	Customer Accounting	7,501,909	
8	Administrative and General Expense	34,382,406	
9	Gross-Up Expenses	363,295	
10	Total Operating Expense	$113,886,661	113,886,661
11	Less Interest on Long-Term Debt		14,431,766
12	Taxable Income	$62,889,496	$62,889,496
13	Add back disallowed parking expense		98,790
14	Tax Rate	21 %	
15	Income Taxes	$13,227,540	
16	Less Tax Adjustments		
17	Net Income Tax	$13,227,540	13,227,540
18	Net Income		$49,661,956
19	Rate Base	$813,248,707	
20	Wtd Cost of Equity (Common + Preferred)	6.11 %	
21	Required Return	$49,661,956	$49,661,956
22	Variance		0

WKP A.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER ALLOCATION FACTORS

LINE NO.	DESCRIPTION	TOTAL BILLED CUSTOMERS (TEST YEAR AVERAGE)	ALLOCATION FACTOR
		(a)	(b)
1	Texas Gas Service Company, a Division of ONE Gas, Inc. - Service Areas		
2	Central-Gulf Service Area	324,981	46.7362%
3	West North Service Area	306,312	44.0514%
4	Rio Grande Valley Service Area	64,059	9.2124%
5	Total TGS	695,351	100.0000%
6	Service Area Factor for this Filing		46.7362%

Based on Test Year Average Total Billed Customers

SCHEDULE B

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

RATE BASE

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
			(a)	(b)	(c)
	NET PLANT IN SERVICE				
1	Gross Plant In Service	C	$1,009,354,909	$(2,749,190)	$1,006,605,719
2	Completed Construction Not Classified	C-1	117,582,375	(106,137)	117,476,238
3	Accumulated Reserves for Depreciation and Amortization	D	(242,592,609)	2,165,203	(240,427,405)
4	Net Plant in Service		$884,344,675	$(690,124)	$883,654,551
	OTHER RATE BASE ITEMS				
5	Materials and Supplies Inventory	B-1	$12,918,778	$(1,208,842)	$11,709,937
6	Prepayments	B-2	4,822,726	(34,711)	4,788,015
7	Rule 8.209 Regulatory Asset - DIMP Deferrals	B-3	1,848,673	0	1,848,673
8	Regulatory Assets	B-11	3,135,695	0	3,135,695
9	Pension & OPEB Regulatory Asset	B-4	(3,315,201)	0	(3,315,201)
10	Prepaid Pension Asset	B-5	20,530,077	0	20,530,077
11	Cash Working Capital	B-6	0	(3,364,662)	(3,364,662)
	NON-INVESTOR SUPPLIED FUNDS				
12	Customer Deposits	B-7	(6,613,930)	0	(6,613,930)
13	Customer Advances	B-8	(5,170,456)	0	(5,170,456)
14	Accumulated Deferred Taxes	B-9	(79,319,324)	0	(79,319,324)
15	Excess Deferred Income Taxes	B-10	0	(14,634,668)	(14,634,668)
16	Total Rate Base		$833,181,714	$(19,933,007)	$813,248,707

WKP B.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUMMARY OF PLANT ADJUSTMENTS

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	ADJUSTED TEST YEAR
			(a)	(b)	(c)
1	PLANT IN SERVICE	Schedule C	$1,009,354,909		$1,006,605,719
2	Excludable Meals and Hotel	WKP C.a, C.b and C.c		(19,067)	
3	Plant Miscoded to Service Area	WKP C.a		(412,459)	
4	Assets that are Fully Retired/Amortized as of 12/31/2023	WKP C.a		(57,905)	
5	TGS Direct Post Test Year Adjustment to include plant	WKP C.a		0	
6	Remove Asset Not Used by Division	WKP C.b		(362)	
7	Remove Assets with Insufficient Documentation	WKP C.b, C.c		(246,634)	
8	Remove Duplicate Vertex Sales Tax	WKP C.b, C.c		(12,953)	
9	Include TGS Division Costs Miscoded to Direct	WKP C.b		12,532	
10	Remove Miscoded Charges	WKP C.c		(1,694)	
11	Remove Artwork	WKP C.c		(6,650)	
12	Remove ONE Gas Aviation	WKP C.c		(1,868,777)	
13	Remove Direct Specific Project	WKP C.c		(46,537)	
14	Remove ONE Gas Foundation Software	WKP C.c		(10,568)	
15	Remove ONE Gas Lease Incentive	WKP C.c		(78,023)	
16	Reclass Activity	WKP C.c		(94)	
17	ONE Gas Post Test Year Adjustment to include plant	WKP C.b, C.c		0	
18	Removal of Retiring Asset	WKP C.a, C.b		0	
19	Total		$1,009,354,909	$(2,749,190)	$1,006,605,719
20	COMPLETED CONSTRUCTION NOT CLASSIFIED	Schedule C-1	$117,582,375		$117,476,238
21	Excludable Meals and Hotel	WKP C-1.a and C-1.c		$(4,027)	
22	TGS Direct Post Test Year Adjustment to include plant	WKP C-1.a and C-1.c		0	
23	Plant Miscoded to Service Area	WKP C-1.a		40,082	
24	Remove TGS Direct Costs Miscoded to Division	WKP C-1.b		(110,790)	
25	Remove Duplicate Vertex Sales Tax	WKP C-1.c		(302)	
26	Remove Artwork	WKP C-1.c		(280)	
27	Remove Direct Specific Project	WKP C-1.c		(17,599)	
28	Remove Miscoded Charges	WKP C-1.c		(13,174)	
29	Remove Assets with Insufficient Documentation	WKP C-1.c		(141)	
30	Reclass Activity	WKP C-1.c		94	
31	Total		$117,582,375	$(106,137)	$117,476,238
32	ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION	Schedule D	$(242,592,609)		$(240,427,405)
33	Plant Miscoded to Service Area	WKP D.a		$8,462	
34	Removal of Retiring Asset	WKP D.a, D.b		0	
35	Assets that are Fully Retired/Amortized as of 12/31/2023	WKP D.a		57,905	
36	TGS Direct Post Test Year Adjustment to include reserve	WKP D.a		0	
37	Asset Not Used by TGS Division	WKP D.b		353	
38	Asset with Insufficient Documentation	WKP D.b		229,831	
39	Remove TGS Direct Costs Miscoded to Division	WKP D.b		1,421	
40	Remove Land Depreciation	WKP D.b		2,024	
41	Include TGS Division Costs Miscoded to Direct	WKP D.b		(2,100)	
42	Remove Artwork	WKP D.c		2,836	
43	Remove ONE Gas Aviation	WKP D.c		1,827,102	
44	Remove ONE Gas Foundation Software	WKP D.c		3,577	
45	Remove ONE Gas Lease Incentive	WKP D.c		30,905	
46	Remove Direct Specific Project	WKP D.c		1,659	

47	Remove Miscoded Charges	WKP D.c		1,229	
48	Total		$(242,592,609)	$2,165,203	$(240,427,405)

SCHEDULE B-1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

MATERIALS AND SUPPLIES

LINE NO.	DESCRIPTION	DIRECT INVENTORY	DIRECT STORES LOAD	OMA INVENTORY	TOTAL
		(a)	(b)	(c)	(d)
1	December 31, 2022	$7,988,695	$24,573	$2,058,544	$10,071,812
2	January 30, 2023	8,132,199	68,294	1,836,082	10,036,574
3	February 28, 2023	8,145,954	163,482	2,059,255	10,368,690
4	March 31, 2023	9,055,445	213,307	2,047,506	11,316,258
5	April 30, 2023	8,891,293	209,134	2,125,689	11,226,115
6	May 31, 2023	9,222,355	182,012	1,939,113	11,343,480
7	June 30, 2023	9,682,595	16,499	1,816,193	11,515,287
8	July 31, 2023	10,070,375	64,719	1,888,300	12,023,394
9	August 31, 2023	10,987,834	49,932	1,772,871	12,810,638
10	September 30, 2023	10,845,843	216	2,099,027	12,945,086
11	October 31, 2023	10,802,630	62,675	2,033,678	12,898,983
12	November 30, 2023	10,667,310	(22,688)	2,109,459	12,754,081
13	December 31, 2023	10,891,240	(21,693)	2,049,231	12,918,778
14	13 Month Average	$9,644,905	$77,728	$1,987,304	$11,709,937

Source: SCH B-1 TGS Materials and Supplies.xlsx

Source: SCH B-1 Stores Balances.xlsx

Source: SCH B-1 Corporate Materials and Supplies.xlsx

SCHEDULE B-2

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

PREPAYMENTS

LINE NO.	DESCRIPTION	DIRECT	TGS DIVISION	CORPORATE	TOTAL
		(a)	(b)	(c)	(d)
1	December 31, 2022	$0	$4,798,303	$21,563,695	
2	January 30, 2023	0	4,352,782	23,603,862	
3	February 28, 2023	0	3,842,339	25,062,259	
4	March 31, 2023	0	3,367,634	25,023,999	
5	April 30, 2023	0	2,871,689	23,593,445	
6	May 31, 2023	0	3,083,987	24,920,131	
7	June 30, 2023	0	2,588,808	26,825,938	
8	July 31, 2023	0	2,111,927	26,646,500	
9	August 31, 2023	0	1,628,821	26,079,127	
10	September 30, 2023	0	1,157,505	23,784,804	
11	October 31, 2023	0	676,793	24,469,998	
12	November 30, 2023	0	5,422,288	24,435,534	
13	December 31, 2023	0	4,929,481	25,318,550	
14	13 Month Average	$0	$3,140,951	$24,717,526	
15	Allocation Factor to TGS	100.0000%	100.0000%	28.7400%	
16	Allocation Factor to Service Area	100.0000%	46.7362%	46.7362%	
17	Total Allocated Prepayments	$0	$1,467,961	$3,320,054	$4,788,015

WKP B-2.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

PREPAYMENTS - TGS DIVISION

LINE NO.	MONTH/YEAR ENDING	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
	(a)	(b)	(c)	(d) = (b)+(c)
1	December 31, 2022	$4,798,303	$0	$4,798,303
2	January 30, 2023	4,352,782	0	4,352,782
3	February 28, 2023	3,842,339	0	3,842,339
4	March 31, 2023	3,367,634	0	3,367,634
5	April 30, 2023	2,871,689	0	2,871,689
6	May 31, 2023	3,083,987	0	3,083,987
7	June 30, 2023	2,588,808	0	2,588,808
8	July 31, 2023	2,111,927	0	2,111,927
9	August 31, 2023	1,628,821	0	1,628,821
10	September 30, 2023	1,157,505	0	1,157,505
11	October 31, 2023	676,793	0	676,793
12	November 30, 2023	5,422,288	0	5,422,288
13	December 31, 2023	4,929,481	0	4,929,481
14	13-Month Average	$3,140,951	$0	$3,140,951
15	Allocation Factor to TGS	100.0000%	100.0000%	100.0000%
16	Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%
17	Total Allocated Prepayments	$1,467,961	$0	$1,467,961

Source: WKP B-2.a.1 Prepayments - TGS Division Detail (CONFIDENTIAL).xlsx

WKP B-2.b.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PREPAYMENTS - CORPORATE ALLOCATED THROUGH DISTRIGAS

LINE NO.	MONTH/YEAR ENDING	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
	(a)	(b)	(c)	(d) = (b)+(c)
1	December 31, 2022	$21,650,048	$(86,353)	$21,563,695
2	January 30, 2023	23,783,957	(180,095)	23,603,862
3	February 28, 2023	25,890,034	(827,776)	25,062,259
4	March 31, 2023	25,058,641	(34,642)	25,023,999
5	April 30, 2023	23,847,176	(253,731)	23,593,445
6	May 31, 2023	25,149,087	(228,956)	24,920,131
7	June 30, 2023	27,331,527	(505,589)	26,825,938
8	July 31, 2023	27,127,320	(480,819)	26,646,500
9	August 31, 2023	26,233,773	(154,646)	26,079,127
10	September 30, 2023	23,918,401	(133,597)	23,784,804
11	October 31, 2023	24,632,497	(162,499)	24,469,998
12	November 30, 2023	24,603,906	(168,372)	24,435,534
13	December 31, 2023	25,460,971	(142,421)	25,318,550
14	13-Month Average	$24,975,949	$(258,423)	$24,717,526
15	Pro Forma, Q1 2024, Allocation Factor to TGS	28.7400%	28.7400%	28.7400%
16	13-Month Average Allocated to TGS	$7,178,088	$(74,271)	$7,103,817
17	Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%
18	Total Allocated Prepayments	$3,354,765	$(34,711)	$3,320,054

Source: WKP B-2.b.1 Prepayments - ONE Gas Corp Detail (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	FERC ACCOUNT	TEST YEAR ACCRUAL	ADJUSTMENT TO ACCRUAL	TOTAL ACCRUAL
		(a)	(b)	(c)
1	(367.0) Mains	$0		$0
2	(371) Other Transmission System	0		0
3	(374.2) Land Rights	140		140
4	(376) Mains	631,986		631,986
5	(376.9) Cathodic Protection Anodes	35,295		35,295
6	(378) Meas & Reg Station -General	10,985		10,985
7	(379) Meas & Reg Station -City	2,339		2,339
8	(380) Services	1,176,963		1,176,963
9	(380.1) Ind Service Line Equip	218		218
10	(380.2) Comm Service Line Equip	321.42		321
11	(380.4) Yard Lines-Customer Svc	(6,339)		(6,339)
12	(381) Meters	(3,724)		(3,724)
13	(382) Meter Installations	197		197
14	(383) House Regulators	230		230
15	(385) Ind Meas & Reg Sta Equip	62		62
16	(394.1) Tools	0		0
17	(397) Communication Equipment	0		0
18	Total	$1,848,673	$0	$1,848,673

Source: SCH B-3 Rule 8.209 Accrual.xlsx

WKP B-3.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	091.053.7202.005100	CENTRAL-GULF	$36,407	$19,950	$169,354	$165,761	$391,472
2	091.053.7202.010517	CENTRAL-GULF	(253)	160	1,360	1,331	2,597
3	091.053.7202.010534	CENTRAL-GULF	(1,219)	640	5,431	5,316	10,168
4	091.053.7202.010563	CENTRAL-GULF	3	1	11	11	25
5	091.053.7202.010564	CENTRAL-GULF	1	0	3	3	7
6	091.053.7202.010568	CENTRAL-GULF	0	0	0	0	0
7	091.053.7202.010595	CENTRAL-GULF	629	185	1,573	1,540	3,928
8	091.053.7202.010742	CENTRAL-GULF	(118)	448	3,801	3,721	7,852
9	091.053.7202.010798	CENTRAL-GULF	(5)	0	3	3	1
10	091.053.7202.010827	CENTRAL-GULF	1,125	402	3,417	3,344	8,288
11	091.053.7202.010846	CENTRAL-GULF	53	26	222	217	517
12	091.053.7202.010849	CENTRAL-GULF	262	60	507	497	1,325
13	091.053.7202.010863	CENTRAL-GULF	1,236	391	3,322	3,252	8,201
14	091.053.7202.010877	CENTRAL-GULF	170	199	1,691	1,656	3,716
15	091.053.7202.010879	CENTRAL-GULF	588	241	2,049	2,005	4,883
16	091.053.7202.010916	CENTRAL-GULF	70	32	270	265	637
17	091.053.7202.010925	CENTRAL-GULF	3	1	7	7	18
18	091.053.7202.010926	CENTRAL-GULF	13	8	72	70	163
19	091.053.7292.005100	CENTRAL-GULF	0	0	0	0	0
20	091.053.7300.010028	CENTRAL-GULF	97	8	64	63	231
21	091.053.7301.005100	CENTRAL-GULF	1	0	3	3	6
22	091.053.7302.005100	CENTRAL-GULF	0	0	0	0	0
23	091.053.7303.005100	CENTRAL-GULF	0	0	0	0	0
24	091.053.7304.005100	CENTRAL-GULF	0	0	0	0	0
25	091.053.7306.005100	CENTRAL-GULF	(0)	0	(0)	(0)	(0)
26	091.053.7307.005100	CENTRAL-GULF	0	0	0	0	0
27	091.053.7308.005100	CENTRAL-GULF	(0)	0	(0)	(0)	(0)
28	091.053.7450.005100	CENTRAL-GULF	331	187	1,590	1,556	3,664
29	091.053.7550.005100	CENTRAL-GULF	623	413	3,502	3,428	7,965
30	091.053.7550.010082	CENTRAL-GULF	26	16	136	133	310
31	091.054.7202.005100	CENTRAL-GULF	54,494	31,276	265,501	259,867	611,138
32	091.054.7202.011065	CENTRAL-GULF	(0)	10	85	83	178
33	091.054.7202.011164	CENTRAL-GULF	168	112	1,024	933	2,237
34	091.054.7202.011200	CENTRAL-GULF	176	32	275	270	753
35	091.054.7202.011271	CENTRAL-GULF	0	1	12	11	24
36	091.054.7202.011286	CENTRAL-GULF	9	87	739	723	1,558
37	091.054.7202.011289	CENTRAL-GULF	1,765	664	5,641	5,521	13,591
38	091.054.7202.011324	CENTRAL-GULF	(47)	256	2,177	2,130	4,516

WKP B-3.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
39	091.054.7202.011341	CENTRAL-GULF	6,264	3,535	30,007	29,370	69,176
40	091.054.7202.011351	CENTRAL-GULF	(17)	135	1,147	1,123	2,389
41	091.054.7202.011354	CENTRAL-GULF	(2)	0	0	0	(2)
42	091.054.7202.011355	CENTRAL-GULF	(1)	17	146	143	305
43	091.054.7202.011362	CENTRAL-GULF	(16)	364	3,087	3,021	6,457
44	091.054.7202.011368	CENTRAL-GULF	459	188	1,599	1,565	3,812
45	091.054.7202.011369	CENTRAL-GULF	405	168	1,425	1,395	3,393
46	091.054.7202.011374	CENTRAL-GULF	914	353	2,993	2,929	7,188
47	091.054.7202.011375	CENTRAL-GULF	(19)	73	616	603	1,272
48	091.054.7202.011387	CENTRAL-GULF	148	44	371	363	925
49	091.054.7202.011388	CENTRAL-GULF	1,792	673	5,715	5,594	13,774
50	091.054.7202.011389	CENTRAL-GULF	(0)	13	107	105	225
51	091.054.7202.011392	CENTRAL-GULF	(0)	4	33	33	70
52	091.054.7202.011393	CENTRAL-GULF	426	215	1,828	1,790	4,260
53	091.054.7202.011400	CENTRAL-GULF	73	19	158	155	405
54	091.054.7202.011402	CENTRAL-GULF	529	145	1,229	1,203	3,105
55	091.054.7202.011403	CENTRAL-GULF	931	348	2,951	2,888	7,117
56	091.054.7202.011404	CENTRAL-GULF	653	93	794	777	2,317
57	091.054.7202.011405	CENTRAL-GULF	202	55	468	458	1,183
58	091.054.7202.011409	CENTRAL-GULF	399	156	1,324	1,296	3,176
59	091.054.7202.011410	CENTRAL-GULF	574	192	1,633	1,598	3,997
60	091.054.7202.011411	CENTRAL-GULF	273	112	953	933	2,272
61	091.054.7202.011412	CENTRAL-GULF	348	87	737	721	1,893
62	091.054.7202.011413	CENTRAL-GULF	1,055	611	5,190	5,080	11,936
63	091.054.7202.011414	CENTRAL-GULF	365	120	1,021	1,000	2,506
64	091.054.7202.011416	CENTRAL-GULF	6	2	19	19	46
65	091.054.7202.011417	CENTRAL-GULF	319	91	773	757	1,941
66	091.054.7202.011418	CENTRAL-GULF	223	60	511	500	1,295
67	091.054.7202.011419	CENTRAL-GULF	10,172	4,810	40,829	39,963	95,773
68	091.054.7202.011420	CENTRAL-GULF	826	95	804	786	2,511
69	091.054.7202.011422	CENTRAL-GULF	559	195	1,659	1,623	4,036
70	091.054.7202.011424	CENTRAL-GULF	420	160	1,357	1,328	3,264
71	091.054.7202.011427	CENTRAL-GULF	1,609	596	5,059	4,952	12,216
72	091.054.7202.011428	CENTRAL-GULF	280	370	3,140	3,073	6,863
73	091.054.7202.011429	CENTRAL-GULF	173	13	111	109	407
74	091.054.7202.011430	CENTRAL-GULF	1,125	500	4,244	4,154	10,022
75	091.054.7202.011431	CENTRAL-GULF	2,482	1,189	10,097	9,883	23,651
76	091.054.7202.011432	CENTRAL-GULF	5,440	2,554	21,679	21,219	50,892

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
77	091.054.7202.011433	CENTRAL-GULF	16	6	48	47	117
78	091.054.7202.011434	CENTRAL-GULF	255	19	164	160	598
79	091.054.7202.011435	CENTRAL-GULF	472	132	1,122	1,098	2,824
80	091.054.7202.011436	CENTRAL-GULF	133	10	85	84	312
81	091.054.7202.011437	CENTRAL-GULF	1,689	961	8,162	7,989	18,801
82	091.054.7202.011440	CENTRAL-GULF	1,654	665	5,648	5,529	13,497
83	091.054.7202.011441	CENTRAL-GULF	94	34	290	284	702
84	091.054.7202.011442	CENTRAL-GULF	4	47	397	388	836
85	091.054.7202.011445	CENTRAL-GULF	617	103	870	852	2,441
86	091.054.7202.011446	CENTRAL-GULF	2,659	1,040	8,825	8,637	21,161
87	091.054.7202.011447	CENTRAL-GULF	7	3	26	25	61
88	091.054.7202.011450	CENTRAL-GULF	191	24	201	196	612
89	091.054.7202.011451	CENTRAL-GULF	10	4	30	29	72
90	091.054.7202.011452	CENTRAL-GULF	178	86	732	716	1,713
91	091.054.7202.011453	CENTRAL-GULF	4,002	1,530	12,991	12,715	31,238
92	091.054.7202.011454	CENTRAL-GULF	756	115	975	954	2,800
93	091.054.7202.011455	CENTRAL-GULF	161	61	518	507	1,248
94	091.054.7202.011457	CENTRAL-GULF	896	313	2,659	2,602	6,471
95	091.054.7202.011458	CENTRAL-GULF	356	85	718	703	1,863
96	091.054.7202.011459	CENTRAL-GULF	279	61	516	505	1,361
97	091.054.7202.011460	CENTRAL-GULF	2,812	844	7,164	7,012	17,833
98	091.054.7202.011461	CENTRAL-GULF	1,781	681	5,783	5,660	13,905
99	091.054.7202.011463	CENTRAL-GULF	4	2	14	13	33
100	091.054.7202.011464	CENTRAL-GULF	443	185	1,571	1,538	3,737
101	091.054.7202.011465	CENTRAL-GULF	150	12	103	101	365
102	091.054.7202.011468	CENTRAL-GULF	1,076	428	3,630	3,553	8,686
103	091.054.7202.011469	CENTRAL-GULF	2,913	616	5,227	5,116	13,872
104	091.054.7202.011472	CENTRAL-GULF	761	194	1,649	1,614	4,219
105	091.054.7202.011473	CENTRAL-GULF	283	111	943	923	2,261
106	091.054.7202.011475	CENTRAL-GULF	275	145	1,230	1,204	2,854
107	091.054.7202.011476	CENTRAL-GULF	212	64	542	531	1,349
108	091.054.7202.011477	CENTRAL-GULF	86	67	568	556	1,277
109	091.054.7202.011481	CENTRAL-GULF	1,186	244	2,071	2,027	5,527
110	091.054.7202.011482	CENTRAL-GULF	5,769	2,275	19,313	18,903	46,259
111	091.054.7202.011483	CENTRAL-GULF	1,656	566	4,808	4,706	11,736
112	091.054.7202.011485	CENTRAL-GULF	297	109	926	906	2,239
113	091.054.7202.011486	CENTRAL-GULF	388	112	950	930	2,380
114	091.054.7202.011488	CENTRAL-GULF	996	436	3,698	3,620	8,750

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
115	091.054.7202.011489	CENTRAL-GULF	408	109	927	907	2,351
116	091.054.7202.011491	CENTRAL-GULF	696	161	1,363	1,334	3,553
117	091.054.7202.011492	CENTRAL-GULF	1,244	504	4,276	4,186	10,209
118	091.054.7202.011493	CENTRAL-GULF	424	156	1,321	1,293	3,193
119	091.054.7202.011499	CENTRAL-GULF	245	71	599	587	1,502
120	091.054.7202.011502	CENTRAL-GULF	421	131	1,114	1,090	2,756
121	091.054.7202.011503	CENTRAL-GULF	107	83	703	688	1,581
122	091.054.7202.011507	CENTRAL-GULF	505	209	1,773	1,735	4,221
123	091.054.7202.011508	CENTRAL-GULF	15	6	54	53	129
124	091.054.7202.011509	CENTRAL-GULF	161	55	469	459	1,145
125	091.054.7202.011511	CENTRAL-GULF	276	116	985	964	2,341
126	091.054.7202.011513	CENTRAL-GULF	340	144	1,219	1,193	2,896
127	091.054.7202.011514	CENTRAL-GULF	113	50	421	412	996
128	091.054.7202.011516	CENTRAL-GULF	249	105	887	868	2,109
129	091.054.7202.011517	CENTRAL-GULF	327	123	1,041	1,019	2,509
130	091.054.7202.011518	CENTRAL-GULF	6	3	22	22	53
131	091.054.7202.011521	CENTRAL-GULF	0	0	1	1	3
132	091.054.7202.011522	CENTRAL-GULF	38	15	127	124	304
133	091.054.7202.011523	CENTRAL-GULF	24	10	87	85	206
134	091.054.7202.011524	CENTRAL-GULF	69	29	249	244	592
135	091.054.7202.011528	CENTRAL-GULF	16	7	56	55	133
136	091.054.7202.011529	CENTRAL-GULF	98	23	198	194	514
137	091.054.7202.011531	CENTRAL-GULF	270	127	1,077	1,054	2,528
138	091.054.7202.011538	CENTRAL-GULF	113	24	200	195	531
139	091.054.7202.011539	CENTRAL-GULF	118	51	436	427	1,033
140	091.054.7202.011544	CENTRAL-GULF	32	14	121	118	286
141	091.054.7202.011547	CENTRAL-GULF	136	23	199	194	552
142	091.054.7202.011548	CENTRAL-GULF	27	3	29	28	87
143	091.054.7202.011550	CENTRAL-GULF	17	12	104	102	236
144	091.054.7202.011553	CENTRAL-GULF	0	0	1	1	2
145	091.054.7202.011557	CENTRAL-GULF	32	5	46	45	128
146	091.054.7202.011559	CENTRAL-GULF	7	5	45	44	100
147	091.054.7300.010051	CENTRAL-GULF	42	14	123	120	300
148	091.054.7300.010052	CENTRAL-GULF	(97)	8	67	66	44
149	091.054.7300.010054	CENTRAL-GULF	(4)	2	15	14	27
150	091.054.7300.010056	CENTRAL-GULF	(0)	1	5	5	10
151	091.054.7300.010057	CENTRAL-GULF	275	97	823	806	2,001
152	091.054.7300.010058	CENTRAL-GULF	1,410	582	4,940	4,836	11,768

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
153	091.054.7300.010059	CENTRAL-GULF	1,624	657	5,573	5,455	13,308
154	091.054.7300.010061	CENTRAL-GULF	257	21	176	172	626
155	091.054.7300.010063	CENTRAL-GULF	228	69	586	574	1,457
156	091.054.7300.010064	CENTRAL-GULF	173	71	599	586	1,428
157	091.054.7300.010066	CENTRAL-GULF	13	11	89	87	200
158	091.054.7301.005100	CENTRAL-GULF	(0)	(0)	(1)	(1)	(2)
159	091.054.7302.005100	CENTRAL-GULF	0	0	1	1	3
160	091.054.7303.005100	CENTRAL-GULF	4	1	11	11	27
161	091.054.7304.005100	CENTRAL-GULF	1	0	2	2	5
162	091.054.7306.005100	CENTRAL-GULF	0	0	1	1	2
163	091.054.7307.005100	CENTRAL-GULF	1	0	1	1	3
164	091.054.7308.005100	CENTRAL-GULF	0	0	0	0	1
165	091.054.7450.005100	CENTRAL-GULF	223	146	1,241	1,215	2,825
166	091.054.7450.010097	CENTRAL-GULF	20	2	14	13	49
167	091.054.7450.010098	CENTRAL-GULF	18	1	12	12	44
168	091.054.7450.010099	CENTRAL-GULF	31	13	111	108	263
169	091.054.7450.010100	CENTRAL-GULF	4	3	21	21	49
170	091.054.7501.005100	CENTRAL-GULF	1	0	2	2	4
171	091.054.7502.005100	CENTRAL-GULF	1	0	3	3	7
172	091.054.7503.005100	CENTRAL-GULF	1	0	2	1	4
173	091.054.7550.005100	CENTRAL-GULF	2,723	1,577	13,386	13,102	30,787
174	091.054.7550.010344	CENTRAL-GULF	0	(0)	(2)	(2)	(3)
175	091.054.7550.010379	CENTRAL-GULF	0	1	8	8	17
176	091.054.7550.010396	CENTRAL-GULF	(12)	19	160	156	323
177	091.054.7550.010403	CENTRAL-GULF	88	49	417	408	961
178	091.054.7550.010404	CENTRAL-GULF	98	24	205	201	527
179	091.054.7550.010405	CENTRAL-GULF	60	26	217	213	516
180	091.054.7550.010406	CENTRAL-GULF	76	18	155	152	402
181	091.054.7550.010407	CENTRAL-GULF	85	29	246	241	601
182	091.054.7550.010408	CENTRAL-GULF	164	30	251	245	690
183	091.054.7550.010409	CENTRAL-GULF	97	46	395	386	924
184	091.054.7550.010410	CENTRAL-GULF	156	59	504	493	1,212
185	091.054.7550.010413	CENTRAL-GULF	129	42	360	352	883
186	091.054.7550.010414	CENTRAL-GULF	257	152	1,286	1,259	2,953
187	091.054.7550.010415	CENTRAL-GULF	87	18	156	153	415
188	091.054.7550.010416	CENTRAL-GULF	85	24	203	199	511
189	091.054.7550.010417	CENTRAL-GULF	87	23	194	190	494
190	091.054.7550.010418	CENTRAL-GULF	62	16	140	137	356

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RULE 8.209 REGULATORY ASSET

LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
191	091.054.7550.010419	CENTRAL-GULF	100	25	211	206	543
192	091.054.7550.010420	CENTRAL-GULF	178	50	427	418	1,073
193	091.054.7550.010421	CENTRAL-GULF	63	19	162	159	404
194	091.054.7550.010422	CENTRAL-GULF	229	62	527	516	1,334
195	091.054.7550.010423	CENTRAL-GULF	226	85	722	706	1,739
196	091.054.7550.010424	CENTRAL-GULF	316	72	609	597	1,594
197	091.054.7550.010425	CENTRAL-GULF	15	6	48	47	116
198	091.054.7550.010426	CENTRAL-GULF	157	66	559	547	1,330
199	091.054.7550.010427	CENTRAL-GULF	35	15	127	124	301
200	091.054.7550.010428	CENTRAL-GULF	34	4	36	35	109
201	091.054.7550.010429	CENTRAL-GULF	78	21	178	174	451
202	091.054.7550.010430	CENTRAL-GULF	30	12	98	96	236
203	091.054.7550.010431	CENTRAL-GULF	64	15	127	125	331
204	091.054.7550.010432	CENTRAL-GULF	162	62	526	515	1,266
		Total	$188,201	$93,291	$792,028	$775,152	$1,848,673

Source: SCH B-3 Rule 8.209 Accrual.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PENSION AND OTHER POST EMPLOYMENT BENEFITS REGULATORY ASSET

LINE NO.	DESCRIPTION	FERC ACCOUNT	REFERENCE	AMOUNT
				(a)
1	Deferred Pension Regulatory Asset	1823	WKP B-4.a	$799,656
2	Reg Assets Def OPEB Recovery	1823	WKP B-4.a	(3,090)
3	Regulatory Assets Proforma Amortization January 2024 Through November 2024	4073		(282,652)
4	Deferred Pension and OPEB since last rate cases	1860		(3,829,114)
5	Total			$(3,315,201)

Source: SCH B-4 Trial Balance Pension OPEB Deferral.xlsx

WKP B-4.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PENSION AND OTHER POST EMPLOYMENT BENEFITS REGULATORY ASSET

PENSION

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2020	2021	2022	2023	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	1823	January	Reg Assets Def Pension Recovery	$0	$(25,795)	$(25,795)	$(25,795)	$(77,386)
2	1823	February	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(25,795)	(77,386)
3	1823	March	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(25,795)	(77,386)
4	1823	April	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(25,795)	(77,386)
5	1823	May	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(25,795)	(77,386)
6	1823	June	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(25,795)	(77,386)
7	1823	July	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(25,795)	(77,386)
8	1823	August	Reg Assets Def Pension Recovery	1,831,471	(25,795)	(25,795)	(25,795)	1,754,085
9	1823	September	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(25,795)	(103,181)
10	1823	October	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(25,795)	(103,181)
11	1823	November	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(25,795)	(103,181)
12	1823	December	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(25,795)	(103,181)
13			Total	$1,728,290	$(309,544)	$(309,544)	$(309,544)	$799,656

OPEB

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2020	2021	2022	2023	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
14	1823	January	Reg Assets Def OPEB Recovery	$0	$100	$100	$100	$299
15	1823	February	Reg Assets Def OPEB Recovery	0	100	100	100	299
16	1823	March	Reg Assets Def OPEB Recovery	0	100	100	100	299
17	1823	April	Reg Assets Def OPEB Recovery	0	100	100	100	299
18	1823	May	Reg Assets Def OPEB Recovery	0	100	100	100	299
19	1823	June	Reg Assets Def OPEB Recovery	0	100	100	100	299
20	1823	July	Reg Assets Def OPEB Recovery	0	100	100	100	299
21	1823	August	Reg Assets Def OPEB Recovery	(7,078)	100	100	100	(6,779)
22	1823	September	Reg Assets Def OPEB Recovery	100	100	100	100	399
23	1823	October	Reg Assets Def OPEB Recovery	100	100	100	100	399
24	1823	November	Reg Assets Def OPEB Recovery	100	100	100	100	399
25	1823	December	Reg Assets Def OPEB Recovery	100	100	100	100	399
26			Total	$(6,679)	$1,196	$1,196	$1,196	$(3,090)
27			Total Pension and OPEB	$1,721,610	$(308,348)	$(308,348)	$(308,348)	$796,566

Source: WKP B-4.a Deferred Pension OPEB Recovery.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

PREPAID PENSION ASSET

LINE NO.	DESCRIPTION	PREPAID PENSION BALANCE
	(a)	(b)
1	Prepaid Pension Asset - TGS	$43,927,569
2	Allocation to Service Area	46.74%
3	Prepaid Pension Asset - CGSA	$20,530,077

Source: SCH B-5 Prepaid Pension Asset.xlsx

SCHEDULE B-6

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CASH WORKING CAPITAL

LINE NO.	DESCRIPTION	TEST YEAR AMOUNT	AVERAGE DAILY AMOUNT	REVENUE LAG	REFERENCE	EXPENSE LAG	REFERENCE	NET (LEAD)/LAG DAYS	WORKING CAPITAL REQUIREMENT
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Operations and Maintenance Expenses								
2	Purchased Gas Costs	$93,904,159	$257,272	45.47	A	(40.63)	B	4.84	$1,245,941
3	Labor - Regular Payroll Expense	30,175,452	82,672	45.47	A	(27.70)	C	17.78	1,469,528
4	Labor - STI Expense	4,795,187	13,137	45.47	A	(242.92)	C	(197.44)	(2,593,929)
5	Non-Labor - Other O&M Expense	33,052,129	90,554	45.47	A	(39.20)	C	6.28	568,243
6	Total O&M Expenses	$161,926,926	$443,635						$689,783
7	Federal Income Taxes								
8	Current Income Taxes	$13,227,540	$36,240	45.47	A	(37.00)	D	8.47	$307,024
9	Deferred Income Taxes	0	0	0.00		0.00		0.00	0
10	Total Federal Income Taxes	$13,227,540	$36,240						$307,024
11	Taxes Other Than Income Taxes								
12	FICA	$2,123,262	$5,817	45.47	A	(12.61)	E	32.87	$191,188
13	Federal Unemployment	16,230	44	45.47	A	(30.01)	E	15.46	687
14	State Unemployment	66,940	183	45.47	A	(113.17)	E	(67.70)	(12,415)
15	State Gross Receipts	4,283,705	11,736	45.47	A	(77.00)	E	(31.53)	(370,059)
16	Local Franchise Tax	11,356,894	31,115	45.47	A	(93.29)	E	(47.82)	(1,487,909)
17	State Franchise Tax	576,902	1,581	45.47	A	47.71	E	93.18	147,276
18	Ad Valorem	6,947,490	19,034	45.47	A	(196.17)	E	(150.70)	(2,868,409)
19	Sales Tax	5,818,131	15,940	45.47	A	(35.88)	E	9.59	152,908
20	RRC Gas Utility Tax	54,341	149	45.47	A	(86.81)	E	(41.34)	(6,155)
21	Taxes Other Than Income Taxes	$31,243,896	$85,600		A				$(4,252,887)
22	Interest on Customer Deposits	$321,437	$881	45.47	A	(168.77)	F	(123.30)	$(108,582)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CASH WORKING CAPITAL

LINE NO.	DESCRIPTION	TEST YEAR AMOUNT	AVERAGE DAILY AMOUNT	REVENUE LAG	REFERENCE	EXPENSE LAG	REFERENCE	NET (LEAD)/LAG DAYS	WORKING CAPITAL REQUIREMENT
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
23	Labor - LTI Expense	$935,345	$2,563	0.00		0.00		0.00	$0
24	Depreciation Expense	$34,876,287	$95,551	0.00		0.00		0.00	$0
25	Return	$64,093,722	$175,599	0.00		0.00		0.00	$0
26	Total	$306,625,153	$837,506						$(3,364,662)

Source: SCH B-6 CWC Tax
SCH B-6 Texas Gas Service Lead-Lag Study

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
1	7202 Austin - Incorporated	$4,840,864
2	7203 Sunset Valley - Incorporated	19,259
3	7204 Rollingwood - Incorporated	5,085
4	7205 West Lake Hills - Incorporated	14,498
5	7206 Cedar Park - Incorporated	26,038
6	7207 Aus Berg Intl Airport - Incorporated	7,780
7	7208 Austin - Environs	217,604
8	7209 West Lake Hills - Environs	2,815
9	7216 Cedar Park - Environs	11,652
10	7260 Lakeway - Incorporated	2,625
11	7262 Bee Cave - Incorporated	31,730
12	7263 Bee Cave - Environs	3,325
13	7292 Kyle - Incorporated	15,483
14	7293 Kyle - Environs	300
15	7294 Dripping Springs - Incorporated	12,561
16	7295 Dripping Springs - Environs	48,189
17	7297 Buda - Environs	33,032
18	7301 Yoakum - Incorporated	34,678
19	7302 Shiner - Incorporated	12,973
20	7303 Cuero - Incorporated	39,826
21	7304 Gonzales - Incorporated	44,556
22	7306 Luling - Incorporated	25,504
23	7307 Lockhart - Incorporated	59,540
24	7308 Nixon - Incorporated	5,875
25	7309 Nixon - Environs	500
26	7310 Yaokum - Environs	945
27	7312 Shiner - Environs	4,715
28	7313 Cuero - Environs	3,389
29	7314 Gonzales - Environs	1,005
30	7316 Luling - Environs	300
31	7317 Lockhart - Environs	100
32	7401 Jamaica Beach - Incorporated	4,681
33	7402 Bayou Vista - Incorporated	6,223
34	7412 Bayou Vista - Environs	1,150
35	7450 Galveston - Incorporated	344,477
36	7452 Galveston - Environs	250
37	7501 Groves - Incorporated	117,141
38	7502 Nederland - Incorporated	104,711
39	7503 Port Neches - Incorporated	64,679
40	7509 Beaumont - Incorporated	250
41	7512 Nederland - Environs	12,241
42	7550 Port Arthur - Incorporated	431,381
42	Total	$6,613,930

Source: SCH B-7 Customer Deposit Balances.xlsx

SCHEDULE B-8

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER ADVANCES

LINE NO.	FERC ACCOUNT	DESCRIPTION	ENDING BALANCE
			(a)
1	2520	LINE EXT DEPOSITS FORFEITED	$494,741
2	2520	LINE EXT DEPOSITS RECEIVED	4,908,594
3	2520	LINE EXT DEPOSITS RECEIVED	(1,072)
4	2520	LINE EXT DEPOSITS RECEIVED	(15,999,129)
5	2520	LINE EXT DEPOSITS REIMBURSED	5,671,349
6	2520	LINE EXT DEPOSITS RECEIVED	(23,050)
7	2520	LINE EXT DEPOSITS RECEIVED	(4,060)
8	2520	LINE EXT DEPOSITS RECEIVED	(10,049)
9	2520	LINE EXT DEPOSITS RECEIVED	(33,279)
10	2520	LINE EXT DEPOSITS RECEIVED	202,884
11	2520	LINE EXT DEPOSITS RECEIVED	(19,555)
12	2520	LINE EXT DEPOSITS RECEIVED	(2,787)
13	2520	LINE EXT DEPOSITS RECEIVED	(260,499)
14	2520	LINE EXT DEPOSITS RECEIVED	(75,400)
15	2520	LINE EXT DEPOSITS RECEIVED	(1,931)
16	2520	LINE EXT DEPOSITS RECEIVED	(15,065)
17	2520	LINE EXT DEPOSITS RECEIVED	(2,148)
18	2520	LINE EXT DEPOSITS RECEIVED	(3,333)
19	2520	LINE EXT DEPOSITS RECEIVED	3,333
20		Total	$(5,170,456)

Source: SCH B-8 Customer Advances Balances.xlsx

SCHEDULE B-9

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DECSCRIPTION	TOTAL ALLOCATED ADIT TO SERVICE AREA
		(a)
1	Central Gulf Service Area Plant Assets Depreciation	$(31,906,926)
2	Central Gulf Service Area Direct Plant Repairs	(62,005,198)
3	Subtotal CGSA Direct Plant Assets Depreciation	$(93,912,124)
4	Central Gulf Serivce Area Other Rate Base Items	(4,661,841)
5	TGS Division Plant Assets Depreciation	(659,027)
6	ONEGAS Plant Assets Depreciation	(2,631,536)
7	Central Gulf Service Area NOL	22,545,204
8	ADFIT - Accumulated Deferred Federal Income Taxes	$(79,319,324)

Source: SCH B-9 ADIT WPs 12.31.23
SCH B-9 Reg NOL WP 12.31.23

SCHEDULE B-10
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

UNAMORTIZED EXCESS ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DECSCRIPTION	PROTECTED (ARAM)	NON-PROTECTED (ARAM)	UNPROTECTED	REGULATORY LIABILITY	GROSS UP	REGULATORY LIABILITY WITH GROSS UP
		(a)	(b)	(c)	(d)	(e)	(f)
1	Central Gulf Service Area Plant Assets Depreciation	$(37,339,553)			$(37,339,553)		$(37,339,553)
2	Central Gulf Service Area Repairs			(10,622,000)	(10,622,000)		(10,622,000)
3	Central Gulf Service Area Cost of Removal Asset		3,375,204		3,375,204		3,375,204
4	Central Gulf Service Area Other Nonprotected plant				0		0
5	Central Gulf Service Area Other Rate Base Items			(3,136,047)	(3,136,047)		(3,136,047)
6	TGS Division Plant Assets Depreciation	(264,573)			(264,573)		(264,573)
7	ONEGas Plant Assets Depreciation	(1,542,000)			(1,542,000)		(1,542,000)
8	Central Gulf Service Area NOL	21,068,802			21,068,802		21,068,802
9	Total EDIT at December 31, 2017	$(18,077,324)	$3,375,204	$(13,758,047)	$(28,460,167)	$0	$(28,460,167)
10	Less 2018 Amortization				$3,413,044		$3,413,044
11	Less 2019 Amortization				3,195,749		3,195,749
12	Less 2020 Amortization				2,685,133		2,685,133
13	Less 2021 Amortization				3,631,834		3,631,834
14	Less 2022 Amortization				399,062		399,062
15	Less 2023 Amortization				500,677		500,677
16	Total EDIT at December 31, 2023	$0	$0	$0	$(14,634,668)	$0	$(14,634,668)

Source: SCH B-10 EDIT

SCHEDULE B-11
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

REG ASSETS

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Unamortized balance of Regulatory Assets from GUD No. 10526	$49,131
2	Less 11 mos. Amortization (line 23, January 2024 - November 2024) Note 1	(16,053)
3	Under-collection of rate case expense from GUD No. 10928	5,618
4	Deferred Winter Storm URI O&M	1,291,744
5	Winter Storm URI related STI	373,400
6	Covid related O&M	1,431,855
7	Regulatory Assets - Total	$3,135,695

Note 1: See data on SCH G-20

SCHEDULE C

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

TOTAL PLANT IN SERVICE - DIRECT AND ALLOCATED

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK ACCT 1010	ADJUSTMENTS ACCT 1010	TEST YEAR ADJUSTED ACCT 1010
			(a)	(b)	(c)
1	Service Area Direct Plant In Service	WKP C.a	$965,281,002	$(468,433)	$964,812,569
2	Allocated TGS Division Plant In Service	WKP C.b	5,416,589	(240,824)	5,175,765
3	Allocated Corporate Plant In Service	WKP C.c	38,657,318	(2,039,933)	36,617,385
4	Total Plant In Service		$1,009,354,909	$(2,749,190)	$1,006,605,719

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP C.a**

CENTRAL-GULF SERVICE AREA

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TWELVE MONTHS ENDED DECEMBER 31, 2023

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	FERC RECLASS	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		INTANGIBLE PLANT											
1	301	Organization	$56,257	$0	$0	$0	$0	$0	$0	$0	$56,257	$0	$56,257
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0
3	302	Franchises & Consents	393,474	0	0	0	0	0	0	0	393,474	0	393,474
4	303	Misc. Intangible	739,593	0	0	0	0	14,336	0	14,336	753,928	0	753,928
5	303	Misc. Intangible - OPC	14,336	0	0	0	0	(14,336)	0	(14,336)	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0
7		Total Intangible Plant	$1,203,659	$0	$0	$0	$0	$0	$0	$0	$1,203,659	$0	$1,203,659
		GATHERING AND TRANSMISSION PLANT											
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0	$0	$0	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0
18	365.1	Land - OPC	89,637	0	0	0	0	(89,637)	0	(89,637)	0	0	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0
20	365.2	Rights-of-Way - OPC	6,959	0	0	0	0	(6,959)	0	(6,959)	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
22	366.1	Compressor Station Structure - OPC	2,346	0	0	0	0	(2,346)	0	(2,346)	0	0	0
23	367	Mains	13,399,503	0	0	0	0	0	0	0	13,399,503	0	13,399,503
24	367	Mains - OPC	16,117,997	0	0	0	0	(16,117,997)	0	(16,117,997)	0	0	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
26	369	Meas & Reg Stations Equip	5,906,625	0	0	0	0	0	0	0	5,906,625	0	5,906,625
27	369	Meas & Reg Stations Equip - OPC	157,730	0	0	0	0	(157,730)	0	(157,730)	0	0	0
28	369.1	Measuring Stations Equip - OPC	828,741	0	0	0	0	(828,741)	0	(828,741)	0	0	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0
31		Total Gathering and Transmission Plant	$36,509,538	$0	$0	$0	$0	$(17,203,410)	$0	$(17,203,410)	$19,306,128	$0	$19,306,128
		DISTRIBUTION PLANT											
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	374.1	Land	19,503	0	0	0	0	89,637	0	89,637	109,140	0	109,140

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP C.a**
CENTRAL-GULF SERVICE AREA
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TWELVE MONTHS ENDED DECEMBER 31, 2023

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	FERC RECLASS	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
34	374.2	Land Rights	95,672	0	0	0	0	6,959	0	6,959	102,631	0	102,631
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	44,795	0	0	0	0	2,346	0	2,346	47,140	0	47,140
37	375.2	Other System Structures	4,141	0	0	0	0	0	0	0	4,141	0	4,141
38	376	Mains	377,005,703	0	0	0	6,819	16,117,997	0	16,124,816	393,130,519	0	393,130,519
39	376.9	Mains - Cathodic Protection Anodes	28,677,978	0	0	0	0	0	0	0	28,677,978	0	28,677,978
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	18,990,854	0	0	0	0	0	0	0	18,990,854	0	18,990,854
42	379	Meas. & Reg. Station - C.G.	4,008,083	0	0	0	0	986,471	0	986,471	4,994,554	0	4,994,554
43	380	Services	297,029,214	0	0	0	22	0	0	22	297,029,237	0	297,029,237
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0
45	380.2	Comm Service Line Equip	(0)	0	0	0	0	0	0	0	(0)	0	(0)
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0
47	381	Meters	81,187,711	0	0	0	0	0	0	0	81,187,711	0	81,187,711
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0
49	383	House Regulators	11,200,891	0	0	0	0	0	0	0	11,200,891	0	11,200,891
50	385	Indust. Meas. & Reg. Stat. Equipment	15,956,743	0	0	0	0	0	0	0	15,956,743	0	15,956,743
51	386	Other Property on Customer Premises	1,063,249	0	0	0	0	0	0	0	1,063,249	0	1,063,249
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
53		Total Distribution Plant	$835,284,538	$0	$0	$0	$6,841	$17,203,410	$0	$17,210,251	$852,494,788	$0	$852,494,788
		GENERAL PLANT											
54	389	Land & Land Rights	$8,347,674	$0	$0	$0	$0	$0	$0	$0	$8,347,674	$0	$8,347,674
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	24,010,665	0	0	0	0	0	0	0	24,010,665	0	24,010,665
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	57,905	0	0	0	0	0	(57,905)	(57,905)	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	2,439,314	0	0	(11)	0	0	0	(11)	2,439,302	0	2,439,302
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP C.a**
CENTRAL-GULF SERVICE AREA Return to Table of Contents
TWELVE MONTHS ENDED DECEMBER 31, 2023

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	FERC RECLASS	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0
84	391.9	Computer & Equipment	2,327,267	0	(48)	(363,818)	0	0	0	(363,865)	1,963,402	0	1,963,402
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0
86	392	Transportation Equipment	20,471,560	0	0	(53,493)	0	0	0	(53,493)	20,418,067	0	20,418,067
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0
91	393	Stores Equipment	5,387	0	0	0	0	0	0	0	5,387	0	5,387
92	394	Tools, Shop & Garage	11,597,087	0	0	0	0	0	0	0	11,597,087	0	11,597,087
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0
96	396	Major Work Equipment	3,190,938	0	0	0	0	0	0	0	3,190,938	0	3,190,938
97	397	Communication Equipment	19,829,123	0	0	0	0	0	0	0	19,829,123	0	19,829,123
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	6,349	0	0	0	0	0	0	0	6,349	0	6,349
100		Total General Plant	$92,283,267	$0	$(48)	$(417,322)	$0	$0	$(57,905)	$(475,274)	$91,807,993	$0	$91,807,993
101		Total Orig Cost Plant in Service	$965,281,002	$0	$(48)	$(417,322)	$6,841	$0	$(57,905)	$(468,433)	$964,812,569	$0	$964,812,569

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC.xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

WKP C.b

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PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE DUPLICATE VERTEX SALES TAX	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	REMOVE MEALS & HOTEL	REMOVE MISCODED CHARGES	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1010	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		INTANGIBLE PLANT													
1	301	Organization	$127,437	$0	$(127,437)	$0	$0	$0	$0	$0	$0	$0	$0	46.7362%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	$0	$0	$0	46.7362%	$0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	$0	$0	$0	46.7362%	$0
4	303	Misc. Intangible	278,560	0	$(278,560)	0	0	0	0	0	$0	$0	$0	46.7362%	$0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	$0	$0	$0	46.7362%	$0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
7		Total Intangible Plant	$405,997	$0	$(405,997)	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT													
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	46.7362%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT													
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	46.7362%	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE DUPLICATE VERTEX SALES TAX	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	REMOVE MEALS & HOTEL	REMOVE MISCODED CHARGES	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1010	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
53		Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT													
54	389	Land & Land Rights	$434,697	$0	$0	$0	$0	$0	$0	$0	$434,697	$0	$434,697	46.7362%	$203,161
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
56	390.1	Structures & Improvements	4,406,102	0	0	0	0	(492)	9	0	4,405,620	0	4,405,620	46.7362%	2,059,019
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
59	390.2	Leasehold Improvement	235,077	(774)	0	0	0	0	0	0	234,303	0	234,303	46.7362%	109,504
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
63	391.1	Office Furniture & Equipment	2,550,064	0	0	(8,657)	26,814	0	0	0	2,568,221	0	2,568,221	46.7362%	1,200,289
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
84	391.9	Computer & Equipment	2,706,698	0	(114,712)	(89)	0	(7,466)	(3,634)	0	2,580,798	0	2,580,798	46.7362%	1,206,167
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
92	394	Tools, Shop & Garage	28,756	0	0	0	0	(180)	0	0	28,576	0	28,576	46.7362%	13,355
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
97	397	Communication Equipment	822,315	0	(107)	0	0	0	0	0	822,208	0	822,208	46.7362%	384,269
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	46.7362%	0
100		Total General Plant	$11,183,711	$(774)	$(114,819)	$(8,746)	$26,814	$(8,138)	$(3,624)	$0	$11,074,424	$0	$11,074,424		$5,175,765

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP C.b**
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE DUPLICATE VERTEX SALES TAX	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	REMOVE MEALS & HOTEL	REMOVE MISCODED CHARGES	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1010	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
101		Total Orig Cost Plant in Service	$11,589,707	$(774)	$(520,816)	$(8,746)	$26,814	$(8,138)	$(3,624)	$0	$11,074,424	$0	$11,074,424		
102		Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%		
103		Total Allocated Plant In Service	$5,416,589	$(362)	$(243,409)	$(4,087)	$12,532	$(3,803)	$(1,694)	$0	$5,175,765	$0	$5,175,765		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PLANT IN SERVICE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK Acct 1010	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE AVIATION	REMOVE DIRECT SPECIFIC PROJECT	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE MISCODED CHARGES	REMOVE MEALS & HOTEL	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	RECLASS ACTIVITY	CORPORATE TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 3/31/2022	CORPORATE ADJUSTED ACCT 1010	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
		INTANGIBLE PLANT																		
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0	46.7362%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
7		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%	$0		$0
		GATHERING AND TRANSMISSION PLANT																		
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0	46.7362%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%	$0		$0
		DISTRIBUTION PLANT																		
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0	46.7362%	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	46.7362%	0
53		Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%	$0		$0
		GENERAL PLANT																		
54	389	Land & Land Rights	$43,763	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$43,763	$0	$43,763	28.7400%	$12,578	46.7362%	$5,878
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
56	390.1	Structures & Improvements	5,027,920	0	0	0	(110,657)	0	0	0	(57)	0	0	4,917,206	0	4,917,206	28.7400%	1,413,205	46.7362%	660,478
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
59	390.2	Leasehold Improvement	6,025,621	0	0	(93,620)	0	0	0	(9,201)	(183)	(18,335)	274,124	6,178,406	0	6,178,406	28.7400%	1,775,674	46.7362%	829,883
60	390.2	OGS Lease Incentive	853,910	0	0	0	0	0	(579,787)	0	0	0	(274,124)	0	0	0	28.7400%	0	46.7362%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
63	391.1	Office Furniture & Equipment	4,951,060	(896)	0	(55,418)	0	0	0	(5,439)	(198)	(1,544)	0	4,887,565	0	4,887,565	28.7400%	1,404,686	46.7362%	656,497
64	391.19	Airplane Hanger Furniture	59,246	0	0	(59,246)	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PLANT IN SERVICE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK Acct 1010	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE AVIATION	REMOVE DIRECT SPECIFIC PROJECT	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE MISCODED CHARGES	REMOVE MEALS & HOTEL	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	RECLASS ACTIVITY	CORPORATE TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE AS OF 3/31/2022	CORPORATE ADJUSTED ACCT 1010	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
67	391.3	Office Machines	316,640	0	0	0	0	0	0	0	0	0	0	316,640	0	316,640	28.7400%	91,002	46.7362%	42,531
68	391.4	Audio Visual Equipment	1,172,382	0	0	0	0	0	0	(60)	(36)	(982)	0	1,171,304	0	1,171,304	28.7400%	336,633	46.7362%	157,329
69	391.5	Artwork	49,414	0	(49,414)	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
70	391.6	Purchased Software	130,403,431	(58,224)	0	0	0	(7,658)	0	0	(99,510)	(2,521)	(698)	130,234,820	0	130,234,820	28.7400%	37,429,487	46.7362%	17,493,120
71	391.6	Banner Software	10,572,924	0	0	0	0	0	0	0	(355)	0	0	10,572,569	0	10,572,569	30.8500%	3,261,638	46.7362%	1,524,365
72	391.6	PowerPlant System	2,448,925	0	0	0	0	0	0	0	0	0	0	2,448,925	0	2,448,925	27.7300%	679,087	46.7362%	317,379
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
74	391.6	Maximo	4,670,073	0	0	0	0	0	0	0	0	0	0	4,670,073	0	4,670,073	25.0000%	1,167,518	46.7362%	545,654
75	391.6	Foundation Software	70,872	0	0	0	0	(70,872)	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
76	391.6	Concur Project	71,646	0	0	0	0	0	0	0	0	0	0	71,646	0	71,646	29.5276%	21,155	46.7362%	9,887
77	391.6	Journey-Employee-ODC Distrigas	69,580,940	0	0	0	0	0	0	0	(12,655)	0	0	69,568,284	0	69,568,284	28.7400%	19,993,925	46.7362%	9,344,401
78	391.6	Journey-Employee Count	1,848,836	0	0	0	0	0	0	0	0	0	0	1,848,836	0	1,848,836	29.5276%	545,917	46.7362%	255,141
79	391.6	Payroll - Time Management	2,957,462	(6,762)	0	0	0	0	0	0	0	0	0	2,950,700	0	2,950,700	29.5276%	871,271	46.7362%	407,199
80	391.6	Accounts Payable Software	1,190,839	0	0	0	0	0	0	0	0	0	0	1,190,839	0	1,190,839	33.3346%	396,961	46.7362%	185,525
81	391.6	Customer Relations Software	1,406,012	0	0	0	0	0	0	0	0	0	0	1,406,012	0	1,406,012	30.8500%	433,755	46.7362%	202,721
82	391.8	Micro Computer Software	26,892,388	0	0	0	0	0	0	0	(73)	(498)	0	26,891,816	0	26,891,816	28.7400%	7,728,708	46.7362%	3,612,104
83	391.81	Aircraft Computer Equipment	36,559	0	0	(36,559)	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
85	391.99	Cloud Computing	2,151,072	0	0	0	0	0	0	0	0	0	0	2,151,072	0	2,151,072	28.7400%	618,218	46.7362%	288,932
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
90	392.6	Aircraft	13,608,723	0	0	(13,608,723)	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
92	394	Tools, Shop & Garage	514,309	0	0	(33,321)	0	0	0	0	0	(85)	0	480,903	0	480,903	28.7400%	138,211	46.7362%	64,595
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
97	397	Communication Equipment	337,647	0	0	0	(235,158)	0	0	0	0	0	0	102,489	0	102,489	28.7400%	29,455	46.7362%	13,766
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	28.7400%	0	46.7362%	0
100		Total General Plant	$287,262,614	$(65,882)	$(49,414)	$(13,886,886)	$(345,815)	$(78,530)	$(579,787)	$(14,700)	$(113,068)	$(23,966)	$(698)	$272,103,869	$0	$272,103,869	28.7938%	$78,349,085		$36,617,385
101		Total Orig Cost Plant in Service	$287,262,614	$(65,882)	$(49,414)	$(13,886,886)	$(345,815)	$(78,530)	$(579,787)	$(14,700)	$(113,068)	$(23,966)	$(698)	$272,103,869	$0	$272,103,869				
102		Allocation Factor to TGS	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%	28.7938%				
103		Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%				
104		Total Allocated Plant In Service	$38,657,318	$(8,866)	$(6,650)	$(1,868,777)	$(46,537)	$(10,568)	$(78,023)	$(1,978)	$(15,216)	$(3,225)	$(94)	$36,617,385	$0	$36,617,385				

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

TOTAL COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT AND ALLOCATED

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK ACCT 1060	ADJUSTMENTS ACCT 1060	TEST YEAR ADJUSTED ACCT 1060
			(a)	(b)	(c)
1	Service Area Direct Completed Construction Not Classified	WKP C-1.a	$113,758,221	$36,170	$113,794,390
2	Allocated TGS Division Completed Construction Not Classified	WKP C-1.b	249,787	(110,790)	138,997
3	Allocated Corporate Completed Construction Not Classified	WKP C-1.c	3,574,367	(31,517)	3,542,850
4	Total Completed Construction Not Classified		$117,582,375	$(106,137)	$117,476,238

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	FERC RECLASS	MISCODED RETIREMENTS ADJUSTMENT ACCT	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		INTANGIBLE PLANT											
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0
4	303	Misc. Intangible	260,537	0	0	0	0	0	0	0	260,537	0	260,537
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0
7		Total Intangible CCNC	$260,537	$0	$0	$0	$0	$0	$0	$0	$260,537	$0	$260,537
		GATHERING AND TRANSMISSION PLANT											
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0
23	367	Mains	374,234	0	0	0	0	0	0	0	374,234	0	374,234
24	367	Mains - OPC	260,764	0	0	(260,764)	0	0	0	(260,764)	0	0	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
26	369	Meas & Reg Stations Equip	110,762	0	0	0	0	0	0	0	110,762	0	110,762
27	369	Meas & Reg Stations Equip - OPC	1,212,211	0	0	(1,212,211)	0	0	0	(1,212,211)	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0
31		Total Gathering and Transmission CCNC	$1,957,972	$0	$0	$(1,472,976)	$0	$0	$0	$(1,472,976)	$484,996	$0	$484,996
		DISTRIBUTION PLANT											
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	374.1	Land	2,072	0	0	0	0	0	0	0	2,072	0	2,072
34	374.2	Land Rights	17,551	0	0	0	0	0	0	0	17,551	0	17,551

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	FERC RECLASS	MISCODED RETIREMENTS ADJUSTMENT ACCT	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	(916)	0	0	0	0	0	0	0	(916)	0	(916)
37	375.2	Other System Structures	1,711,547	0	0	0	0	0	0	0	1,711,547	0	1,711,547
38	376	Mains	63,407,642	(48)	0	260,764	0	0	0	260,717	63,668,359	0	63,668,359
39	376.9	Mains - Cathodic Protection Anodes	567,491	0	0	0	0	0	0	0	567,491	0	567,491
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	4,753,906	0	0	0	0	0	0	0	4,753,906	0	4,753,906
42	379	Meas. & Reg. Station - C.G.	1,071,624	0	0	1,212,211	0	0	0	1,212,211	2,283,835	0	2,283,835
43	380	Services	7,493,876	0	0	0	0	0	0	0	7,493,876	0	7,493,876
44	380.1	Ind Service Line Equip	2,174	0	0	0	0	0	0	0	2,174	0	2,174
45	380.2	Comm Service Line Equip	11,773	0	0	0	0	0	0	0	11,773	0	11,773
46	380.4	Yard Lines-Customer Svc	152,167	0	0	0	0	0	0	0	152,167	0	152,167
47	381	Meters	565,258	0	0	0	0	0	0	0	565,258	0	565,258
48	382	Meter Installations	7,147	0	0	0	0	0	0	0	7,147	0	7,147
49	383	House Regulators	85,896	0	0	0	0	0	0	0	85,896	0	85,896
50	385	Indust. Meas. & Reg. Stat. Equipment	399,248	0	0	0	0	0	0	0	399,248	0	399,248
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
53		Total Distribution CCNC	$80,248,456	$(48)	$0	$1,472,976	$0	$0	$0	$1,472,928	$81,721,384	$0	$81,721,384
		GENERAL PLANT											
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	7,285,047	(3,836)	226,908	0	0	0	0	223,072	7,508,119	0	7,508,119
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	236	0	0	0	0	24,300	0	24,300	24,536	0	24,536
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0
68	391.4	Audio Visual Equipment	24,300	0	0	0	0	(24,300)	0	(24,300)	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP C-1.a**
CENTRAL-GULF SERVICE AREA
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COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	FERC RECLASS	MISCODED RETIREMENTS ADJUSTMENT ACCT	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0
84	391.9	Computer & Equipment	158,449	(28)	0	0	0	0	0	(28)	158,421	0	158,421
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0
86	392	Transportation Equipment	4,784,318	0	(186,826)	0	0	0	0	(186,826)	4,597,492	0	4,597,492
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0
91	393	Stores Equipment	118,374	0	0	0	0	0	0	0	118,374	0	118,374
92	394	Tools, Shop & Garage	3,784,232	0	0	0	0	0	0	0	3,784,232	0	3,784,232
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0
96	396	Major Work Equipment	341,131	0	0	0	0	0	0	0	341,131	0	341,131
97	397	Communication Equipment	14,795,168	0	0	0	0	0	0	0	14,795,168	0	14,795,168
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0
100		Total General CCNC	$31,291,256	$(3,865)	$40,082	$0	$0	$0	$0	$36,217	$31,327,474	$0	$31,327,474
101		Total Orig Cost CCNC	$113,758,221	$(3,912)	$40,082	$0	$0	$0	$0	$36,170	$113,794,390	$0	$113,794,390

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC.xlsx

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COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	REMOVE TGS DIRECT COSTS	REMOVE MEALS & HOTEL COSTS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	$0	0	46.7362%	$0
2	301	Organization - OPC	0	0	0	0	0	0	46.7362%	0
3	302	Franchises & Consents	0	0	0	0	0	0	46.7362%	0
4	303	Misc. Intangible - OPC	0	0	0	0	0	0	46.7362%	0
5	303	Misc. Intangible	0	0	0	0	0	0	46.7362%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	46.7362 %	0
7		Total Intangible Plant	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT								
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	46.7362%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	46.7362%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	46.7362%	0
11	329	Other Structures	0	0	0	0	0	0	46.7362%	0
12	332	Field Lines	0	0	0	0	0	0	46.7362%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	46.7362%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	46.7362%	0
15	336	Purification Equipment	0	0	0	0	0	0	46.7362%	0
16	337	Other Equip	0	0	0	0	0	0	46.7362%	0
17	365	Land & Land Rights	0	0	0	0	0	0	46.7362%	0
18	365.1	Land - OPC	0	0	0	0	0	0	46.7362%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	46.7362%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	46.7362%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	46.7362%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	46.7362%	0
23	367	Mains	0	0	0	0	0	0	46.7362%	0
24	367	Mains - OPC	0	0	0	0	0	0	46.7362%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	46.7362%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	46.7362%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	46.7362%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	46.7362%	0
29	371	Other Equipment	0	0	0	0	0	0	46.7362%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	46.7362 %	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT								
32	374	Land	$0	$0	$0	$0	$0	$0	46.7362 %	$0
33	374.1	Land	0	0	0	0	0	0	46.7362 %	0
34	374.2	Land Rights	0	0	0	0	0	0	46.7362 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	46.7362 %	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	46.7362 %	0

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LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	REMOVE TGS DIRECT COSTS	REMOVE MEALS & HOTEL COSTS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
37	375.2	Other System Structures	0	0	0	0	0	0	46.7362 %	0
38	376	Mains	0	0	0	0	0	0	46.7362 %	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	46.7362 %	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	46.7362 %	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	46.7362 %	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	46.7362 %	0
43	380	Services	0	0	0	0	0	0	46.7362 %	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	46.7362 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	46.7362 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	46.7362 %	0
47	381	Meters	0	0	0	0	0	0	46.7362 %	0
48	382	Meter Installations	0	0	0	0	0	0	46.7362 %	0
49	383	House Regulators	0	0	0	0	0	0	46.7362 %	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	46.7362 %	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	46.7362 %	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	46.7362 %	0
53		Total Distribution CCNC	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT								
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	46.7362%	0
55	390	Structures & Improvements	0	0	0	0	0	0	46.7362%	0
56	390.1	Structures & Improvements	379,347	(237,054)	0	142,293	0	142,293	46.7362%	66,502
57	390.17	Building Improv Plum	0	0	0	0	0	0	46.7362%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	46.7362%	0
59	390.2	Leasehold Improvement	18,181	0	0	18,181	0	18,181	46.7362%	8,497
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	46.7362%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	46.7362%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	46.7362%	0
63	391.1	Office Furniture & Equipment	0	0	0	0	0	0	46.7362%	0
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	46.7362%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	46.7362%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	46.7362%	0
67	391.3	Office Machines	0	0	0	0	0	0	46.7362%	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	46.7362%	0
69	391.5	Artwork	0	0	0	0	0	0	46.7362%	0
70	391.6	Purchased Software	0	0	0	0	0	0	46.7362%	0
71	391.6	Banner Software	0	0	0	0	0	0	46.7362%	0
72	391.6	PowerPlant System	0	0	0	0	0	0	46.7362%	0
73	391.6	Riskworks	0	0	0	0	0	0	46.7362%	0
74	391.6	Maximo	0	0	0	0	0	0	46.7362%	0
75	391.6	Foundation Software	0	0	0	0	0	0	46.7362%	0

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LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	REMOVE TGS DIRECT COSTS	REMOVE MEALS & HOTEL COSTS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
76	391.6	Concur Project	0	0	0	0	0	0	46.7362%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	46.7362%	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	46.7362%	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	46.7362%	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	46.7362%	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	46.7362%	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	46.7362%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	46.7362%	0
84	391.9	Computer & Equipment	65,544	0	0	65,544	0	65,544	46.7362%	30,633
85	391.99	Cloud Computing	0	0	0	0	0	0	46.7362%	0
86	392	Transportation Equipment	0	0	0	0	0	0	46.7362%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	46.7362%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	46.7362%	0
89	392.5	Trailers	0	0	0	0	0	0	46.7362%	0
90	392.6	Aircraft	0	0	0	0	0	0	46.7362%	0
91	393	Stores Equipment	0	0	0	0	0	0	46.7362%	0
92	394	Tools, Shop & Garage	71,390	0	0	71,390	0	71,390	46.7362%	33,365
93	394.1	Tools	0	0	0	0	0	0	46.7362%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	46.7362%	0
95	395	CNG Equipment	0	0	0	0	0	0	46.7362%	0
96	396	Major Work Equipment	0	0	0	0	0	0	46.7362%	0
97	397	Communication Equipment	0	0	0	0	0	0	46.7362%	0
98	397.2	Telephone Equipment	0	0	0	0	0	0	46.7362%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	46.7362%	0
100		Total General plant	$534,461	$(237,054)	$0	$297,407	$0	$297,407		$138,997
101		Total Orig Cost Plant in Service	$534,461	$(237,054)	$0	$297,407	$0	$297,407		
102		Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%		
103		Total Allocated CCNC	$249,787	$(110,790)	$0	$138,997	$0	$138,997		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlxs

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CENTRAL-GULF SERVICE AREA
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COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE DIRECT SPECIFIC PROJECT	REMOVE MEALS & HOTEL	REMOVE MISCODED CHARGES	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	RECLASS ACTIVITY	CORPORATE TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1060	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		INTANGIBLE PLANT															
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	46.7362%	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
3	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
7		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%	$0		$0
		GATHERING AND TRANSMISSION PLANT															
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	46.7362%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%	$0		$0
		DISTRIBUTION PLANT															
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	46.7362%	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362%	0
53		Total Distribution CCNC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%	$0		$0
		GENERAL PLANT															
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	28.74%	$0	46.7362%	0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0

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TWELVE MONTHS ENDED DECEMBER 31, 2023

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	REMOVE VERTEX DUPLICATE SALES TAX	REMOVE ARTWORK	REMOVE DIRECT SPECIFIC PROJECT	REMOVE MEALS & HOTEL	REMOVE MISCODED CHARGES	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	RECLASS ACTIVITY	CORPORATE TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1060	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
56	390.1	Structures & Improvements	657,608	0	0	(2,855)	0	0	0	0	654,753	0	654,753	28.74%	188,176	46.7362%	87,946
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
59	390.2	Leasehold Improvement	1,500,714	0	(2,088)	0	0	(98,283)	(22)	315,831	1,716,152	0	1,716,152	28.74%	493,222	46.7362%	230,513
60	390.2	OGS Lease Incentive	315,831	0	0	0	0	0	0	(315,831)	0	0	0	28.74%	0	46.7362%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
63	391.1	Office Furniture & Equipment	11,233	0	0	0	0	0	0	0	11,233	0	11,233	28.74%	3,228	46.7362%	1,509
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
67	391.3	Office Machines	901,551	0	0	0	0	0	0	0	901,551	0	901,551	28.74%	259,106	46.7362%	121,096
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
70	391.6	Purchased Software	22,755,151	(2,252)	0	(128,439)	(852)	0	(911)	698	22,623,395	0	22,623,395	28.74%	6,501,964	46.7362%	3,038,771
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0	30.85%	0	46.7362%	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0	27.73%	0	46.7362%	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
74	391.6	Maximo	414,934	0	0	0	0	0	0	0	414,934	0	414,934	25.00%	103,734	46.7362%	48,481
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0	29.53%	0	46.7362%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0	29.53%	0	46.7362%	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0	29.53%	0	46.7362%	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0	33.33%	0	46.7362%	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0	30.85%	0	46.7362%	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
92	394	Tools, Shop & Garage	108,323	0	0	0	0	0	(118)	0	108,204	0	108,204	28.74%	31,098	46.7362%	14,534
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
97	397	Communication Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362%	0
100		Total General plant	$26,665,344	$(2,252)	$(2,088)	$(131,294)	$(852)	$(98,283)	$(1,052)	$698	$26,430,223	$0	$26,430,223	28.68%	$7,580,527		$3,542,850
101		Total Orig Cost Plant in Service	$26,665,344	$(2,252)	$(2,088)	$(131,294)	$(852)	$(98,283)	$(1,052)	$698	$26,430,223	$0	$26,430,223				
102		Allocation Factor to TGS	28.6813%	28.6813%	28.6813%	28.6813%	28.6813%	$0	28.6813%	28.6813%	28.6813%	28.6813%	28.6813%				
103		Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	$0	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%				
104		Total Allocated CCNC	$3,574,367	$(302)	$(280)	$(17,599)	$(114)	$(13,174)	$(141)	$94	$3,542,850	$0	$3,542,850				

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

TOTAL ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - DIRECT AND ALLOCATED

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK ACCTS 1080100 & 1110	ADJUSTMENTS ACCTS 1080100 & 1110	TEST YEAR ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)
1	Service Area Direct Accumulated Reserves	WKP D.a	$(220,618,261)	$66,366	$(220,551,895)
2	Allocated TGS Division Accumulated Reserves	WKP D.b	(1,623,003)	231,529	(1,391,474)
3	Allocated Corporate Accumulated Reserves	WKP D.c	(20,351,344)	1,867,308	(18,484,037)
4	Total Accumulated Reserves		$(242,592,609)	$2,165,203	$(240,427,405)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

WKP D.a
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ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCTS 1080100 & 1110	MISCODED RETIREMENTS ADJUSTMENT ACCTS 1080100 & 1110	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVE CHANGES	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		INTANGIBLE PLANT											
1	301	Organization	$(56,257)	$0	$(56,257)	$0	$0	$0	$0	$0	$(56,257)	$0	$(56,257)
2	301	Organization - OPC	479	0	479	0	0	0	0	0	479	0	479
3	302	Franchises & Consents	(393,474)	0	(393,474)	0	0	0	0	0	(393,474)	0	(393,474)
4	303	Misc. Intangible	0	(766,222)	(766,222)	0	0	(14,336)	0	(14,336)	(780,558)	0	(780,558)
5	303	Misc. Intangible - OPC	0	(14,336)	(14,336)	0	0	14,336	0	14,336	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0
7		Total Intangible Plant Reserves	$(449,251)	$(780,558)	$(1,229,809)	$0	$0	$0	$0	$0	$(1,229,809)	$0	$(1,229,809)
		GATHERING AND TRANSMISSION PLANT											
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0
20	365.2	Rights-of-Way - OPC	(2,462)	0	(2,462)	0	0	2,462	0	2,462	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
22	366.1	Compressor Station Structure - OPC	(2,346)	0	(2,346)	0	0	2,346	0	2,346	0	0	0
23	367	Mains	264,444	0	264,444	0	0	0	0	0	264,444	0	264,444
24	367	Mains - OPC	(3,280,126)	0	(3,280,126)	0	0	3,280,126	0	3,280,126	0	0	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
26	369	Meas & Reg Stations Equip	(226,912)	0	(226,912)	0	0	(12,458)	0	(12,458)	(239,370)	0	(239,370)
27	369	Meas & Reg Stations Equip - OPC	(125,305)	0	(125,305)	0	0	125,305	0	125,305	0	0	0
28	369.1	Measuring Stations Equip - OPC	(606,953)	0	(606,953)	0	0	606,953	0	606,953	0	0	0
29	371	Other Equipment		0	0	0	0	0	0	0	0	0	0
30	371	Other Equipment - OPC	(12,458)	0	(12,458)	0	0	12,458	0	12,458	0	0	0
31		Total Gathering and Transmission Plant Reserves	$(3,992,117)	$0	$(3,992,117)	$0	$0	$4,017,192	$0	$4,017,192	$25,075	$0	$25,075
		DISTRIBUTION PLANT											
32	374	Land	$(255)	$0	$(255)	$0	$0	$0	$0	$0	$(255)	$0	$(255)
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0
34	374.2	Land Rights	(9,440)	0	(9,440)	0	0	(2,462)	0	(2,462)	(11,902)	0	(11,902)
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	(32,320)	0	(32,320)	0	0	(2,346)	0	(2,346)	(34,665)	0	(34,665)
37	375.2	Other System Structures	(130,397)	0	(130,397)	0	0	0	0	0	(130,397)	0	(130,397)
38	376	Mains	(76,579,114)	0	(76,579,114)	0	6,819	(3,280,126)	0	(3,273,307)	(79,852,421)	0	(79,852,421)
39	376.9	Mains - Cathodic Protection Anodes	(12,715,301)	0	(12,715,301)	0	0	0	0	0	(12,715,301)	0	(12,715,301)
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	(4,012,074)	0	(4,012,074)	0	0	0	0	0	(4,012,074)	0	(4,012,074)
42	379	Meas. & Reg. Station - C.G.	(845,114)	0	(845,114)	0	0	(732,258)	0	(732,258)	(1,577,372)	0	(1,577,372)
43	380	Services	(40,261,009)	0	(40,261,009)	0	22	0	0	22	(40,260,987)	0	(40,260,987)
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0
47	381	Meters	(35,453,793)	0	(35,453,793)	0	0	0	0	0	(35,453,793)	0	(35,453,793)
48	382	Meter Installations	(2,791)	0	(2,791)	0	0	0	0	0	(2,791)	0	(2,791)
49	383	House Regulators	(4,883,641)	0	(4,883,641)	0	0	0	0	0	(4,883,641)	0	(4,883,641)
50	385	Indust. Meas. & Reg. Stat. Equipment	(5,287,968)	0	(5,287,968)	0	0	0	0	0	(5,287,968)	0	(5,287,968)
51	386	Other Property on Customer Premises	(1,041,339)	0	(1,041,339)	0	0	0	0	0	(1,041,339)	0	(1,041,339)
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
53		Total Distribution Plant Reserves	$(181,254,556)	$0	$(181,254,556)	$0	$6,841	$(4,017,192)	$0	$(4,010,350)	$(185,264,906)	$0	$(185,264,906)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCTS 1080100 & 1110	MISCODED RETIREMENTS ADJUSTMENT ACCTS 1080100 & 1110	OPC RECLASS	ASSETS THAT ARE FULLY RETIRED/AMORTIZED AS OF 12/31/2023	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVE CHANGES	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		GENERAL PLANT											
54	389	Land & Land Rights	$4,733	$0	$4,733	$0	$0	$0	$0	$0	$4,733	$0	$4,733
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	(2,518,943)	0	(2,518,943)	(2,921)	0	0	0	(2,921)	(2,521,863)	0	(2,521,863)
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	(57,905)	(57,905)	0	0	0	57,905	57,905	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	(798,801)	0	(798,801)	0	0	0	0	0	(798,801)	0	(798,801)
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0
84	391.9	Computer & Equipment	(1,096,913)	0	(1,096,913)	0	0	0	0	0	(1,096,913)	0	(1,096,913)
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0
86	392	Transportation Equipment	(9,723,437)	0	(9,723,437)	4,542	0	0	0	4,542	(9,718,895)	0	(9,718,895)
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0
91	393	Stores Equipment	(7,599)	0	(7,599)	0	0	0	0	0	(7,599)	0	(7,599)
92	394	Tools, Shop & Garage	(4,559,234)	0	(4,559,234)	0	0	0	0	0	(4,559,234)	0	(4,559,234)
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0
95	395	CNG Equipment	37,480	0	37,480	0	0	0	0	0	37,480	0	37,480
96	396	Major Work Equipment	(1,344,194)	0	(1,344,194)	0	0	0	0	0	(1,344,194)	0	(1,344,194)
97	397	Communication Equipment	(14,072,660)	0	(14,072,660)	0	0	0	0	0	(14,072,660)	0	(14,072,660)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	(4,308)	0	(4,308)	0	0	0	0	0	(4,308)	0	(4,308)
100		Total General Plant Reserves	$(34,083,875)	$(57,905)	$(34,141,779)	$1,621	$0	$0	$57,905	$59,525	$(34,082,254)	$0	$(34,082,254)
101		Total Accumulated Reserves For Depreciation	(219,779,799)	$(838,462)	$(220,618,261)	$1,621	$6,841	$0	$57,905	$66,366	$(220,551,895)	$0	$(220,551,895)

Source: WKP C.a and WKP C-1.a_D.a Accum Depr and Amort Adjustment.xlsx
Source: WKP D.a REG BKS_091_PP Rpt_1080100_1080500_Accum Depreciation.xlsx
Source: WKP D.a REG BKS_091_PP Rpt_1110100_1110500_Accum Amortization.xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

WKP D.b
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ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE TGS DIRECT COSTS	REMOVE LAND DEPRECIATION	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	PRO FORMA ADJUSTMENT RESERVE BALANCING	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(k)	(l)	(m)
		INTANGIBLE PLANT												
1	301	Organization	$(127,437)	$0	$127,437	$0	$0	$0	$0	$0	$0	$0	46.7362%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	46.7362%	0
4	303	Misc. Intangible	(278,560)	0	278,560	0	0	0	0	0	0	0	46.7362%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
7		Total Intangible Plant Reserves	$(405,997)	$0	$405,997	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT												
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	46.7362%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	46.7362%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	46.7362%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	46.7362%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	46.7362%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	46.7362%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	46.7362%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	46.7362%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	46.7362%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	46.7362%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	46.7362%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	46.7362%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	46.7362%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	46.7362%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	46.7362%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	46.7362%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	46.7362%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
31		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT												
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	46.7362 %	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
53		Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT												
54	389	Land & Land Rights	$(4,331)	$0	$0	$0	$4,331	$0	$0	$0	$0	$0	46.7362 %	$0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP D.b**
CENTRAL-GULF SERVICE AREA
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TWELVE MONTHS ENDED DECEMBER 31, 2023

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE TGS DIRECT COSTS	REMOVE LAND DEPRECIATION	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	PRO FORMA ADJUSTMENT RESERVE BALANCING	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(k)	(l)	(m)
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
56	390.1	Structures & Improvements	(495,882)	0	0	3,040	0	0	0	(492,842)	0	(492,842)	46.7362 %	(230,336)
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
59	390.2	Leasehold Improvement	(236,249)	755	0	0	0	0	0	(235,494)	0	(235,494)	46.7362 %	(110,061)
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
63	391.1	Office Furniture & Equipment	(717,433)	0	0	0	0	(4,493)	0	(721,926)	0	(721,926)	46.7362 %	(337,401)
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
84	391.9	Computer & Equipment	(1,071,078)	0	85,766	0	0	0	0	(985,311)	0	(985,311)	46.7362 %	(460,497)
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
92	394	Tools, Shop & Garage	(11,791)	0	0	0	0	0	0	(11,791)	0	(11,791)	46.7362 %	(5,511)
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
97	397	Communication Equipment	(529,928)	0	0	0	0	0	0	(529,928)	0	(529,928)	46.7362 %	(247,668)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	46.7362 %	0
100		Total General Plant Reserves	$(3,066,692)	$755	$85,766	$3,040	$4,331	$(4,493)	$0	$(2,977,293)	$0	$(2,977,293)		$(1,391,474)
101		Total Accumulated Reserves For Depreciation	$(3,472,689)	$755	$491,763	$3,040	$4,331	$(4,493)	$0	$(2,977,293)	$0	$(2,977,293)		
####		Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%		
103		Total Allocated Accumulated Reserves	$(1,623,003)	$353	$229,831	$1,421	$2,024	$(2,100)	$0	$(1,391,474)	$0	$(1,391,474)		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE DIRECT SPECIFIC ASSET	REMOVE MISCODED CHARGES	RECLASS ACTIVITY	CORPORATE TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	CORPORATE ADJUSTED ACCTS 1080100 & 1110	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		INTANGIBLE PLANT															
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	46.7362 %	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
7		Total Intangible Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0		$0
		GATHERING AND TRANSMISSION PLANT															
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	46.7362 %	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
31		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0		$0
		DISTRIBUTION PLANT															
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	46.7362 %	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	46.7362 %	0
53		Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0		$0
		GENERAL PLANT															
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	28.74%	$0	46.7362 %	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110	REMOVE ARTWORK	REMOVE AVIATION	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE DIRECT SPECIFIC ASSET	REMOVE MISCODED CHARGES	RECLASS ACTIVITY	CORPORATE TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	CORPORATE ADJUSTED ACCTS 1080100 & 1110	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
56	390.1	Structures & Improvements	(324,287)	0	0	0	0	1,986	0	0	(322,301)	0	(322,301)	28.74%	(92,629)	46.7362 %	(43,291)
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
59	390.2	Leasehold Improvement	(3,955,533)	0	11,358	0	0	0	9,155	(79,849)	(4,014,869)	0	(4,014,869)	28.74%	(1,153,873)	46.7362 %	(539,276)
60	390.2	OGS Lease Incentive	(310,158)	0	0	0	230,308	0	0	79,849	0	0	0	28.74%	0	46.7362 %	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
63	391.1	Office Furniture & Equipment	(2,034,720)	0	4,715	0	0	0	0	0	(2,030,004)	0	(2,030,004)	28.74%	(583,423)	46.7362 %	(272,670)
64	391.19	Airplane Hanger Furniture	(10,568)	0	10,568	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
67	391.3	Office Machines	(143,933)	0	0	0	0	0	0	0	(143,933)	0	(143,933)	28.74%	(41,366)	46.7362 %	(19,333)
68	391.4	Audio Visual Equipment	(618,195)	0	0	0	0	0	0	0	(618,195)	0	(618,195)	28.74%	(177,669)	46.7362 %	(83,036)
69	391.5	Artwork	(21,136)	21,136	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
70	391.6	Purchased Software	(62,213,733)	0	0	7,162	0	5,223	0	0	(62,201,348)	0	(62,201,348)	28.74%	(17,876,667)	46.7362 %	(8,354,875)
71	391.6	Banner Software	(2,440,926)	0	0	0	0	0	0	0	(2,440,926)	0	(2,440,926)	30.85%	(753,026)	46.7362 %	(351,936)
72	391.6	PowerPlant System	(943,188)	0	0	0	0	0	0	0	(943,188)	0	(943,188)	27.73%	(261,546)	46.7362 %	(122,237)
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
74	391.6	Maximo	(3,147,859)	0	0	0	0	0	0	0	(3,147,859)	0	(3,147,859)	25.00%	(786,965)	46.7362 %	(367,797)
75	391.6	Foundation Software	(19,495)	0	0	19,495	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
76	391.6	Concur Project	(57,213)	0	0	0	0	0	0	0	(57,213)	0	(57,213)	29.53%	(16,893)	46.7362 %	(7,895)
77	391.6	Journey-Employee-ODC Distrigas	(49,013,601)	0	0	0	0	0	0	0	(49,013,601)	0	(49,013,601)	28.74%	(14,086,509)	46.7362 %	(6,583,499)
78	391.6	Journey-Employee Count	(1,437,868)	0	0	0	0	0	0	0	(1,437,868)	0	(1,437,868)	29.53%	(424,568)	46.7362 %	(198,427)
79	391.6	Payroll - Time Management	(629,163)	0	0	0	0	0	0	0	(629,163)	0	(629,163)	29.53%	(185,777)	46.7362 %	(86,825)
80	391.6	Accounts Payable Software	(413,915)	0	0	0	0	0	0	0	(413,915)	0	(413,915)	33.33%	(137,977)	46.7362 %	(64,485)
81	391.6	Customer Relations Software	(58,554)	0	0	0	0	0	0	0	(58,554)	0	(58,554)	30.85%	(18,064)	46.7362 %	(8,442)
82	391.8	Micro Computer Software	(9,953,232)	0	0	0	0	0	0	0	(9,953,232)	0	(9,953,232)	28.74%	(2,860,559)	46.7362 %	(1,336,917)
83	391.81	Aircraft Computer Equipment	25,788	0	(25,788)	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
85	391.99	Cloud Computing	(238,330)	0	0	0	0	0	0	0	(238,330)	0	(238,330)	28.74%	(68,496)	46.7362 %	(32,012)
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
90	392.6	Aircraft	(13,608,723)	0	13,608,723	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
92	394	Tools, Shop & Garage	(59,686)	0	6,379	0	0	0	0	0	(53,306)	0	(53,306)	28.74%	(15,320)	46.7362 %	(7,160)
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
97	397	Communication Equipment	(34,358)	0	0	0	0	5,154	0	0	(29,204)	0	(29,204)	28.74%	(8,393)	46.7362 %	(3,923)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	28.74%	0	46.7362 %	0
100		Total General Plant Reserves	$(151,662,584)	$21,136	$13,615,956	$26,658	$230,308	$12,363	$9,155	$0	$(137,747,008)	$0	$(137,747,008)	28.71 %	$(39,549,721)		$(18,484,037)
101		Total Accumulated Reserves For Depreciation	$(151,662,584)	$21,136	$13,615,956	$26,658	$230,308	$12,363	$9,155	$0	$(137,747,008)	$0	$(137,747,008)				
102		Allocation Factor to TGS	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%	28.7119%				
103		Allocation Factor to Service Area	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%	46.7362%				
104		Total Allocated Accumulated Reserves	$(20,351,344)	$2,836	$1,827,102	$3,577	$30,905	$1,659	$1,229	$0	$(18,484,037)	$0	$(18,484,037)				

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve.xlxs

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

COST OF CAPITAL

LINE NO.	DESCRIPTION	RATIO	COST RATE %	COMPOSITE RATE %
		(a)	(b)	(c)
1	Long-Term Debt	40.42%	4.39%	1.77%
2	Common Equity	59.58%	10.25%	6.11%
3	Total	100.000%		7.88%

Source: SCH E Cost of Capital

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

FEDERAL INCOME TAX

LINE NO.	DESCRIPTION	REFERENCE	PER BOOKS	ADJUSTMENT	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$833,181,714	$(19,933,007)	$813,248,707
2	Rate of Return	E	7.8812%	7.8812%	7.8812%
3	Required Return		$65,664,681	$(1,570,959)	$64,093,722
4	Less: Interest on Long-Term Debt (1)		14,785,494	(353,728)	14,431,766
5	Net After Tax Income before parking adjustment		$50,879,188	$(1,217,232)	$49,661,956
6	Add: Parking Expense (2)		98,790		98,790
7	Net After Tax Income		$50,977,977	$(1,217,232)	$49,760,746
8	Gross-Up Factor [1 / (1-0.21)]		1.2658228	1.2658228	1.2658228
9	Net Taxable Income		$64,529,086	$(1,540,800)	$62,988,286
10	Tax Rate		21.0000%	21.0000%	21.0000%
11	Federal Income Tax		$13,551,108	$(323,568)	$13,227,540
12	Net Income Tax Expense		$13,551,108	$(323,568)	$13,227,540
	Note (1)				
13	Debt Component of Return	E	1.7746%		1.7746%
14	Total Rate Base	B	$833,181,714		$813,248,707
15	Interest on Long-Term Debt		$14,785,494		$14,431,766

Note (2)

16 Per IRS Notice 2018-99, the Tax Cuts and Jobs Act of 2017 added Code Section 274(a)(4) precluding employers from deducting for tax purposes the amount paid to a third party for the use of a parking lot. In calendar year 2021, there was new tax guidance and there was no direct parking diallowance to the direct service areas but includes the allocation for Corporate and Division.

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUMMARY OF OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
			(a)	(b)	(c)
	OPERATING REVENUES				
1	Gas Sales, Transportation & Other Utility Revenue	G-1,2,3	$243,232,019	$(77,813,492)	$165,418,527
	OPERATING EXPENSES				
2	Cost of Gas	G-1	$93,904,159	$(93,904,159)	$0
3	Base Payroll Expense	G-4	26,304,816	1,509,420	27,814,236
4	Overtime Payroll Expense	G-5	2,225,380	135,836	2,361,215
5	Employee Benefits and Payroll Taxes	G-6	8,632,279	638,824	9,271,103
6	Pension and Other Post Employment Benefits Regulatory Asset Amortization	G-7	308,348	(860,882)	(552,533)
7	Incentive Compensation	G-8	6,422,501	(691,969)	5,730,532
8	Miscellaneous Adjustments	G-9	3,035,590	(3,035,590)	0
9	Rents and Leases Adjustment	G-10	690,591	1,636	692,227
10	Interest on Customer Deposits	G-11	92,616	228,821	321,437
11	Uncollectible Expense	G-12	795,692	293,919	1,089,612
12	Injuries and Damages	G-13	240,966	(54,917)	186,049
13	Advertising Expense	G-14	150,493	0	150,493
14	Depreciation and Amortization Expense	G-15	28,209,353	7,702,632	35,911,985
15	Ad Valorem Tax Expense	G-16	6,172,432	775,058	6,947,490
16	Texas Franchise Tax Expense	G-17	0	383,482	383,482
17	Stores Load Clearing	G-18	190,785	(4,682)	186,103
18	Transportation & Work Equipment Clearing	G-19	2,703,974	(98,673)	2,605,301
19	Regulatory Expense	G-20	0	522,616	522,616
20	Distrigas % Adjustment	G-21	0	156,972	156,972
21	Causal % Adjustment - NOT USED	G-22	0	0	0
22	Pipeline Integrity Testing	G-23	0	169,787	169,787
23	Excess Deferred Income Tax Amortization	G-24	0	(500,677)	(500,677)
24	Unadjusted Expenses		20,075,936		20,075,936
25	Total Operating Expense Adjustments		$200,155,910	$(86,632,544)	$113,523,366
26					
27	Net Operating Revenue & Expense Adjustments		$43,076,110	$8,819,052	$51,895,162

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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SUMMARY OF OPERATING REVENUES & EXPENSES

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
				(a)	(b)	(c)
	REVENUE					
1	Gas Sales Revenue	480-482		$229,525,612	$(77,823,927)	$151,701,685
2	Forfeited Discounts	4870		0	0	0
3	Misc Fees	4880		2,024,278	304,384	2,328,662
4	Transportation	4893		10,875,428	512,753	11,388,181
5	Misc. Rent Revenue	4930		0	0	0
6	Other Utility Revenue	4950		806,701	(806,701)	0
7	Total Revenue			$243,232,019	$(77,813,492)	$165,418,527
8	COST OF GAS	805		$93,904,159	$(93,904,159)	$0
	DEPRECIATION & AMORTIZATION					
9	Depreciation and Amortization Expense	4030-4050		$28,209,353	$7,702,632	$35,911,985
10	Pension and OPEB Reg Asset Amortization Expense	4073		325,860	(860,882)	(535,021)
11	Total Depr. & Amort.			$28,535,214	$6,841,750	$35,376,964
	TAXES OTHER THAN INCOME					
12	Payroll	4081		$1,758,758	$219,157	$1,977,915
13	Ad Valorem	4081	190	6,172,432	775,058	6,947,490
14	Revenue Related	4081	133, 138 & 140	26,330	0	26,330
15	Other	4081	131, 233 & 995	766,097	383,482	1,149,578
16	Total Taxes Other Than Income			$8,723,616	$1,377,697	$10,101,313
17	Excess Deferred Income Tax Amortization	4101	102	$0	$(500,677)	$(500,677)
18	Interest on Customer Deposits	4310		$92,616	$228,821	$321,437
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION					
19	Underground Storage	8140-8360		$0	$0	$0
20	Operation Supervision and Engineering	8500		13,162	501	13,663
21	Transmission Communication Equip	8520		0	0	0
22	Compressor Station Labor and Expenses	8530		0	0	0
23	Mains Expenses	8560		906,658	194,640	1,101,298
24	Measuring and Regulating Station Expenses	8570		191,868	663	192,531
25	Trans/Compression of Gas by Others	8580		0	0	0
26	Other Expenses	8590		101	0	101
27	Rent	8600		3	0	3
28	Maintenance Supervision and Engineering	8610		1,095	0	1,095
29	Maintenance of Mains	8630		235,778	5,535	241,314
30	Maintenance of Measuring and Regulating Station Equipment	8650		31,144	0	31,144
31	Maintenance of Communication Equipment	8660		0	0	0
32	Total Transmission			$1,379,809	$201,340	$1,581,149
	DISTRIBUTION OPERATIONS					
33	Supervision and Engineering	8700		$738,144	$29,098	$767,242
34	Distribution Load Dispatch	8710		265,007	13,339	278,346
35	Mains & Services	8740		6,818,555	125,268	6,943,822
36	Meas & Reg. Stat. Exp. - General	8750		407,832	16,618	424,450
37	Meas & Reg. Stat. Exp. - Ind.	8760		51,421	2,745	54,166
38	Meas & Reg. Stat. Exp. - City Gate	8770		22,878	450	23,329
39	Meter & House Reg. Exp.	8780		6,089,654	229,278	6,318,931
40	Customer Installation Exp	8790		2,574	0	2,574
41	Other Expense	8800		1,220,045	28,585	1,248,630
42	Rents	8810		35,043	0	35,043
43	Corporate & TGS Division Expenses	8820		0	0	0
44	Total Distribution Operations			$15,651,152	$445,380	$16,096,533

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA **SCHEDULE G**
TWELVE MONTHS ENDED DECEMBER 31, 2023 **Page 3**

SUMMARY OF OPERATING REVENUES & EXPENSES

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
				(a)	(b)	(c)
	DISTRIBUTION MAINTENANCE					
45	Supervision and Engineering	8850		$0	$0	$0
46	Struct. & Improv.	8860		1,202,834	0	1,202,834
47	Mains	8870		3,915,490	127,969	4,043,460
48	Meas. & Reg. Stat. Exp. - Gen	8890		946,254	14,904	961,158
49	Meas. & Reg. Stat. Exp. - Ind.	8900		644,432	36,282	680,714
50	Meas. & Reg. Stat. Exp. - City Gate	8910		52,838	1,356	54,194
51	Maintenance of Services	8920		1,663,285	56,686	1,719,971
52	Meters & House Reg.	8930		0	0	0
53	Other Equipment	8940		0	0	0
54	Clearing - Meter Shop - Small Meters	8950		0	0	0
55	Clearing - Meter Shop - Large Meters	8960		0	0	0
56	Total Distribution Maintenance			$8,425,134	$237,197	$8,662,331
57	Total Distribution Expense			$24,076,286	$682,577	$24,758,864
	CUSTOMER ACCOUNTING					
58	Supervision	9010		$(106)	$402	$296
59	Meter Reading	9020		746,452	27,453	773,904
60	Customer Accounting	9030		3,885,940	65,957	3,951,897
61	Bad Debts	9040		697,568	293,919	991,488
62	Miscellaneous	9050		412,588	240	412,828
63	Total Customer Accounting			$5,742,442	$387,971	$6,130,413
	CUSTOMER INFORMATION					
64	Supervision	9070		$0	$0	$0
65	Customer Assistance Expense	9080		1,098,098	52,039	1,150,137
66	Inform. & Instruct. Adver. Exp.	9090		77,438	0	77,438
67	Customer Svc and Informational Svc	9100		0	0	0
68	Total Customer Information			$1,175,536	$52,039	$1,227,575
	SALES					
69	Supervision	9110		$0	$0	$0
70	Demonstrating and Selling Expense	9120		0	0	0
71	Advertising	9130		143,921	0	143,921
72	Employee Sales Referrals	9140		0	0	0
73	Misc. Gas Sales Expense	9163		0	0	0
74	Total Sales			$143,921	$0	$143,921
75	Total Customer Accounts Expense			$7,061,900	$440,009	$7,501,909
	ADMINISTRATIVE & GENERAL					
76	Salaries	9200		$7,351,561	$404,669	$7,756,230
77	Office Supplies & Expenses	9210		1,755,142	(29,716)	1,725,426
78	Transferred Credit	9220		(6,462,470)	0	(6,462,470)
79	Outside Services	9230		864,209	0	864,209
80	Property Insurance	9240		323,442	4,361	327,803
81	Injuries & Damages	9250		2,347,511	40,398	2,387,910
82	Employee Pensions & Benefits	9260		5,755,626	1,367,875	7,123,501
83	A&G Franchise Elections	9270		0	0	0
84	Regulatory Commission Expenses	9280		446,177	522,616	968,792
85	Duplicate Charges- Credit	9290		0	0	0
86	General Advertising Expense	9301		107	0	107
87	Misc. General Expenses	9302		23,037,688	(4,310,106)	18,727,582
88	Rents	9310		690,591	0	690,591
89	Maintenance of General Plant	9320		272,724	0	272,724
90	Misc. General Expenses	9400's		0	0	0
91	Total Administrative & General Expense			$36,382,309	$(1,999,903)	$34,382,406
92	Total Operating Expense			$200,155,910	$(86,632,544)	$113,523,366
93	Earnings Before Income Tax & Interest Expense			$43,076,110	$8,819,052	$51,895,162

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOKS WKP G.a.2 (Note 1)	REMOVE COST OF GAS RELATED ADJ G-1	NORMALIZE GAS SALES REVENUE ADJ G-2	NORMALIZE OTHER UTILITY SALES REVENUE ADJ G-3	BASE PAYROLL ADJ G-4	OVERTIME PAYROLL ADJ G-5	BENEFITS & PAYROLL TAX ADJ G-6	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ G-7	INCENTIVE COMPENSATION ADJ G-8	MISC ADJ G-9	RENT ADJ G-10	CUSTOMER DEPOSITS ADJ G-11	UNCOLLECTIBLE EXPENSE ADJ G-12	INJURIES & DAMAGES ADJ G-13	ADVERTISING ADJ G-14	DEPRECIATION ADJ G-15	AD VALOREM TAX ADJ G-16	TEXAS FRANCHISE TAX ADJ G-17	STORES LOAD ADJ G-18	TWF LOAD ADJ G-19	REGULATORY EXP ADJ G-20	DISTRIGAS % ADJ G-21	CAUSAL % ADJ G-22	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-23	EXCESS DEFERRED INCOME TAX AMORTIZATION ADJ G-24	TOTAL ADJUSTMENTS	TEST YEAR ADJUSTED
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)
	REVENUE																													
1	Gas Sales Revenue	480-482		$229.525.612	$(93.904.159)	$16.080.231	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(77.823.927)	$151.701.685
2	Forfeited Discounts	4870		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Misc Fees	4880		2.024.278	0	0	304.384	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	304.384	2.328.662
4	Transportation	4893		10.875.428	0	0	512.753	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	512.753	11.388.181
5	Misc. Rent Revenue	4930		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Other Utility Revenue	4950		806.701	0	0	(806.701)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(806.701)	0
7	Total Revenue			$243.232.019	$(93.904.159)	$16.080.231	$10.436	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(77.813.492)	$165.418.527
8	COST OF GAS	805		$93.904.159	$(93.904.159)																								$(93.904.159)	$0
	DEPRECIATION & AMORTIZATION																													
9	Depreciation and Amortization Expense	4030-4050		$28.209.353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7.702.632	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7.702.632	$35.911.985
10	Pension and OPEB Reg Asset Amortization Expense (Note 2)	4073		325.860	0	0	0	0	0	0	(860.882)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(860.882)	(535.021)
11	Total Depr. & Amort.			$28.535.214	$0	$0	$0	$0	$0	$0	$(860.882)	$0	$0	$0	$0	$0	$0	$0	$7.702.632	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6.841.750	$35.376.964
	TAXES OTHER THAN INCOME																													
12	Payroll	4081		$1.758.758	$0	$0	$0	$0	$0	$219,357	$0	$(10,097)	$9.897	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$219.157	$1.977.915
13	Ad Valorem	4081	190	6.172.432	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	775.058	0	0	0	0	0	0	0	0	775.058	6.947.490
14	Revenue Related	4081	133, 138 & 140	26.330	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26.330
15	Other	4081	131, 233 & 995	766.097	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	383.482	0	0	0	0	0	0	0	383.482	1.149.578
16	Total Taxes Other Than Income			$8.723.616	$0	$0	$0	$0	$0	$219.357	$0	$(10.097)	$9.897	$0	$0	$0	$0	$0	$0	$775.058	$383.482	$0	$0	$0	$0	$0	$0	$0	$1.377.697	$10.101.313
17	Excess Deferred Income Tax Amortization	4101	102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(500.677)	$(500.677)	$(500.677)
18	Interest on Customer Deposits	4310		$92.616	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$228.821	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$228.821	$321.437
19	Underground Storage	8140-8360		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION																													
20	Operation Supervision and Engineering	8500		13.162	$0	$0	$0	$481	$20	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	501	13.663
21	Transmission Communication Equip	8520		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Compressor Station Labor and Expenses	8530		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Mains Expenses	8560		$906.657.62	0	0	0	25.258	3.538	0	0	0	(183)	0	0	0	0	0	0	0	0	0	(3.761)	0	0	0	169.787	0	194.640	1.101.298
24	Measuring and Regulating Station Expenses	8570		191.867.93	0	0	0	713	116	0	0	0	0	0	0	0	0	0	0	0	0	0	(166)	0	0	0	0	0	663	192.531
25	Trans/Compression of Gas by Others	8580		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Other Expenses	8590		101	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	101
27	Rent	8600		3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
28	Maintenance Supervision and Engineering	8610		1.095	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.095
29	Maintenance of Mains	8630		235.778	0	0	0	5.634	255	0	0	0	(0)	0	0	0	0	0	0	0	0	0	(353)	0	0	0	0	0	5.535	241.314
30	Maintenance of Measuring and Regulating Station Equipment	8650		31.144	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31.144
31	Maintenance of Communication Equipment	8660		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total Transmission			$1.379.809	$0	$0	$0	$32.086	$3.929	$0	$0	$0	$(183)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(4.279)	$0	$0	$0	$169.787	$0	$201.340	$1.581.149
	DISTRIBUTION OPERATIONS																													
33	Supervision and Engineering	8700		$738.144	$0	$0	$0	$27.481	$2,592	$0	$0	$0	$(616)	$0	$0	$0	$0	$0	$0	$0	$0	(3)	$(356)	$0	$0	$0	$0	$0	$29.098	$767.242
34	Distribution Load Dispatch	8710		265.007	0	0	0	12.797	542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	13.339	278.346
35	Mains & Services	8740		6.818.555	0	0	0	119.896	18.594	0	0	0	(49)	0	0	0	0	0	0	0	0	(1.437)	(11.737)	0	0	0	0	0	125.268	6.943.822
36	Meas & Reg. Stat. Exp. - General	8750		407.832	0	0	0	14.356	2.262	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16.618	424.450
37	Meas & Reg. Stat. Exp. - Ind.	8760		51.421	0	0	0	2.548	197	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.745	54.166
38	Meas & Reg. Stat. Exp. - City Gate	8770		22.878	0	0	0	432	18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	450	23.329
39	Meter & House Reg. Exp.	8780		6.089.654	0	0	0	229.812	37.440	0	0	0	(10)	0	0	0	0	0	0	0	0	(1.879)	(36.085)	0	0	0	0	0	229.278	6.318.931
40	Customer Installation Exp	8790		2.574	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2.574
41	Other Expense	8800		1.220.045	0	0	0	29.257	3.895	0	0	0	(4.316)	0	0	0	0	0	0	0	0	(250)	0	0	0	0	0	0	28.585	1.248.630
42	Rents	8810		35.043	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35.043
43	Corporate & TGS Division Expenses	8820		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Total Distribution Operations			$15.651.152	$0	$0	$0	$436.579	$65.541	$0	$0	$0	$(4.991)	$0	$0	$0	$0	$0	$0	$0	$0	$(3.570)	$(48.178)	$0	$0	$0	$0	$0	$445.380	$16.096.533
	DISTRIBUTION MAINTENANCE										0	0																		
45	Supervision and Engineering	8850		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	Struct. & Improv.	8860		1.202.834	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.202.834
47	Mains	8870		3.915.490	0	0	0	125.127	20.390	0	0	0	(20)	0	0	0	0	0	0	0	0	(780)	(16.748)	0	0	0	0	0	127.969	4.043.460
48	Meas. & Reg. Stat. Exp. - Gen	8890		946.254	0	0	0	22.406	3.651	0	0	0	0	0	0	0	0	0	0	0	0	0	(11.153)	0	0	0	0	0	14.904	961.158
49	Meas. & Reg. Stat. Exp. - Ind.	8900		644.432	0	0	0	31.639	5.156	0	0	0	0	0	0	0	0	0	0	0	0	0	(512)	0	0	0	0	0	36.282	680.714
50	Meas. & Reg. Stat. Exp. - City Gate	8910		52.838	0	0	0	1.166	190	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.356	54.194
51	Maintenance of Services	8920		1.663.285	0	0	0	62.894	10.226	0	0	0	0	0	0	0	0	0	0	0	0	(288)	(16.147)	0	0	0	0	0	56.686	1.719.971
52	Meters & House Reg.	8930		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	Other Equipment	8940		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Clearing - Meter Shop - Small Meters	8950		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Clearing - Meter Shop - Large Meters	8960		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
56	Total Distribution Maintenance			$8.425.134	$0	$0	$0	$243.232	$39.612	$0	$0	$0	$(20)	$0	$0	$0	$0	$0	$0	$0	$0	$(1.068)	$(44.560)	$0	$0	$0	$0	$0	$237.197	$8.662.331
57	Total Distribution Expense			$24.076.286	$0	$0	$0	$679.811	$105.153	$0	$0	$0	$(5.011)	$0	$0	$0	$0	$0	$0	$0	$0	$(4.637)	$(92.738)	$0	$0	$0	$0	$0	$682.577	$24.758.864
	CUSTOMER ACCOUNTING																													
58	Supervision	9010		$(106)	$0	$0	$0	$385	$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$402	$296
59	Meter Reading	9020		746.452	0	0	0	25.069	4.085	0	0	0	0	0	0	0	0	0	0	0	0	(45)	(1.656)	0	0	0	0	0	27.453	773.904
60	Customer Accounting	9030		3.885.940	0	0	0	90.223	3.878	0	0	0	(28.144)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	65.957	3.951.897
61	Bad Debts	9040		697.568	0	0	0	0	0	0	0	0	0	0	0	293.919	0	0	0	0	0	0	0	0	0	0	0	0	293.919	991.488
62	Miscellaneous	9050		412.588	0	0	0	207	33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	240	412.828
63	Total Customer Accounting			$5.742.442	$0	$0	$0	$115.883	$8.013	$0	$0	$0	$(28.144)	$0	$0	$293.919	$0	$0	$0	$0	$0	$(45)	$(1.656)	$0	$0	$0	$0	$0	$387.971	$6.130.413
	CUSTOMER INFORMATION																													
64	Supervision	9070		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
65	Customer Assistance Expense	9080		1.098.098	0	0	0	52.254	7.933	0	0	0	(8.148)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	52.039	1.150.137
66	Inform. & Instruct. Adver. Exp.	9090		77.438	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77.438
67	Customer Svc and Informational Svc	9100		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Total Customer Information			$1.175.536	$0	$0	$0	$52.254	$7.933	$0	$0	$0	$(8.148)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52.039	$1.227.575
	SALES																													
69	Supervision	9110		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
70	Demonstrating and Selling Expense	9120		$0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
71	Advertising	9130		143.921	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	143.921

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOKS WKP G.a.2 (Note 1) (a)	REMOVE COST OF GAS RELATED ADJ G-1 (b)	NORMALIZE GAS SALES REVENUE ADJ G-2 (c)	NORMALIZE OTHER UTILITY SALES REVENUE ADJ G-3 (d)	BASE PAYROLL ADJ G-4 (e)	OVERTIME PAYROLL ADJ G-5 (f)	BENEFITS & PAYROLL TAX ADJ G-6 (g)	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ G-7 (h)	INCENTIVE COMPENSATION ADJ G-8 (i)	MISC. ADJ G-9 (j)
72	Employee Sales Referrals	9140		0	0	0	0	0	0	0	0	0	0
73	Misc. Gas Sales Expense	9163		0	0	0	0	0	0	0	0	0	0
74	Total Sales			$143.921	$0	$0	$0	$0	$0	$0	$0	$0	$0
75	Total Customer Accounts Expense			$7.061.900	$0	$0	$0	$168.137	$15.946	$0	$0	$0	$(36.293)
	ADMINISTRATIVE & GENERAL												
76	Salaries	9200		$7.351.561	$0	$0	$0	$160.966	$8,636	$0	$0	$0	$235.068
77	Office Supplies & Expenses	9210		1.755.142	0	0	0	0	0	0	0	0	(29.716)
78	Transferred Credit	9220		(6.462.470)	0	0	0	0	0	0	0	0	0
79	Outside Services	9230		864.209	0	0	0	0	0	0	0	0	0
80	Property Insurance	9240		323.442	0	0	0	0	0	0	0	0	4.361
81	Injuries & Damages	9250		2.347.511	0	0	0	0	0	0	0	0	95.315
82	Employee Pensions & Benefits	9260		5.755.626	0	0	0	0	0	625.110	0	0	742.765
83	A&G Franchise Elections	9270		0	0	0	0	0	0	0	0	0	0
84	Regulatory Commission Expenses	9280		446.177	0	0	0	0	0	0	0	0	0
85	Duplicate Charges- Credit	9290		0	0	0	0	0	0	0	0	0	0
86	General Advertising Expense	9301		107	0	0	0	0	0	0	0	0	0
87	Misc. General Expenses	9302		23.037.688	0	0	0	468.421	2.172	(205.644)	0	(681.871)	(4.051.792)
88	Rents	9310		690.591	0	0	0	0	0	0	0	0	0
89	Maintenance of General Plant	9320		272.724	0	0	0	0	0	0	0	0	0
90	Misc. General Expenses	9400's		0	0	0	0	0	0	0	0	0	0
91	Total Administrative & General Expense			$36.382.309	$0	$0	$0	$629.387	$10.807	$419.466	$0	$(681.871)	$(3.004.000)
92	Total Operating Expense			$200.155.910	$(93.904.159)	$0	$0	$1.509.420	$135.836	$638.824	$(860.882)	$(691.969)	$(3.035.590)
93	Earnings Before Income Tax & Interest Expense			$43.076.110	$0	$16.080.231	$10.436	$(1.509.420)	$(135.836)	$(638.824)	$860.882	$691.969	$3.035.590

LINE NO.	RENT ADJ G-10 (k)	CUSTOMER DEPOSITS ADJ G-11 (l)	UNCOLLECTIBLE EXPENSE ADJ G-12 (m)	INJURIES & DAMAGES ADJ G-13 (n)	ADVERTISING ADJ G-14 (o)	DEPRECIATION ADJ G-15 (p)	AD VALOREM TAX ADJ G-16 (q)	TEXAS FRANCHISE TAX ADJ G-17 (r)	STORES LOAD ADJ G-18 (s)	TWE LOAD ADJ G-19 (t)	REGULATORY EXP ADJ G-20 (u)	DISTRIGAS % ADJ G-21 (v)	CAUSAL % ADJ G-22 (w)	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-23 (x)	EXCESS DEFERERED INCOME TAX AMORTIZATION ADJ G-24 (y)	TOTAL ADJUSTMENTS (z)	TEST YEAR ADJUSTED (aa)
72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
73	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
74	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$143.921
75	$0	$0	$293.919	$0	$0	$0	$0	$0	$(45)	$(1.656)	$0	$0	$0	$0	$0	$440.009	$7.501.909
76	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$404.669	$7.756.230
77	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(29.716)	1.725.426
78	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(6.462.470)
79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	864.209
80	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.361	327.803
81	0	0	0	(54.917)	0	0	0	0	0	0	0	0	0	0	0	40.398	2.387.910
82	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.367.875	7.123.501
83	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	0	0	0	0	0	0	0	0	0	0	522.616	0	0	0	0	522.616	968.792
85	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
86	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	107
87	1.636	0	0	0	0	0	0	0	0	0	0	156.972	0	0	0	(4.310.106)	18.727.582
88	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	690.591
89	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	272.724
90	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
91	$1.636	$0	$0	$(54.917)	$0	$0	$0	$0	$0	$0	$522.616	$156.972	$0	$0	$0	$(1.999.903)	$34.382.406
92	$1.636	$228.821	$293.919	$(54.917)	$0	$7.702.632	$775.058	$383.482	$(4.682)	$(98.673)	$522.616	$156.972	$0	$169.787	$(500.677)	$(86.632.544)	$113.523.366
93	$(1.636)	$(228.821)	$(293.919)	$54.917	$0	$(7.702.632)	$(775.058)	$(383.482)	$4.682	$98.673	$(522.616)	$(156.972)	$0	$(169.787)	$500.677	$8.819.052	$51.895.162

NOTE 2:

Account 4073	$325.860	
Test Year 2023 Pension & OPEB Amortization	308.348	(Schedule G-7)
Test Year 2023 Amortization expense of regulatory asset	17.512	(Schedule G-20)
	$0	

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NUMBER	SUB ACCOUNT	SERVICE AREA PER BOOKS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d) = (a) + (b) + (c)
	REVENUE						
1	Gas Sales Revenue	480-482		$229,525,612	$0	$0	$229,525,612
2	Forfeited Discounts	4870		0	0	0	0
3	Misc Fees	4880		2,024,278	0	0	2,024,278
4	Transportation	4893		10,875,428	0	0	10,875,428
5	Misc. Rent Revenue	4930		0	0	0	0
6	Other Utility Revenue	4950		806,701	0	0	806,701
7	Total Revenue			$243,232,019	$0	$0	$243,232,019
8	COST OF GAS	805		$93,904,159	$0	$0	$93,904,159
	DEPRECIATION & AMORTIZATION						
9	Depreciation and Amortization Expense	4030-4050		$24,800,057	$7,294,765	$3,409,296	$28,209,353
10	Pension and OPEB Reg Asset Amortization Expense (Note 2)	4073		325,860	0	0	325,860
11	Total Depr. & Amort.			$25,125,918	$7,294,765	$3,409,296	$28,535,214
	TAXES OTHER THAN INCOME						
12	Payroll	4081		$0	$3,763,160	$1,758,758	$1,758,758
13	Ad Valorem	4081	190	6,266,317	(200,883)	(93,885)	6,172,432
14	Revenue Related	4081	133, 138 & 140	26,330	0	0	26,330
15	Other	4081	131, 233 & 995	0	1,639,193	766,097	766,097
16	Total Taxes Other Than Income			$6,292,647	$5,201,470	$2,430,970	$8,723,616
17	Excess Deferred Income Tax Amortization	4101	102	$0	$0	$0	$0
18	Interest on Customer Deposits	4310		$92,616	$0	$0	$92,616
19	Underground Storage	8140-8360		$0	$0	$0	$0
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION						
20	Operation Supervision and Engineering	8500		$0	$28,162	$13,162	$13,162
21	Transmission Communication Equip	8520		0	0	0	0
22	Compressor Station Labor and Expenses	8530		0	0	0	0
23	Mains Expenses	8560		629,136	593,805	277,522	906,658
24	Measuring and Regulating Station Expenses	8570		191,868	0	0	191,868
25	Trans/Compression of Gas by Others	8580		0	0	0	0
26	Other Expenses	8590		55	98	46	101
27	Rent	8600		0	7	3	3
28	Maintenance Supervision and Engineering	8610		0	2,343	1,095	1,095
29	Maintenance of Mains	8630		122,224	242,969	113,555	235,778
30	Maintenance of Measuring and Regulating Station Equipment	8650		31,144	0	0	31,144
31	Maintenance of Communication Equipment	8660		0	0	0	0
32	Total Transmission			$974,427	$867,384	$405,382	$1,379,809
	DISTRIBUTION OPERATIONS						
33	Supervision and Engineering	8700		$239,520	$1,066,889	$498,624	$738,144
34	Distribution Load Dispatch	8710		0	567,027	265,007	265,007
35	Mains & Services	8740		6,625,317	413,466	193,238	6,818,555
36	Meas & Reg. Stat. Exp. - General	8750		394,679	28,143	13,153	407,832
37	Meas & Reg. Stat. Exp. - Ind.	8760		14,396	79,221	37,025	51,421
38	Meas & Reg. Stat. Exp. - City Gate	8770		14,019	18,956	8,859	22,878
39	Meter & House Reg. Exp.	8780		6,035,750	115,336	53,904	6,089,654
40	Customer Installation Exp	8790		2,574	0	0	2,574
41	Other Expense	8800		1,005,641	458,755	214,405	1,220,045
42	Rents	8810		34,934	233	109	35,043
43	Corporate & TGS Division Expenses	8820		0	$0	$0	$0
44	Total Distribution Operations			$14,366,830	$2,748,026	$1,284,323	$15,651,152
	DISTRIBUTION MAINTENANCE						
45	Supervision and Engineering	8850		$0	$0	$0	$0
46	Struct. & Improv.	8860		1,191,633	23,968	11,202	1,202,834
47	Mains	8870		3,808,680	228,538	106,810	3,915,490

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NUMBER	SUB ACCOUNT	SERVICE AREA PER BOOKS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d) = (a) + (b) + (c)
48	Meas. & Reg. Stat. Exp. - Gen	8890		946,254	0	0	946,254
49	Meas. & Reg. Stat. Exp. - Ind.	8900		644,432	0	0	644,432
50	Meas. & Reg. Stat. Exp. - City Gate	8910		52,838	0	0	52,838
51	Maintenance of Services	8920		1,659,381	8,354	3,904	1,663,285
52	Meters & House Reg.	8930		0	0	0	0
53	Other Equipment	8940		0	0	0	0
54	Clearing - Meter Shop - Small Meters	8950		0	0	0	0
55	Clearing - Meter Shop - Large Meters	8960		0	0	0	0
56	Total Distribution Maintenance			$8,303,218	$260,860	$121,916	$8,425,134
57	Total Distribution Expense			$22,670,048	$3,008,886	$1,406,239	$24,076,286
	CUSTOMER ACCOUNTING						
58	Supervision	9010		$0	$(227)	$(106)	$(106)
59	Meter Reading	9020		746,452	0	0	746,452
60	Customer Accounting	9030		143,987	8,006,541	3,741,953	3,885,940
61	Bad Debts	9040		795,692	(209,953)	(98,124)	697,568
62	Miscellaneous	9050		3,930	874,394	408,658	412,588
63	Total Customer Accounting			$1,690,061	$8,670,756	$4,052,382	$5,742,442
	CUSTOMER INFORMATION						
64	Supervision	9070		$0	$0	$0	$0
65	Customer Assistance Expense	9080		967,926	278,524	130,172	1,098,098
66	Inform. & Instruct. Adver. Exp.	9090		0	165,692	77,438	77,438
67	Customer Svc and Informational Svc	9100		0	0	0	0
68	Total Customer Information			$967,926	$444,216	$207,610	$1,175,536
	SALES						
69	Supervision	9110		$0	$0	$0	$0
70	Demonstrating and Selling Expense	9120		0	0	0	0
71	Advertising	9130		120,000	51,184	23,921	143,921
72	Employee Sales Referrals	9140		0	0	0	0
73	Misc. Gas Sales Expense	9163		0	0	0	0
74	Total Sales			$120,000	$51,184	$23,921	$143,921
75	Total Customer Accounts Expense			$2,777,987	$9,166,156	$4,283,913	$7,061,900
	ADMINISTRATIVE & GENERAL						
76	Salaries	9200		$292,375	$15,104,321	$7,059,186	$7,351,561
77	Office Supplies & Expenses	9210		588,591	2,496,033	1,166,551	1,755,142
78	Transferred Credit	9220		0	(13,827,547)	(6,462,470)	(6,462,470)
79	Outside Services	9230		90,053	1,656,438	774,156	864,209
80	Property Insurance	9240		0	692,059	323,442	323,442
81	Injuries & Damages	9250		(428,415)	5,939,564	2,775,926	2,347,511
82	Employee Pensions & Benefits	9260		1,974,682	8,089,971	3,780,945	5,755,626
83	A&G Franchise Elections	9270		0	0	0	0
84	Regulatory Commission Expenses	9280		336,502	234,667	109,675	446,177
85	Duplicate Charges- Credit	9290		0	0	0	0
86	General Advertising Expense	9301		0	229	107	107
87	Misc. General Expenses	9302		(177,344)	49,672,485	23,215,032	23,037,688
88	Rents	9310		25,064	1,424,006	665,526	690,591
89	Maintenance of General Plant	9320		2,772	577,608	269,952	272,724
90	Misc. General Expenses	9400's		0	0	0	0
91	Total Administrative & General Expense			$2,704,281	$72,059,834	$33,678,028	$36,382,309
92	Total Operating Expense			$154,542,082	$97,598,496	$45,613,828	$200,155,910
93	Earnings Before Income Tax & Interest Expense			$88,689,938	$(97,598,496)	$(45,613,828)	$43,076,110

Note 1: Allocation Factor 46.7362 %

Note 2: See "WKP G.a.1 Op Inc Adjs" for Account 4073 Reconcilation

Source: WKP G.a.2 Op Inc Book TYE12 2023 GL Detail Rev Exp acct (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR
FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
				(a)	(b)	(c)	(d)
1	4030	4030100	DEPRECIATION EXPENSE	$630,057			$630,057
2	4030	4030300	DEPR EXP-TEXAS 8.209 ACCRUAL				0
3	4030	4030500	DEPRECIATION EXPENSE - NSC	195			195
4	4030	4030995	DEPR INDIRECT ALLOCATION		475,687	6,154,809	6,630,496
5	4043	4043100	AMORT OF GAS PLANT	34,002			34,002
6	4043	4043500	AMORT OF GAS PLANT - NSC	16			16
7	4081	4081100	GEN TAX O/H TRF TO CAPITAL	(2,376,275)			(2,376,275)
8	4081	4081101	GEN TAX FED UNEMPL INS TAX	44,439			44,439
9	4081	4081102	GEN TAX FICA	5,532,302			5,532,302
10	4081	4081103	GEN TAX FICA INCENTIVE	366,310			366,310
11	4081	4081104	GEN TAX FICA LTI	12,097			12,097
12	4081	4081131	GEN TAX SALES TAX ALLOWANCE	(76,374)			(76,374)
13	4081	4081132	GEN TAX STATE UNEMPL INS	184,287			184,287
14	4081	4081190	GEN TAX AD VALOREM	(200,883)			(200,883)
15	4081	4081191	GEN TAX AD VALOREM RULE 8.209	0			0
16	4081	4081995	GEN TAX DISTRIGAS ALLOCATION			1,715,567	1,715,567
17	4091	4091100	CURRENT INCOME TAX ACCR	0			0
18	4101	4101100	DEFERRED INCOME TAX ACCR	0			0
19	4101	4101102	DEFERRED INCOME TAX AMORTIZATION EXCESS DTL	0			0
20	4140	4140230	MISC UTIL INCOME-DISTR	0			0
21	4170	4170112	MISC NONUTIL REV CNG EXCISE TAX	0			0
22	4171	4171995	OPER REV DISTRIGAS ALLOCATION				0
23	4191	4191120	INT CAP AFTER CONSTRUC	0			0
24	4210	4210100	MISC NONOPERATING INCOME	0			0
25	4210	4210995	MISC NONOP INCOME DISTRIGAS ALLOCATION				0
26	4261	4261210	CIVIC EXPENSES - CONTRIBUTIONS	0			0
27	4261	4261212	CIVIC EXPENSES - BUSINESS & COMMERCIAL DEVEL SPONSORSHIPS	0			0
28	4261	4261213	CIVIC EXPENSES - PROFESSIONAL ASSOCIATIONS SPONSORSHIPS	0			0
29	4261	4261225	DONATIONS-OTHER 501 (C)(3)	0			0
30	4263	4263100	PENALTIES	0			0
31	4264	4264102	GOVERNMENTAL AFFAIRS EXPENSE	0			0
32	4265	4265101	MISCELLANEOUS NONOPERATING EXPENSES	0			0
33	4265	4265116	WRITE-OFF DISALLOWED CAPITAL	0			0
34	4265	4265995	MISC NONOP DISTRIGAS ALLOCATION				0
35	4300	4300901	ALLOC INTERCO INTEREST	0			0
36	4310	4310103	INT EXP CUSTOMER DEPOSITS	0			0
37	4310	4310901	ST DEBT INT EXP INTERCO	0			0
38	4320	4320100	INT CAP DURING CONSTRUC	0			0
39	4320	4320101	INT CAP AFTER CONSTRUC	0			0
40	4800	4800111	UTIL GAS SALES RES UNBILLED	0			0
41	4800	4800114	UTIL GAS SALES RES EST	0			0
42	4810	4810111	UTIL GAS SALES COMM UNBILLED	0			0
43	4810	4810211	UTIL GAS SALES IND UNBILLED	0			0
44	4820	4820111	UTIL GAS SALES CITY GATE UNBILLED	0			0
45	4880	4880100	SVC REVENUE MISC	0			0
46	4950	4950300	OTH GAS REV UTIL MISC	0			0
47	8040	8040100	NATURAL GAS CITY GATE PURCHASES	0			0
48	8050	8050108	OTH GAS PURCH RESIDENTIAL UNBILLED	0			0
49	8050	8050134	OTH GAS PURCH UNBILLED COMM	0			0
50	8050	8050144	OTH GAS PURCH UNBILLED IND	0			0
51	8050	8050208	OTH GAS PURCH PUBLIC AUTHORITY UNBILLED	0			0
52	8051	8051100	OTH GAS PURCH UNRECOV GAS ADJ	0			0
53	8500	8500100	TRANS GEN SUPERVISION	21,094	7,068		28,162
54	8560	8560100	TRANS MAINS MISC EXP	151,603	122		151,724
55	8560	8560207	TRANS MAINS TOOLS	3,229			3,229
56	8560	8560225	TRANS MAINS UNIFORMS	87			87
57	8560	8560245	TRANS MAINS LINE PIGGING		32		32
58	8560	8560250	TRANS MAINS PIPELINE INTEGRITY MANAGEMENT	203,483	235,784		439,267
59	8560	8560402	TRANS MAINS CODE LEAK SURVEY	(534)			(534)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR
FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
				(a)	(b)	(c)	(d)
60	8590	8590100	TRANS OTH MISC EXP	98			98
61	8600	8600206	TRANS RENT VEHICLE	7			7
62	8610	8610100	TRANS MNT GEN SUPERVISION		2,343		2,343
63	8630	8630100	TRANS MNT MAINS	188,731			188,731
64	8630	8630115	TRANS MNT MAINS REPAIRS FR LEAKAGE	54,238			54,238
65	8700	8700100	DISTR GEN SUPERVISION	824,817	242,072		1,066,889
66	8710	8710100	DISTR LOAD DISPATCHING	566,912			566,912
67	8710	8710228	DISTR LOAD PERS USE AUTO	115			115
68	8740	8740100	DISTR MAINS & SVC MISC	5,411	200		5,611
69	8740	8740207	DISTR MAINS & SVC TOOLS	5,689	1,317		7,007
70	8740	8740225	DISTR MAINS & SVC UNIFORMS	1,306			1,306
71	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT PROGRAM	53,521	67,908		121,429
72	8740	8740302	DISTR MAINS & SVC CODE LINE LOCATE	3,278			3,278
73	8740	8740400	DISTR MAINS & SVC LEAK SURVEY MAINS	274,835			274,835
74	8750	8750100	DISTR MEAS & REG ST MISC	28,143			28,143
75	8760	8760100	DISTR IND MEAS & REG ST MISC	79,221			79,221
76	8770	8770100	DISTR C G MEAS & REG ST MISC	18,956			18,956
77	8780	8780100	DISTR MEAS & HOUSE REG MISC	75,083	4,451		79,534
78	8780	8780112	DISTR MEAS & HOUSE REG TURN ON/OFFS & SVC ORDER	3,356			3,356
79	8780	8780139	DISTR MEAS & HOUSE MEAS SVC CTR	32,436			32,436
80	8780	8780211	DISTR MEAS & HOUSE REG REPRODUCTION	9			9
81	8800	8800100	DISTR OTHER EXPENSES	413,158	29,802		442,959
82	8800	8800120	DISTR OTH SVC BLDG	394			394
83	8800	8800205	DISTR OTH FLEET OPER	20			20
84	8800	8800210	DISTR OTH OFFICE SUPPLIES	971	114		1,085
85	8800	8800221	DISTR OTH TRAINING & EDUCATION	14,140			14,140
86	8800	8800400	DISTR OTH SAFETY	124	33		157
87	8810	8810100	DISTR RENTS	233			233
88	8860	8860100	DISTR MNT STRUC & IMPROVE MISC	39			39
89	8860	8860120	DISTR MNT STRUC & IMPROV SVC BLDG	23,929			23,929
90	8870	8870100	DISTR MNT MAINS MISC	225,204			225,204
91	8870	8870101	DISTR MNT MAINS CATHODIC PROTECT	3,238			3,238
92	8870	8870120	DISTR MNT MAINS LEAK REPAIR	96			96
93	8920	8920100	DISTR MNT SERVICES MISC	8,354			8,354
94	9010	9010100	CUST ACCTG/COLL SUPERVISION	(227)			(227)
95	9030	9030100	CUST REC/COLLEC EXP MISC	1,697,746	3		1,697,749
96	9030	9030110	CUST RECORDS EXPENSE	3,705,488	354		3,705,841
97	9030	9030111	CUST REC/COLLEC ENVELOPE BILLING	154			154
98	9030	9030125	CUST REC/COLLEC LOCKBOX	203,994			203,994
99	9030	9030170	CUST COLLEC AGENCY FEE	170,500			170,500
100	9030	9030210	CUST REC/COLLEC OFFICE SUPPLIES	220,486			220,486
101	9030	9030226	CUST REC/COLLEC POSTAGE	2,007,818			2,007,818
102	9040	9040100	UNCOLLECTIBLE CUST ACCTS	(209,953)			(209,953)
103	9050	9050100	CUST ACCTS MISC EXP	122	726,925		727,047
104	9050	9050110	CUST ACCTS CUSTOMER PROTECTION PROGRAM		134		134
105	9050	9050120	CUST ACCTS SVC BLDG	146,877			146,877
106	9050	9050221	CUST ACCTS TRAINING & EDUCATION	179			179
107	9050	9050228	CUST ACCTS PERS USE AUTO	158			158
108	9080	9080100	CUST ASST MISC EXP	278,524			278,524
109	9090	9090100	INFO/INSTRUC MISC	8,076			8,076
110	9090	9090321	INFO/INSTRUC CORP COMM DIRECT	157,616			157,616
111	9130	9130100	ADVERTISING MISC EXP	51,184			51,184
112	9200	9200100	A&G SALARIES	6,434,131	3,318,918		9,753,049
113	9200	9200700	A&G SALARIES INCENTIVE PLAN	4,797,475			4,797,475
114	9200	9200712	A&G SALARIES ESPP	196,201			196,201
115	9200	9200713	A&G SALARIES LT INCENT-RESTRICTED	158,708			158,708
116	9200	9200714	A&G SALARIES LT INCENT-PERFORMANCE	198,888			198,888
117	9210	9210100	A&G SUPPLIES & EXPENSES MISC	942,762	103,701		1,046,463
118	9210	9210101	A&G S&E ADMIN	382			382

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
				(a)	(b)	(c)	(d)
119	9210	9210102	A&G S&E EMPL MISC	7,147			7,147
120	9210	9210106	A&G COVID 19 RESPONSE	34,596			34,596
121	9210	9210201	A&G S&E ASSOC MTGS	5,279	1,823		7,101
122	9210	9210202	A&G S&E SUBS/PUBLICATIONS	41,174	176		41,350
123	9210	9210204	A&G S&E COMMUNICATION	27			27
124	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	170,023	47,714		217,737
125	9210	9210210	A&G S&E OFFICE SUPPLIES	1,455	178		1,632
126	9210	9210211	A&G S&E REPRODUCTION COSTS	66			66
127	9210	9210220	A&G S&E MEMBERSHIP DUES	6,212	1,162		7,374
128	9210	9210221	A&G S&E TRAINING & ED	95,345	9,368		104,713
129	9210	9210222	A&G S&E LODGING	2,570	889		3,459
130	9210	9210223	A&G S&E AIRFARE	933	137		1,070
131	9210	9210224	A&G S&E COMPUTER EXP		10		10
132	9210	9210226	A&G S&E POSTAGE	2,180	7		2,187
133	9210	9210228	A&G S&E PERS USE AUTO		44		44
134	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	6,964	31		6,995
135	9210	9210301	A&G S&E TELE LONG DISTANCE	62,951			62,951
136	9210	9210302	A&G S&E TELE EQUIPMENT		2		2
137	9210	9210303	A&G S&E TELE LOCAL LINES	161,159			161,159
138	9210	9210304	A&G S&E CELLULAR PHONES	365,862			365,862
139	9210	9210308	A&G S&E TELE DATA	252,862			252,862
140	9210	9210309	A&G S&E TELE SCADA	566			566
141	9210	9210349	A&G S&E VALIDATED PARKING	39			39
142	9210	9210402	A&G S&E OTH BLDG OPER	89,529	47,448		136,977
143	9210	9210404	A&G S&E MAIL ROOM	17,157			17,157
144	9210	9210411	A&G S&E TRAIN MGMT PROGRAM	100			100
145	9210	9210412	A&G S&E EMPL TRAINING PROGRAM		29		29
146	9210	9210413	A&G S&E TECH/CUST SVC TRAINING	546			546
147	9210	9210807	A&G S&E TRANSITION COSTS	23,416			23,416
148	9210	9210880	A&G S&E Auto-NSC	(7,989)			(7,989)
149	9220	9220902	A&G TRF TO CONSTRUCTION	(13,827,547)			(13,827,547)
150	9230	9230110	A&G OUTSIDE SVC MISC	924,745	138,458		1,063,203
151	9230	9230115	A&G OUTSIDE SVC LEGAL REGULATORY	93,927			93,927
152	9230	9230120	A&G OUTSIDE SVC LEGAL	462,744			462,744
153	9230	9230302	A&G OUTSIDE SVC IT APPLICATION SUPPORT		5,476		5,476
154	9230	9230307	A&G OUTSIDE SVC CLOUD COMPUTING ARRANGEMENTS	23,449	4,548		27,997
155	9230	9230810	A&G OUTSIDE SVC CONTRACT	3,092			3,092
156	9240	9240100	A&G PROPERTY INSURANCE PREMIUMS	692,059			692,059
157	9250	9250100	A&G INSURANCE	38,633			38,633
158	9250	9250120	A&G INJ & DAMAGES WORKERS COMP	365,879			365,879
159	9250	9250130	A&G INJ & DAMAGES 3RD PARTY GENERAL LIABILITY DAMAGES	220,020			220,020
160	9250	9250135	A&G INJ & DAMAGES PROPERTY	(128,266)			(128,266)
161	9250	9250140	A&G INJ & DAMAGES 3RD PARTY VEHICLE ACCIDENT DAMAGES	601			601
162	9250	9250145	A&G INJ & DAMAGES EMPLOYEMENT PRACTICES LIABILITY	189			189
163	9250	9250180	A&G INJ & DAMAGES LIABILITY INSURANCE PREMIUMS	4,961,277			4,961,277
164	9250	9250200	A&G INJ & DAMAGES MISC SETTLEMENTS	481,231			481,231
165	9260	9260101	A&G EMPL BEN 401(K) CO MATCH	3,564,975			3,564,975
166	9260	9260102	A&G EMPL BEN 401(K) ADMIN	132,055	24,377		156,432
167	9260	9260103	A&G EMPL BEN DEF COMP CO MATCH	544			544
168	9260	9260112	A&G EMPL BEN SERP ADMIN		197		197
169	9260	9260115	A&G EMPL BEN PENSION ADMIN	36,999	5,676		42,676
170	9260	9260141	A&G EMPL BEN PROFIT SHARING	2,991,678			2,991,678
171	9260	9260190	A&G EMPL BEN RESERVE	9,949,007			9,949,007
172	9260	9260192	A&G EMPL BEN RESERVE IBNR	(909,318)			(909,318)
173	9260	9260197	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	251,796			251,796
174	9260	9260198	A&G EMPL BEN ACCR PSP ON STI	201,086			201,086
175	9260	9260302	A&G EMPL BEN TUITION LOANS	39,056			39,056
176	9260	9260307	A&G EMPL BEN EMPLOYEE EVENTS	17,780	151		17,931
177	9260	9260310	A&G EMPL BEN SVC RECOGNITION	73,200			73,200

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUPPORTING WORKPAPER FOR OPERATING REVENUE & EXPENSE PER BOOK, INCLUDING O&M EXPENSE FACTOR
FOR SHARED SERVICE, INCLUDING COSTS ALLOCATED ON A CAUSAL BASIS AND THROUGH DISTRIGAS

LINE NO.	FERC ACCOUNT	NATURAL ACCOUNT	ACCOUNT DESCRIPTION	SHARED SERVICES	CAUSAL	DISTRIGAS	TOTAL
				(a)	(b)	(c)	(d)
178	9260	9260326	A&G EMPL BEN EMPL ASST PROGRAM	20,194			20,194
179	9260	9260328	A&G EMPL BEN DISABILITY	60,101			60,101
180	9260	9260413	A&G EMPL BEN ACTUARY ONE GAS PENSION-SC	1,403,673			1,403,673
181	9260	9260431	A&G EMPL BEN ACTUARY OPEB-SC	33,851			33,851
182	9260	9260511	A&G EMPL BEN ACTUARY SERP-NSC	3,692			3,692
183	9260	9260513	A&G EMPL BEN ACTUARY ONE GAS PENSION-NSC	(1,972,212)			(1,972,212)
184	9260	9260531	A&G EMPL BEN ACTUARY OPEB-NSC	28,596			28,596
185	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL	(8,626,989)			(8,626,989)
186	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC	877,292			877,292
187	9260	9260995	A&G EMPL BEN SERP DISTRIGAS ALLOC			302,027	302,027
188	9260	9260996	A&G EMPL BEN PENSION DISTRIGAS			(444,049)	(444,049)
189	9260	9260997	A&G EMPL BEN FAS 106 DISTRIGAS ALLOC			24,535	24,535
190	9280	9280100	A&G REG COMMISSION EXP	234,667			234,667
191	9301	9301100	A&G ADVERTISING MISC	229			229
192	9302	9302032	A&G MISC INVOICE PRICE VARIANCE	0			0
193	9302	9302100	A&G MISC EXPENSES	(47)			(47)
194	9302	9302105	A&G MISC INDUSTRY DUES	17,040			17,040
195	9302	9302106	A&G MISC AGA INDUSTRY DUES	186,912			186,912
196	9302	9302120	A&G MISC EMPL MOVING	6,395	41,099		47,494
197	9302	9302310	A&G MISC UNITED WAY	2,833			2,833
198	9302	9302311	A&G MISC OGS VOLUNTEERS	5,479			5,479
199	9302	9302320	A&G MISC DIVERSITY & INCLUSION	3,803			3,803
200	9302	9302800	A&G MISC PROCUREMENT CARD CLEARING	(55,511)			(55,511)
201	9302	9302901	A&G MISC O/H TRF TO AFFIL	1,733,780			1,733,780
202	9302	9302915	A&G MISC ROYALTY ALLOCATED	9,799,681			9,799,681
203	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT		1,047,630		1,047,630
204	9302	9302995	A&G MISC DISTRIGAS ALLOC			36,883,394	36,883,394
205	9310	9310100	A&G RENTS LAND/FACILITY	1,381,494			1,381,494
206	9310	9310120	A&G RENTS EQUIPMENT	42,512			42,512
207	9320	9320140	A&G MNT AGREEMENT FEES	183,973	393,636		577,608
208				$45,974,983	$6,987,231	$44,636,282	$97,598,496
209							
210							

LINE NO.		
211	Calculation of O&M Expense Factor	
212		
213	Per Book Shared Services (net of the A&G transfer credit)	$97,598,496
214	Less: depreciation expense that does not get an O&M factor	(7,294,765)
215	Less: tax expense accounts	(5,201,470)
216	Total O&M Shared Service Expenses	$85,102,260
217		
218		
219		
220	Total O&M Shared Service Expenses	$85,102,260
221	Add back Account 9220902 A&G Transfer Credit/Construction Overhead	13,827,547
222	Grand Total Shared Service Expenses:	$98,929,808
223		
224	O&M effective expense factor	86.02%
225	Capitalization factor	13.98%
226		100.00%

Source: WKP G.a.2.a1 Shared Service per book including Distrigas (CONFIDENTIAL).xlsx
Source: WKP G.a.2.a2 Corporate Costs Allocated on a Causal Basis and Through Distrigas-(CONFIDENTIAL).xlsx

SCHEDULE G-1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

REMOVE GAS REVENUE AND COST OF GAS

LINE NO.	DESCRIPTION	AMOUNT	
		(a)	
1	Remove Cost of Gas Revenue Collected through Cost of Gas Clause	$93,904,159	Source: SCH G-2 and SCH G-3 Revenue Reconciliation
2	Remove Test Year Cost of Gas Expense	(93,904,159)	Source: SCH G-2 and SCH G-3 Revenue Reconciliation
3	Net Adjustment	$0	

SCHEDULE G-2
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

NORMALIZE GAS SALES REVENUE

LINE NO.	DESCRIPTION	TOTAL # OF BILLS	CCF	REVENUE	
		(a)	(b)	(c)	
1	Operating Gas Sales Revenue (1):	3,886,575	147,551,803	$229,525,612	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx, SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx
2	Less: Test Year Gas Costs collected through Cost of Gas Clause			(93,904,159)	
3	Base Sales Revenue as Recorded	3,886,575	147,551,803	$135,621,453	
	Adjustments:				
4	Remove Test Year WNA			$(2,602,511)	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
5	Weather Normalization Adjustment		3,842,798	1,141,969	Source: SCH G-2 Weather Adjustment 10 Norm.xlsx, SCH G-2 HDD Detail.xlsx
6	Customer Growth (Loss) Adjustment	20,392	1,034,174	890,498	Source: SCH G-2 Growth Adjustment.xlsx
7	Remove Test Year GRIP			(26,261,403)	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
8	GRIP Annualization Adjustment			42,911,678	Source: SCH G-2 and SCH G-3 Annualization.xlsx
9	Total Adjustments	20,392	4,876,971	$16,080,231	
10	Base Revenue As Adjusted	3,906,967	152,428,775	$151,701,685	

Calculation of Normalized Gas Sales Revenue used for Advertising Limitation Calculation:

LINE NO.	DESCRIPTION	(a)	(b)
11	Calculation of Normalized Cost of Gas Revenue		
12	Normalized CCF		152,428,775
13	Test Year Cost of Gas Revenue	$93,904,159	
14	Test Year CCF	147,551,803	
15	Effective Rate	0.63641	0.63641
16	Normalized Cost of Gas Revenue		$97,007,196

Note 1: Operating gas sales revenue does not include franchise or gross receipt taxes.

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

NORMALIZE OTHER UTILITY REVENUE

LINE NO.	DESCRIPTION	TOTAL BILLS	TOTAL VOLUMES	REVENUE	
		(a)	(b)	(c)	
1	Test Year Transportation Revenue - Acct 4893	10,523	107,801,973	$10,875,428	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx and SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx
	Adjustments:				
2	Remove Test Year GRIP			(529,628)	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
3	Annualization Adjustment			974,705	Source: SCH G-2 and SCH G-3 Annualization.xlsx
4	Remove Estimated Revenue Journal Entries			67,676	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
5	Total Adjustments	0	0	$512,753	
6	Total Transportation Revenue As Adjusted	10,523	107,801,973	$11,388,181	
7	Test Year Service Fees - Acct 4880			$2,024,278	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
8	Service Fee Annualization			304,384	Source: SCH G-3 Service Fee Annualization.xlsx
9	Total Service Fee Revenue As Adjusted			$2,328,662	
10	Test Year Other Utility Revenue - Acct 4950			$806,701	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
11	Remove Interest on Storage			(806,701)	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
12	Total Other Utility Revenue As Adjusted			$0	
13	Total Transportation, Service Fees, and Other Utility Revenue As Adjusted			$13,716,843	

SCHEDULE G-4

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BASE PAYROLL ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)
1	Hourly Base Payroll for December 2023	WKP G-4.c	$1,305,655	$535,835	$421,208	
2	Salary Base Payroll for December 2023	WKP G-4.c	565,555	1,096,475	5,829,577	
3	Total Base Payroll for December 2023		$1,871,211	$1,632,310	$6,250,785	
4	Annualized Hourly Base Payroll		$16,973,521	$6,965,856	$5,475,702	
5	Annualized Salary Base Payroll		6,786,666	13,157,700	69,954,924	
6	Total Proforma Base Payroll		$23,760,187	$20,123,556	$75,430,625	
7	December Merit Increase Percent		0.000%	0.000%	0.000%	
8	Adjustment to include December Merit Increases		0	0	0	
9	Total Proforma Base Payroll		$23,760,187	$20,123,556	$75,430,625	
10	Total Test Year Base Payroll	WKP G-4.b	22,429,636	19,141,911	71,242,474	
11	Total Allocable Base Payroll Adjustment (Ln 9 minus Ln 10)		$1,330,551	$981,645	$4,188,151	
12	Allocation to TGS		100%	100%	28.74%	
13	Allocated Base Payroll Adjustment to TGS (Ln 11 times Ln 12)		$1,330,551	$981,645	$1,203,675	
14	Allocation to Service Area	WKP A.b	100%	46.74%	46.74%	
15	Allocated Base Payroll Adjustment to Service Area (Ln 13 times Ln 14)		$1,330,551	$458,784	$562,552	
16	Payroll Expense Factor	WKP G-4.b	55.82%	65.02%	83.27%	
17	Test Year Base Payroll O&M Expense Adjustment (Ln 15 times Ln 16)		$742,711.56	$298,288	$468,421	
18	Adjustment Summary:					
19	Account 9302				$468,421	$468,421
20	Other O&M Accounts (See WKP G-4.a for Distribution by FERC Account)		742,712	298,288	0	1,040,999
21	Total		$742,712	$298,288	$468,421	$1,509,420
22	Total Test Year Base Payroll Expense after Allocation		$12,520,189	$5,816,562	$7,968,065	$26,304,816
23	Total as Adjusted Base Payroll Expense after Allocation		$13,262,901	$6,114,850	$8,436,485	$27,814,236

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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BASE PAYROLL EXPENSE

	DISTRIBUTION OF DIRECT BASE PAYROLL O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT				DISTRIBUTION OF SHARED SERVICE BASE PAYROLL O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT			
LINE NO.	MAIN ACCOUNT	PER BOOK O&M PAYROLL	RATIO OF PAYROLL BY ACCOUNT	TOTAL	MAIN ACCOUNT	PER BOOK O&M PAYROLL	RATIO OF PAYROLL BY ACCOUNT	TOTAL
		(a)	(b)	(c)		(d)	(e)	(f)
1	8500	$0	0.00%	$0	8500	$21,094	0.16%	$481
2	8530	0	0.00%	0	8530	0	0.00%	0
3	8560	397,196	2.76%	20,468	8560	210,131	1.61%	4,790
4	8570	13,831	0.10%	713	8570	0	0.00%	0
5	8590	0	0.00%	0	8590	0	0.00%	0
6	8610	0	0.00%	0	8610	0	0.00%	0
7	8630	2,560	0.02%	132	8630	241,350	1.84%	5,502
8	8650	0	0.00%	0	8650	0	0.00%	0
9	8700	229,837	1.59%	11,844	8700	685,933	5.24%	15,637
10	8710	0	0.00%	0	8710	561,347	4.29%	12,797
11	8740	2,174,810	15.09%	112,071	8740	343,277	2.62%	7,826
12	8750	266,134	1.85%	13,714	8750	28,143	0.22%	642
13	8760	14,396	0.10%	742	8760	79,221	0.61%	1,806
14	8770	0	0.00%	0	8770	18,956	0.14%	432
15	8780	4,458,180	30.93%	229,736	8780	3,356	0.03%	77
16	8790	0	0.00%	0	8790	0	0.00%	0
17	8800	427,293	2.96%	22,019	8800	317,507	2.43%	7,238
18	8850	0	0.00%	0	8850	0	0.00%	0
19	8860	0	0.00%	0	8860	0	0.00%	0
20	8870	2,428,127	16.85%	125,125	8870	96	0.00%	2
21	8890	434,803	3.02%	22,406	8890	0	0.00%	0
22	8900	613,967	4.26%	31,639	8900	0	0.00%	0
23	8910	22,632	0.16%	1,166	8910	0	0.00%	0
24	8920	1,216,810	8.44%	62,704	8920	8,354	0.06%	190
25	8930	0	0.00%	0	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	16,898	0.13%	385
27	9020	486,475	3.38%	25,069	9020	0	0.00%	0
28	9030	9,039	0.06%	466	9030	3,937,330	30.09%	89,757
29	9050	3,930	0.03%	203	9050	179	0.00%	4
30	9080	920,424	6.39%	47,431	9080	211,569	1.62%	4,823
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	292,375	2.03%	15,066	9200	6,400,101	48.91%	145,900
34	9210	0	0.00%	0	9210	0	0.00%	0
35	9230	0	0.00%	0	9230	0	0.00%	0
36	9280	0	0.00%	0	9302	0	0.00%	0
37	9302	0	0.00%	0	9302	0	0.00%	0
38	9320	0	0.00%	0	9320	0	0.00%	0
39	Total	$14,412,818	100.00%	$742,712	Total	$13,084,842	100.00%	$298,288

WKP G-4.b
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

TEST YEAR TOTAL PAYROLL

BASE AND OVERTIME

LINE NO.	DESCRIPTION		HOURLY: PAYROLL DIRECTLY CHARGED TO SERVICE AREA (a)	HOURLY: SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA (b)	HOURLY: DISTRIGAS PAYROLL (c)	SALARY: PAYROLL DIRECTLY CHARGED TO SERVICE AREA (d)	SALARY: SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA (e)	SALARY: DISTRIGAS PAYROLL (f)
	Capital							
1		1010	$0	$0	$0	$0	$0	$0
2		1540	0	0	0	0	0	0
3		1630	346.862	0	11.561	84.840	0	35.609
4		1840	6.930.566	3.158.339	717.942	3.684.319	3.882.047	11.207.866
5		1860	0	0	0	0	0	403
6		2530	83.947	0	0	276.884	0	0
7	Total Capital		$7.361.376	$3.158.339	$729.504	$4.046.044	$3.882.047	$11.243.877
	Expense							
8		8500	$0	$0	$0	$0	$21.094	$64.225
9		8530	0	0	0	0	0	0
10		8560	303.091	22.807	163	94.106	187.324	201.210
11		8570	13.831	0	0	0	0	0
12		8590	0	0	0	0	0	0
13		8610	0	0	0	0	0	31.678
14		8630	2.560	241.350	0	0	0	0
15		8650	0	0	142.855	0	0	0
16		8700	2.231	14.209	96.526	227.606	671.725	1.423.154
17		8710	0	467.325	0	0	94.022	0
18		8740	1.829.886	118.141	52.375	344.924	225.136	425.740
19		8750	168.929	0	0	97.205	28.143	0
20		8760	0	5.544	0	14.396	73.677	0
21		8770	0	1.109	0	0	17.847	0
22		8780	4.180.988	3.356	170.334	277.192	0	76.205
23		8790	0	0	0	0	0	0
24		8800	283.312	8.638	42.032	143.981	308.868	65.628
25		8850	0	0	0	0	0	120.577
26		8860	0	0	109	0	0	0
27		8870	2.276.295	96	0	151.832	0	0
28		8890	359.595	0	0	75.207	0	0
29		8900	538.760	0	0	75.207	0	0
30		8910	22.632	0	0	0	0	0
31		8920	1.193.929	8.354	0	22.881	0	0
32		8930	0	0	0	0	0	0
33		9010	0	0	103.578	0	16.898	757.807
34		9020	427.106	0	0	59.369	0	0
35		9030	0	2.887.975	0	9.039	1.049.355	0
36		9050	3.930	179	604.671	0	0	1.943.219
37		9080	358.763	0	0	561.660	211.569	1.335.043
38		9120	0	0	0	0	0	0
39		9130	0	0	0	0	0	0
40		9200	15.174	728.114	3.503.971	277.201	5.671.987	48.399.327
41		9210	0	0	5.668	0	0	1.922
42		9230	0	0	7.151	0	0	0
42		9280	0	0	0	0	0	0
43		9302	0	0	7.583	0	0	0
44		9320	0	0	0	0	0	0
45	Total Expense		$11.981.012	$4.507.197	$4.737.013	$2.431.806	$8.577.645	$54.845.734
46	Total Test Year		$19.342.388	$7.665.537	$5.466.517	$6.477.850	$12.459.691	$66.089.611
47	Payroll Expense Factor		56%	65%	83%			
48	Overtime Factor		21%	15%	6%			

BASE

LINE NO.	DESCRIPTION		HOURLY: PAYROLL DIRECTLY CHARGED TO SERVICE AREA (g)	HOURLY: SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA (h)	HOURLY: DISTRIGAS PAYROLL (i)	SALARY: PAYROLL DIRECTLY CHARGED TO SERVICE AREA (j)	SALARY: SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA (k)	SALARY: DISTRIGAS PAYROLL (l)
	Capital							
1		1010						
2		1540						
3		1630	282.312		9.665	84.840		35.609
4		1840	5.972.876	2.476.633	634.803	3.684.020	3.881.768	11.207.534
5		1860						403
6		2530	77.281			276.884		
7	Total Capital		$6.332.469	$2.476.633	$644.468	$4.045.744	$3.881.768	$11.243.545
	Expense							
8		8500					$21.094	$64.225
9		8530						
10		8560	270.509	19.897		94.106	187.324	201.178
11		8570	11.637					
12		8590						
13		8610						31.678
14		8630	1.904	230.329				
15		8650			142.855			
16		8700	2.023	14.160	81.994	227.606	671.725	1.423.125
17		8710		354.478			94.022	
18		8740	1.529.578	108.455	52.325	344.303	225.123	425.724
19		8750	147.316			97.205	28.143	
20		8760		5.461		14.396	73.645	
21		8770		1.092			17.840	
22		8780	3.280.624		147.212	276.998		76.205
23		8790						
24		8800	225.605	8.626	42.032	143.929	308.776	65.628
25		8850						120.577
26		8860						
27		8870	1.733.200	96		151.780		
28		8890	316.733			75.207		
29		8900	468.958			75.207		
30		8910	17.759					
31		8920	877.348	7.946		22.881		
32		8930						
33		9010			100.118		16.898	757.719
34		9020	380.125			59.369		
35		9030		2.794.923		9.039	1.049.313	
36		9050	2.888	179	583.352			1.943.151
37		9080	339.253			561.660	211.569	1.335.043
38		9120						
39		9130						
40		9200	15.076	660.731	3.341.593	277.201	5.671.666	48.398.048
41		9210			4.843			1.922
42		9230			6.333			
42		9280						
43		9302			7.583			
44		9320						
45	Total Expense		$9.620.537	$4.206.372	$4.510.239	$2.430.886	$8.577.137	$54.844.223
46	Total Test Year		$15.953.005	$6.683.005	$5.154.707	$6.476.630	$12.458.905	$66.087.767

OVERTIME

LINE NO.	DESCRIPTION		HOURLY: PAYROLL DIRECTLY CHARGED TO SERVICE AREA (m)	HOURLY: SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA (n)	HOURLY: DISTRIGAS PAYROLL (o)	SALARY: PAYROLL DIRECTLY CHARGED TO SERVICE AREA (p)	SALARY: SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA (q)	SALARY: DISTRIGAS PAYROLL (r)
	Capital							
1		1010						
2		1540						
3		1630	64.550		1.896			
4		1840	957.690	681.706	83.140	300	278	332
5		1860						
6		2530	6.667					
7	Total Capital		$1.028.907	$681.706	$85.036	$300	$278	$332
	Expense							
8		8500						
9		8530						
10		8560	32.582	2.910	163			32
11		8570	2.193					
12		8590						
13		8610						
14		8630	656	11.021				
15		8650						
16		8700	209	48	14.532			29
17		8710		112.847				
18		8740	300.308	9.687	50	621	13	16
19		8750	21.613					
20		8760		83			32	
21		8770		17			6	
22		8780	900.363	3.356	23.122	194		
23		8790						
24		8800	57.707	12		52	92	
25		8850						
26		8860			109			
27		8870	543.095			52		
28		8890	42.862					
29		8900	69.802					
30		8910	4.873					
31		8920	316.581	409				
32		8930						
33		9010			3.460			88
34		9020	46.981					
35		9030		93.053			43	
36		9050	1.042		21.319			68
37		9080	19.510					
38		9120						
39		9130						
40		9200	99	67.383	162.378		321	1.279
41		9210			825			
42		9230			818			
42		9280						
43		9302						
44		9320						
45	Total Expense		$2.360.476	$300.825	$226.774	$919	$508	$1.511
46	Total Test Year		$3.389.382	$982.531	$311.810	$1.219	$786	$1.843

Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Direct and Shared Service(CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Corporate(CONFIDENTIAL).xlsx

Percentages to use on TWE and Stores calculation of proforma payroll for Direct:

Main Account		Direct Per Book Non-Expense Payroll	Ratio by Account to Total Payroll
FERC 1540		$0	0.00%
1630		431.703	1.67%
1840 (non TWE)		10.614.886	41.11%
1840 (TWE 1840100-1840289)		0	0.00%
	1860	0	0.00%
	2530	360.831	1.40%
Total Non-Exp Mains		$11.407.419	44.18%
Total Expense Mains		14.412.818	55.82%
Total Payroll		$25.820.237	100.00%

Percentages to use on TWE and Stores calculation of proforma payroll for Shared Svcs:

Main Account	Shared Services Per Book Capital Payroll	Ratio by Account to Total Payroll
FERC 1540	$0	0.00%
1630	0	0.00%
1840 (non TWE)	6.865.693	34.11%
1840 (TWE 1840100-1840289)	174.693	0.87%
1860	0	0.00%
2530	0	0.00%
Total Non-Exp Mains	$7.040.386	34.98%
Total Expense Mains	13.084.842	65.02%
Total Payroll	$20.125.228	100.00%

Note: Average load rate for Stores during the test year 24.89 %
Note: Average load rate for TWE during the test year 52.42 %

WKP G-4.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BASE PAYROLL

		BASE					
		HOURLY			SALARY		
LINE NO.	DESCRIPTION	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL
		(a)	(b)	(c)	(d)	(e)	(f)
	Capital						
1	1010						
2	1540						
3	1630	25,502		678	7,345		3,105
4	1840	481,513	206,778	57,649	333,049	349,526	1,101,077
5	1860						
6	2530	6,132			21,422		
7	Total Capital	$513,146	$206,778	$58,327	$361,816	$349,526	$1,104,182
	Expense						
8	8500					$1,844	$5,485
9	8530						
10	8560	22,528	1,093	11,349	8,174	16,153	23,950
11	8570						
12	8590						
13	8610						2,705
14	8630		18,959				
15	8650						
16	8700		968	6,543	20,951	66,617	128,873
17	8710		28,154			8,980	
18	8740	141,037	4,060	4,172	29,145	20,919	37,911
19	8750	13,570			7,623	2,436	
20	8760				663	6,720	
21	8770					1,615	
22	8780	269,460		13,478	24,548		6,641
23	8790						
24	8800	17,048	555	2,273	14,735	26,978	5,681
25	8850						10,161
26	8860						
27	8870	142,217			11,519		

WKP G-4.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BASE PAYROLL

		BASE					
		HOURLY			SALARY		
LINE NO.	DESCRIPTION	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL
		(a)	(b)	(c)	(d)	(e)	(f)
28	8890	26,961			5,530		
29	8900	40,432			5,530		
30	8910	1,478					
31	8920	61,639	2,751		1,972		
32	8930						
33	9010			8,072			69,497
34	9020	29,345			4,688		
35	9030		220,590		809	88,256	
36	9050			51,520			179,191
37	9080	25,599			43,692	17,896	119,780
38	9120						
39	9130						
40	9200	1,194	51,928	265,471	24,160	488,535	4,135,521
41	9210						
42	9230						
43	9280						
44	9302						
45	9320						
46	Total Expense	$792,509	$329,057	$362,880	$203,740	$746,949	$4,725,395
47	Total Base Payroll	$1,305,655	$535,835	$421,208	$565,555	$1,096,475	$5,829,577

Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Direct and Shared Service(CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Corporate(CONFIDENTIAL).xlsx

SCHEDULE G-5

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

OVERTIME PAYROLL ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)
1	Total Proforma Hourly Base Payroll	G-4	$16,973,521	$6,965,856	$5,475,702	
2	Overtime as a % of Hourly Base Payroll (Actual for the Test Period)	WKP G-4.b	21%	15%	6%	
3	Total Annualized Overtime Payroll (Ln 1 times Ln 2)		$3,606,202	$1,024,116	$331,227	
4	Test Period Overtime Payroll	WKP G-4.b	3,389,382	982,531	311,810	
5	Overtime Payroll Adjustment Total (Ln 3 minus Ln 4)		$216,819	$41,585	$19,417	
6	Allocation to TGS		100.00%	100.00%	28.74%	
7	Allocated Base Payroll Adjustment to TGS (Ln 5 times Ln 6)		$216,819	$41,585	$5,580	
8	Allocation to Service Area	WKP A.b	100.00%	46.74%	46.74%	
9	Allocated Base Payroll Adjustment to Service Area (Ln 7 times Ln 8)		$216,819	$19,435	$2,608	
10	Payroll Expense Factor	WKP G-4.b	56%	65%	83%	
11	Test Year Base Payroll O&M Expense Adjustment (Ln 9 times Ln 10)		$121,028	$12,636	$2,172	
	Adjustment Summary:					
12	Account 9302				$2,172	$2,172
13	Other O&M Accounts (See WKP G-5.a for Distribution by FERC Account)		121,028	12,636		133,664
14	Total (Ln 12 plus Ln 13)		$121,028	$12,636	$2,172	$135,836
15	Total Test Year Overtime Expense after Allocation		$1,891,948	$298,557	$34,874	$2,225,380
16	Total As Adjusted Overtime Expense after Allocation		$2,012,976	$311,193	$37,046	$2,361,215

WKP G-5.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

OVERTIME PAYROLL EXPENSE

	DISTRIBUTION OF DIRECT OVERTIME PAYROLL O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT				DISTRIBUTION OF SHARED SERVICES OVERTIME PAYROLL O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT			
LINE NO.	MAIN ACCOUNT	PER BOOK O&M PAYROLL	RATIO OF PAYROLL BY ACCOUNT	TOTAL	MAIN ACCOUNT	PER BOOK O&M PAYROLL	RATIO OF PAYROLL BY ACCOUNT	TOTAL
		(a)	(b)	(c)		(d)	(e)	(f)
1	8500	$0	0.00%	$0	8500	$21,094	0.16%	$20
2	8530	0	0.00%	0	8530	0	0.00%	0
3	8560	397,196	2.76%	3,335	8560	210,131	1.61%	203
4	8570	13,831	0.10%	116	8570	0	0.00%	0
5	8590	0	0.00%	0	8590	0	0.00%	0
6	8610	0	0.00%	0	8610	0	0.00%	0
7	8630	2,560	0.02%	21	8630	241,350	1.84%	233
8	8650	0	0.00%	0	8650	0	0.00%	0
9	8700	229,837	1.59%	1,930	8700	685,933	5.24%	662
10	8710	0	0.00%	0	8710	561,347	4.29%	542
11	8740	2,174,810	15.09%	18,262	8740	343,277	2.62%	332
12	8750	266,134	1.85%	2,235	8750	28,143	0.22%	27
13	8760	14,396	0.10%	121	8760	79,221	0.61%	77
14	8770	0	0.00%	0	8770	18,956	0.14%	18
15	8780	4,458,180	30.93%	37,436	8780	3,356	0.03%	3
16	8790	0	0.00%	0	8790	0	0.00%	0
17	8800	427,293	2.96%	3,588	8800	317,507	2.43%	307
18	8850	0	0.00%	0	8850	0	0.00%	0
19	8860	0	0.00%	0	8860	0	0.00%	0
20	8870	2,428,127	16.85%	20,390	8870	96	0.00%	0
21	8890	434,803	3.02%	3,651	8890	0	0.00%	0
22	8900	613,967	4.26%	5,156	8900	0	0.00%	0
23	8910	22,632	0.16%	190	8910	0	0.00%	0
24	8920	1,216,810	8.44%	10,218	8920	8,354	0.06%	8
25	8930	0	0.00%	0	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	16,898	0.13%	16
27	9020	486,475	3.38%	4,085	9020	0	0.00%	0
28	9030	9,039	0.06%	76	9030	3,937,330	30.09%	3,802
29	9050	3,930	0.03%	33	9050	179	0.00%	0
30	9080	920,424	6.39%	7,729	9080	211,569	1.62%	204
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	292,375	2.03%	2,455	9200	6,400,101	48.91%	6,181
34	9210	0	0.00%	0	9210	0	0.00%	0
35	9230	0	0.00%	0	9230	0	0.00%	0
36	9301	0	0.00%	0	9301	0	0.00%	0
37	9302	0	0.00%	0	9302	0	0.00%	0
38	9320	0	0.00%	0	9320	0	0.00%	0
39	Total	$14,412,818	100.00%	$121,028	Total	$13,084,842	100.00%	$12,636

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BENEFITS AND PAYROLL TAX ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	RATE PER DIRECT PAYROLL $	DIRECT	RATE PER SHARED SERVICES PAYROLL $	SHARED SERVICES	RATE PER DISTRIGAS PAYROLL $	DISTRIGAS	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Total Proforma Base and Overtime Payroll $	G-4		$27,366,388		$21,147,671		$75,761,852	
2	BENEFITS COMPUTED PER PAYROLL $								
3	H&W BENEFITS*	WKP G-6.b	14.27%	$3,904,594	14.27%	$3,017,317	12.79%	$9,692,689	
4	PENSION	WKP G-6.b	0.12%	33,979	0.12%	26,258	-0.12%	(93,626)	
5	OPEB	WKP G-6.b	0.21%	57,533	0.21%	44,460	0.03%	24,300	
6	SERP	WKP G-6.b	0.0045%	1,221	0.0045%	0	1.0504%	0	
7	401K & NQDC	WKP G-6.b	5.87%	1,606,974	5.87%	1,241,806	4.54%	3,436,649	
8	PROFIT SHARING	WKP G-6.b	3.70%	1,011,350	3.70%	781,532	2.65%	2,004,429	
				$6,615,651		$5,111,372		$15,064,441	
9	ADDITIONAL BENEFITS								
10	A&G EMPL BEN MISC ADMIN	WKP G-6.b				0		(553)	
11	A&G EMPL BEN FAS 112	WKP G-6.b				0		1,840	
12	A&G EMPL BEN SCHOLARSHIPS	WKP G-6.b				0		116,500	
13	A&G EMPL BEN TUITION LOANS	WKP G-6.b				39,056		64,624	
14	A&G EMPL BEN ADOPTION ALLOW	WKP G-6.b				0		0	
15	A&G EMPL BEN SPR/SUMMER ACTIVITIES	WKP G-6.b						0	
16	A&G EMPL BEN EMPLOYEE EVENTS	WKP G-6.b		1,182		17,931		(27,681)	
17	A&G EMPL BEN SVC RECOGNITION	WKP G-6.b				73,200		64,000	
18	A&G EMPL BEN EMPLOYEE REFERRAL	WKP G-6.b				0		156,522	
19	A&G EMPL BEN DRUG & ALCOHOL TESTING	WKP G-6.b				0		89,160	
20	A&G EMPL BEN EMPL ASST PROGRAM	WKP G-6.b				20,194		15,473	
21	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	WKP G-6.b				0		0	
22	A&G EMPL BEN DISABILITY	WKP G-6.b				60,101		46,646	
23	A&G EMPL BEN ACCOMMODATIONS	WKP G-6.b				0		6,598	
24	A&G EMPL BEN WELLNESS PROGRAM	WKP G-6.b				0		85,286	
				$1,182		$210,481		$618,415	
25	Annualized Test Year Benefits			$6,616,832		$5,321,853		$15,682,856	
26	PAYROLL TAX RATE PER PAYROLL $	WKP G-6.b	7.90%	$2,161,519	7.90%	$1,670,337	5.81%	$4,401,821	
27	Total Annualized Benefits and Payroll Tax			$8,778,351		$6,992,191		$20,084,676	
28	Test Year Benefits and Payroll Tax			$7,665,230		$6,257,901		$21,923,338	
29	Allocable Adjustment to Benefits and Payroll Tax			$1,113,121		$734,289		$(1,838,661)	
30	Allocation to TGS			100%		100%		28.74%	

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BENEFITS AND PAYROLL TAX ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	RATE PER DIRECT PAYROLL $	DIRECT	RATE PER SHARED SERVICES PAYROLL $	SHARED SERVICES	RATE PER DISTRIGAS PAYROLL $	DISTRIGAS	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
31	Allocated Benefits and Payroll Tax Adjustment to TGS			$1,113,121		$734,289		$(528,431)	
32	Allocation to Service Area	WKP A.b		100%		46.74%		46.74%	
33	Allocated Benefits and Payroll Tax Adjustment to Service Area			$1,113,121		$343,179		$(246,969)	
34	Payroll Expense Factor	WKP G-4.b		55.82%		65.02%		83.27%	
35	Test Year Benefits and Payroll Tax Adjustment			$621,343		$223,125		$(205,644)	
36	Adjustment Summary:								
37	Account 9302			$0		$0		$(205,644)	$(205,644)
38	Other O&M Accounts (See WKP G4a for Distribution by FERC Account)			621,343		223,125			844,468
39	Total			$621,343		$223,125		$(205,644)	$638,824

* Includes: Medical, Dental, Flexible Spending Plan Administration, Accidental Death & Dismemberment, Long Term Disability and Life Insurance

		Direct	Shared Services	Distrigas	Total
Total Test Year Benefits and Payroll Tax Expense after Allocation		$4,278,720	$1,901,559	$2,452,000	$8,632,279
Total As Adjusted Benefits and Payroll Tax Expense after Allocation		4,900,063	2,124,684	2,246,357	9,271,103
	Taxes only	$1,206,557	$507,557	$492,319	$2,206,433

Source: SCH G-6 -Corporate Test Year Benefits and Payroll Taxes (CONFIDENTIAL).xlsx
Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes-Direct and Shared Services.xlsx

WKP G-6.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BENEFITS AND PAYROLL TAX EXPENSE

	DISTRIBUTION OF DIRECT BENEFITS AND PAYROLL TAX O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT				DISTRIBUTION OF SHARED SERVICE BENEFITS AND PAYROLL TAX O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT			
LINE NO.	MAIN ACCOUNT	TEST YEAR BEENFITS AND PAYROLL TAX ADJUSTMENT	RATIO OF PAYROLL BY ACCOUNT	TOTAL	MAIN ACCOUNT	TEST YEAR BEENFITS AND PAYROLL TAX ADJUSTMENT	RATIO OF PAYROLL BY ACCOUNT	TOTAL
		(a)	(b)	(c)		(d)	(e)	(f)
1	4081	$2,010,222	25.98%	$161,399	4081	$1,586,193	25.98%	$57,959
2	8560	0	0.00%	0	8560	0	0.00%	0
3	8570	0	0.00%	0	8570	0	0.00%	0
4	8590	0	0.00%	0	8590	0	0.00%	0
5	8610	0	0.00%	0	8610	0	0.00%	0
6	8630	0	0.00%	0	8630	0	0.00%	0
7	8650	0	0.00%	0	8650	0	0.00%	0
8	8700	0	0.00%	0	8700	0	0.00%	0
9	8710	0	0.00%	0	8710	0	0.00%	0
10	8740	0	0.00%	0	8740	0	0.00%	0
11	8750	0	0.00%	0	8750	0	0.00%	0
12	8760	0	0.00%	0	8760	0	0.00%	0
13	8770	0	0.00%	0	8770	0	0.00%	0
14	8780	0	0.00%	0	8780	0	0.00%	0
15	8790	0	0.00%	0	8790	0	0.00%	0
16	8800	0	0.00%	0	8800	0	0.00%	0
17	8850	0	0.00%	0	8850	0	0.00%	0
18	8860	0	0.00%	0	8860	0	0.00%	0
19	8870	0	0.00%	0	8870	0	0.00%	0
20	8890	0	0.00%	0	8890	0	0.00%	0
21	8900	0	0.00%	0	8900	0	0.00%	0
22	8910	0	0.00%	0	8910	0	0.00%	0
23	8920	0	0.00%	0	8920	0	0.00%	0
24	8930	0	0.00%	0	8920	0	0.00%	0
25	9010	0	0.00%	0	9010	0	0.00%	0
26	9020	0	0.00%	0	9020	0	0.00%	0
27	9030	0	0.00%	0	9030	0	0.00%	0
28	9050	0	0.00%	0	9050	0	0.00%	0
29	9080	0	0.00%	0	9080	0	0.00%	0
30	9120	0	0.00%	0	9120	0	0.00%	0
31	9130	0	0.00%	0	9130	0	0.00%	0
32	9200	0	0.00%	0	9200	0	0.00%	0
33	9210	0	0.00%	0	9210	0	0.00%	0
34	9260	5,655,008	74.02%	459,944	9260	4,671,709	74.02%	165,166
35	9302	0	0.00%	0	9302	0	0.00%	0
36	9320	0	0.00%	0	9320	0	0.00%	0
37	Total	$7,665,230	100.00%	$621,343	Total	$6,257,901	100.00%	$223,125

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BENEFITS AND TAXES

LINE NO.		DESCRIPTION	TEXAS EMPLOYEES		CORPORATE SHARED SERVICE AND DISTRIGAS EMPLOYEES	
			(a)	(b)	(c)	(d)
	Based on Known and Measurable for 2024					
	H&W Benefits					
1	9260190	A&G EMPL BEN RESERVE	$10,754,473		$11,066,234	
2			$10,754,473	14.27%	$11,066,234	12.79%
	Pension					
3	9260413	ONE GAS RETIREMENT PLAN SC	$1,204,699		$1,626,303	
4	9260513	ONE GAS RETIREMENT PLAN NSC	(1,215,596)		(1,819,037)	
5	9260115	EMPL BEN PENSION ADMIN	104,486		85,840	
			$93,589	0.12%	$(106,894)	-0.12%
	OPEB					
6	9260431	OPEB SC	$30,824		$84,532	
7	9260531	OPEB NSC	127,641		(56,788)	
8	9260132	A&G EMPL BEN FAS 106 ADMIN	0		0	
			$158,465	0.21%	$27,744	0.03%
	SERP					
9	9260411	SERP SC			$0	
10	9260511	SERP NSC	3,362		826,600	
11	9260112	A&G EMPL BEN SERP ADMIN			82,000	
			$3,362	0.00%	$908,600	1.05%
	Based on Test Year Data					
	401k & NQDC					
12	9260101	A&G EMPL BEN 401(K) CO MATCH	$4,275,313		$3,512,363	
13	9260102	A&G EMPL BEN 401(K) ADMIN	150,795		123,882	
14	9260103	A&G EMPL BEN DEF COMP CO MATCH	0		258,500	
15	9260104	A&G EMPL BEN DEF COMP ADMIN	0		28,910	
			$4,426,108	5.87%	$3,923,655	4.54%
	Profit Sharing Plan					
16	9260141	A&G EMPL BEN PROFIT SHARING	$2,785,574		$2,288,475	
17	9260140	A&G EMPL BEN PROFIT SHARING ADMIN	0		0	
			$2,785,574	3.70%	$2,288,475	2.65%
	Non - Payroll Related 9260 Expenditures					
18	9260118	A&G EMPL BEN MISC ADMIN			(553)	
19	9260119	A&G EMPL BEN FAS 112			1,840	
20	9260301	A&G EMPL BEN SCHOLARSHIPS			116,500	
21	9260302	A&G EMPL BEN TUITION LOANS	39,056		64,624	
22	9260303	A&G EMPL BEN ADOPTION ALLOW				
23	9260306	A&G EMPL BEN SPR/SUMMER ACTIVITIES	103			
24	9260307	A&G EMPL BEN EMPLOYEE EVENTS	21,625		(27,681)	
25	9260310	A&G EMPL BEN SVC RECOGNITION	73,200		64,000	
26	9260314	A&G EMPL BEN EMPLOYEE REFERRAL			156,522	
27	9260321	A&G EMPL BEN DRUG & ALCOHOL TESTING			89,160	
28	9260326	A&G EMPL BEN EMPL ASST PROGRAM	20,194		15,473	
29	9260327	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT				
30	9260328	A&G EMPL BEN DISABILITY	60,101		46,646	
31	9260329	A&G EMPL BEN ACCOMMODATIONS			6,598	
32	9260337	A&G EMPL BEN WELLNESS PROGRAM			85,286	
			$214,279		$618,415	
	Based on Known and Measurable for 2024					
	Payroll Taxes					
33	4081102	GEN TAX FICA	$5,735,000	7.61%	$4,818,000	5.57%
34	4081101	GEN TAX FED UNEMPL INS TAX	42,500	0.06%	34,200	0.04%
35	4081132	GEN TAX STATE UNEMPL INS	176,000	0.23%	173,400	0.20%
			$5,953,500	7.90%	$5,025,600	5.81%
36	Total Benefit and Payroll Expense		$24,389,350		$23,751,829	
37	Total Labor*		$75,375,594	32.07%	$86,498,021	26.74%

38 * Total Labor used to calculate % is adjusted for known and measurable changes

Source: WKP G-6.b Benefits and Payroll Tax Support.xlsx

WKP G-6.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

BASE YEAR LEVEL PENSION AND OPEB

LINE NO.	DESCRIPTION	REFERENCE	DIRECT	SHARED SERVICES	DISTRIGAS	TOTAL
			(a)	(b)	(c)	(d)
1	PENSION	SCH G-6	$33,979	$26,258	-$93,626	
2	OPEB	SCH G-6	57,533	44,460	24,300	
3	TOTAL		$91,512	$70,717	-$69,326	
4	Allocation to TGS	SCH G-6	100.00 %	100.00 %	28.74 %	
5	PENSION		$33,979	$26,258	-$26,908	
6	OPEB		57,533	44,460	6,984	
7	TOTAL		$91,512	$70,717	-$19,924	
8	Allocation to Service Area	SCH G-6	100.00 %	46.74 %	46.74 %	
9	PENSION		$33,979	$12,272	-$12,576	
10	OPEB		57,533	20,779	3,264	
11	TOTAL		$91,512	$33,051	-$9,312	
12	Payroll Expense Factor	SCH G-6	55.82 %	65.02 %	83.27 %	
13	PENSION		$18,967	$7,979	-$10,472	$16,474
14	OPEB		32,115	13,510	2,718	48,343
15	TOTAL		$51,082	$21,489	-$7,754	$64,817

SCHEDULE G-7

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

AMORTIZATION OF PENSION & OTHER POST EMPLOYMENT BENEFITS

LINE NO.	YEAR ENDED DECEMBER 2023	BEGINNING OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION	END OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION
	(a)	(b)	(c)	(d)	(e)
1	2023			$(3,315,201)	
2	2024	$(3,315,201)		(3,315,201)	
3	2025	(3,315,201)	$(552,533)	(2,762,667)	
4	2026	(2,762,667)	(552,533)	(2,210,134)	
5	2027	(2,210,134)	(552,533)	(1,657,600)	
6	2028	(1,657,600)	(552,533)	(1,105,067)	
7	2029	(1,105,067)	(552,533)	(552,533)	
8	2030	(552,533)	(552,533)	0	
9	Annualized Amortization of Pension & Other Post Employment Benefits Reg Asset - Account 4073				$(552,533)
10	Test Year Pension & Other Post Employment Benefits Reg Asset Amortization Expense - Account 4073				308,348
11	Total Adjustment to Test Period Expense				$(860,882)

SCHEDULE G-8

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

INCENTIVE COMPENSATION

			CORPORATE ALLOCATED TO TGS							Allocated to CGSA		
LINE NO.	DESCRIPTION	ACCT. 'NO.	UNALLOCATED CORPORATE PER BOOK	ADJUSTMENTS	UNALLOCATED ADJUSTED TEST YEAR	ALLOCATION TO TGS	ALLOCATED CORPORATE PER BOOK TO TGS	ALLOCATED ADJUSTMENT TO TGS	ALLOCATED ADJUSTED TEST YEAR TO TGS	TOTAL PER BOOK AS ALLOCATED TO CGSA	TOTAL ADJUSTMENT AS ALLOCATED TO CGSA	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO CGSA
										46.7362%		
1	GEN TAX FICA INCENTIVE	4081	$796,458	$(31,342)	$765,116	28.74%	$228,902	$(9,008)	$219,894	$106,980	$(4,210)	$102,770
2	A&G SALARIES INCENTIVE PLAN	9302	13,661,346	(1,418,496)	12,242,850	28.74%	3,926,271	(407,676)	3,518,595	1,834,990	(190,532)	1,644,458
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9302	651,648	(27,784)	623,864	28.74%	187,284	(7,985)	179,299	87,529	(3,732)	83,797
4	A&G EMPL BEN ACCR PSP ON STI	9302	573,778	(2,482)	571,296	28.74%	164,904	(713)	164,190	77,070	(333)	76,736
5	TOTAL SHORT TERM INCENTIVE		$15,683,230	$(1,480,104)	$14,203,126		$4,507,360	$(425,382)	$4,081,978	$2,106,569	$(198,807)	$1,907,762
6	GEN TAX FICA INCENTIVE - RESTRICTED	4081	$116,488		$116,488	28.74%	$33,479	$0	$33,479	$15,647	$0	$15,647
7	A&G SALARIES LT INCENT-RESTRICTED	9302	2,513,022		2,513,022	28.74%	722,243	0	722,243	337,549	0	337,549
8	GEN TAX FICA INCENTIVE- PERFORMANCE	4081	156,969	(43,831)	113,138	28.74%	45,113	(12,597)	32,516	21,084	(5,887)	15,197
9	A&G SALARIES LT INCENT-PERFORMANCE	9302	6,562,292	(3,627,714)	2,934,578	28.74%	1,886,003	(1,042,605)	843,398	881,446	(487,274)	394,172
10	TOTAL LONG TERM INCENTIVE		$9,348,771	$(3,671,545)	$5,677,226		$2,686,837	$(1,055,202)	$1,631,635	$1,255,725	$(493,161)	$762,564

			TGS			Allocated to CGSA		
LINE NO.	DESCRIPTION	ACCT. 'NO.	TGS PER BOOK	ADJUSTMENTS	TGS ADJUSTED TEST YEAR	TOTAL PER BOOK AS ALLOCATED TO CGSA	TOTAL ADJUSTMENT AS ALLOCATED TO CGSA	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO CGSA
						46.7362%		
	Short Term Incentive							
1	GEN TAX FICA INCENTIVE	4081	$313,549		$313,549	$146,541	$0	$146,541
2	A&G SALARIES INCENTIVE PLAN	9200	5,382,165		5,382,165	2,515,419	0	2,515,419
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9260	256,538		256,538	119,896	0	119,896
4	A&G EMPL BEN ACCR PSP ON STI	9260	225,883		225,883	105,569	0	105,569
5	TOTAL SHORT TERM INCENTIVE		$6,178,135	$0	$6,178,135	$2,887,425	$0	$2,887,425
6	GEN TAX FICA INCENTVIE - RESTRICTED	4081	$7,106		$7,106	$3,321	$0	$3,321
7	A&G SALARIES LT INCENT-RESTRICTED	9200	158,708		158,708	74,174	0	74,174
8	GEN TAX FICA INCENTIVE - PERFORMANCE	4081	4,991		4,991	2,333	0	2,333
9	A&G SALARIES LT INCENT-PERFORMANCE	9200	198,888		198,888	92,953	0	92,953
10	TOTAL LONG TERM INCENTIVE		$369,694	$0	$369,694	$172,781	$0	$172,781
11	Total Test Year Incentive Compensation after Allocation					$6,422,501		
12	Total As Adjusted Benefits and Payroll Tax Expense after Allocation					$5,730,532		

Source: SCH G-8 Incentive Compensation per book (CONFIDENTIAL).xlsx

WKP G-8.a STI ADJUSTMENT

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

STI ADJUSTMENT FOR NAMED EXECUTIVE OFFICERS

								ADJUSTMENT BASED ON FINANCIAL METRIC			
LINE NO.	NAMED EXECUTIVE OFFICER	STI PAID	FICA TAXES	401(k) MATCH	PROFIT SHARE	FINANCIAL METRIC WEIGHT	SAFETY METRIC WEIGHT	GEN TAX FICA INCENTIVE	A&G SALARIES INCENTIVE PLAN	A&G EMPL BEN ACCR 401(K) CO MATCH	A&G EMPL BEN ACCR PSP ON STI
ACCT		9302	4081	9302	9302			4081	9302	9302	9302
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h) = (c) * (f)	(i) = (b) * (f)	(j) = (d) * (f)	(k) = (e) * (f)
1	McAnnally	794,902	12,070	12,710	1,453	69.88 %	38.27 %	8,434	555,478	8,882	1,015
2	Lawhorn	351,500	15,550			69.88 %	38.27 %	10,866	245,628	—	—
3	Dinan	362,000	5,249	13,032		69.88 %	38.27 %	3,668	252,966	9,107	—
4	McCormick	311,500	5,466	14,018		69.88 %	38.27 %	3,820	217,676	9,795	—
5	Bender	210,000	6,517		2,100	69.88 %	38.27 %	4,554	146,748	—	1,467
6	**Total**							**31,342**	**1,418,496**	**27,784**	**2,482**

WKP G-8.b LTI ADJUSTMENT
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

LTI ADJUSTMENT FOR NAMED EXECUTIVE OFFICERS

LINE NO.	COMPANY	ACCT. 'NO.	NAMED EXECUTIVE OFFICERS (NEO)	January	February	March	April	May	June	July	August	September	October	November	December	Total A&G SALARIES LTI - PERFORMANCE
1	OGS	9302	*NEO*	$239,268	$260,025	$317,487	$317,487	$317,487	$317,487	$317,487	$317,487	$317,487	$317,487	$317,487	$271,038	$3,627,714
2	OGS	9302		207,054	254,356	249,333	245,125	245,125	245,125	245,125	237,826	237,826	241,700	244,925	281,274	2,934,797
3	TOTAL OGS PSU			$446,322	$514,381	$566,820	$562,612	$562,612	$562,612	$562,612	$555,313	$555,313	$559,187	$562,412	$552,313	$6,562,511
4	TGS	9200		$14,131	$15,221	$19,766	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,667	$16,436	$16,436	$198,660
5	TOTAL TGS PSU			14,131	15,221	19,766	16,667	16,667	16,667	16,667	16,667	16,667	16,667	16,436	16,436	198,660
6	GRAND TOTAL			$460,453	$529,602	$586,586	$579,280	$579,280	$579,280	$579,280	$571,980	$571,980	$575,854	$578,848	$568,749	$6,761,171

LINE NO.	COMPANY	ACCT. 'NO.	NAMED EXECUTIVE OFFICERS (NEO)	TOTAL PSU TAX
7	OGS	4081	NEO	$43,831
8		4081		113,138
9	TOTAL OGS PSU TAXES			$156,969
10	TGS			$4,991
11	TOTAL TGS PSU TAXES			4,991
12	GRAND TOTAL			$161,961

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

MISCELLANEOUS ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT	DIRECT SERVICE AREA	SHARED SERVICES ALLOCATION TO SERVICE AREA	DISTRIGAS ALLOCATION TO SERVICE AREA	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)
1	Payroll Taxes	4081	$1,181,058	$(1,171,015)	$(145)	$9,897
2	Transmission O & M - Mains Expenses	8560	0	(183)	0	(183)
3	Transmission Other Misc Expenses	8590	0	0	0	0
4	Maintenance of Mains	8630	0	(0)	0	(0)
5	Distr. Operations- General Supervision	8700	(222)	(394)	0	(616)
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0
7	Distr. Operations - Mains & Services	8740	(49)	0	0	(49)
8	Distr Meas & Reg St Misc	8750	0	0	0	0
9	Distr. Operations - Meter & House Reg. Exp.	8780	(10)	0	0	(10)
10	Distr. Operations - Other Expense	8800	(4,270)	(46)	0	(4,316)
11	Distr. Operations - Rents	8810	0	0	0	0
12	Distr. Operations - Struct. & Improv.	8860	0	0	0	0
13	Distr. Maintenance - Mains	8870	(20)	0	0	(20)
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0
15	Distr. Maintenance - Ind .Meas. & Reg. Stat. Misc.	8900	0	0	0	0
16	Customer Accounting - Supervision	9010	0	0	0	0
17	Customer Accounting - Meter Reading	9020	0	0	0	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	0	(28,144)	0	(28,144)
19	Customer Accounting - Bad Debt	9040	0	0	0	0
20	Customer Accounting - Misc. Expense	9050	0	0	0	0
21	Customer Assistance-Misc. Expense	9080	(2,277)	(5,871)	0	(8,148)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0
24	Advertising-Misc. Expense	9130	0	0	0	0
25	Salaries	9200	0	235,068	0	235,068
26	Admin & Gen - Office Supp & Exp	9210	(27,019)	(2,697)	0	(29,716)
27	Admin & Gen - Outside Services	9230	0	0	0	0
28	Property Insurance	9240	0	4,361	0	4,361
29	Admin & Gen - Injuries & Damages	9250	0	95,315	0	95,315
30	Admin & Gen - Employee Pensions & Benefits	9260	2,950,870	(2,085,398)	(122,707)	742,765
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0
32	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0
33	Admin & Gen - Labor Attends Credit	9290	0	0	0	0
34	Admin & Gen - Advertising	9301	0	0	0	0
35	Admin & Gen - Misc General	9302	(25,646)	(3,943,519)	(82,627)	(4,051,792)
36	Admin & Gen - Rents	9310	0	0	0	0
37	Totals		$4,072,414	$(6,902,523)	$(205,480)	$(3,035,590)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

MISCELLANEOUS ADJUSTMENTS

DIRECT SERVICE AREA

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF CLUBS AND CIVIC EXPENSE		REMOVAL OF MEAL/HOTEL COSTS OVER RRC THRESHOLD AND REMOVAL OF SPOUSE AND ALCOHOL ACTIVITY	ADJUSTMENT TO INCLUDE DIRECT BENEFITS AND PAYROLL RELATED TAXES	ADJUSTMENT TO INCLUDE DIRECT O/H FOR PAYROLL RELATED TAXES AND BENEFITS	DIRECT SERP WITH PAYROLL FACTOR APPLIED SCH G-6 BENEFITS & PAYROLL	OTHER ADJUSTMENTS	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Payroll Taxes	4081				2,010,222	$(829,165)			$1,181,058
2	Transmission O & M - Mains Expenses	8560								0
3	Transmission Other Misc Expenses	8590								0
4	Maintenance of Mains	8630								0
5	Distr. Operations- General Supervision	8700			(222)					(222)
6	Distr. Operations - Distribution Load Dispatch	8710								0
7	Distr. Mains & Services	8740			(49)					(49)
8	Distr Meas & Reg St Misc	8750								0
9	Distr. Operations - Meter & House Reg. Exp.	8780			(10)					(10)
10	Distr. Operations - Other Expense	8800	(164)		(3,923)				(183)	(4,270)
11	Distr. Operations - Rents	8810								0
12	Distr. Structuctures & Improvements	8860								0
13	Distr. Maintenance - Mains	8870	(20)							(20)
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890								0
15	Distr. Maintenance- Cathodic Protection	8900								0
16	Customer Accounting - Supervision	9010								0
17	Customer Accounting - Meter Reading	9020								0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030								0
19	Customer Accounting - Bad Debts	9040								0
20	Customer Accounting - Misc. Expense	9050								0
21	Customer Asst.- Misc. Expenses	9080	(151)		(1,910)				(217)	(2,277)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090								0
23	Demo/Sell- Misc. Expenses	9120								0
24	Advertising-Misc. Expense	9130								0
25	Advertising-Misc. Expense	9200								0
26	Admin & Gen - Office Supp & Exp	9210	(23,458)		(704)				(2,857)	(27,019)
27	Admin & Gen - Outside Services	9230								0
28	Property Insurance	9240								0
29	Admin & Gen - Injuries & Damages	9250								0
30	Admin & Gen - Employee Pensions & Benefits	9260				5,655,008	(2,704,138)			2,950,870
31	Admin & Gen - A&G Franchise Elections	9270								0
32	Admin & Gen - Regulatory Commission Expense	9280								0
33	Admin & Gen - Labor Attends Credit	9290								0
34	Admin & Gen - Advertising	9301								0
35	Admin & Gen - Misc General	9302	(20,646)						(5,000)	(25,646)
36	Admin & Gen - Rents	9310								0
37	Totals		$(44,438)	##	$(6,818)	$7,665,230	$(3,533,302)	$0	$(8,257)	$4,072,414

Source: SCH G-9.a Direct TY 12 31 2023 Civic Charitable Misc Adjustments .xlsx

Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr (CONFIDENTIAL)

Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes-Direct and Shared Services.xlsx

Source: SCH G-20 Regulatory Expenses - COVID (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

MISCELLANEOUS ADJUSTMENTS
SHARED SERVICES

LINE NO.	DESCRIPTION	ACCT	ADJUSTMENT FOR KNOWN AND MEASURABLE CHANGE IN INSURANCE PREMIUMS	REMOVE URI RECLASSIFICATION ENTRY	ADJUSTMENT TO REMOVE COSTS ASSOCIATED WITH ROYALTY FEES	REMOVE MEAL/HOTEL COSTS OVER RRC THRESHOLD AND REMOVAL OF SPOUSE AND ALCOHOL ACTIVITY	REMOVE MANAGEMENT DECISION TO NOT SEEK RECOVERY	REMOVE - RULE 7.5414 CONTRIBUTIONS, DONATIONS TO CHARITABLE, RELIGIOUS, OR OTHER NONPROFIT ORGANIZATIONS	ADJUSTMENT FOR MISCODED ACTIVITY	ADJUSTMENT TO REMOVE PAYROLL RELATED TAXES AND BENEFITS	ADJUSTMENT TO INCLUDE SHARED SERVICE PAYROLL RELATED TAXES AND BENEFITS	ADJUSTMENT TO REMOVE TOTAL O/H FOR PAYROLL RELATED TAXES AND BENEFITS	ADJUSTMENT TO INCLUDE SHARED SERVICES PORTION OF O/H FOR PAYROLL RELATED TAXES AND BENEFITS	TOTAL	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l) = sum(a:k)	(m)	(n)	(o) = l*m*n
1	Payroll Taxes	4081					$(52,761)			$(5,761,028)	1,586,192.69	$2,376,275	$(654,263)	$(2,505,585)	100.00%	46.7362%	$(1,171,015)
2	Transmission O & M - Mains Expenses	8560				(455)								(455)	86.02%	46.7362%	(183)
3	Transmission Other Misc Expenses	8590												0	86.02%	46.7362%	—
4	Maintenance of Mains	8630				(0)								(0)	86.02%	46.7362%	(0)
5	Distr. Operations- General Supervision	8700				(275)	(163)	(541)						(980)	86.02%	46.7362%	(394)
6	Distr. Operations - Distribution Load Dispatch	8710												0	86.02%	46.7362%	—
7	Distr. Mains & Services	8740												0	86.02%	46.7362%	—
8	Distr Meas & Reg St Misc	8750												0	86.02%	46.7362%	—
9	Distr. Operations - Meter & House Reg. Exp.	8780												0	86.02%	46.7362%	—
10	Distr. Operations - Other Expense	8800				(99)	(15)							(114)	86.02%	46.7362%	(46)
11	Distr. Operations - Rents	8810												0	86.02%	46.7362%	—
12	Distr. Structuctures & Improvements	8860												0	86.02%	46.7362%	—
13	Distr. Maintenance - Mains	8870												0	86.02%	46.7362%	—
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890												0	86.02%	46.7362%	—
15	Distr. Maintenance- Cathodic Protection	8900												0	86.02%	46.7362%	—
16	Customer Accounting - Supervision	9010												0	86.02%	46.7362%	—
17	Customer Accounting - Meter Reading	9020												0	86.02%	46.7362%	—
18	Customer Records and Collections	9030				(164)			(69,840)					(70,004)	86.02%	46.7362%	(28,144)
19	Customer Accounting - Bad Debts	9040												0	100.00%	46.7362%	—
20	Customer Accounting - Misc. Expense	9050												0	86.02%	46.7362%	—
21	Customer Asst.- Misc. Expenses	9080				(49)	(992)	(13,562)						(14,603)	86.02%	46.7362%	(5,871)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090												0	86.02%	46.7362%	—
23	Demo/Sell- Misc. Expenses	9120												0	86.02%	46.7362%	—
24	Advertising-Misc. Expense	9130												0	86.02%	46.7362%	—
25	Administrative and General Salaries	9200		351,330			233,360							584,690	86.02%	46.7362%	235,068
26	Admin & Gen - Office Supp & Exp	9210				(6,034)	(540)	(135)						(6,709)	86.02%	46.7362%	(2,697)
27	Admin & Gen - Outside Services	9230												0	86.02%	46.7362%	—
28	Property Insurance	9240	10,848											10,848	86.02%	46.7362%	4,361
29	Admin & Gen - Injuries & Damages	9250	237,080											237,080	86.02%	46.7362%	95,315
30	Admin & Gen - Employee Pensions & Benefits	9260					938,857			(16,413,591)	4,671,709	7,749,697	(2,133,736)	(5,187,065)	86.02%	46.7362%	(2,085,398)
31	Admin & Gen - A&G Franchise Elections	9270												0	86.02%	46.7362%	—
32	Admin & Gen - Regulatory Commission Expense	9280												0	86.02%	46.7362%	—
33	Admin & Gen - Labor Attends Credit	9290												0	86.02%	46.7362%	—
34	Admin & Gen - Advertising	9301												0	86.02%	46.7362%	—
35	Admin & Gen - Misc General	9302			(9,799,681)	(824)		(8,311)						(9,808,816)	86.02%	46.7362%	(3,943,519)
36	Admin & Gen - Rents	9310												0	86.02%	46.7362%	0
37	Totals		$247,928	$351,330	$(9,799,681)	$(7,900)	$1,117,745	$(22,550)	$(69,840)	$(22,174,619)	$6,257,901	$10,125,972	$(2,787,999)	$(16,761,713)			$(6,902,523)

Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes-Direct and Shared Services.xlsx
Source: WKP G-9.b.3 Insurance Adjustment.xlsx
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr (CONFIDENTIAL).xlxs

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

MISCELLANEOUS ADJUSTMENTS
DISTRIGAS AMOUNT ALLOCATED TO TGS

LINE NO.	DESCRIPTION	ACCT	REMOVE - RULE 7.5414 CONTRIBUTIONS, DONATIONS TO CHARITABLE, RELIGIOUS, OR OTHER NONPROFIT ORGANIZATIONS		REMOVE MEAL/HOTEL COSTS OVER RRC THRESHOLD AND REMOVAL OF SPOUSE AND ALCOHOL ACTIVITY	REMOVE SERP ACTIVITY	REMOVE MANAGEMENT DECISION TO NOT SEEK RECOVERY	REMOVAL OF CORPORATE AIRCRAFT	ADJUSTMENT FOR KNOWN AND MEASURABLE CHANGE IN INSURANCE PREMIUMS		REMOVE LEGISLATIVE/ GOVERNMENTAL ACTIVITY	TOTAL	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)=sum(a:i)	(k)	(l)	(m)=j*k*l
1	Payroll Taxes	4081	$0	$0	$0	$(1,243)	$881	$0	$0	$0	$0	$(362)	86.02%	46.7362%	$(145)
2	Transmission O & M - Mains Expenses	8560	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
3	Transmission Other Misc Expenses	8590	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
4	Maintenance of Mains	8630	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
5	Distr. Operations- General Supervision	8700	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
7	Distr. Mains & Services	8740	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
8	Distr Meas & Reg St Misc	8750	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
10	Distr. Operations - Other Expense	8800	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
11	Distr. Operations - Rents	8810	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
12	Distr. Structuctures & Improvements	8860	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
13	Distr. Maintenance - Mains	8870	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
15	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
16	Customer Accounting - Supervision	9010	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
17	Customer Accounting - Meter Reading	9020	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
19	Customer Accounting - Bad Debts	9040	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
20	Customer Accounting - Misc. Expense	9050	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
21	Customer Asst.- Misc. Expenses	9080	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
24	Advertising-Misc. Expense	9130	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
25	Advertising-Misc. Expense	9200	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
26	Admin & Gen - Office Supp & Exp	9210	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
27	Admin & Gen - Outside Services	9230	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
28	Property Insurance	9240	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
29	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
30	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	(305,213)	0	0	0	0	0	(305,213)	86.02%	46.7362%	(122,707)
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
32	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
33	Admin & Gen - Labor Attends Credit	9290	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
34	Admin & Gen - Advertising	9301	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
35	Admin & Gen - Misc General	9302	(59,693)	0	(28,556)	(18,357)	287,548	(404,249)	31,882	0	(14,096)	(205,521)	86.02%	46.7362%	(82,627)
36	Admin & Gen - Rents	9310	0	0	0	0	0	0	0	0	0	0	86.02%	46.7362%	0
37	Totals		$(59,693)	$0	$(28,556)	$(324,813)	$288,429	$(404,249)	$31,882	$0	$(14,096)	$(511,096)			$(205,480)

Source: WKP G-9.b.2 Misc Adjustments Distrigas.xlsx
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distrigas (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RENTS AND LEASES ADJUSTMENT

LINE NO.	DESCRIPTION	ACCT	DIRECT SERVICE AREA	SHARED SERVICES ALLOCATION TO SERVICE AREA	DISTRIGAS ALLOCATION TO SERVICE AREA	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)
1	Transmission O & M - Mains Expenses	8560	$0	$0	$0	$0
2	Distr. Operations - Supervision and Engineering	8700	0	0	0	0
3	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0
4	Distr. Operations - Mains & Services	8740	0	0	0	0
5	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0
6	Distr. Operations - Other Expense	8800	0	0	0	0
7	Distr. Operations - Rents	8810	0	0	0	0
8	Distr. Maintenance - Mains	8870	0	0	0	0
9	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0
10	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0	0	0
11	Customer Accounting - Supervision	9010	0	0	0	0
12	Customer Accounting - Customer Accounting	9030	0	0	0	0
13	Customer Accounting - Miscellaneous	9050	0	0	0	0
14	Customer Accounting - Customer Assistance Expense	9080	0	0	0	0
15	Admin & Gen - Office Supp & Exp	9210	0	0	0	0
16	Admin & Gen - Outside Services	9230	0	0	0	0
17	Admin & Gen - Injuries & Damages	9250	0	0	0	0
18	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	0
19	Admin & Gen - General Advertising Expense	9301	0	0	0	0
20	Admin & Gen - Misc General	9302	0	0	1,636	1,636
21	Admin & Gen - Rents	9310	0	0	0	0
22	Totals		$0	$0	$1,636	$1,636

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RENTS AND LEASES ADJUSTMENTS
DIRECT SERVICE AREA

LINE NO.	DESCRIPTION	ACCT	ANNUALIZE LEASE PAYMENTS	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)
1	Transmission O & M - Mains Expenses	8560	$0	$0
2	Distr. Operations - Supervision and Engineering	8700	0	0
3	Distr. Operations - Distribution Load Dispatch	8710	0	0
4	Distr. Operations - Mains & Services	8740	0	0
5	Distr. Operations - Meter & House Reg. Exp.	8780	0	0
6	Distr. Operations - Other Expense	8800	0	0
7	Distr. Operations - Rents	8810	0	0
8	Distr. Maintenance - Mains	8870	0	0
9	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0
10	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0
11	Customer Accounting - Supervision	9010	0	0
12	Customer Accounting - Customer Accounting	9030	0	0
13	Customer Accounting - Miscellaneous	9050	0	0
14	Customer Accounting - Customer Assistance Expense	9080	0	0
15	Admin & Gen - Office Supp & Exp	9210	0	0
16	Admin & Gen - Outside Services	9230	0	0
17	Admin & Gen - Injuries & Damages	9250	0	0
18	Admin & Gen - Employee Pensions & Benefits	9260	0	0
19	Admin & Gen - General Advertising Expense	9301	0	0
20	Admin & Gen - Misc General	9302	0	0
21	Admin & Gen - Rents	9310	0	0
22	Totals		$0	$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RENTS AND LEASES ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ADUSTMENT TO FIRST PLACE TOWER LEASE	ADJUSTMENT TO BARTON SKYWAY LEASE	GRAND TOTAL	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
				(a)	(b)	(c)	(d)	(e)	(f)
1	Shared Service	Transmission O & M - Mains Expenses	8560	$0	$0	$0	86.02%	46.7362%	$0
2	Shared Service	Distr. Operations - Supervision and Engineering	8700	0	0	0	86.02%	46.7362%	0
3	Shared Service	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	86.02%	46.7362%	0
4	Shared Service	Distr. Operations - Mains & Services	8740	0	0	0	86.02%	46.7362%	0
5	Shared Service	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	86.02%	46.7362%	0
6	Shared Service	Distr. Operations - Other Expense	8800	0	0	0	86.02%	46.7362%	0
7	Shared Service	Distr. Operations - Rents	8810	0	0	0	86.02%	46.7362%	0
8	Shared Service	Distr. Maintenance - Mains	8870	0	0	0	86.02%	46.7362%	0
9	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	86.02%	46.7362%	0
10	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0	0	86.02%	46.7362%	0
11	Shared Service	Customer Accounting - Supervision	9010	0	0	0	86.02%	46.7362%	0
12	Shared Service	Customer Accounting - Customer Accounting	9030	0	0	0	86.02%	46.7362%	0
13	Shared Service	Customer Accounting - Miscellaneous	9050	0	0	0	86.02%	46.7362%	0
14	Shared Service	Customer Accounting - Customer Assistance Expense	9080	0	0	0	86.02%	46.7362%	0
15	Shared Service	Admin & Gen - Office Supp & Exp	9210	0	0	0	86.02%	46.7362%	0
16	Shared Service	Admin & Gen - Outside Services	9230	0	0	0	86.02%	46.7362%	0
17	Shared Service	Admin & Gen - Injuries & Damages	9250	0	0	0	86.02%	46.7362%	0
18	Shared Service	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	86.02%	46.7362%	0
19	Shared Service	Admin & Gen - General Advertising Expense	9301	0	0	0	86.02%	46.7362%	0
20	Shared Service	Admin & Gen - Misc General	9302	0	0	0	86.02%	46.7362%	0
21	Shared Service	Admin & Gen - Rents	9310	0	0	0	86.02%	46.7362%	0
22	Grand Total Shared Services			$0	$0	$0			$0
23									
24			O&M Expense Factor	86.02%	86.02%	86.02%			
25			Adjustment to TGS O&M	$0	$0	$0			
26									
27			Allocation to Service Area	46.7362%	46.7362%	46.7362%			
28									
29			Adjustment to Service Area O&M	$0	$0	$0			

DISTRIGAS

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ADUSTMENT TO FIRST PLACE TOWER LEASE	ADJUSTMENT TO IMAGENET LEASE	GRAND TOTAL	DISTRIGAS ALLOCATION FACTOR	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
30	OGS Corporate Allocated through Distrigas (1007)	Admin & Gen - Misc General	9302	$0	$14,162	$14,162	28.74%	86.02%	46.7362%	$1,636
31	Grand Total Distrigas			$0	$14,162	$14,162				$1,636
32										
33			Distrigas Allocation Percent	28.74%	28.74%	28.74%				
34			Corporate Adjustment Allocated to TGS	$0	$4,070	$4,070				
35										
36			O&M Expense Factor	86.02%	86.02%	86.02%				
37			Adjustment to TGS O&M	$0	$3,501	$3,501				
38										
39			Allocation to Service Area	46.7362%	46.7362%	46.7362%				
40										
41			Adjustment to Service Area O&M	$0	$1,636	$1,636				

Source: WKP G-10.b.1 Rent Adjustment Distr & SS (CONFIDENTIAL).xlsx

SCHEDULE G-11

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

INTEREST ON CUSTOMER DEPOSITS

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	Service Area Active Customer Deposits		$6,613,930
2	Interest Rate on Customer Deposits		4.86%
3	Annualized Interest on Customer Deposits		$321,437
4	Test Year Interest on Customer Deposits - Acct 4310	WKP G.a.2	92,616
5	Adjustment to Test Year Expense		$228,821

Source: SCH G-11 Interest on Customer Deposits_ PUC Interest Rate for Deposits.pdf

SCHEDULE G-12

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

UNCOLLECTIBLE EXPENSE

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT
		(a)	(b)	(c)
1	As Adjusted Base (Non-Gas) Revenue	G-2		$151,701,685
2	As Adjusted Transportation, Fees & Other Utility Revenue	G-3		13,716,843
3	Total Adjusted Base and Other Revenue (Note 2)			$165,418,527
4	Uncollectible Expense Ratio (Note 1)			0.006587
5	Adjusted Uncollectible Expense			$1,089,612
6	Test Year Uncollectible Expense - Acct 9040			795,692
7	Adjustment to Test Year Expense			$293,919

	Note 1: Calculation of Uncollectible Ratio	Base Revenue Write Offs	Base Revenue	Uncollectible Ratio
8	Twelve Months Ended December 2021	$894,279	$126,821,152	0.00705
9	Twelve Months Ended December 2022	919,846	137,791,869	0.00668
10	Twelve Months Ended December 2023	907,234	148,521,158	0.00611
11	Average	$907,120	$137,711,393	0.00659

Note 2: Actual bad debt write-offs relating to gas cost recovery revenue are to be recovered through the Cost of Gas Clause. Therefore, uncollectible expenses above is calculated based only on base revenue.

Source: SCH G-12 Uncollectibles TY 12 31 2023.xlsx

SCHEDULE G-13
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

INJURIES AND DAMAGES

LINE NO.	DESCRIPTION	REFERENCE	EMPLOYEE INJURY	AUTO	GENERAL LIABILITY	AMOUNT
		(a)	(b)	(c)	(d)	(e) = (b)+(c)+(d)
	Summary of Paid Claims for TGS Division					
1	Jan. 2019 - Dec. 2020		$384,399	$67,729	$154,109	$606,237
2	Jan. 2020 - Dec. 2021		102,671	17,705	142,584	262,959
3	Jan. 2021 - Dec. 2022		163,140	8,834	152,762	324,736
4	Jan. 2022 - Dec. 2023		150,370	9,167	162,493	322,030
5	Total		$800,579	$103,435	$611,948	$1,515,963
6	Average Claims for TGS Division		$200,145	$25,859	$152,987	$378,991
7	Per Book	Acct 9250	167,255	601	347,731	515,586
8	Adjustment					$(136,596)
9	Allocation to Service Area					46.7362%
10	Adjustment to Employee Injury, Auto, and General Liability Claims					$(63,840)
11	O&M Expense Factor					86.02%
12	Adjustment to Employee Injury, Auto, and General Liability Claims with O&M factor applied					$(54,917)

Source: SCH G-13 Inj and Dam per book (CONFIDENTIAL).xlsx

WKP G-13.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

INJURIES AND DAMAGES

The information contained within this report reflects the payment activities (not accidents) by:

Type of Loss / Claim (Employee Injury, Auto or General Liability Claim);

Year & Month payment activity was conducted and accumulative cost.

Claims = Number of claims with activities for the month reporting.

Payments = Number of payment activities (invoices) for the month reporting.

Type Expense

Employee Injuries

INDEMNITY - Temporary Income Benefits (TIBs) or Workers' Comp Pay from Insurer; compensation for permanent impairment rating.

MEDICAL - All medical expenses directly related to the treatment of the employee's injury.

EXPENSES - All other expenses not related to pay or medical, but are related to the claim such as mileage reimbursement, medical review fees, etc.

Auto and General Liability

PROPERTY DAMAGE - All expenses directly related to the repair of damage to other parties property.

MEDICAL - All medical expenses directly related to the treatment of personal physical injuries to other parties.

EXPENSES - All other expenses not related to property damage or medical, but are directly related to the claim such as rental car fees, settlements, etc.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

Employee Injuries

Period Reporting: January 1, 2020 through December 31, 2023

Employee Injuries	2020	2021	2022	2023
	$ Paid	$ Paid	$ Paid	$ Paid
January	$13,328	$14,253	$8,970	$8,417
February	16,122	18,962	11,622	21,647
March	7,548	9,353	8,116	58,365
April	8,887	16,695	7,888	22,930
May	4,992	7,068	5,669	35,944
June	15,145	11,697	4,422	54,685
July	6,647	22,311	10,792	53,924
August	10,705	12,090	5,499	25,485
September	19,240	12,261	7,732	17,168
October	15,085	4,753	8,900	26,110
November	19,095	13,882	10,716	45,559
December	13,578	19,816	12,344	14,165
Sub Total	$150,370	$163,140	$102,671	$384,399
			$200,145	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

Auto Accidents

Period Reporting: January 1, 2020 through December 31, 2023

Auto Accidents	2020	2021	2022	2023
	$ Paid	$ Paid	$ Paid	$ Paid
January	$0	$0	$13,854	$0
February	0	0	0	10,117
March	0	0	0	0
April	0	1,641	0	100
May	0	0	3,851	0
June	0	0	0	0
July	5,346	0	0	0
August	0	0	0	20,500
September	0	7,193	0	25,000
October	3,822	0	0	0
November	0	0	0	0
December	0	0	0	12,011
Sub Total	$9,167	$8,834	$17,705	$67,729
4 Year Average			$25,859	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

General Liability

Period Reporting: January 1, 2020 through December 31, 2023

General Liability	2020	2021	2022	2023
	$ Paid	$ Paid	$ Paid	$ Paid
January	$9,118	$27,456	$27,697	$17,267
February	14,715	2,139	2,622	15,570
March	34,864	2,797	8,158	1,597
April	52,812	9,609	19,571	5,124
May	983	20,052	3,813	52,254
June	295	25,712	12,840	39,480
July	2,574	9,161	11,752	3,202
August	8,716	13,695	5,916	5,487
September	10,926	8,519	34,724	6,724
October	13,310	19,448	2,603	140
November	5,022	5,028	8,290	700
December	9,157	9,145	4,597	6,566
Sub Total	$162,493	$152,762	$142,584	$154,109
4 Year Average			$152,987	

SCHEDULE G-14

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

ADVERTISING EXPENSE

LINE NO.	DESCRIPTION	REFERENCE	ACCOUNT	RECORDED TEST YEAR	ADJUSTMENTS PER OTHER SCHEDULES	MISC ADJUSTMENTS TO ADVERTISING	TOTAL ADUSTMENTS	ADJUSTED TEST YEAR
				(a)	(b)	(c)	(d)	(e)
1	Advertising - Sales	WKP G.a.1	9130	$143,921	$0	$0	$0	$143,921
2	Advertising - Misc. Adm & Gen. Expense	WKP G.a.1	9301	107	0	0	0	107
3	Distrigas Allocated Advertising	WKP G.a.2	9302	6,464	0	0	0	6,464
4	Total Adjusted Advertising Expense			$150,493	$0	$0	$0	$150,493

5 Note 1: Adjusted Test Year Advertising Expense is below 0.50% limitation calculated below, therefore no adjustment is needed for amounts over limitation.

ALLOWABLE ADVERTISING EXPENSE CALCULATION:

LINE NO.	DESCRIPTION	REFERENCE			
6	Revenue Requirement	A			$191,207,923
7	Normalized CCF	G-2		152,428,775	
8	Test Year Cost of Gas Revenue	G-2	$93,904,159		
9	Test Year CCF	G-2	147,551,803		
10	Effective Rate		0.636414850	0.636414850	
11	Normalized Cost of Gas Revenue			$97,007,936	97,007,936
12	Total Revenue				$288,215,859
13	Allowed Rate				0.50 %
14	Allowable Advertising (Note 1)				$1,441,079

O&M Expense Factor	86.02%
Allocation to Service Area	46.7362%
Distrigas Allocation Factor	28.7400%

Source: WKP G.a.2 Op Inc Book TYE12 2023 GL Detail Rev Exp acct (CONFIDENTIAL).xlsx
Source: WKP G.a.2.a1 Shared Service per book including Distrigas (CONFIDENTIAL).xlsx
Source: WKP G.a.2.a2 Corporate Costs Allocated on a Causal Basis and Through Distrigas-(CONFIDENTIAL).xlsx

Actual Advertising expense represents in gross receipts 0.052 %

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **SCHEDULE G-15**
CENTRAL-GULF SERVICE AREA
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TWELVE MONTHS ENDED DECEMBER 31, 2023

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT DEPR & AMORT EXP	TGS DIVISION ALLOCATED DEPR & AMORT EXP	CORPORATED ALLOCATED DEPR & AMORT EXP	TOTAL DEPR & AMORT EXP
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0
3	302	Franchises & Consents	0	0	0	0
4	303	Misc. Intangible	41,187	0	0	41,187
5	303	Misc. Intangible - OPC	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0
7		Total Intangible Plant	$41,187	$0	$0	$41,187
		GATHERING AND TRANSMISSION PLANT				
8	325	Land & Land Rights	$0	$0	$0	$0
9	327	Field Comprss Station Strucutres	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0
11	329	Other Structures	0	0	0	0
12	332	Field Lines	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0
15	336	Purification Equipment	0	0	0	0
16	337	Other Equip	0	0	0	0
17	365	Land & Land Rights	0	0	0	0
18	365.1	Land - OPC	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0
20	365.2	Rights-of-Way - OPC	0	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0
23	367	Mains	366,381	0	0	366,381
24	367	Mains - OPC	0	0	0	0
25	368	Compressor Station Equip	0	0	0	0
26	369	Meas & Reg Stations Equip	206,396	0	0	206,396
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0
29	371	Other Equipment	0	0	0	0
30	371	Other Equipment	0	0	0	0
31		Total Gathering and Transmission Plant	$572,778	$0	$0	$572,778
		DISTRIBUTION PLANT				
32	374	Land	$0	$0	$0	$0
33	374.1	Land	0	0	0	0
34	374.2	Land Rights	0	0	0	0
35	375	Structures & Improvements	0	0	0	0
36	375.1	Structures & Improvements	1,428	0	0	1,428
37	375.2	Other System Structures	40,833	0	0	40,833
38	376	Mains	10,200,708	0	0	10,200,708
39	376.9	Mains - Cathodic Protection Anodes	1,952,051	0	0	1,952,051
40	377	Compressor Station Equipment	0	0	0	0
41	378	Meas. & Reg. Station - General	505,997	0	0	505,997
42	379	Meas. & Reg. Station - C.G.	143,430	0	0	143,430
43	380	Services	9,660,122	0	0	9,660,122
44	380.1	Ind Service Line Equip	76	0	0	76
45	380.2	Comm Service Line Equip	382	0	0	382
46	380.4	Yard Lines-Customer Svc	4,608	0	0	4,608
47	381	Meters	3,335,369	0	0	3,335,369
48	382	Meter Installations	297	0	0	297
49	383	House Regulators	383,759	0	0	383,759
50	385	Indust. Meas. & Reg. Stat. Equipment	389,274	0	0	389,274
51	386	Other Property on Customer Premises	126,420	0	0	126,420
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0
53		Total Distribution Plant	$26,744,756	$0	$0	$26,744,756
		GENERAL PLANT				
54	389	Land & Land Rights	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **SCHEDULE G-15**
CENTRAL-GULF SERVICE AREA
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TWELVE MONTHS ENDED DECEMBER 31, 2023

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT DEPR & AMORT EXP	TGS DIVISION ALLOCATED DEPR & AMORT EXP	CORPORATED ALLOCATED DEPR & AMORT EXP	TOTAL DEPR & AMORT EXP
			(a)	(b)	(c)	(d)
56	390.1	Leasehold Improvements	794,273	54,413	15,043	863,730
57	390.17	Building Improv Plum	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0
59	390.2	Leasehold Improvement	0	3,170	189,921	193,091
60	390.2	OGS Lease Incentive	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0
63	391.1	Office Furniture & Equipment	164,256	80,019	43,867	288,142
64	391.19	Airplane Hanger Furniture	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0
67	391.3	Office Machines	0	0	8,181	8,181
68	391.4	Audio Visual Equipment	0	0	31,466	31,466
69	391.5	Artwork	0	0	0	0
70	391.6	Purchased Software	0	0	1,579,376	1,579,376
71	391.6	Banner Software	0	0	117,259	117,259
72	391.6	PowerPlant System	0	0	24,414	24,414
73	391.6	Riskworks	0	0	0	0
74	391.6	Maximo	0	0	45,703	45,703
75	391.6	Dynamic Risk Assessment	0	0	0	0
76	391.6	Concur Project	0	0	761	761
77	391.6	Journey-Employee-ODC Distrigas	0	0	718,800	718,800
78	391.6	Journey-Employee Count	0	0	19,626	19,626
79	391.6	Ariba Software	0	0	31,323	31,323
80	391.6	Accounts Payable Software	0	0	14,271	14,271
81	391.6	Customer Relations Software	0	0	15,594	15,594
82	391.8	Micro Computer Software	0	0	722,421	722,421
83	391.81	Aircraft Computer Equipment	0	0	0	0
84	391.9	Computer & Equipment	303,118	176,686	0	479,803
85	391.99	Cloud Computing	0	0	22,226	22,226
86	392	Transportation Equipment	0	0	0	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
89	392.5	Trailers	0	0	0	0
90	392.6	Aircraft	0	0	0	0
91	393	Stores Equipment	8,251	0	0	8,251
92	394	Tools, Shop & Garage	1,025,421	3,115	5,275	1,033,811
93	394.1	Tools	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0
95	395	CNG Equipment	0	0	0	0
96	396	Major Work Equipment	0	0	0	0
97	397	Communication Equipment	2,308,286	25,618	688	2,334,592
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	423	0	0	423
100		Total General Plant	$4,604,028	$343,021	$3,606,215	$8,553,264
101		Total	$31,962,749	$343,021	$3,606,215	$35,911,985
102		Total Annualized Depreciation & Amortization Expense	$31,962,749	$343,021	$3,606,215	$35,911,985
103		Test Year Depreciation & Amortization Expense Accts 403 & 404	24,800,057	310,454	3,098,842	28,209,353
104		Adjustment to Test Year	$7,162,692	$32,567	$507,373	$7,702,632

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP G-15.a.1**

CENTRAL-GULF SERVICE AREA

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TWELVE MONTHS ENDED DECEMBER 31, 2023

DEPRECIATION AND AMORTIZATION EXPENSE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT AS ADJUSTED ACCT 1010 PLANT (WKP C.a)	DIRECT AS ADJUSTED ACCT 1060 CCNC (WKP C-1.a)	LESS LAND	LESS TRANSPORT & WORK EQUIP	LESS FULLY DEPRECIATED PLANT	PLUS DIMP DEFERRAL (Rule 8.209)	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA DIRECT EXPENSE
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT									
1	301	Organization	$56,257	$0	$0	$0	(56,257)	$0	$0	4.0000 %	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	6.6670 %	0
3	302	Franchises & Consents	393,474	0	0	0	(393,474)	0	0	4.0200 %	0
4	303	Misc. Intangible	753,928	260,537	0	0	0	0	1,014,465	4.0600 %	41,187
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	— %	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	4.0600 %	0
7		Total Intangible Plant	$1,203,659	$260,537	$0	$0	$(449,731)	$0	$1,014,465		$41,187
		GATHERING AND TRANSMISSION PLANT									
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	— %	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	— %	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	— %	0
11	329	Other Structures	0	0	0	0	0	0	0	— %	0
12	332	Field Lines	0	0	0	0	0	0	0	— %	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	— %	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	— %	0
15	336	Purification Equipment	0	0	0	0	0	0	0	— %	0
16	337	Other Equip	0	0	0	0	0	0	0	— %	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	— %	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	— %	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	— %	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	1.3000 %	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	— %	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	4.0400 %	0
23	367	Mains	13,399,503	374,234	0	0	0	0	13,773,737	2.6600 %	366,381
24	367	Mains - OPC	0	0	0	0	0	0	0	1.7500 %	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	— %	0
26	369	Meas & Reg Stations Equip	5,906,625	110,762	0	0	0	0	6,017,387	3.4300 %	206,396
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	1.8300 %	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	2.6200 %	0
29	371	Other Equipment	0	0	0	0	0	0	0	2.6200 %	0
30	371	Other Equipment - OPC	0	0	0	0	0		0	2.6200 %	0
31		Total Gathering and Transmission Plant	$19,306,128	$484,996	$0	$0	$0	$0	$19,791,124		$572,778
		DISTRIBUTION PLANT									
32	374	Land	$0	$0	$0	$0	$0	$0	$0	— %	$0
33	374.1	Land	109,140	2,072	(111,212)	0	0	0	0	— %	0

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
34	374.2	Land Rights	102,631	17,551	0	0	0	140	120,321	— %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	— %	0
36	375.1	Structures & Improvements	47,140	(916)	0		0	0	46,224	3.0900 %	1,428
37	375.2	Other System Structures	4,141	1,711,547	0	0	0	0	1,715,688	2.3800 %	40,833
38	376	Mains	393,130,519	63,668,359	0	0	0	631,986	457,430,864	2.2300 %	10,200,708
39	376.9	Mains - Cathodic Protection Anodes	28,677,978	567,491	0	0	0	35,295	29,280,764	6.6667 %	1,952,051
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	— %	0
41	378	Meas. & Reg. Station - General	18,990,854	4,753,906	0	0	0	10,985	23,755,746	2.1300 %	505,997
42	379	Meas. & Reg. Station - C.G.	4,994,554	2,283,835	0	0	0	2,339	7,280,728	1.9700 %	143,430
43	380	Services	297,029,237	7,493,876	0	0	0	1,176,963	305,700,076	3.1600 %	9,660,122
44	380.1	Ind Service Line Equip	0	2,174	0	0	0	218	2,392	3.1600 %	76
45	380.2	Comm Service Line Equip	(0)	11,773	0	0	0	321	12,094	3.1600 %	382
46	380.4	Yard Lines-Customer Svc	0	152,167	0	0	0	(6,339)	145,828	3.1600 %	4,608
47	381	Meters	81,187,711	565,258	0	0	0	(3,724)	81,749,245	4.0800 %	3,335,369
48	382	Meter Installations	0	7,147	0	0	0	197	7,344	4.0400 %	297
49	383	House Regulators	11,200,891	85,896	0	0	0	230	11,287,016	3.4000 %	383,759
50	385	Indust. Meas. & Reg. Stat. Equipment	15,956,743	399,248	0	0	0	62	16,356,053	2.3800 %	389,274
51	386	Other Property on Customer Premises	1,063,249	0	0	0	0	0	1,063,249	11.8900 %	126,420
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	— %	0
53		Total Distribution Plant	$852,494,788	$81,721,384	$(111,212)	$0	$0	$1,848,673	$935,953,633		$26,744,756
		GENERAL PLANT									
54	389	Land & Land Rights	$8,347,674	$0	$(8,347,674)	$0	$0	$0	$0	— %	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	— %	0
56	390.1	Structures & Improvements	24,010,665	7,508,119	0	0	0	0	31,518,784	2.5200 %	794,273
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	— %	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	— %	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0	— %	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	— %	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	— %	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	— %	0
63	391.1	Office Furniture & Equipment	2,439,302	24,536	0	0	0	0	2,463,838	6.6667 %	164,256
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	— %	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	— %	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	— %	0
67	391.3	Office Machines	0	0	0	0	0	0	0	— %	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	— %	0
69	391.5	Artwork	0	0	0	0	0	0	0	— %	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	— %	0
71	391.6	Banner Software	0	0	0	0	0	0	0	— %	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	— %	0
73	391.6	Riskworks	0	0	0	0	0	0	0	— %	0
74	391.6	Maximo	0	0	0	0	0	0	0	— %	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	— %	0

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
76	391.6	Concur Project	0	0	0	0	0	0	0	— %	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	— %	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	— %	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	— %	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	— %	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	— %	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	— %	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	— %	0
84	391.9	Computer & Equipment	1,963,402	158,421	0	0	0	0	2,121,823	14.2857 %	303,118
85	391.99	Cloud Computing	0	0	0	0	0	0	0	— %	0
86	392	Transportation Equipment	20,418,067	4,597,492	0	(25,015,559)	0	0	0	6.4300 %	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	6.4300 %	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	6.4300 %	0
89	392.5	Trailers	0	0	0	0	0	0	0	6.4300 %	0
90	392.6	Aircraft	0	0	0	0	0	0	0	6.4300 %	0
91	393	Stores Equipment	5,387	118,374	0	0	0	0	123,761	6.6667 %	8,251
92	394	Tools, Shop & Garage	11,597,087	3,784,232	0	0	0	0	15,381,319	6.6667 %	1,025,421
93	394.1	Tools	0	0	0	0	0	0	0	— %	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	— %	0
95	395	CNG Equipment	0	0	0	0	0	0	0	— %	0
96	396	Major Work Equipment	3,190,938	341,131	0	(3,532,069)	0	0	0	4.8000 %	0
97	397	Communication Equipment	19,829,123	14,795,168	0	0	0	0	34,624,291	6.6667 %	2,308,286
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	— %	0
99	398	Miscellaneous General Plant	6,349	0	0	0	0	0	6,349	6.6667 %	423
100		Total General Plant	$91,807,993	$31,327,474	$(8,347,674)	$(28,547,628)	$0	$0	$86,240,165		$4,604,028
101		Total Plant in Service	$964,812,569	$113,794,390	$(8,458,886)	$(28,547,628)	$(449,731)	$1,848,673	$1,042,999,387		$31,962,749
102		Total Annualized Depreciation & Amortization Expense									$31,962,749
103		Test Year Depreciation & Amortization Expense (Accts. 403 & 404)									24,800,057
104		Adjustment to Test Year									$7,162,692

Note: Depreciation Related to Transportation Work Equipment:

		Vehicles (392)	Work Equip (396)	Total	
105	Plant in Service + CCNC	$25,015,559	$3,532,069	$28,547,628	
106	Less Fully Depreciated Plant	0	0	0	
107	Net Depreciable Plant	$25,015,559	$3,532,069	$28,547,628	
108	Depreciation Rate	6.4300%	4.800%		
109	Proforma Depreciation Expense	$1,608,500	$169,539	$1,778,040	(to Schedule G-19)

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FULLY DEPRECIATED PLANT - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT	FULLY DEPREICATED PLANT
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$56,257	$(56,257)	$0	$(56,257)
2	301	Organization - OPC	0	479	479	0
3	302	Franchises & Consents	393,474	(393,474)	0	(393,474)
4	303	Misc. Intangible	1,014,465	(780,558)	233,908	0
5	303	Misc. Intangible - OPC	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0
7		Total Intangible Plant	$1,464,196	$(1,229,809)	$234,387	$(449,731)
		GATHERING AND TRANSMISSION PLANT				
8	325	Land & Land Rights	$0	$0	$0	$0
9	327	Field Comprss Station Strucutres	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0
11	329	Other Structures	0	0	0	0
12	332	Field Lines	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0
15	336	Purification Equipment	0	0	0	0
16	337	Other Equip	0	0	0	0
17	365	Land & Land Rights	0	0	0	0
18	365.1	Land - OPC	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0
20	365.2	Rights-of-Way - OPC	0	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0
23	367	Mains	13,773,737	264,444	14,038,181	0
24	367	Mains - OPC	0	0	0	0
25	368	Compressor Station Equip	0	0	0	0
26	369	Meas & Reg Stations Equip	6,017,387	(239,370)	5,778,018	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0
29	371	Other Equipment	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0
31		Total Gathering and Transmission Plant	$19,791,124	$25,075	$19,816,199	$0
		DISTRIBUTION PLANT				
32	374	Land	$0	$(255)	$(255)	$0
33	374.1	Land	111,212	0	111,212	0
34	374.2	Land Rights	120,182	(11,902)	108,280	0
35	375.1	Structures & Improvements	0	0	0	0
36	375.1	Structures & Improvements	46,224	(34,665)	11,559	0
37	375.2	Other System Structures	1,715,688	(130,397)	1,585,291	0
38	376	Mains	456,798,878	(79,852,421)	376,946,457	0
39	376.9	Mains - Cathodic Protection Anodes	29,245,469	(12,715,301)	16,530,168	0
40	377	Compressor Station Equipment	0	0	0	0
41	378	Meas. & Reg. Station - General	23,744,761	(4,012,074)	19,732,686	0
42	379	Meas. & Reg. Station - C.G.	7,278,389	(1,577,372)	5,701,017	0
43	380	Services	304,523,113	(40,260,987)	264,262,126	0
44	380.1	Ind Service Line Equip	2,174	0	2,174	0
45	380.2	Comm Service Line Equip	11,773	0	11,773	0
46	380.4	Yard Lines-Customer Svc	152,167	0	152,167	0
47	381	Meters	81,752,969	(35,453,793)	46,299,176	0
48	382	Meter Installations	7,147	(2,791)	4,357	0
49	383	House Regulators	11,286,787	(4,883,641)	6,403,146	0
50	385	Indust. Meas. & Reg. Stat. Equipment	16,355,991	(5,287,968)	11,068,023	0
51	386	Other Property on Customer Premises	1,063,249	(1,041,339)	21,910	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0

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FULLY DEPRECIATED PLANT - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT	FULLY DEPREICATED PLANT
			(a)	(b)	(c)	(d)
53		Total Distribution Plant	$934,216,172	$(185,264,906)	$748,951,266	$0
		GENERAL PLANT				
54	389	Land & Land Rights	$8,347,674	$4,733	$8,352,407	$0
55	390	Structures & Improvements	0	0	0	0
56	390.1	Structures & Improvements	31,518,784	(2,521,863)	28,996,921	0
57	390.17	Building Improv Plum	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0
63	391.1	Office Furniture & Equipment	2,463,838	(798,801)	1,665,038	0
64	391.19	Airplane Hanger Furniture	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0
67	391.3	Office Machines	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0
69	391.5	Artwork	0	0	0	0
70	391.6	Purchased Software	0	0	0	0
71	391.6	Banner Software	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0
73	391.6	Riskworks	0	0	0	0
74	391.6	Maximo	0	0	0	0
75	391.6	Foundation Software	0	0	0	0
76	391.6	Concur Project	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0
78	391.6	Journey-Employee Count	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0
84	391.9	Computer & Equipment	2,121,823	(1,096,913)	1,024,910	0
85	391.99	Cloud Computing	0	0	0	0
86	392	Transportation Equipment	25,015,559	(9,718,895)	15,296,663	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
89	392.5	Trailers	0	0	0	0
90	392.6	Aircraft	0	0	0	0
91	393	Stores Equipment	123,761	(7,599)	116,162	0
92	394	Tools, Shop & Garage	15,381,319	(4,559,234)	10,822,085	0
93	394.1	Tools	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0
95	395	CNG Equipment	0	37,480	37,480	0
96	396	Major Work Equipment	3,532,069	(1,344,194)	2,187,874	0
97	397	Communication Equipment	34,624,291	(14,072,660)	20,551,632	0
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	6,349	(4,308)	2,041	0
100		Total General Plant	$123,135,467	$(34,082,254)	$89,053,212	$0
101		Total Orig Cost Plant in Service	$1,078,606,959	$(220,551,895)	$858,055,064	$(449,731)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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DEPRECIATION AND AMORTIZATION EXPENSE - TGS DIVISION

LINE NO.	ACCT	DESCRIPTION	TGS DIVISION AS ADJUSTED ACC 1010 PLANT (WKP C.b)	TGS DIVISION AS ADJUSTED ACC 1060 CCNC (WKP C-1.b)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA TGS DIVISION DEPR & AMORT EXPENSE	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	0.0000%	0	46.7362%	$0
2	301	Organization - OPC	0	0	0	0	0.0000%	0	46.7362%	0
3	302	Franchises & Consents	0	0	0	0	0.0000%	0	46.7362%	0
4	303	Misc. Intangible	0	0	0	0	0.0000%	0	46.7362%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0.0000%	0	46.7362%	0
6	303.1	Misc. Intangible	0	0	0	0	0.0000%	0	46.7362%	0
7		Total Intangible Plant	$0	$0	$0	$0		$0		$0
		GATHERING AND TRANSMISSION PLANT								
8	325	Land & Land Rights	$0	$0	$0	$0	0.0000%	0	46.7362%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0.0000%	0	46.7362%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0.0000%	0	46.7362%	0
11	329	Other Structures	0	0	0	0	0.0000%	0	46.7362%	0
12	332	Field Lines	0	0	0	0	0.0000%	0	46.7362%	0
13	333	Field Compressor Station Equip	0	0	0	0	0.0000%	0	46.7362%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0.0000%	0	46.7362%	0
15	336	Purification Equipment	0	0	0	0	0.0000%	0	46.7362%	0
16	337	Other Equip	0	0	0	0	0.0000%	0	46.7362%	0
17	365	Land & Land Rights	0	0	0	0	0.0000%	0	46.7362%	0
18	365.1	Land - OPC	0	0	0	0	0.0000%	0	46.7362%	0
19	365.2	Rights-of-Way	0	0	0	0	0.0000%	0	46.7362%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0.0000%	0	46.7362%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0.0000%	0	46.7362%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0.0000%	0	46.7362%	0
23	367	Mains	0	0	0	0	0.0000%	0	46.7362%	0
24	367	Mains - OPC	0	0	0	0	0.0000%	0	46.7362%	0
25	368	Compressor Station Equip	0	0	0	0	0.0000%	0	46.7362%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0.0000%	0	46.7362%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0.0000%	0	46.7362%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0.0000%	0	46.7362%	0
29	371	Other Equipment	0	0	0	0	0.0000%	0	46.7362%	0
30	371	Other Equipment - OPC	0	0	0	0	0.0000%	0	46.7362%	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
		DISTRIBUTION PLANT								
32	374	Land	$0	$0	$0	$0	0.0000%	0	46.7362%	$0

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DEPRECIATION AND AMORTIZATION EXPENSE - TGS DIVISION

LINE NO.	ACCT	DESCRIPTION	TGS DIVISION AS ADJUSTED ACC 1010 PLANT (WKP C.b)	TGS DIVISION AS ADJUSTED ACC 1060 CCNC (WKP C-1.b)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA TGS DIVISION DEPR & AMORT EXPENSE	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
33	374.1	Land	0	0	0	0	0.0000%	0	46.7362%	0
34	374.2	Land Rights	0	0	0	0	0.0000%	0	46.7362%	0
35	375.1	Structures & Improvements	0	0	0	0	0.0000%	0	46.7362%	0
36	375.1	Structures & Improvements	0	0	0	0	0.0000%	0	46.7362%	0
37	375.2	Other System Structures	0	0	0	0	0.0000%	0	46.7362%	0
38	376	Mains	0	0	0	0	0.0000%	0	46.7362%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0.0000%	0	46.7362%	0
40	377	Compressor Station Equipment	0	0	0	0	0.0000%	0	46.7362%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0.0000%	0	46.7362%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0.0000%	0	46.7362%	0
43	380	Services	0	0	0	0	0.0000%	0	46.7362%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0.0000%	0	46.7362%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0.0000%	0	46.7362%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0.0000%	0	46.7362%	0
47	381	Meters	0	0	0	0	0.0000%	0	46.7362%	0
48	382	Meter Installations	0	0	0	0	0.0000%	0	46.7362%	0
49	383	House Regulators	0	0	0	0	0.0000%	0	46.7362%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0	46.7362%	0
51	386	Other Property on Customer Premises	0	0	0	0	0.0000%	0	46.7362%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0	46.7362%	0
53		Total Distribution Plant	$0	$0	$0	$0		$0		$0
		GENERAL PLANT								
54	389	Land & Land Rights	$434,697	$0	$0	$434,697	0.0000%	$0	46.7362%	$0
55	390	Structures & Improvements	0	0	0	0	0.0000%	0	46.7362%	0
56	390.1	Structures & Improvements	4,405,620	142,293	0	4,547,912	2.5600%	116,427	46.7362%	54,413
57	390.17	Building Improv Plum	0	0	0	0	0.0000%	0	46.7362%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0.0000%	0	46.7362%	0
59	390.2	Leasehold Improvement	234,303	18,181	0	252,484	2.6864%	6,783	46.7362%	3,170
60	390.2	OGS Lease Incentive	0	0	0	0	0.0000%	0	46.7362%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0.0000%	0	46.7362%	0
62	391	Office Furniture & Equipment	0	0	0	0	0.0000%	0	46.7362%	0
63	391.1	Office Furniture & Equipment	2,568,221	0	0	2,568,221	6.6667%	171,215	46.7362%	80,019
64	391.19	Airplane Hanger Furniture	0	0	0	0	0.0000%	0	46.7362%	0
65	391.2	Data Processing Equipment	0	0	0	0	0.0000%	0	46.7362%	0
66	391.2	Oracle Equipment	0	0	0	0	0.0000%	0	46.7362%	0
67	391.3	Office Machines	0	0	0	0	0.0000%	0	46.7362%	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP G-15.b.1**
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DEPRECIATION AND AMORTIZATION EXPENSE - TGS DIVISION

LINE NO.	ACCT	DESCRIPTION	TGS DIVISION AS ADJUSTED ACC 1010 PLANT (WKP C.b)	TGS DIVISION AS ADJUSTED ACC 1060 CCNC (WKP C-1.b)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA TGS DIVISION DEPR & AMORT EXPENSE	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
68	391.4	Audio Visual Equipment	0	0	0	0	0.0000%	0	46.7362%	0
69	391.5	Artwork	0	0	0	0	0.0000%	0	46.7362%	0
70	391.6	Purchased Software	0	0	0	0	0.0000%	0	46.7362%	0
71	391.6	Banner Software	0	0	0	0	0.0000%	0	46.7362%	0
72	391.6	PowerPlant System	0	0	0	0	0.0000%	0	46.7362%	0
73	391.6	Riskworks	0	0	0	0	0.0000%	0	46.7362%	0
74	391.6	Maximo	0	0	0	0	0.0000%	0	46.7362%	0
75	391.6	Foundation Software	0	0	0	0	0.0000%	0	46.7362%	0
76	391.6	Concur Project	0	0	0	0	0.0000%	0	46.7362%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0.0000%	0	46.7362%	0
78	391.6	Journey-Employee Count	0	0	0	0	0.0000%	0	46.7362%	0
79	391.6	Payroll - Time Management	0	0	0	0	0.0000%	0	46.7362%	0
80	391.6	Accounts Payable Software	0	0	0	0	0.0000%	0	46.7362%	0
81	391.6	Customer Relations Software	0	0	0	0	0.0000%	0	46.7362%	0
82	391.8	Micro Computer Software	0	0	0	0	0.0000%	0	46.7362%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0.0000%	0	46.7362%	0
84	391.9	Computer & Equipment	2,580,798	65,544	0	2,646,343	14.2857%	378,049	46.7362%	176,686
85	391.99	Cloud Computing	0	0	0	0	0.0000%	0	46.7362%	0
86	392	Transportation Equipment	0	0	0	0	0.0000%	0	46.7362%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0.0000%	0	46.7362%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0.0000%	0	46.7362%	0
89	392.5	Trailers	0	0	0	0	0.0000%	0	46.7362%	0
90	392.6	Aircraft	0	0	0	0	0.0000%	0	46.7362%	0
91	393	Stores Equipment	0	0	0	0	0.0000%	0	46.7362%	0
92	394	Tools, Shop & Garage	28,576	71,390	0	99,966	6.6667%	6,664	46.7362%	3,115
93	394.1	Tools	0	0	0	0	0.0000%	0	46.7362%	0
94	394.2	Shop Equipment	0	0	0	0	0.0000%	0	46.7362%	0
95	395	CNG Equipment	0	0	0	0	0.0000%	0	46.7362%	0
96	396	Major Work Equipment	0	0	0	0	0.0000%	0	46.7362%	0
97	397	Communication Equipment	822,208	0	0	822,208	6.6667%	54,814	46.7362%	25,618
98	397.2	Telephone Equipment	0	0	0	0	0.0000%	0	46.7362%	0
99	398	Miscellaneous General Plant	0	0	0	0	6.6667%	0	46.7362%	0
100		Total General Plant	$11,074,424	$297,407	$0	$11,371,831		$733,951		$343,021
101		Total Plant in Service	$11,074,424	$297,407	$0	$11,371,831		$733,951		$343,021

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DEPRECIATION AND AMORTIZATION EXPENSE - TGS DIVISION

LINE NO.	ACCT	DESCRIPTION	TGS DIVISION AS ADJUSTED ACC 1010 PLANT (WKP C.b)	TGS DIVISION AS ADJUSTED ACC 1060 CCNC (WKP C-1.b)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA TGS DIVISION DEPR & AMORT EXPENSE	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
102		Total Annualized Depreciation & Amortization Expense						$733,951	46.7362%	$343,021
103		Test Year Depreciation & Amortization Expense Accts 403 & 404						664,269	46.7362%	310,454
104		Adjustment to Test Year						$69,682	46.7362%	$32,567

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP G-15.b.2**
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FULLY DEPRECIATED PLANT - TGS DIVISION

			TGS DIVISION AS ADJUSTED			
LINENO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0
3	302	Franchises & Consents	0	0	0	0
4	303	Misc. Intangible	0	0	0	0
5	303	Misc. Intangible - OPC	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0
7		Total Intangible Plant	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT				
8	325	Land & Land Rights	$0	$0	$0	$0
9	327	Field Comprss Station Strucutres	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0
11	329	Other Structures	0	0	0	0
12	332	Field Lines	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0
15	336	Purification Equipment	0	0	0	0
16	337	Other Equip	0	0	0	0
17	365	Land & Land Rights	0	0	0	0
18	365.1	Land - OPC	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0
20	365.2	Rights-of-Way - OPC	0	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0
23	367	Mains	0	0	0	0
24	367	Mains - OPC	0	0	0	0
25	368	Compressor Station Equip	0	0	0	0
26	369	Meas & Reg Stations Equip	0	0	0	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0
29	371	Other Equipment	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0
		DISTRIBUTION PLANT				
32	374	Land	$0	$0	$0	$0
33	374.1	Land	0	0	0	0
34	374.2	Land Rights	0	0	0	0
35	375.1	Structures & Improvements	0	0	0	0
36	375.1	Structures & Improvements	0	0	0	0
37	375.2	Other System Structures	0	0	0	0
38	376	Mains	0	0	0	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0
40	377	Compressor Station Equipment	0	0	0	0
41	378	Meas. & Reg. Station - General	0	0	0	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0
43	380	Services	0	0	0	0
44	380.1	Ind Service Line Equip	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP G-15.b.2**
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FULLY DEPRECIATED PLANT - TGS DIVISION

			TGS DIVISION AS ADJUSTED			
LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
45	380.2	Comm Service Line Equip	0	0	0	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0
47	381	Meters	0	0	0	0
48	382	Meter Installations	0	0	0	0
49	383	House Regulators	0	0	0	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0
51	386	Other Property on Customer Premises	0	0	0	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0
53		Total Distribution Plant	$0	$0	$0	$0
		GENERAL PLANT				
54	389	Land & Land Rights	$434,697	$0	$434,697	$0
55	390	Structures & Improvements	0	0	0	0
56	390.1	Structures & Improvements	4,547,912	(492,842)	4,055,070	0
57	390.17	Building Improv Plum	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0
59	390.2	Leasehold Improvement	252,484	(235,494)	16,990	0
60	390.2	OGS Lease Incentive	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0
63	391.1	Office Furniture & Equipment	2,568,221	(721,926)	1,846,295	0
64	391.19	Airplane Hanger Furniture	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0
67	391.3	Office Machines	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0
69	391.5	Artwork	0	0	0	0
70	391.6	Purchased Software	0	0	0	0
71	391.6	Banner Software	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0
73	391.6	Riskworks	0	0	0	0
74	391.6	Maximo	0	0	0	0
75	391.6	Foundation Software	0	0	0	0
76	391.6	Concur Project	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0
78	391.6	Journey-Employee Count	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0
84	391.9	Computer & Equipment	2,646,343	(985,311)	1,661,031	0
85	391.99	Cloud Computing	0	0	0	0
86	392	Transportation Equipment	0	0	0	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
89	392.5	Trailers	0	0	0	0
90	392.6	Aircraft	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP G-15.b.2**
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FULLY DEPRECIATED PLANT - TGS DIVISION

			TGS DIVISION AS ADJUSTED			
LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
91	393	Stores Equipment	0	0	0	0
92	394	Tools, Shop & Garage	99,966	(11,791)	88,175	0
93	394.1	Tools	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0
95	395	CNG Equipment	0	0	0	0
96	396	Major Work Equipment	0	0	0	0
97	397	Communication Equipment	822,208	(529,928)	292,280	0
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	0	0	0	0
100		Total General Plant	$11,371,831	$(2,977,293)	$8,394,538	$0
101		Total Orig Cost Plant in Service	$11,371,831	$(2,977,293)	$8,394,538	$0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACC 1010 PLANT (WKP C.c)	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACCT 1060 CCNC (WKP C-1.c)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	CORPORATE ALLOCATED TO TGS ANNUAL PROFORMA DEPR & AMORT EXP	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	0.0000%	$0		
2	301	Organization - OPC	0	0	0	0	0.0000%	0		
3	302	Franchises & Consents	0	0	0	0	0.0000%	0		
4	303	Misc. Intangible	0	0	0	0	0.0000%	0		
5	303	Misc. Intangible - OPC	0	0	0	0	0.0000%	0		
6	303.1	Misc. Intangible	0	0	0	0	0.0000%	0		
7		Total Intangible Plant	$0	$0	$0	$0		$0		$0
		GATHERING AND TRANSMISSION PLANT								
8	325	Land & Land Rights	$0	$0	$0	$0	0.0000%	$0		
9	327	Field Comprss Station Strucutres	0	0	0	0	0.0000%	0		
10	328	Field Meas/Reg Station Structures	0	0	0	0	0.0000%	0		
11	329	Other Structures	0	0	0	0	0.0000%	0		
12	332	Field Lines	0	0	0	0	0.0000%	0		
13	333	Field Compressor Station Equip	0	0	0	0	0.0000%	0		
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0.0000%	0		
15	336	Purification Equipment	0	0	0	0	0.0000%	0		
16	337	Other Equip	0	0	0	0	0.0000%	0		
17	365	Land & Land Rights	0	0	0	0	0.0000%	0		
18	365.1	Land - OPC	0	0	0	0	0.0000%	0		
19	365.2	Rights-of-Way	0	0	0	0	0.0000%	0		
20	365.2	Rights-of-Way - OPC	0	0	0	0	0.0000%	0		
21	366	Meas/Reg Station Structures	0	0	0	0	0.0000%	0		
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0.0000%	0		
23	367	Mains	0	0	0	0	0.0000%	0		
24	367	Mains - OPC	0	0	0	0	0.0000%	0		
25	368	Compressor Station Equip	0	0	0	0	0.0000%	0		
26	369	Meas & Reg Stations Equip	0	0	0	0	0.0000%	0		
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0.0000%	0		
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0.0000%	0		
29	371	Other Equipment	0	0	0	0	0.0000%	0		
30	371	Other Equipment - OPC	0	0	0	0	0.0000%	0		
31		Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0

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DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACC 1010 PLANT (WKP C.c)	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACCT 1060 CCNC (WKP C-1.c)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	CORPORATE ALLOCATED TO TGS ANNUAL PROFORMA DEPR & AMORT EXP	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		DISTRIBUTION PLANT								
32	374	Land	$0	$0	$0	$0	0.0000%	$0		
33	374.1	Land	0	0	0	0	0.0000%	0		
34	374.2	Land Rights	0	0	0	0	0.0000%	0		
35	375.1	Structures & Improvements	0	0	0	0	0.0000%	0		
36	375.1	Structures & Improvements	0	0	0	0	0.0000%	0		
37	375.2	Other System Structures	0	0	0	0	0.0000%	0		
38	376	Mains	0	0	0	0	0.0000%	0		
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0.0000%	0		
40	377	Compressor Station Equipment	0	0	0	0	0.0000%	0		
41	378	Meas. & Reg. Station - General	0	0	0	0	0.0000%	0		
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0.0000%	0		
43	380	Services	0	0	0	0	0.0000%	0		
44	380.1	Ind Service Line Equip	0	0	0	0	0.0000%	0		
45	380.2	Comm Service Line Equip	0	0	0	0	0.0000%	0		
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0.0000%	0		
47	381	Meters	0	0	0	0	0.0000%	0		
48	382	Meter Installations	0	0	0	0	0.0000%	0		
49	383	House Regulators	0	0	0	0	0.0000%	0		
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		
51	386	Other Property on Customer Premises	0	0	0	0	0.0000%	0		
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		
53		Total Distribution Plant	$0	$0	$0	$0		$0		$0
		GENERAL PLANT								
54	389	Land & Land Rights	$12,578	$0	$0	$12,578	0.0000%	$0	46.7362%	$0
55	390	Structures & Improvements	0	0	0	0	0.0000%	0	46.7362%	0
56	390.1	Structures & Improvements	1,413,205	188,176	0	1,601,381	2.0100%	32,188	46.7362%	15,043
57	390.17	Building Improv Plum	0	0	0	0	0.0000%	0	46.7362%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0.0000%	0	46.7362%	0
59	390.2	Leasehold Improvement	1,775,674	493,222	0	2,268,896	17.9104%	406,368	46.7362%	189,921
60	390.2	OGS Lease Incentive	0	0	0	0	0.0000%	0	46.7362%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0.0000%	0	46.7362%	0
62	391	Office Furniture & Equipment	0	0	0	0	0.0000%	0	46.7362%	0
63	391.1	Office Furniture & Equipment	1,404,686	3,228	0	1,407,914	6.6667%	93,861	46.7362%	43,867

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACC 1010 PLANT (WKP C.c)	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACCT 1060 CCNC (WKP C-1.c)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	CORPORATE ALLOCATED TO TGS ANNUAL PROFORMA DEPR & AMORT EXP	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
64	391.19	Airplane Hanger Furniture	0	0	0	0	6.6667%	0	46.7362%	0
65	391.2	Data Processing Equipment	0	0	0	0	0.0000%	0	46.7362%	0
66	391.2	Oracle Equipment	0	0	0	0	0.0000%	0	46.7362%	0
67	391.3	Office Machines	91,002	259,106	0	350,108	5.0000%	17,505	46.7362%	8,181
68	391.4	Audio Visual Equipment	336,633	0	0	336,633	20.0000%	67,327	46.7362%	31,466
69	391.5	Artwork	0	0	0	0	0.0000%	0	46.7362%	0
70	391.6	Purchased Software	37,429,487	6,501,964	0	43,931,451	7.6923%	3,379,342	46.7362%	1,579,376
71	391.6	Banner Software	3,261,638	0	0	3,261,638	7.6923%	250,895	46.7362%	117,259
72	391.6	PowerPlant System	679,087	0	0	679,087	7.6923%	52,237	46.7362%	24,414
73	391.6	Riskworks	0	0	0	0	7.6923%	0	46.7362%	0
74	391.6	Maximo	1,167,518	103,734	0	1,271,252	7.6923%	97,789	46.7362%	45,703
75	391.6	Foundation Software	0	0	0	0	7.6923%	0	46.7362%	0
76	391.6	Concur Project	21,155	0	0	21,155	7.6923%	1,627	46.7362%	761
77	391.6	Journey-Employee-ODC Distrigas	19,993,925	0	0	19,993,925	7.6923%	1,537,994	46.7362%	718,800
78	391.6	Journey-Employee Count	545,917	0	0	545,917	7.6923%	41,994	46.7362%	19,626
79	391.6	Payroll - Time Management	871,271	0	0	871,271	7.6923%	67,021	46.7362%	31,323
80	391.6	Accounts Payable Software	396,961	0	0	396,961	7.6923%	30,535	46.7362%	14,271
81	391.6	Customer Relations Software	433,755	0	0	433,755	7.6923%	33,366	46.7362%	15,594
82	391.8	Micro Computer Software	7,728,708	0	0	7,728,708	20.0000%	1,545,742	46.7362%	722,421
83	391.81	Aircraft Computer Equipment	0	0	0	0	0.0000%	0	46.7362%	0
84	391.9	Computer & Equipment	0	0	0	0	0.0000%	0	46.7362%	0
85	391.99	Cloud Computing	618,218	0	0	618,218	7.6923%	47,555	46.7362%	22,226
86	392	Transportation Equipment	0	0	0	0	0.0000%	0	46.7362%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	16.6667%	0	46.7362%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0.0000%	0	46.7362%	0
89	392.5	Trailers	0	0	0	0	0.0000%	0	46.7362%	0
90	392.6	Aircraft	0	0	0	0	6.2800%	0	46.7362%	0
91	393	Stores Equipment	0	0	0	0	0.0000%	0	46.7362%	0
92	394	Tools, Shop & Garage	138,211	31,098	0	169,309	6.6667%	11,287	46.7362%	5,275
93	394.1	Tools	0	0	0	0	0.0000%	0	46.7362%	0
94	394.2	Shop Equipment	0	0	0	0	0.0000%	0	46.7362%	0
95	395	CNG Equipment	0	0	0	0	0.0000%	0	46.7362%	0
96	396	Major Work Equipment	0	0	0	0	0.0000%	0	46.7362%	0
97	397	Communication Equipment	29,455	0	0	29,455	5.0000%	1,473	46.7362%	688
98	397.2	Telephone Equipment	0	0	0	0	0.0000%	0	46.7362%	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP G-15.c.1**
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DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACC 1010 PLANT (WKP C.c)	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACCT 1060 CCNC (WKP C-1.c)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	CORPORATE ALLOCATED TO TGS ANNUAL PROFORMA DEPR & AMORT EXP	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
99	398	Miscellaneous General Plant	0	0	0	0	0.0000%	0	46.7362%	0
100		Total General Plant	$78,349,085	$7,580,527	$0	$85,929,613		$7,716,107		$3,606,215
101		Total Plant in Service	$78,349,085	$7,580,527	$0	$85,929,613		$7,716,107		$3,606,215
102		Total Annualized Depreciation & Amortization Expense						$7,716,107	46.7362%	$3,606,215
103		Test Year Depreciation & Amortization Expense Accts 403 & 404						6,630,496	46.7362%	3,098,842
104		Adjustment to Test Year						$1,085,611	46.7362%	$507,373

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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FULLY DEPRECIATED PLANT - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE UNALLOCATED AS ADJUSTED PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
			(a)	(b)	(c)	(d)	(e)	(f)
		INTANGIBLE PLANT						
1	301	Organization	$0	$0	$0	$0		
2	301	Organization - OPC	0	0	0	0		
3	302	Franchises & Consents	0	0	0	0		
4	303	Misc. Intangible	0	0	0	0		
5	303	Misc. Intangible - OPC	0	0	0	0		
6	303.1	Misc. Intangible	0	0	0	0		
7		Total Intangible Plant	$0	$0	$0	$0		
		GATHERING AND TRANSMISSION PLANT						
8	325	Land & Land Rights	$0	$0	$0	$0		
9	327	Field Comprss Station Strucutres	0	0	0	0		
10	328	Field Meas/Reg Station Structures	0	0	0	0		
11	329	Other Structures	0	0	0	0		
12	332	Field Lines	0	0	0	0		
13	333	Field Compressor Station Equip	0	0	0	0		
14	334	Field Meas/Reg Station Equipment	0	0	0	0		
15	336	Purification Equipment	0	0	0	0		
16	337	Other Equip	0	0	0	0		
17	365	Land & Land Rights	0	0	0	0		
18	365.1	Land - OPC	0	0	0	0		
19	365.2	Rights-of-Way	0	0	0	0		
20	365.2	Rights-of-Way - OPC	0	0	0	0		
21	366	Meas/Reg Station Structures	0	0	0	0		
22	366.1	Compressor Station Structure - OPC	0	0	0	0		
23	367	Mains	0	0	0	0		
24	367	Mains - OPC	0	0	0	0		
25	368	Compressor Station Equip	0	0	0	0		
26	369	Meas & Reg Stations Equip	0	0	0	0		
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0		
28	369.1	Measuring Stations Equip - OPC	0	0	0	0		
29	371	Other Equipment	0	0	0	0		
30	371	Other Equipment	0	0	0	0		
31		Total Gathering and Transmission Plant	$0	$0	$0	$0		
		DISTRIBUTION PLANT						
32	374	Land	0	0	0	0		
33	374.1	Land	0	0	0	0		
34	374.2	Land Rights	0	0	0	0		
35	375.1	Structures & Improvements	0	0	0	0		
36	375.1	Structures & Improvements	0	0	0	0		
37	375.2	Other System Structures	0	0	0	0		
38	376	Mains	0	0	0	0		
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0		
40	377	Compressor Station Equipment	0	0	0	0		
41	378	Meas. & Reg. Station - General	0	0	0	0		
42	379	Meas. & Reg. Station - C.G.	0	0	0	0		
43	380	Services	0	0	0	0		
44	380.1	Ind Service Line Equip	0	0	0	0		
45	380.2	Comm Service Line Equip	0	0	0	0		
46	380.4	Yard Lines-Customer Svc	0	0	0	0		
47	381	Meters	0	0	0	0		
48	382	Meter Installations	0	0	0	0		
49	383	House Regulators	0	0	0	0		
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0		
51	386	Other Property on Customer Premises	0	0	0	0		
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0		
53		Total Distribution Plant	$0	$0	$0	$0		
		GENERAL PLANT						
54	389	Land & Land Rights	$43,763	$0	$43,763	$0	28.74%	$0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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FULLY DEPRECIATED PLANT - CORPORATE

			CORPORATE UNALLOCATED AS ADJUSTED					
LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED
			(a)	(b)	(c)	(d)	(e)	(f)
55	390	Structures & Improvements	0	0	0	0	28.74%	0
56	390.1	Structures & Improvements	5,571,959	(322,301)	5,249,658	0	28.74%	0
57	390.17	Building Improv Plum	0	0	0	0	28.74%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	28.74%	0
59	390.2	Leasehold Improvement	7,894,558	(4,014,869)	3,879,689	0	28.74%	0
60	390.2	OGS Lease Incentive	0	0	0	0	28.74%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	28.74%	0
62	391	Office Furniture & Equipment	0	0	0	0	28.74%	0
63	391.1	Office Furniture & Equipment	4,898,797	(2,030,004)	2,868,793	0	28.74%	0
64	391.19	Airplane Hanger Furniture	0	0	0	0	28.74%	0
65	391.2	Data Processing Equipment	0	0	0	0	28.74%	0
66	391.2	Oracle Equipment	0	0	0	0	28.74%	0
67	391.3	Office Machines	1,218,191	(143,933)	1,074,259	0	28.74%	0
68	391.4	Audio Visual Equipment	1,171,304	(618,195)	553,109	0	28.74%	0
69	391.5	Artwork	0	0	0	0	28.74%	0
70	391.6	Purchased Software	152,858,215	(62,201,348)	90,656,867	0	28.74%	0
71	391.6	Banner Software	10,572,569	(2,440,926)	8,131,643	0	30.85%	0
72	391.6	PowerPlant System	2,448,925	(943,188)	1,505,737	0	27.73%	0
73	391.6	Riskworks	0	0	0	0	28.74%	0
74	391.6	Maximo	5,085,007	(3,147,859)	1,937,148	0	25.00%	0
75	391.6	Foundation Software	0	0	0	0	28.74%	0
76	391.6	Concur Project	71,646	(57,213)	14,433	0	29.53%	0
77	391.6	Journey-Employee-ODC Distrigas	69,568,284	(49,013,601)	20,554,683	0	28.74%	0
78	391.6	Journey-Employee Count	1,848,836	(1,437,868)	410,968	0	29.53%	0
79	391.6	Payroll - Time Management	2,950,700	(629,163)	2,321,537	0	29.53%	0
80	391.6	Accounts Payable Software	1,190,839	(413,915)	776,924	0	33.33%	0
81	391.6	Customer Relations Software	1,406,012	(58,554)	1,347,458	0	30.85%	0
82	391.8	Micro Computer Software	26,891,816	(9,953,232)	16,938,584	0	28.74%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	28.74%	0
84	391.9	Computer & Equipment	0	0	0	0	28.74%	0
85	391.99	Cloud Computing	2,151,072	(238,330)	1,912,743	0	28.74%	0
86	392	Transportation Equipment	0	0	0	0	28.74%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	28.74%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	28.74%	0
89	392.5	Trailers	0	0	0	0	28.74%	0
90	392.6	Aircraft	0	0	0	0	28.74%	0
91	393	Stores Equipment	0	0	0	0	28.74%	0
92	394	Tools, Shop & Garage	589,107	(53,306)	535,801	0	28.74%	0
93	394.1	Tools	0	0	0	0	28.74%	0
94	394.2	Shop Equipment	0	0	0	0	28.74%	0
95	395	CNG Equipment	0	0	0	0	28.74%	0
96	396	Major Work Equipment	0	0	0	0	28.74%	0
97	397	Communication Equipment	102,489	(29,204)	73,285	0	28.74%	0
98	397.2	Telephone Equipment	0	0	0	0	28.74%	0
99	398	Miscellaneous General Plant	0	0	0	0	28.74%	0
100		Total General Plant	$298,534,092	$(137,747,008)	$160,787,084	$0		$0
101		Total Orig Cost Plant in Service	$298,534,092	$(137,747,008)	$160,787,084	$0		$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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AD VALOREM TAX EXPENSE

LINE NO.	DESCRIPTION	AMOUNT	AMOUNT	AMOUNT
		(a)	(b)	(c)
	DIRECT SERVICE AREA PLANT @ 12/31/2023			
1	Plant In Service - Gathering/Transmission/Distribution		$871,800,917	
2	Plant In Service - General		91,807,993	
3	CCNC - Gathering/Transmission/Distribution		82,206,380	
4	CCNC - General		31,327,474	
5	Accumulated Depreciation - Gathering/Transmission/Distribution		(185,239,831)	
6	Accumulated Depreciation - General		(34,082,254)	
7	Net Plant - Service Area Direct 12/31/2023		$857,820,677	$857,820,677
	CALCULATION OF EFFECTIVE RATE			
8	Ad Valorem Taxes Paid TYE 2023 for Service Area Direct Plant at 1/1/2023		$6,245,581	
	DIRECT SERVICE AREA PLANT @ 1/1/2023:			
9	Plant In Service - Gathering/Transmission/Distribution	$784,675,101		
10	Plant In Service - General	84,637,135		
11	CCNC - Gathering/Transmission/Distribution	83,235,603		
12	CCNC - General	22,936,617		
13	Accumulated Depreciation - Gathering/Transmission/Distribution	(175,610,541)		
14	Accumulated Depreciation - General	(28,716,325)		
		$771,157,589	771,157,589	
15	Effective Tax Rate		0.008099	0.008099
16	Annualized Ad Valorem Tax Expense			$6,947,490
17	Test Year Ad Valorem Tax Expense - Acct 4081190			6,172,432
18	Adjustment to Test Year Expense			$775,058

Source: WKP G-16 Ad Valorem Tax (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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PLANT IN SERVICE - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/22	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization	$56,257	$(0)	$56,257
2	(302) Franchises & Consents	393,474	0	393,474
3	(303) Misc. Intangible	753,928	0	753,928
4	Total Intangible Plant - Direct	$1,203,659	$(0)	$1,203,659
	GATHERING AND TRANSMISSION PLANT			
5	(325) Land & Land Rights	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0
8	(329) Other Structures	0	0	0
9	(332) Field Lines	0	0	0
10	(333) Field Compressor Station Equip	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0
12	(336) Purification Equipment	0	0	0
13	(337) Other Equip	0	0	0
14	(365) Land & Land Rights	89,637	0	89,637
15	(365.2) Rights-of-Way	6,959	0	6,959
16	(366) Meas/Reg Station Structures	2,346	0	2,346
17	(367) Mains	12,770,103	0	12,770,103
18	(368) Compressor Station Equip	0	0	0
19	(369) Measure/Reg. Station Equipment	3,354,581	0	3,354,581
20	(371) Other Equipment	0	0	0
21	Total Gathering and Transmission Plant - Direct	$16,223,626	$0	$16,223,626
	DISTRIBUTION PLANT			
22	(374) Land	$19,503	$0	$19,503
23	(374.2) Land & Land Rights	95,672	-	95,672
24	(375) Structures & Improvements	48,935	0	48,935
25	(376) Mains	352,870,986	0	352,870,986
26	(376.9) Cathodic Protection Anodes	27,479,580	0	27,479,580
27	(377) Compressor Station Equipment	0	0	0
28	(378) Meas. & Reg. Station - General	18,222,370	0	18,222,370
29	(379) Meas. & Reg. Station - C.G.	4,005,995	0	4,005,995

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PLANT IN SERVICE - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/22	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
30	(380) Services	265,163,485	0	265,163,485
31	(380.1) Ind Service Line Equip	0	0	0
32	(380.2) Comm Service Line Equip	0	0	0
33	(380.4) Yard Lines-Customer Svc	0	0	0
34	(381) Meters	73,928,571	0	73,928,571
35	(382) Meter Installations	0	0	0
36	(383) House Regulators	9,948,066	0	9,948,066
37	(385) Indust. Meas. & Reg. Stat. Equipment	15,605,062	0	15,605,062
38	(386) Other Property on Customer Premises	1,063,249	0	1,063,249
39	(387) Meas. & Reg. Stat. Equipment	0	0	0
40	Total Distribution Plant - Direct	$768,451,475	$0	$768,451,475
	GENERAL PLANT			
41	(389) Land & Land Rights	$5,942,548	$0	$5,942,548
42	(390) Structures & Improvements	24,041,068	0	24,041,068
43	(391) Office Furniture & Equipment	2,501,736	0	2,501,736
44	(391.9) Computer & Equipment	1,560,776	0	1,560,776
45	(392) Transportation Equipment	17,299,078	0	17,299,078
46	(393) Stores Equipment	5,387	0	5,387
47	(394) Tools, Shop & Garage	10,470,468	0	10,470,468
48	(395) CNG Equipment	0	0	0
49	(396) Major Work Equipment	2,562,833	0	2,562,833
50	(397) Communication Equipment	20,246,891	0	20,246,891
51	(398) Miscellaneous General Plant	6,349	0	6,349
52	Total General Plant - Direct	$84,637,135	$0	$84,637,135
53	Total Orig Cost Plant in Service - Direct	$870,515,895	$0	$870,515,895

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/22	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization	$0	$0	$0
2	(302) Franchises & Consents	0	0	0
3	(303) Misc. Intangible	0	0	0
4	Total Intangible CCNC - Direct	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT			
5	(325) Land & Land Rights	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0
8	(329) Other Structures	0	0	0
9	(332) Field Lines	0	0	0
10	(333) Field Compressor Station Equip	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0
12	(336) Purification Equipment	0	0	0
13	(337) Other Equip	0	0	0
14	(365) Land & Land Rights	0	0	0
15	(365.2) Rights-of-Way	0	0	0
16	(366) Meas/Reg Station Structures	0	0	0
17	(367) Mains	15,732,832	0	15,732,832
18	(368) Compressor Station Equip	0	0	0
19	(369) Measure/Reg. Station Equipment	1,910,915	0	1,910,915
20	(371) Other Equipment	0	0	0
21	Total Gathering and Transmission CCNC - Direct	$17,643,747	$0	$17,643,747
	DISTRIBUTION PLANT			
22	(374) Land	$2,072	$0	$2,072
23	(374.2) Land & Land Rights	22,919	0	22,919
24	(375) Structures & Improvements	1,710,631	0	1,710,631
25	(376) Mains	48,838,606	0	48,838,606
26	(376.9) Cathodic Proteciton Anodes	322,108	0	322,108
27	(377) Compressor Station Equipment	0	0	0
28	(378) Meas. & Reg. Station - General	4,061,724	0	4,061,724
29	(379) Meas. & Reg. Station - C.G.	970,538	0	970,538
30	(380) Services	6,455,477	0	6,455,477
31	(380.1) Ind Service Line Equip	18,397	0	18,397
32	(380.2) Comm Service Line Equip	11,181	0	11,181
33	(380.4) Yard Lines-Customer Svc	61,918	0	61,918
34	(381) Meters	1,470,816	0	1,470,816
35	(382) Meter Installations	6,429	0	6,429
36	(383) House Regulators	1,210,870	0	1,210,870
37	(385) Indust. Meas. & Reg. Stat. Equipment	428,170	0	428,170

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT

AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/22	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
38	(386) Other Property on Customer Premises	0	0	0
39	(387) Meas. & Reg. Stat. Equipment	0	0	0
40	Total Distribution CCNC - Direct	$65,591,857	$0	$65,591,857
	GENERAL PLANT			
41	(389) Land & Land Rights	$2,403,115	$0	$2,403,115
42	(390) Structures & Improvements	1,201,518.00	0	1,201,518
43	(391) Office Furniture & Equipment	36,251	0	36,251
44	(391.9) Computer & Equipment	25,430	0	25,430
45	(392) Transportation Equipment	1,875,839	0	1,875,839
46	(393) Stores Equipment	2,137	0	2,137
47	(394) Tools, Shop & Garage	2,677,199	0	2,677,199
48	(395) CNG Equipment	0	0	0
49	(396) Major Work Equipment	613,990	0	613,990
50	(397) Communication Equipment	14,101,138	0	14,101,138
51	(398) Miscellaneous General Plant	0	0	0
52	Total General CCNC - Direct	$22,936,617	$0	$22,936,617
53	Total Orig Cost CCNC - Direct	$106,172,220	$0	$106,172,220

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION- DIRECT

AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/22 1080100	YTD BALANCE 12/31/22 1110000	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)	(d)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)				
1	(301) Organization	$(55,777)	$0	$0	$(55,777)
2	(302) Franchises & Consents	(393,474)	0	0	(393,474)
3	(303) Misc. Intangible	0	(753,928)	0	(753,928)
4	Total Intangible Plant Reserves - Direct	$(449,251)	$(753,928)	$0	$(1,203,180)
	GATHERING AND TRANSMISSION PLANT				
5	(325) Land & Land Rights	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0
8	(329) Other Structures	0	0	0	0
9	(332) Field Lines	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0
12	(336) Purification Equipment	0	0	0	0
13	(337) Other Equip	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0
15	(365.2) Rights-of-Way	(2,372)	0	0	(2,372)
16	(366) Meas/Reg Station Structures	(2,346)	0	0	(2,346)
17	(367) Mains	(3,351,191)	0	0	(3,351,191)
18	(368) Compressor Station Equip		0	0	0
19	(369) Measure/Reg. Station Equipment	(882,542)	0	0	(882,542)
20	(371) Other Equipment	(12,458)	0	0	(12,458)
21	Total Gathering and Transmission Plant Reserves - Direct	$(4,250,907)	$0	$0	$(4,250,907)
	DISTRIBUTION PLANT				
22	(374) Land	(255)	$0	$0	$(255)
23	(374.2) Land & Land Rights	(9,440)	0	0	(9,440)
24	(375) Structures & Improvements	(121,134)	0	0	(121,134)
25	(376) Mains	(72,017,419)	0	0	(72,017,419)
26	(376.9) Cathodic Protection Anodes	(11,681,652)	0	0	(11,681,652)
27	(377) Compressor Station Equipment	0	0	0	0
28	(378) Meas. & Reg. Station - General	(3,577,245)	0	0	(3,577,245)
29	(379) Meas. & Reg. Station - C.G.	(781,846)	0	0	(781,846)
30	(380) Services	(39,530,941)	0	0	(39,530,941)
31	(380.1) Ind Service Line Equip	0	0	0	0
32	(380.2) Comm Service Line Equip	0	0	0	0
33	(380.4) Yard Lines-Customer Svc	0	0	0	0
34	(381) Meters	(32,886,811)	0	0	(32,886,811)
35	(382) Meter Installations	(2,793)	0	0	(2,793)
36	(383) House Regulators	(4,710,609)	0	0	(4,710,609)
37	(385) Indust. Meas. & Reg. Stat. Equipment	(4,996,448)	0	0	(4,996,448)
38	(386) Other Property on Customer Premises	(1,043,041)	0	0	(1,043,041)
39	(387) Meas. & Reg. Stat. Equipment	0	0	0	0
40	Total Distribution Plant Reserves - Direct	$(171,359,634)	$0	$0	$(171,359,634)
	GENERAL PLANT				
41	(389) Land & Land Rights	4,733	$0	$0	$4,733
42	(390) Structures & Improvements	(2,084,984)	(188,578)	0	(2,273,562)
43	(391) Office Furniture & Equipment	(686,221)	0	0	(686,221)
44	(391.9) Computer & Equipment	(833,347)	0	0	(833,347)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION- DIRECT

AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/22 1080100	YTD BALANCE 12/31/22 1110000	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)	(d)
45	(392) Transportation Equipment	(7,827,036)	0	0	(7,827,036)
46	(393) Stores Equipment	(5,828)	0	0	(5,828)
47	(394) Tools, Shop & Garage	(3,713,900)	0	0	(3,713,900)
48	(395) CNG Equipment	37,480	0	0	37,480
49	(396) Major Work Equipment	(1,151,956)	0	0	(1,151,956)
50	(397) Communication Equipment	(12,262,805)	0	0	(12,262,805)
51	(398) Miscellaneous General Plant	(3,885)	0	0	(3,885)
52	Total General Plant Reserves - Direct	$(28,527,747)	$(188,578)	$0	$(28,716,325)
53	Total Accumulated Reserves - Direct	$(204,587,540)	$(942,507)	$0	$(205,530,047)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

TEXAS FRANCHISE ("GROSS MARGIN") TAX EXPENSE

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	Total Texas Franchise Tax in calendar year ended 12/31/2023		$820,524
2	Allocation to Central Gulf Service Area	WKP A.b Alloc Factors	46.74 %
3	Texas Franchise Tax Allocated to CGSA		$383,482
4	Test Year Expense - Acct 4091100		0
5	Adjustment to Test Year		$383,482
6	Texas Franchise Tax Rate	0.0075	

Source: Sch G-17 Texas Franchise Tax (CONFIDENTIAL)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

STORES LOAD CLEARING

LINE NO.	DESCRIPTION	(a)	(b)	(c)	AMOUNT (d)
1	Test Year Charges into Stores Account 1630 for direct and allocated charges:		$3,560,158		
2	Test Year Amounts Cleared Out of Account 1630 to Service Area		3,686,037		
3	Test Year Amount Under/(Over) Cleared		$(125,879)		$(125,879)
	Plus/Minus Adjustments To Test Year Amounts Charged into Acct 1630 for direct and allocated charges:				
		Adjusted Test Year	Recorded Test Year	Adjustment	
4	Payroll (from Direct and Shared Svcs)	$451,855	$445,417	$6,439	
5	Benefits & Payroll Taxes	136,624	131,993	4,632	
6	Other	3,007,097	2,982,749	24,349	
7	Total Other Adjustments	$3,595,577	$3,560,158	$35,419	35,419
8	Total Adjusted Amount Under/(Over) Cleared				$(90,460)
	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				
9	Adjustment to Test Year Expense Accounts (See account breakdown below)				$(4,682)
10	Adjustment to Test Year Non-Expense Accounts				(85,778)
11	Total Adjustment to Test Year Clearing Acct 1630				$(90,460)

LINE NO.	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:	Acct.	Amount	Percentage	Amount Under/ (Over) Cleared
12					
13		8700	$133	0.00 %	$(3)
14		8740	58,558	1.59 %	(1,437)
15		8750	0	0%	0
16		8770	0	0%	0
17		8780	76,565	2.08 %	(1,879)
18		8800	10,202	0.28 %	(250)
19		8870	31,766	0.86 %	(780)
20		8890	0	0%	0
21		8920	11,738	0.32 %	(288)
22		9020	1,824	0.05 %	(45)
23		9210	0	0%	0
24	Total Adjustment to Test Year Expense Accounts		$190,785	0.051759	$(4,682)
25	Total Adjustment to Test Year Non-Expense Accounts		3,495,252	0.948241	(85,777.77)
	Adjustment to Test Year Clearing		$3,686,037	1.000000	$(90,460)

Source: SCH G-18 STORES CLEARING TY 12 31 2023 (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

TRANSPORTATION AND WORK EQUIPMENT CLEARING

LINE NO.	DESCRIPTION				AMOUNT
		(a)	(b)	(c)	(d)
1	Test Year Charges into TWE Clearing Accounts 1840100-1840289		$4,626,073		
2	Test Year Amounts Cleared Out of TWE Accounts 1840100-1840289		4,645,479		
3	Test Year Amount Under/(Over) Cleared		$(19,406)		$(19,406)
	Plus/Minus Adjustments To Test Year Amounts Charged into TWE Acct 1840100-1840289:				
		Adjusted Test Year	Recorded Test Year	Adjustment	
4	Depreciation	$1,778,040	$1,936,154	$(158,114)	
5	Lease Costs		0	0	
6	Payroll	239,209	234,552	4,656	
7	Benefits & Payroll Taxes	71,440	68,098	3,341	
8	Other (gasoline, maintenance, etc)	2,387,269	2,387,269	0	
9	Total	$4,475,956	$4,626,073	$(150,117)	(150,117)
10	Total Adjusted Amount Under/(Over) Cleared				$(169,523)
	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				
11	Adjustment to Test Year Expense Accounts (See account breakdown below)				$(98,673)
12	Adjustment to Test Year Non-Expense Accounts				(70,849)
13	Total Adjustment to Test Year TWE Clearing Acct 1840				$(169,523)

LINE NO.	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				Amount Under/
14		Acct.	Amount	Percentage	(Over) Cleared
15		8560	$103,061	0.022185	$(3,761)
16		8570	4,543	0.000978	(166)
17		8630	9,666	0.002081	(353)
18		8700	9,755	0.002100	(356)
19		8740	321,627	0.069234	(11,737)
20		8750	0	0.000000	0
21		8760	0	0.000000	0
22		8770	0	0.000000	0
23		8780	988,855	0.212864	(36,085)
24		8790	0	0.000000	0
25		8800	0	0.000000	0
26		8870	458,937	0.098792	(16,748)
27		8890	305,635	0.065792	(11,153)
28		8900	14,043	0.003023	(512)
29		8910	0	0.000000	—
30		8920	442,469	0.095247	(16,147)
31		8930	0	0.000000	0
32		9020	45,382	0.009769	(1,656)
33		9030	0	0.000000	0
34		9050	0	0.000000	0
35		9210	0	0.000000	0
36	Total Adjustment to Test Year Expense Accounts		$2,703,974	0.582066	$(98,673)
37	Total Adjustment to Test Year Non-Expense Accounts		1,941,505	0.417934	(70,849)
38	Adjustment to Test Year Clearing		$4,645,479	1.000000	$(169,523)

Source: SCH G-19 TWE Clearing Adjustment TY 12 31 2023(CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

REGULATORY EXPENSE AMORTIZATION

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Unamortized balance of Regulatory Assets from GUD No. 10526	$49,131
2	Less 11 mos. Amortization (line 23, January 2024 - November 2024) [Note 1]	(16,053)
3	Under-collection of rate case expense from GUD No. 10928	5,618
4	Deferred Winter Storm URI O&M	1,291,744
5	Winter Storm URI related STI	373,400
6	Covid related O&M	1,431,855
7	Regulatory Assets - Total	$3,135,695
8	Amortization Period (in years)	6
9	Annual Regulatory Asset Amortization Expense	$522,616
10	Test Year Regulatory Asset Amortization Expense - Acct 407.3	0.00
11	Adjustment to Test Year Expense	$522,616

Note 1: Amortization of Regulatory Asset between end of Test Year and beginning of effective rates.

	MONTH	2024	GRAND TOTAL
12	January	$(1,459)	$(1,459)
13	February	(1,459)	(1,459)
14	March	(1,459)	(1,459)
15	April	(1,459)	(1,459)
16	May	(1,459)	(1,459)
17	June	(1,459)	(1,459)
18	July	(1,459)	(1,459)
19	August	(1,459)	(1,459)
20	September	(1,459)	(1,459)
21	October	(1,459)	(1,459)
22	November	(1,459)	(1,459)
23			$(16,053)

Source: SCH G-20 Rate Case Exp TY 12 31 2023 (CONFIDENTIAL).xlsx
SCH G-20 Regulatory Expenses - COVID (CONFIDENTIAL).xlsx
SCH G-20 Regulatory Expenses - Winter Storm URI O&M (CONFIDENTIAL).xlsx
SCH G-20 Regulatory Expenses - Winter Storm URI STI (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

DISTRIGAS ALLOCATION PERCENTAGE

							ADJUSTMENT FOR Q1 2024 ALLOCATION %		
LINE NO.	DESCRIPTION	YEAR	MONTH	CORPORATE ALLOCABLE $	DISTRIGAS ALLOCATION %	$ ALLOCATED TO TGS	DISTRIGAS ALLOCATION %	$ ALLOCATED TO TGS	ADJUSTMENT
		(a)	(b)	(c)	(d)	(e)=(c) x (d)	(f)	(g)=(c) x (f)	(h)=(g) - (e)
1	4081	2023	1	$515,297	28.24%	$145,520			
2		2023	2	737,269	28.24%	208,205			
3		2023	3	778,879	28.24%	219,955			
4		2023	4	406,372	28.47%	115,694			
5		2023	5	403,554	28.47%	114,892			
6		2023	6	514,572	28.47%	146,499			
7		2023	7	446,348	28.54%	127,388			
8		2023	8	359,921	28.54%	102,722			
9		2023	9	536,738	28.54%	153,185			
10		2023	10	433,494	28.51%	123,589			
11		2023	11	481,982	28.51%	137,413			
12		2023	12	422,678	28.51%	120,505			
13	4081 Total			$6,037,104		$1,715,567			
14	9260	2023	1	$(34,432)	28.24%	$(9,724)			
15		2023	2	(34,425)	28.24%	(9,722)			
16		2023	3	(34,425)	28.24%	(9,722)			
17		2023	4	(34,425)	28.47%	(9,801)			
18		2023	5	(34,425)	28.47%	(9,801)			
19		2023	6	(34,425)	28.47%	(9,801)			
20		2023	7	(34,425)	28.54%	(9,825)			
21		2023	8	(34,425)	28.54%	(9,825)			
22		2023	9	(34,425)	28.54%	(9,825)			
23		2023	10	(34,425)	28.51%	(9,815)			
24		2023	11	(34,425)	28.51%	(9,815)			
25		2023	12	(34,425)	28.51%	(9,815)			
26	9260 Total			$(413,107)		$(117,488)			
27	9302	2023	1	$10,113,953	28.24%	$2,856,180			
28		2023	2	8,448,373	28.24%	2,385,821			
29		2023	3	14,537,066	28.24%	4,105,268			
30		2023	4	9,264,972	28.47%	2,637,737			
31		2023	5	9,237,270	28.47%	2,629,851			
32		2023	6	11,146,278	28.47%	3,173,345			
33		2023	7	10,777,543	28.54%	3,075,911			
34		2023	8	8,323,212	28.54%	2,375,445			
35		2023	9	11,168,936	28.54%	3,187,614			
36		2023	10	9,143,790	28.51%	2,606,895			
37		2023	11	12,636,311	28.51%	3,602,612			
38		2023	12	14,895,528	28.51%	4,246,715			
39	9302 Total			$129,693,233		$36,883,394	28.74%	$37,273,835	$390,441
40	Total			$135,317,230		$38,481,473		$37,273,835	$390,441
41								O&M Expense Factor	86.02%
42								Adjustment to TGS O&M	335,869
43								Allocation to Service Area	46.7362%
44							Adjustment to Service Area after O&M		$156,972

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

DISTRIGAS ALLOCATION PERCENTAGE

LINE NO.	DESCRIPTION	GROSS PLANT & INVESTMENT	ALLOCATION FACTOR	OPERATING INCOME	ALLOCATION FACTOR	LABOR EXPENSE	ALLOCATION FACTOR	ALLOCATION FACTOR
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	1st Quarter 2023 - based on 12 months Ended Dec 2022							
1	Oklahoma Natural Gas Company	$3,165,034,324	42.03%	$149,957,404	42.53%	$57,282,431	37.00%	40.51%
2	Kansas Gas Service Company	2,329,905,690	30.94%	95,432,694	27.07%	54,059,190	34.92%	30.98%
3	Texas Gas Service Company	2,035,068,038	27.03%	104,370,801	29.60%	43,483,087	28.09%	28.24%
4	Utility Insurance Company	0	0.00%	2,814,793	0.80%	0	0.00%	0.27%
5	Total	$7,530,008,052	100.00%	$352,575,692	100.00%	$154,824,709	100.00%	100.00%
	2nd Quarter 2023 - based on 12 months Ended Mar 2023							
6	Oklahoma Natural Gas Company	$3,218,984,333	42.05%	$151,012,705	42.22%	$58,689,108	37.33%	40.54%
7	Kansas Gas Service Company	2,357,816,903	30.80%	96,557,323	27.00%	54,230,871	34.49%	30.76%
8	Texas Gas Service Company	2,077,800,366	27.14%	107,661,899	30.10%	44,307,558	28.18%	28.47%
9	Utility Insurance Company	0	0.00%	2,415,529	0.68%	0	0.00%	0.23%
10	Total	$7,654,601,602	100.00%	$357,647,456	100.00%	$157,227,537	100.00%	100.00%
	3rd Quarter 2023 - based on 12 months Ended Jun 2023							
11	Oklahoma Natural Gas Company	$3,284,686,912	42.06%	$152,011,601	42.47%	$60,413,156	37.64%	40.73%
12	Kansas Gas Service Company	2,395,435,424	30.67%	96,179,379	26.87%	54,419,676	33.91%	30.48%
13	Texas Gas Service Company	2,129,922,322	27.27%	107,054,333	29.91%	45,655,390	28.45%	28.54%
14	Utility Insurance Company	0	0.00%	2,706,384	0.76%	0	0.00%	0.25%
15	Total	$7,810,044,657	100.00%	$357,951,697	100.00%	$160,488,221	100.00%	100.00%
	4th Quarter 2023 - based on 12 months Ended Sep 2023							
16	Oklahoma Natural Gas Company	$3,350,581,440	42.01%	$154,646,230	42.50%	$62,220,196	38.15%	40.88%
17	Kansas Gas Service Company	2,434,303,640	30.52%	99,532,115	27.35%	54,285,594	33.29%	30.39%
18	Texas Gas Service Company	2,190,303,183	27.46%	107,347,713	29.50%	46,566,554	28.56%	28.51%
19	Utility Insurance Company	0	0.00%	2,360,230	0.65%	0	0.00%	0.22%
20	Total	$7,975,188,264	100.00%	$363,886,288	100.00%	$163,072,345	100.00%	100.00%
	1st Quarter 2024 - based on 12 months Ended Dec 2023							
21	Oklahoma Natural Gas Company	$3,408,887,578	41.87%	$156,066,534	42.96%	$63,216,648	38.39%	41.08%
22	Kansas Gas Service Company	2,474,943,803	30.40%	99,012,329	27.25%	54,184,004	32.90%	30.18%
23	Texas Gas Service Company	2,257,856,066	27.73%	108,228,998	29.79%	47,270,550	28.71%	28.74%
24	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
25	Total	$8,141,687,446	100.00%	$363,307,861	100.00%	$164,671,202	100.00%	100.00%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CAUSAL ALLOCATION PERCENTAGE

LINE NO.	CAUSAL METHOD	YEAR	MONTH	CORPORATE ALLOCABLE $	CAUSAL ALLOCATION %	$ ALLOCATED TO TGS
		(a)	(b)	(c)	(d)	(e)=(c) x (d)
1	Invoice Count	2023	1	$43,014	25.00 %	$10,754
2	Invoice Count	2023	2	30,759	25.00%	7,690
3	Invoice Count	2023	3	29,518	25.00%	7,379
4	Invoice Count	2023	4	36,277	25.00%	9,069
5	Invoice Count	2023	5	36,290	25.00%	9,072
6	Invoice Count	2023	6	36,911	25.00%	9,228
7	Invoice Count	2023	7	36,553	25.00%	9,138
8	Invoice Count	2023	8	36,917	25.00%	9,229
9	Invoice Count	2023	9	36,491	25.00%	9,123
10	Invoice Count	2023	10	37,147	25.00%	9,287
11	Invoice Count	2023	11	28,784	25.00%	7,196
12	Invoice Count	2023	12	28,479	25.00%	7,120
13	**Invoice Count Total**			**$417,141**		**$104,285**
14	Employee Count	2023	1	$1,026,416	24.16 %	$247,982
15	Employee Count	2023	2	1,092,625	24.16%	263,978
16	Employee Count	2023	3	1,108,601	24.16%	267,838
17	Employee Count	2023	4	1,107,323	24.16%	267,529
18	Employee Count	2023	5	1,102,329	24.16%	266,323
19	Employee Count	2023	6	1,183,071	24.16%	285,830
20	Employee Count	2023	7	1,192,227	24.16%	288,042
21	Employee Count	2023	8	1,238,220	24.16%	299,154
22	Employee Count	2023	9	1,056,790	24.16%	255,320
23	Employee Count	2023	10	1,111,093	24.16%	268,440
24	Employee Count	2023	11	1,119,264	24.16%	270,414
25	Employee Count	2023	12	1,325,073	24.16%	320,138
26	**Employee Count Total**			**$13,663,032**		**$3,300,988**
27	Property Accounting Gross PP&E	2023	1	$420	27.04 %	$114
28	Property Accounting Gross PP&E	2023	2	140	27.04%	38
29	Property Accounting Gross PP&E	2023	3	139	27.04%	38
30	Property Accounting Gross PP&E	2023	4	311	27.04%	84
31	Property Accounting Gross PP&E	2023	5	77	27.04%	21
32	Property Accounting Gross PP&E	2023	6	2,872	27.04%	777
33	Property Accounting Gross PP&E	2023	7	395	27.04%	107
34	Property Accounting Gross PP&E	2023	8	485	27.04%	131
35	Property Accounting Gross PP&E	2023	9	6,253	27.04%	1,691
36	Property Accounting Gross PP&E	2023	10	3,677	27.04%	994
37	Property Accounting Gross PP&E	2023	11	1,089	27.04%	294
38	Property Accounting Gross PP&E	2023	12	166	27.04%	45
39	**Property Accounting Gross PP&E Total**			**$16,024**		**$4,333**

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CAUSAL ALLOCATION PERCENTAGE

LINE NO.	CAUSAL METHOD	YEAR	MONTH	CORPORATE ALLOCABLE $	CAUSAL ALLOCATION %	$ ALLOCATED TO TGS
		(a)	(b)	(c)	(d)	(e)=(c) x (d)
40	Administrative Cost for SERP	2023	1	$3,762	0.27 %	10
41	Administrative Cost for SERP	2023	2	9,653	0.27%	26
42	Administrative Cost for SERP	2023	3	8,529	0.27%	23
43	Administrative Cost for SERP	2023	4	1,157	0.27%	3
44	Administrative Cost for SERP	2023	5	7,590	0.27%	20
45	Administrative Cost for SERP	2023	6	8,244	0.27%	22
46	Administrative Cost for SERP	2023	7	1,740	0.27%	5
47	Administrative Cost for SERP	2023	8	5,060	0.27%	14
48	Administrative Cost for SERP	2023	9	10,560	0.27%	29
49	Administrative Cost for SERP	2023	10	1,924	0.27%	5
50	Administrative Cost for SERP	2023	11	6,810	0.27%	18
51	Administrative Cost for SERP	2023	12	8,030	0.27%	22
52	**Administrative Cost for SERP Total**			**$73,059**		**$197**
53	Administrative Cost for Pension	2023	1	$1,090	20.08 %	$219
54	Administrative Cost for Pension	2023	2	3,611	20.08%	725
55	Administrative Cost for Pension	2023	3	887	20.08%	178
56	Administrative Cost for Pension	2023	4	887	20.08%	178
57	Administrative Cost for Pension	2023	5	5,410	20.08%	1,086
58	Administrative Cost for Pension	2023	6	6,567	20.08%	1,319
59	Administrative Cost for Pension	2023	7	887	20.08%	178
60	Administrative Cost for Pension	2023	8	1,775	20.08%	356
61	Administrative Cost for Pension	2023	9	2,647	20.08%	532
62	Administrative Cost for Pension	2023	10	1,226	20.08%	246
63	Administrative Cost for Pension	2023	11	2,392	20.08%	480
64	Administrative Cost for Pension	2023	12	887	20.08%	178
65	**Administrative Costs for Pension Total**			**$28,266**		**$5,676**
66	Customer Count	2023	1	$636,780	30.81 %	$196,192
67	Customer Count	2023	2	586,919	30.81%	180,830
68	Customer Count	2023	3	622,015	30.81%	191,643
69	Customer Count	2023	4	606,115	30.81%	186,744
70	Customer Count	2023	5	576,555	30.81%	177,637
71	Customer Count	2023	6	555,607	30.81%	171,182
72	Customer Count	2023	7	556,348	30.81%	171,411
73	Customer Count	2023	8	649,580	30.81%	200,136
74	Customer Count	2023	9	594,518	30.81%	183,171
75	Customer Count	2023	10	558,282	30.81%	172,007
76	Customer Count	2023	11	507,823	30.81%	156,460
77	Customer Count	2023	12	632,359	30.81%	194,830
78	**Customer Count Total**			**$7,082,900**		**$2,182,242**
79	Miles of Pipe	2023	1	$235,187	25.00 %	$58,797

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CAUSAL ALLOCATION PERCENTAGE

LINE NO.	CAUSAL METHOD	YEAR	MONTH	CORPORATE ALLOCABLE $	CAUSAL ALLOCATION %	$ ALLOCATED TO TGS
		(a)	(b)	(c)	(d)	(e)=(c) x (d)
80	Miles of Pipe	2023	2	239,383	25.00%	59,846
81	Miles of Pipe	2023	3	230,954	25.00%	57,738
82	Miles of Pipe	2023	4	537,431	25.00%	134,358
83	Miles of Pipe	2023	5	237,122	25.00%	59,280
84	Miles of Pipe	2023	6	241,776	25.00%	60,444
85	Miles of Pipe	2023	7	226,782	25.00%	56,696
86	Miles of Pipe	2023	8	224,168	25.00%	56,042
87	Miles of Pipe	2023	9	401,106	25.00%	100,277
88	Miles of Pipe	2023	10	241,070	25.00%	60,267
89	Miles of Pipe	2023	11	403,831	25.00%	100,958
90	Miles of Pipe	2023	12	436,478	25.00%	109,120
91	**Miles of Pipe Total**			**$3,655,286**		**$913,822**
92	**Total**			**$24,935,708**		**$6,511,543**

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CAUSAL ALLOCATION FACTORS

	2023			2024		
LINE NO.	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR
		(a)	(b)		(c)	(d)
		Invoice Count			Invoice Count	
1	Oklahoma Natural Gas Company	49,807	27.00%	Oklahoma Natural Gas Company	56,046	28.00%
2	Kansas Gas Service Company	34,152	18.00%	Kansas Gas Service Company	37,032	18.00%
3	Texas Gas Service Company	46,352	25.00%	Texas Gas Service Company	50,510	25.00%
4	ONE Gas Inc.	56,245	30.00%	ONE Gas Inc.	57,312	29.00%
5	Total	186,556	100.00%	Total	200,900	100.00%
		Employee Count			Employee Count	
6	Oklahoma Natural Gas Company	1,184	31.46%	Oklahoma Natural Gas Company	1,250	32.13%
7	Kansas Gas Service Company	979	26.02%	Kansas Gas Service Company	967	24.86%
8	Texas Gas Service Company	909	24.16%	Texas Gas Service Company	937	24.09%
9	ONE Gas Inc.	691	18.36%	ONE Gas Inc.	736	18.92%
10	Total	3,763	100.00%	Total	3,890	100.00%
		Powerplant			Powerplant	
11	Oklahoma Natural Gas Company	$3,165,034,324	42.03%	Oklahoma Natural Gas Company	$3,408,887,578	41.87%
12	Kansas Gas Service Company	2,329,905,690	30.94%	Kansas Gas Service Company	2,474,943,803	30.40%
13	Texas Gas Service Company	2,035,068,038	27.03%	Texas Gas Service Company	2,257,856,066	27.73%
14	Total	$7,530,008,052	100.00%	Total	$8,141,687,447	100.00%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CAUSAL ALLOCATION FACTORS

	2023			2024		
LINE NO.	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR
		(a)	(b)		(c)	(d)
		Miles of Pipe			Miles of Pipe	
15	Oklahoma Natural Gas Company	20,000	45.00%	Oklahoma Natural Gas Company	20,100	45.00%
16	Kansas Gas Service Company	13,200	30.00%	Kansas Gas Service Company	13,300	30.00%
17	Texas Gas Service Company	11,300	25.00%	Texas Gas Service Company	11,400	25.00%
18	Total	44,500	100.00%	Total	44,800	100.00%
		Customer Count			Customer Count	
19	Oklahoma Natural Gas Company	913,000	40.47%	Oklahoma Natural Gas Company	918,960	40.55%
20	Kansas Gas Service Company	648,000	28.72%	Kansas Gas Service Company	648,000	28.60%
21	Texas Gas Service Company	695,000	30.81%	Texas Gas Service Company	699,000	30.85%
22	Total	2,256,000	100.00%	Total	2,265,960	100.00%
		Admistrative costs for SERP			Admistrative costs for SERP	
23	Oklahoma Natural Gas Company	$121,214	8.75%	Oklahoma Natural Gas Company	$98,112	8.86%
24	Kansas Gas Service Company	197,803	14.29%	Kansas Gas Service Company	179,757	16.23%
25	Texas Gas Service Company	3,692	0.27%	Texas Gas Service Company	3,362	0.30%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CAUSAL ALLOCATION FACTORS

	2023			2024		
LINE NO.	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR
		(a)	(b)		(c)	(d)
26	ONE Gas Inc.	1,061,980	76.69%	ONE Gas Inc.	826,600	74.61%
27	Total	$1,384,689	100.00%	Total	$1,107,831	100.00%
		Property Accounting Gross PP&E			Property Accounting Gross PP&E	
28	Oklahoma Natural Gas Company	$3,165,034,324	42.06%	Oklahoma Natural Gas Company	$3,408,887,578	41.89%
29	Kansas Gas Service Company	2,325,471,750	30.90%	Kansas Gas Service Company	2,470,509,863	30.36%
30	Texas Gas Service Company	2,035,068,038	27.04%	Texas Gas Service Company	2,257,856,066	27.75%
31	Total	$7,525,574,112	100.00%	Total	8,137,253,507	100.00%
		Administrative cost for Pension			Administrative cost for Pension	
32	Oklahoma Natural Gas Company	$1,899,077	27.17%	Oklahoma Natural Gas Company	$1,830,050	29.50%
33	Kansas Gas Service Company	1,990,303	28.47%	Kansas Gas Service Company	1,543,178	24.87%
34	Texas Gas Service Company	1,403,673	20.08%	Texas Gas Service Company	1,204,699	19.42%
35	ONE Gas Inc.	1,696,703	24.28%	ONE Gas Inc.	1,626,303	26.21%
36	Total	$6,989,756	100.00%	Total	$6,204,230	100.00%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PIPELINE INTEGRITY EXPENSE

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Total Expense for Planned Testing 2023 through 2029	$1,188,512
2	Number of Years to Levelize Expense	7
3	Levelized Pipeline Integrity Expense	$169,787
4	Test Year Pipeline Integrity Expense[1]	0
5	Adjustment to Test Year	$169,787

Source: SCH G-23 PIT Expense.xlsx

[1]Test year pipeline integrity expense is not included in per book costs. It is collected separately via the Pipeline Integrity Testing Expenses Rider.

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

AMORTIZATION OF EXCESS DEFERRED INCOME TAXES

LINE NO.	MONTH	MONTHLY AMMORTIZATION
	(a)	(b)
1	January 2023	$(99,635)
2	Febuary 2023	(80,659)
3	March 2023	(29,941)
4	April 2023	(32,494)
5	May 2023	(23,231)
6	June 2023	(11,966)
7	July 2023	(21,329)
8	August 2023	(22,480)
9	September 2023	(15,922)
10	October 2023	(36,149)
11	November 2023	(66,890)
12	December 2023	(59,981)
13	Test Year EDIT Amortization - Account 4101110	$(500,677)

Source: SCH B-10 EDIT

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Costs	$ 147,270,825	$ 139,383,041	$ 7,086,829	$ 60,061	$ 736,279	$ 4,614
2	Demand Costs	$ 42,906,367	$ 29,710,869	$ 8,709,720	$ 1,296,772	$ 3,137,751	$ 51,255
3	Commodity Costs	$ 1,030,731	$ 516,218	$ 324,443	$ 88,798	$ 95,446	$ 5,826
4	Cost of Service Before Revenue Credits	$ 191,207,923	$ 169,610,129	$ 16,120,993	$ 1,445,630	$ 3,969,476	$ 61,695
5	Revenues Credited to Cost of Service (1)	$ 4,998,958	$ 4,638,075	$ 283,166	$ 20,246	$ 56,580	$ 890
6	Total Cost of Service	$ 186,208,965	$ 164,972,054	$ 15,837,826	$ 1,425,384	$ 3,912,896	$ 60,805
7	Revenue at Current Rates	$ 160,419,569	$ 128,025,477	$ 24,405,808	$ 3,033,999	$ 4,829,278	$ 125,006
8	Revenue Deficiency	$ 25,789,396	$ 36,946,576	$ (8,567,982)	$ (1,608,615)	$ (916,382)	$ (64,201)
9	Revenue-to-Cost Ratios:						
10	Current Revenue	0.8651	0.7822	1.5315	2.1127	1.2309	2.0406
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge, special contract, irrigation, and unmetered gas service revenue are used to offset each class' cost of service. Service charge revenue is directly assigned to classes and is included in the revenue credit on line 5. Allocation of the remaining revenues to be credited is based on each class' cost of service relative to the total cost of service on line 4. The components of the total revenue credit are as follows:

Service Charges	$ 2,328,662
Special Contract	$ 2,641,581
Irrigation	$ 26,751
Unmetered Gas Service	$ 1,964
	$ 4,998,958

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Intangible Plant					
1	301	Organization	NONINTPLT	$ 56,257	$ 41,233	$ 14,924	$ 100
2	302	Franchises and Consents	NONINTPLT	$ 393,474	$ 288,396	$ 104,381	$ 697
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 1,014,465	$ 743,550	$ 269,118	$ 1,797
4		Total Intangible Plant		$ 1,464,196	$ 1,073,180	$ 388,423	$ 2,593
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ —	$ —	$ —	$ —
9	367	Transmission Mains	DEM	$ 13,773,737	$ —	$ 13,773,737	$ —
10	368	Compression Station Equipment	DEM	$ —	$ —	$ —	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 5,597,704	$ —	$ 5,597,704	$ —
12	369	Odorization	COM	$ 419,683	$ —	$ —	$ 419,683
13	371	Other Equipment	DEM	$ —	$ —	$ —	$ —
14		Total Transmission Plant		$ 19,791,124	$ —	$ 19,371,441	$ 419,683
15							
16		**Distribution Plant**					
17	374	Land & Land Rights	DIS376-379	$ 231,394	$ 128,609	$ 102,567	$ 218
18	375	Structures and Improvements	DIS376-379	$ 1,761,912	$ 979,273	$ 780,979	$ 1,661
19	376	Distribution Mains	MAINS	$ 485,900,194	$ 286,924,064	$ 198,976,129	$ —
20	376	Odorization	COM	$ 144,153	$ —	$ —	$ 144,153
21	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
22	378	Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 23,056,553	$ —	$ 23,056,553	$ —
23	378	Odorization	COM	$ 688,208	$ —	$ —	$ 688,208
24	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 6,791,781	$ —	$ 6,791,781	$ —
25	379	Odorization Tank	COM	$ 486,607	$ —	$ —	$ 486,607
26	380	Services	CUS	$ 304,689,226	$ 304,689,226	$ —	$ —
27	381	Meters	CUS	$ 81,752,969	$ 81,752,969	$ —	$ —
28	382	Meter Installations	CUS	$ 7,147	$ 7,147	$ —	$ —
29	383	House Regulators	CUS	$ 11,286,787	$ 11,286,787	$ —	$ —
30	385	Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 16,308,207	$ —	$ 16,308,207	$ —
31	385	Odorization	COM	$ 47,784	$ —	$ —	$ 47,784
32	386	Other Property - Customer Premises	CUS	$ 1,063,249	$ 1,063,249	$ —	$ —
33	387	Other Equipment	DIS376-379	$ —	$ —	$ —	$ —
34		Total Distribution Plant		$ 934,216,172	$ 686,831,324	$ 246,016,216	$ 1,368,632
35							
36		**General Plant**					
37	389	Land & Land Rights	GENPLT	$ 8,556,713	$ 6,346,210	$ 2,198,274	$ 12,229
38	390	Structures & Improvements	GENPLT	$ 35,571,127	$ 27,224,805	$ 8,300,148	$ 46,175
39	391	Office Furniture and Equipment	GENPLT	$ 45,275,392	$ 44,061,087	$ 1,207,587	$ 6,718
40	392	Transportation Equipment	GENPLT	$ 25,015,559	$ 18,391,321	$ 6,587,590	$ 36,648
41	393	Stores Equipment	GENPLT	$ 123,761	$ 90,988	$ 32,591	$ 181
42	394	Tools, Shop & Garage	GENPLT	$ 15,487,513	$ 11,419,672	$ 4,045,336	$ 22,505
43	394	Odorization	COM	$ 19,654	$ —	$ —	$ 19,654
44	396	Major Work Equipment	GENPLT	$ 3,532,069	$ 2,596,760	$ 930,134	$ 5,175
45	397	Communication Equipment	GENPLT	$ 35,022,327	$ 25,853,651	$ 9,117,951	$ 50,725
46	398	Miscellaneous General Plant	GENPLT	$ 6,349	$ 4,668	$ 1,672	$ 9
47		Total General Plant		$ 168,610,464	$ 135,989,162	$ 32,421,282	$ 200,020
48							
49		Total Plant in Service		$ 1,124,081,957	$ 823,893,666	$ 298,197,362	$ 1,990,928
50							
51		**Depreciation & Amortization Reserve**					
52	301-303	Intangible Plant	DISPLTRES	$ (1,229,809)	$ (902,346)	$ (325,995)	$ (1,469)
53	325-371	Transmission Plant	DEM	$ 25,075	$ —	$ 25,075	$ —
54	374-387	Distribution Plant	DISPLTRES	$ (185,264,906)	$ (135,934,080)	$ (49,109,538)	$ (221,288)
55	389-398	General Plant	GENPLTRES	$ (53,957,765)	$ (44,929,505)	$ (8,974,094)	$ (54,165)
56		Total Depreciation & Amortization Reserve		$ (240,427,405)	$ (181,765,931)	$ (58,384,553)	$ (276,922)
57							
58		Net Plant in Service		$ 883,654,551	$ 642,127,735	$ 239,812,810	$ 1,714,007

Classified Rate Base
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
59							
60		Customer Deposits	CUS	$ (6,613,930)	$ (6,613,930)	$ —	$ —
61							
62		Customer Advances	MAINS/SVCS	$ (5,170,456)	$ (3,869,152)	$ (1,301,304)	$ —
63							
64		Accumulated Deferred Income Taxes	TOTPLT	$ (79,319,324)	$ (58,136,943)	$ (21,041,894)	$ (140,487)
65							
66		Excess Deferred Income Tax	TOTPLT	$ (14,634,668)	$ (10,726,451)	$ (3,882,296)	$ (25,920)
67							
68		Materials and Supplies	TOTPLT	$ 11,709,937	$ 8,582,775	$ 3,106,421	$ 20,740
69							
70		Prepayments	OPEXP	$ 4,788,015	$ 3,898,711	$ 835,833	$ 53,471
71							
72		Pension & FAS 106 Regulatory Asset	OPEXP	$ 17,214,876	$ 14,017,464	$ 3,005,162	$ 192,250
73							
74		DIMP Deferrals	OPEXP	$ 1,848,673	$ 1,505,309	$ 322,719	$ 20,645
75							
76		Regulatory Assets	OPEXP	$ 3,135,695	$ 2,553,285	$ 547,391	$ 35,018
77							
78		Cash Working Capital	OPEXP	$ (3,364,662)	$ (2,739,725)	$ (587,361)	$ (37,575)
79							
80		Total Rate Base		$ 813,248,707	$ 590,599,078	$ 220,817,480	$ 1,832,149

Classified Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Transmission & Distribution Operations Exp.**					
2	814-866	Transmission Expenses	DEM	$ 1,581,149	$ —	$ 1,581,149	$ —
3	8700	Operation Supervision & Engineering	DIS871-879	$ 767,175	$ 633,067	$ 118,807	$ 15,301
4	8700	Odorization	COM	$ 67	$ —	$ —	$ 67
5	8710	Distribution Load Dispatch	COM	$ 278,346	$ —	$ —	$ 278,346
6	8740	Mains and Services Expenses	MAINS/SVCS	$ 6,942,347	$ 5,195,092	$ 1,747,255	$ —
7	8740	Odorization	COM	$ 1,475	$ —	$ —	$ 1,475
8	8750	Measuring & Reg. Stat. Exp.-Gen.	DEM	$ 336,559	$ —	$ 336,559	$ —
9	8750	Odorization	COM	$ 87,890	$ —	$ —	$ 87,890
10	8760	Meas. & Reg. Stat. Exp.- Ind.	DEM	$ 54,166	$ —	$ 54,166	$ —
11	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 23,329	$ —	$ 23,329	$ —
12	8780	Meter and House Regulator Exp.	CUS	$ 6,318,931	$ 6,318,931	$ —	$ —
13	8790	Customer Installation Expenses	CUS	$ 2,574	$ 2,574	$ —	$ —
14	8800	Other Expenses	DIS871-879	$ 1,248,595	$ 1,030,331	$ 193,361	$ 24,902
15	8800	Odorization	COM	$ 36	$ —	$ —	$ 36
16	8810	Rents	DIS871-879	$ 35,043	$ 28,917	$ 5,427	$ 699
17	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
18		Total Transmission & Distribution Oper. Exp.		$ 17,677,682	$ 13,208,912	$ 4,060,054	$ 408,716
19							
20		**Distribution Maintenance Expenses**					
21	8850	Maintenance Supervision and Engineering	DIS887-893	$ —	$ —	$ —	$ —
22	8860	Structures and Improvements	DIS887-893	$ 1,202,834	$ 662,351	$ 527,429	$ 13,054
23	8870	Maintenance of Mains	MAINS	$ 4,043,460	$ 2,387,663	$ 1,655,797	$ —
24	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 880,201	$ —	$ 880,201	$ —
25	8890	Odorization	COM	$ 80,957	$ —	$ —	$ 80,957
26	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 680,714	$ —	$ 680,714	$ —
27	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 54,194	$ —	$ 54,194	$ —
28	8920	Maintenance of Services	CUS	$ 1,719,971	$ 1,719,971	$ —	$ —
29	8930	Maintenance of Meters & House Reg.	CUS	$ —	$ —	$ —	$ —
30	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
31	8950	Clearing - Meter Shop - Small Meters	DEM	$ —	$ —	$ —	$ —
32	8960	Clearing - Meter Shop - Large Meters	DEM	$ —	$ —	$ —	$ —
33		Total Distribution Maintenance Expenses		$ 8,662,331	$ 4,769,984	$ 3,798,335	$ 94,012
34							
35		Total Operations & Maintenance Expenses		$ 26,340,013	$ 17,978,897	$ 7,858,389	$ 502,728
36							
37		**Customer Accounts Expenses**					
38	9010	Supervision	CUS	$ 296	$ 296	$ —	$ —
39	9020	Meter Reading Expense	CUS	$ 773,904	$ 773,904	$ —	$ —
40	9030	Customer Accounting	CUS	$ 3,951,897	$ 3,951,897	$ —	$ —
41	9040	Bad Debts (includes gross up)	CUS	$ 1,161,363	$ 1,161,363	$ —	$ —
42	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 412,828	$ 412,828	$ —	$ —
43		Total Customer Accounts Expenses		$ 6,300,288	$ 6,300,288	$ —	$ —
44							
45		**Customer Information Expenses**					
46	9070	Supervision	CUS	$ —	$ —	$ —	$ —
47	9080	Customer Assistance	CUS	$ 1,150,137	$ 1,150,137	$ —	$ —
48	9090	Informational and Instructional Advertising	CUS	$ 77,438	$ 77,438	$ —	$ —
49	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —
50		Total Customer Information Expenses		$ 1,227,575	$ 1,227,575	$ —	$ —
51							
52		**Sales and Advertising Expenses**					
53	9110	Supervision	CUS	$ —	$ —	$ —	$ —
54	9120	Demonstrating and Selling	CUS	$ —	$ —	$ —	$ —
55	9130	Advertising	CUS	$ 143,921	$ 143,921	$ —	$ —
56	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —
57	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

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CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
58		Total Sales and Advertising Expenses		$ 143,921	$ 143,921	$ —	$ —
59							
60		**Administrative & General Expenses**					
61	920-940	Administrative & General Expenses	ADMINGEN	$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077
62		Total Administrative & General Expenses		$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077
63							
64		**Depreciation and Amortization Expense**					
65	301-303	Intangible Plant	PLT301-03	$ 41,187	$ 30,188	$ 10,926	$ 73
66	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —
67	366	Meas. and Reg. Station Structures	PLT366	$ —	$ —	$ —	$ —
68	367	Transmission Mains	PLT367	$ 366,381	$ —	$ 366,381	$ —
69	368	Compression Station Equipment	PLT368	$ —	$ —	$ —	$ —
70	369	Measuring and Reg. Station Equipment	PLT369	$ 192,001	$ —	$ 192,001	$ —
71	369	Odorization	COM	$ 14,395	$ —	$ —	$ 14,395
72	371	Other Equipment	PLT371	$ —	$ —	$ —	$ —
73	375	Structures and Improvements	PLT375	$ 42,262	$ 23,489	$ 18,733	$ 40
74	376	Mains	MAINS	$ 12,149,545	$ 7,174,306	$ 4,975,239	$ —
75	376	Odorization	COM	$ 3,215	$ —	$ —	$ 3,215
76	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
77	378	Meas. & Reg. Sta. Equip. - General	PLT378	$ 491,339	$ —	$ 491,339	$ —
78	378	Odorization Tank	COM	$ 14,659	$ —	$ —	$ 14,659
79	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 133,844	$ —	$ 133,844	$ —
80	379	Odorization Tank	COM	$ 9,586	$ —	$ —	$ 9,586
81	380	Services	PLT380	$ 9,665,188	$ 9,665,188	$ —	$ —
82	381	Meters	PLT381	$ 3,335,369	$ 3,335,369	$ —	$ —
83	382	Meter Installations	PLT382	$ 297	$ 297	$ —	$ —
84	383	House Regulators	PLT383	$ 383,759	$ 383,759	$ —	$ —
85	385	Meas. & Reg. Sta. Equip. - Ind.	PLT385	$ 388,137	$ —	$ 388,137	$ —
86	385	Odorization	COM	$ 1,137	$ —	$ —	$ 1,137
87	386	Other Property - Customer Premises	PLT386	$ 126,420	$ 126,420	$ —	$ —
88	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —
89	389-398	General Plant	GENDEP	$ 8,551,954	$ 7,307,740	$ 1,236,027	$ 8,186
90	389-398	General Plant - Odorization	COM	$ 1,310	$ —	$ —	$ 1,310
91	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ (535,021)	$ (435,649)	$ (93,397)	$ (5,975)
92		Total Depreciation and Amortization Expense		$ 35,376,964	$ 27,611,108	$ 7,719,230	$ 46,627
93							
94		**Taxes Other Than Income**					
95	4080	Payroll and Other	OPEXP	$ 3,127,494	$ 2,546,607	$ 545,959	$ 34,927
96	4080	Ad Valorem - Allocated	TOTPLT	$ 6,947,490	$ 5,092,149	$ 1,843,036	$ 12,305
97	4080	Revenue Related (includes gross up)	CUS	$ 219,750	$ 219,750	$ —	$ —
98		Total Taxes Other Than Income		$ 10,294,734	$ 7,858,507	$ 2,388,995	$ 47,232
99							
100	4101	Excess Deferred Income Tax Amortization	RB	$ (500,677)	$ (363,603)	$ (135,946)	$ (1,128)
101							
102	4310	Interest on Customer Deposits	CUS	$ 321,437	$ 321,437	$ —	$ —
103							
104		Required Return	RB	$ 64,093,722	$ 46,546,269	$ 17,403,058	$ 144,395
105		Income Taxes	RB	$ 13,227,540	$ 9,606,130	$ 3,591,610	$ 29,800
106		Total Cost of Service Before Revenue Credits		$ 191,207,923	$ 147,270,825	$ 42,906,367	$ 1,030,731

Classification Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7		DEM-COM	Demand and Commodity Factor		0.00000	0.50000	0.50000
8							
9			Total Transmission Plant	$ 19,791,124	$ —	$ 19,371,441	$ 419,683
10			Total Distribution Plant	$ 934,216,172	$ 686,831,324	$ 246,016,216	$ 1,368,632
11			Total General Plant	$ 168,610,464	$ 135,989,162	$ 32,421,282	$ 200,020
12			Total Non-Intangible Plant	$ 1,122,617,760	$ 822,820,486	$ 297,808,939	$ 1,988,335
13		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.73295	0.26528	0.00177
14							
15	376		Distribution Mains	$ 485,900,194	$ 286,924,064	$ 198,976,129	$ —
16	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
17	378		Meas. & Reg. Sta. Equip.- Gen.	$ 23,056,553	$ —	$ 23,056,553	$ —
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 7,278,389	$ —	$ 6,791,781	$ 486,607
19			Total Accounts 376-379	$ 516,235,135	$ 286,924,064	$ 228,824,463	$ 486,607
20		DIS376-379	Accounts 376-379 Factor	1.00000	0.55580	0.44326	0.00094
21							
22	376		Mains	$ 485,900,194	$ 286,924,064	$ 198,976,129	$ —
23		MAINS	Distribution Mains Allocated Factor	1.00000	0.59050	0.40950	0.00000
24							
25	376/380		Mains and Services-Allocated	$ 790,589,420	$ 591,613,291	$ 198,976,129	$ —
26		MAINS/SVCS	Mains and Services Allocated Factor	1.00000	0.74832	0.25168	0.00000
27							
28	374-87		Total Distribution Plant	$ 934,216,172	$ 686,831,324	$ 246,016,216	$ 1,368,632
29		DISPLT	Distribution Plant Factor	1.00000	0.73520	0.26334	0.00147
30							
31							
32	374		Land & Land Rights	$ (12,157)	$ (6,757)	$ (5,389)	$ (11)
33	375		Structures and Improvements	$ (165,063)	$ (91,742)	$ (73,165)	$ (156)
34	376		Distribution Mains	$ (92,558,158)	$ (54,655,592)	$ (37,902,566)	$ —
35	376		Odorization	$ (9,564)	$ —	$ —	$ (9,564)
36	378		Meas. & Reg. Sta. Equip.-Gen.	$ (3,863,368)	$ —	$ (3,863,368)	$ —
37	379		Meas. & Reg. Sta. Equip.-City Gate	$ (1,521,540)	$ —	$ (1,521,540)	$ —
38	378-379		Odorization Tank	$ (204,539)	$ —	$ —	$ (204,539)
39	380		Services	$ (40,260,987)	$ (40,260,987)	$ —	$ —
40	381		Meters	$ (35,453,793)	$ (35,453,793)	$ —	$ —
41	382		Meter Installations	$ (2,791)	$ (2,791)	$ —	$ —
42	383		House Regulators	$ (4,883,641)	$ (4,883,641)	$ —	$ —
43	385		Meas. & Reg. Sta. Equip.-Ind.	$ (5,281,931)	$ —	$ (5,281,931)	$ —
44	385		Odorization	$ (6,037)	$ —	$ —	$ (6,037)
45	386		Other Property-Customer Premises	$ (1,041,339)	$ (578,778)	$ (461,580)	$ (982)
46	387		Other Equipment	$ —	$ —	$ —	$ —
47			Total Distribution Plant Reserve	$ (185,264,906)	$ (135,934,080)	$ (49,109,538)	$ (221,288)
48		DISPLTRES	Distribution Plant Reserve Factor	$ 1.00000	0.73373	0.26508	0.00119
49							
50			General Plant Reserve	$ (53,957,765)	$ (44,929,505)	$ (8,974,094)	$ (54,165)
51		GENPLTRES	General Plant Reserve Factor	1.00000	0.83268	0.16632	0.00100
52							
53			Total Plant	$ 1,124,081,957	$ 823,893,666	$ 298,197,362	$ 1,990,928
54		TOTPLT	Total Plant Factor	1.00000	0.73295	0.26528	0.00177
55							
56			Total Operations and Maintenance Expenses	$ 26,340,013	$ 17,978,897	$ 7,858,389	$ 502,728
57			Total Customer Accounts Expenses	$ 6,300,288	$ 6,300,288	$ —	$ —
58			Total Customer Service Expenses	$ 1,227,575	$ 1,227,575	$ —	$ —
59			Total Sales and Advertising Expenses	$ 143,921	$ 143,921	$ —	$ —
60			Administrative and General Expenses	$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077
61			Total Operating Expenses	$ 68,394,204	$ 55,690,977	$ 11,939,421	$ 763,805

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
62		OPEXP	Operating Expense Factor	1.00000	0.81426	0.17457	0.01117
63							
64	8710		Distribution Load Dispatch	$ 278,346	$ —	$ —	$ 278,346
65	8740		Mains and Services Expenses	$ 6,942,347	$ 5,195,092	$ 1,747,255	$ —
66	8750		Measuring & Reg. Stat. Exp.-Gen.	$ 336,559	$ —	$ 336,559	$ —
67	8760		Meas. & Reg. Stat. Exp.- Ind.	$ 54,166	$ —	$ 54,166	$ —
68	8770		Meas. & Regulating Station Exp.- City Gate	$ 23,329	$ —	$ 23,329	$ —
69	8780		Meter and House Regulator Exp.	$ 6,318,931	$ 6,318,931	$ —	$ —
70	8790		Customer Installation Expenses	$ 2,574	$ 2,574	$ —	$ —
71			Total Accounts 871-879	$ 13,956,252	$ 11,516,597	$ 2,161,309	$ 278,346
72		DIS871-879	Accounts 871-879 Factor	1.00000	0.82519	0.15486	0.01994
73							
74	8870		Maintenance of Mains	$ 4,043,460	$ 2,387,663	$ 1,655,797	$ —
75	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen.	$ 961,158	$ —	$ 880,201	$ 80,957
76	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind.	$ 680,714	$ —	$ 680,714	$ —
77	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 54,194	$ —	$ 54,194	$ —
78	8920		Maintenance of Services	$ 1,719,971	$ 1,719,971	$ —	$ —
79	8930		Maintenance of Meters & House Reg.	$ —	$ —	$ —	$ —
80			Total Accounts 887-893	$ 7,459,496	$ 4,107,634	$ 3,270,905	$ 80,957
81		DIS887-893	Accounts 887-893 Factor	1.00000	0.55066	0.43849	0.01085
82							
83			Total Operations and Maintenance Expenses	$ 26,340,013	$ 17,978,897	$ 7,858,389	$ 502,728
84			Total Customer Accounts Expenses	$ 6,300,288	$ 6,300,288	$ —	$ —
85			Total Customer Service Expenses	$ 1,227,575	$ 1,227,575	$ —	$ —
86			Total Sales and Advertising Expenses	$ 143,921	$ 143,921	$ —	$ —
87			Total Operating Exp. Without A&G Expenses	$ 34,011,797	$ 25,650,681	$ 7,858,389	$ 502,728
88		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.75417	0.23105	0.01478
89							
90	920-932		Administrative and General Expenses	$ 34,382,406	$ 30,040,296	$ 4,081,032	$ 261,077
91		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.87371	0.11870	0.00759
92							
93	366		Meas. and Reg. Station Structures	$ —	$ —	$ —	$ —
94		PLT366	Measuring and Reg. Station Structures Factor	0.00000	0.00000	0.00000	0.00000
95							
96	367		Transmission Mains	$ 13,773,737	$ —	$ 13,773,737	$ —
97		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
98							
99	368		Compression Station Equipment	$ —	$ —	$ —	$ —
100		PLT368	Compression Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
101							
102	369		Measuring and Reg. Station Equipment	$ 5,597,704	$ —	$ 5,597,704	$ —
103		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
104							
105	371		Other Equipment	$ —	$ —	$ —	$ —
106		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
107							
108	375		Structures and Improvements	$ 1,761,912	$ 979,273	$ 780,979	$ 1,661
109		PLT375	Structures and Improvements Factor	1.00000	0.55580	0.44326	0.00094
110							
111	378		Meas. & Reg. Sta. Equip.- Gen.	$ 23,056,553	$ —	$ 23,056,553	$ —
112		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
113							
114	379		Meas. & Reg. Sta. Equip.- City Gate	$ 6,791,781	$ —	$ 6,791,781	$ —
115		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
116							
117	380		Services	$ 304,689,226	$ 304,689,226	$ —	$ —
118		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
119							
120	381		Meters	$ 81,752,969	$ 81,752,969	$ —	$ —
121		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
122							

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
123	382		Meter Installations	$ 7,147	$ 7,147	$ —	$ —
124		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000
125							
126	383		House Regulators	$ 11,286,787	$ 11,286,787	$ —	$ —
127		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
128							
129	385		Meas. & Reg. Sta. Equip. - Ind.	$ 16,308,207	$ —	$ 16,308,207	$ —
130		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
131							
132	386		Other Property - Customer Premises	$ 1,063,249	$ 1,063,249	$ —	$ —
133		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
134							
135	387		Other Equipment	$ —	$ —	$ —	$ —
136		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
137							
138	301-03		Intangible Plant	$ 1,464,196	$ 1,073,180	$ 388,423	$ 2,593
139		PLT301-03	Intangible Plant	1.00000	0.73295	0.26528	0.00177
140							
141	389-98		General Plant Depreciation Expense	$ 8,553,264	$ 7,308,860	$ 1,236,217	$ 8,188
142		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.85451	0.14453	0.00096
143							
144			Rate Base	$ 813,248,707	$ 590,599,078	$ 220,817,480	$ 1,832,149
145		RB	Rate Base Factor	1.00000	0.72622	0.27153	0.00225

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	301-303	**Intangible Plant**							
2		Customer	NONINCUS	1,073,180	1,024,184	44,383	203	4,394	16
3		Demand	NONINDEM	388,423	280,099	71,500	10,645	25,758	421
4		Commodity	COM	2,593	1,299	816	223	240	15
5		Total Intangible Plant		1,464,196	1,305,581	116,699	11,072	30,392	452
6	365-371	**Transmission Plant**							
7		Customer	CUS	—	—	—	—	—	—
8		Demand	DEM	19,371,441	13,969,087	3,565,837	530,910	1,284,623	20,984
9		Commodity	COM	419,683	210,189	132,104	36,156	38,863	2,372
10		Total Transmission Plant		19,791,124	14,179,276	3,697,941	567,066	1,323,486	23,356
11		**Distribution Plant**							
12	374	**Land & Land Rights**							
13		Customer	CUS	128,609	122,738	5,319	24	527	2
14		Demand	DEM	102,567	73,963	18,880	2,811	6,802	111
15		Commodity	COM	218	109	69	19	20	1
16		Total Land & Land Rights		231,394	196,810	24,268	2,854	7,348	114
17	375	**Structures and Improvements**							
18		Customer	376-379CUS	979,273	934,564	40,499	185	4,009	15
19		Demand	DEM	780,979	563,177	143,760	21,404	51,791	846
20		Commodity	COM	1,661	832	523	143	154	9
21		Total Structures and Improvements		1,761,912	1,498,573	184,782	21,733	55,954	870
22	376	**Distribution Mains**							
23		Customer	CUS	286,924,064	273,824,552	11,866,181	54,351	1,174,659	4,321
24		Demand	DEM	198,976,129	143,485,187	36,626,932	5,453,307	13,195,162	215,542
25		Commodity	COM	—	—	—	—	—	—
26		Total Distribution Mains		485,900,194	417,309,739	48,493,112	5,507,658	14,369,821	219,864
27	376	**Odorization**							
28		Customer	CUS	—	—	—	—	—	—
29		Demand	DEM	—	—	—	—	—	—
30		Commodity	COM	144,153	72,196	45,375	12,419	13,349	815
31		Total Odorization		144,153	72,196	45,375	12,419	13,349	815
32	377	**Compressor Station Equipment**							
33		Customer	CUS	—	—	—	—	—	—
34		Demand	DEM	—	—	—	—	—	—
35		Commodity	COM	—	—	—	—	—	—
36		Total Compressor Station Equipment		—	—	—	—	—	—
37	378	**Meas. & Reg. Sta. Equip.- Gen.**							
38		Customer	CUS	—	—	—	—	—	—
39		Demand	DEM	23,056,553	16,626,486	4,244,181	631,907	1,529,002	24,976
40		Commodity	COM	—	—	—	—	—	—
41		Total Meas. & Reg. Sta. Equip.- Gen.		23,056,553	16,626,486	4,244,181	631,907	1,529,002	24,976
42	378	**Odorization Tank**							
43		Customer	CUS	—	—	—	—	—	—
44		Demand	DEM	—	—	—	—	—	—
45		Commodity	COM	688,208	344,673	216,627	59,289	63,729	3,890
46		Total Odorization Tank		688,208	344,673	216,627	59,289	63,729	3,890
47	379	**Meas. & Reg. Station - City Gate**							
48		Customer	CUS	—	—	—	—	—	—
49		Demand	DEM	6,791,781	4,897,673	1,250,211	186,141	450,399	7,357
50		Commodity	COM	—	—	—	—	—	—
51		Total Meas. & Reg. Equip.-City Gate		6,791,781	4,897,673	1,250,211	186,141	450,399	7,357
52	379	**Odorization Tank**							
53		Customer	CUS	—	—	—	—	—	—
54		Demand	DEM	—	—	—	—	—	—
55		Commodity	COM	486,607	243,706	153,169	41,921	45,060	2,750
56		Total Odorization Tank		486,607	243,706	153,169	41,921	45,060	2,750
57	380	**Services**							
58		Customer	SERCUS	304,689,226	288,586,355	14,430,315	85,739	1,580,299	6,519
59		Demand	DEM	—	—	—	—	—	—

Allocated Rate Base

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CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
60		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Services		$ 304,689,226	$ 288,586,355	$ 14,430,315	$ 85,739	$ 1,580,299	$ 6,519
62	381	**Meters**							
63		Customer	METCUS	$ 81,752,969	$ 75,145,213	$ 5,777,039	$ 83,943	$ 738,927	$ 7,847
64		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meters		$ 81,752,969	$ 75,145,213	$ 5,777,039	$ 83,943	$ 738,927	$ 7,847
67	382	**Meter Installations**							
68		Customer	METCUS	$ 7,147	$ 6,570	$ 505	$ 7	$ 65	$ 1
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
71		Total Meter Installations		$ 7,147	$ 6,570	$ 505	$ 7	$ 65	$ 1
72	383	**House Regulators**							
73		Customer	REGCUS	$ 11,286,787	$ 9,860,317	$ 1,190,936	$ 34,941	$ 197,167	$ 3,426
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
76		Total House Regulators		$ 11,286,787	$ 9,860,317	$ 1,190,936	$ 34,941	$ 197,167	$ 3,426
77	385	**Meas. & Reg. Sta. Equip. - Ind.**							
78		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	NRDEM	$ 16,308,207	$ —	$ 10,764,272	$ 1,602,670	$ 3,877,920	$ 63,346
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Meas. & Reg. Sta. Equip.- Ind.		$ 16,308,207	$ —	$ 10,764,272	$ 1,602,670	$ 3,877,920	$ 63,346
82	385	**Odorization**							
83		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ 47,784	$ 23,932	$ 15,041	$ 4,117	$ 4,425	$ 270
86		Total Odorization		$ 47,784	$ 23,932	$ 15,041	$ 4,117	$ 4,425	$ 270
87	386	**Other Prop.-Customer Premises**							
88		Customer	CUS	$ 1,063,249	$ 1,014,706	$ 43,972	$ 201	$ 4,353	$ 16
89		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Other Prop.- Cust. Premises		$ 1,063,249	$ 1,014,706	$ 43,972	$ 201	$ 4,353	$ 16
92	387	**Other Equipment**							
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
97		**Total Distribution Plant**							
98		Customer		$ 686,831,324	$ 649,495,014	$ 33,354,767	$ 259,392	$ 3,700,004	$ 22,147
99		Demand		$ 246,016,216	$ 165,646,486	$ 53,048,236	$ 7,898,240	$ 19,111,076	$ 312,178
100		Commodity		$ 1,368,632	$ 685,448	$ 430,804	$ 117,908	$ 126,736	$ 7,736
101		Total Distribution Plant		$ 934,216,172	$ 815,826,949	$ 86,833,806	$ 8,275,540	$ 22,937,816	$ 342,061
102		**Total General Plant**							
103		Customer	CUS	$ 135,989,162	$ 129,780,580	$ 5,624,039	$ 25,760	$ 556,736	$ 2,048
104		Demand	DEM	$ 32,421,282	$ 23,379,557	$ 5,968,013	$ 888,565	$ 2,150,027	$ 35,121
105		Commodity	COM	$ 200,020	$ 100,175	$ 62,960	$ 17,232	$ 18,522	$ 1,131
106		Total General Plant		$ 168,610,464	$ 153,260,312	$ 11,655,011	$ 931,556	$ 2,725,285	$ 38,299
107		**Total Plant in Service**							
108		Customer		$ 823,893,666	$ 780,299,778	$ 39,023,188	$ 285,355	$ 4,261,134	$ 24,211
109		Demand		$ 298,197,362	$ 203,275,228	$ 62,653,585	$ 9,328,360	$ 22,571,484	$ 368,704
110		Commodity		$ 1,990,928	$ 997,111	$ 626,684	$ 171,519	$ 184,361	$ 11,253
111		Total Plant in Service		$ 1,124,081,957	$ 984,572,117	$ 102,303,457	$ 9,785,235	$ 27,016,979	$ 404,168
112		**Depreciation & Amort. Reserve**							
113		**Intangible Plant**							
114		Customer	CUS	$ (902,346)	$ (861,149)	$ (37,318)	$ (171)	$ (3,694)	$ (14)
115		Demand	DEM	$ (325,995)	$ (235,080)	$ (60,008)	$ (8,934)	$ (21,618)	$ (353)
116		Commodity	COM	$ (1,469)	$ (736)	$ (462)	$ (127)	$ (136)	$ (8)
117		Total Intangible Plant		$ (1,229,809)	$ (1,096,965)	$ (97,788)	$ (9,232)	$ (25,449)	$ (375)
118		**Transmission Plant**							
119		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
120		Demand	DEM	$ 25,075	$ 18,082	$ 4,616	$ 687	$ 1,663	$ 27

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Transmission Plant		$ 25,075	$ 18,082	$ 4,616	$ 687	$ 1,663	$ 27
123		**Distribution Plant**							
124		Customer	DISPLTCUS	$ (135,934,080)	$ (128,544,672)	$ (6,601,402)	$ (51,338)	$ (732,286)	$ (4,383)
125		Demand	DISPLTDEM	$ (49,109,538)	$ (33,066,204)	$ (10,589,442)	$ (1,576,640)	$ (3,814,936)	$ (62,317)
126		Commodity	COM	$ (221,288)	$ (110,827)	$ (69,655)	$ (19,064)	$ (20,491)	$ (1,251)
127		Total Distribution Plant		$ (185,264,906)	$ (161,721,703)	$ (17,260,498)	$ (1,647,041)	$ (4,567,713)	$ (67,951)
128		**General Plant**							
129		Customer	GENPTCUS	$ (44,929,505)	$ (42,617,919)	$ (2,073,646)	$ (14,140)	$ (222,610)	$ (1,191)
130		Demand	DISPLTDEM	$ (8,974,094)	$ (6,042,395)	$ (1,935,075)	$ (288,109)	$ (697,127)	$ (11,388)
131		Commodity	COM	$ (54,165)	$ (27,127)	$ (17,049)	$ (4,666)	$ (5,016)	$ (306)
132		Total General Plant		$ (53,957,765)	$ (48,687,442)	$ (4,025,770)	$ (306,916)	$ (924,753)	$ (12,884)
133		**Total Depr. & Amort. Reserve**							
134		Customer		$ (181,765,931)	$ (172,023,740)	$ (8,712,365)	$ (65,649)	$ (958,590)	$ (5,587)
135		Demand		$ (58,384,553)	$ (39,325,598)	$ (12,579,909)	$ (1,872,996)	$ (4,532,019)	$ (74,030)
136		Commodity		$ (276,922)	$ (138,690)	$ (87,167)	$ (23,857)	$ (25,643)	$ (1,565)
137		Total Depr. & Amortization Reserve		$ (240,427,405)	$ (211,488,028)	$ (21,379,441)	$ (1,962,502)	$ (5,516,252)	$ (81,183)
138		**Net Plant in Service**							
139		Customer		$ 642,127,735	$ 608,276,038	$ 30,310,823	$ 219,707	$ 3,302,544	$ 18,624
140		Demand		$ 239,812,810	$ 163,949,630	$ 50,073,676	$ 7,455,364	$ 18,039,466	$ 294,673
141		Commodity		$ 1,714,007	$ 858,421	$ 539,517	$ 147,662	$ 158,718	$ 9,688
142		Total Net Plant in Service		$ 883,654,551	$ 773,084,089	$ 80,924,016	$ 7,822,733	$ 21,500,728	$ 322,985
143		**Customer Deposits**							
144		Customer	DEPCUS	$ (6,613,930)	$ (3,223,171)	$ (3,345,736)	$ (35,898)	$ (9,126)	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —
147		Total Customer Deposits		$ (6,613,930)	$ (3,223,171)	$ (3,345,736)	$ (35,898)	$ (9,126)	$ —
148		**Customer Advances**							
149		Customer	MSCUS	$ (3,869,152)	$ (3,678,168)	$ (171,979)	$ (916)	$ (18,017)	$ (71)
150		Demand	DEM	$ (1,301,304)	$ (938,393)	$ (239,540)	$ (35,665)	$ (86,296)	$ (1,410)
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Customer Advances		$ (5,170,456)	$ (4,616,562)	$ (411,519)	$ (36,581)	$ (104,314)	$ (1,481)
153		**Accum. Deferred Income Taxes**							
154		Customer	TPLTCUS	$ (58,136,943)	$ (55,060,799)	$ (2,753,619)	$ (20,136)	$ (300,681)	$ (1,708)
155		Demand	TPLTDEM	$ (21,041,894)	$ (14,343,842)	$ (4,421,066)	$ (658,243)	$ (1,592,726)	$ (26,017)
156		Commodity	COM	$ (140,487)	$ (70,360)	$ (44,221)	$ (12,103)	$ (13,009)	$ (794)
157		Total Accum. Deferred Inc. Taxes		$ (79,319,324)	$ (69,475,000)	$ (7,218,905)	$ (690,482)	$ (1,906,417)	$ (28,520)
158		**Excess Deferred Income Taxes**							
159		Customer	TPLTCUS	$ (10,726,451)	$ (10,158,893)	$ (508,051)	$ (3,715)	$ (55,477)	$ (315)
160		Demand	TPLTDEM	$ (3,882,296)	$ (2,646,484)	$ (815,701)	$ (121,448)	$ (293,863)	$ (4,800)
161		Commodity	COM	$ (25,920)	$ (12,982)	$ (8,159)	$ (2,233)	$ (2,400)	$ (147)
162		**Total Excess Deferred Income Taxes**		$ (14,634,668)	$ (12,818,359)	$ (1,331,911)	$ (127,396)	$ (351,740)	$ (5,262)
163		**Materials and Supplies**							
164		Customer	TPLTCUS	$ 8,582,775	$ 8,128,643	$ 406,518	$ 2,973	$ 44,390	$ 252
165		Demand	TPLTDEM	$ 3,106,421	$ 2,117,586	$ 652,683	$ 97,177	$ 235,135	$ 3,841
166		Commodity	COM	$ 20,740	$ 10,387	$ 6,528	$ 1,787	$ 1,921	$ 117
167		Total Materials and Supplies		$ 11,709,937	$ 10,256,616	$ 1,065,729	$ 101,936	$ 281,445	$ 4,210
168		**Prepayments**							
169		Customer	OPEXPCUS	$ 3,898,711	$ 3,676,739	$ 198,028	$ 1,992	$ 21,789	$ 163
170		Demand	OPEXPDEM	$ 835,833	$ 551,864	$ 187,434	$ 27,907	$ 67,525	$ 1,103
171		Commodity	COM	$ 53,471	$ 26,780	$ 16,831	$ 4,607	$ 4,951	$ 302
172		Total Prepayments		$ 4,788,015	$ 4,255,383	$ 402,293	$ 34,505	$ 94,265	$ 1,568
173		**Pension & FAS 106 Reg. Asset**							
174		Customer	OPEXPCUS	$ 14,017,464	$ 13,219,384	$ 711,992	$ 7,161	$ 78,341	$ 586
175		Demand	OPEXPDEM	$ 3,005,162	$ 1,984,179	$ 673,902	$ 100,336	$ 242,779	$ 3,966
176		Commodity	COM	$ 192,250	$ 96,284	$ 60,515	$ 16,562	$ 17,803	$ 1,087
177		Total Pen. & FAS 106 Reg. Asset		$ 17,214,876	$ 15,299,847	$ 1,446,409	$ 124,059	$ 338,922	$ 5,639
178		**DIMP Deferrals**							
179		Customer	TPLTCUS	$ 1,505,309	$ 1,425,660	$ 71,298	$ 521	$ 7,785	$ 44
180		Demand	TPLTDEM	$ 322,719	$ 219,991	$ 67,806	$ 10,095	$ 24,428	$ 399
181		Commodity	COM	$ 20,645	$ 10,340	$ 6,499	$ 1,779	$ 1,912	$ 117
182		Total DIMP Deferrals		$ 1,848,673	$ 1,655,990	$ 145,602	$ 12,395	$ 34,125	$ 560

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CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
183		**Regulatory Assets**							
184		Customer	TPLTCUS	$ 2,553,285	$ 2,418,186	$ 120,935	$ 884	$ 13,205	$ 75
185		Demand	TPLTDEM	$ 547,391	$ 373,146	$ 115,011	$ 17,124	$ 41,434	$ 677
186		Commodity	COM	$ 35,018	$ 17,538	$ 11,023	$ 3,017	$ 3,243	$ 198
187		**Total Regulatory Assets**		$ 3,135,695	$ 2,808,870	$ 246,969	$ 21,025	$ 57,882	$ 950
188		**Cash Working Capital**							
189		Customer	OPEXPCUS	$ (2,739,725)	$ (2,583,740)	$ (139,159)	$ (1,400)	$ (15,312)	$ (115)
190		Demand	OPEXPDEM	$ (587,361)	$ (387,809)	$ (131,715)	$ (19,611)	$ (47,451)	$ (775)
191		Commodity	COM	$ (37,575)	$ (18,819)	$ (11,828)	$ (3,237)	$ (3,480)	$ (212)
192		Total Cash Working Capital		$ (3,364,662)	$ (2,990,368)	$ (282,702)	$ (24,248)	$ (66,243)	$ (1,102)
193		**Total Rate Base**							
194		Customer		$ 590,599,078	$ 562,439,879	$ 24,901,049	$ 171,174	$ 3,069,441	$ 17,535
195		Demand		$ 220,817,480	$ 150,879,867	$ 46,162,491	$ 6,873,036	$ 16,630,428	$ 271,657
196		Commodity		$ 1,832,149	$ 917,590	$ 576,705	$ 157,840	$ 169,658	$ 10,356
197		Total Rate Base		$ 813,248,707	$ 714,237,336	$ 71,640,245	$ 7,202,050	$ 19,869,528	$ 299,548

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1		**Transmission and Distribution Operating Expense**							
2	814-866	**Transmission Expenses**							
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 1,581,149	$ 1,140,195	$ 291,053	$ 43,334	$ 104,854	$ 1,713
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 1,581,149	$ 1,140,195	$ 291,053	$ 43,334	$ 104,854	$ 1,713
7	8700	**Operation Supervision & Engineering**							
8		Customer	871-879CUS	$ 633,067	$ 587,987	$ 39,465	$ 556	$ 5,007	$ 52
9		Demand	DEM	$ 118,807	$ 85,674	$ 21,870	$ 3,256	$ 7,879	$ 129
10		Commodity	COM	$ 15,301	$ 7,663	$ 4,816	$ 1,318	$ 1,417	$ 86
11		Total Supervision & Engineering		$ 767,175	$ 681,324	$ 66,151	$ 5,130	$ 14,302	$ 267
12	8700	**Odorization**							
13		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
14		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
15		Commodity	COM	$ 67	$ 34	$ 21	$ 6	$ 6	$ 0
16		Total Odorization		$ 67	$ 34	$ 21	$ 6	$ 6	$ 0
17	8710	**Distribution Load Dispatch**							
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 278,346	$ 139,403	$ 87,615	$ 23,980	$ 25,775	$ 1,573
21		Total Distribution Load Dispatch		$ 278,346	$ 139,403	$ 87,615	$ 23,980	$ 25,775	$ 1,573
22	8740	**Mains and Services Expenses**							
23		Customer	MSCUS	$ 5,195,092	$ 4,938,659	$ 230,916	$ 1,230	$ 24,192	$ 95
24		Demand	DEM	$ 1,747,255	$ 1,259,976	$ 321,629	$ 47,887	$ 115,870	$ 1,893
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services		$ 6,942,347	$ 6,198,635	$ 552,545	$ 49,117	$ 140,062	$ 1,988
27	8740	**Odorization**							
28		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM	$ 1,475	$ 739	$ 464	$ 127	$ 137	$ 8
31		Total Odorization		$ 1,475	$ 739	$ 464	$ 127	$ 137	$ 8
32	8750	**Meas. & Reg. Station - Gen.**							
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ 336,559	$ 242,699	$ 61,953	$ 9,224	$ 22,319	$ 365
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
36		Total Meas. & Reg. Station - Gen.		$ 336,559	$ 242,699	$ 61,953	$ 9,224	$ 22,319	$ 365
37	8750	**Odorization**							
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
40		Commodity	COM	$ 87,890	$ 44,018	$ 27,665	$ 7,572	$ 8,139	$ 497
41		Total Odorization		$ 87,890	$ 44,018	$ 27,665	$ 7,572	$ 8,139	$ 497
42	8760	**Meas. & Reg. Stat. - Ind.**							
43		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	NRDEM	$ 54,166	$ —	$ 35,752	$ 5,323	$ 12,880	$ 210
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Stat. - Ind.		$ 54,166	$ —	$ 35,752	$ 5,323	$ 12,880	$ 210
47	8770	**Meas. & Reg. Stat.- City Gate**							
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 23,329	$ 16,823	$ 4,294	$ 639	$ 1,547	$ 25
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Stat. - City Gate		$ 23,329	$ 16,823	$ 4,294	$ 639	$ 1,547	$ 25
52	8780	**Meter & House Reg. Exp.**							
53		Customer	MTRGCUS	$ 6,318,931	$ 5,755,497	$ 486,840	$ 8,882	$ 66,866	$ 847
54		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meter & House Reg. Exp.		$ 6,318,931	$ 5,755,497	$ 486,840	$ 8,882	$ 66,866	$ 847
57	8790	**Customer Installation Expense**							
58		Customer	METCUS	$ 2,574	$ 2,366	$ 182	$ 3	$ 23	$ 0
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Customer Install. Expense		$ 2,574	$ 2,366	$ 182	$ 3	$ 23	$ 0

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
62	8800	**Other Expenses**							
63		Customer	871-879CUS	$ 1,030,331	$ 956,963	$ 64,230	$ 905	$ 8,149	$ 84
64		Demand	DEM	$ 193,361	$ 139,436	$ 35,593	$ 5,299	$ 12,823	$ 209
65		Commodity	COM	$ 24,902	$ 12,472	$ 7,838	$ 2,145	$ 2,306	$ 141
66		Total Other Expenses		$ 1,248,595	$ 1,108,871	$ 107,662	$ 8,350	$ 23,277	$ 434
67	8800	**Odorization**							
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 36	$ 18	$ 11	$ 3	$ 3	$ 0
71		Total Odorization		$ 36	$ 18	$ 11	$ 3	$ 3	$ 0
72	8810	**Rents**							
73		Customer	871-879CUS	$ 28,917	$ 26,858	$ 1,803	$ 25	$ 229	$ 2
74		Demand	DEM	$ 5,427	$ 3,913	$ 999	$ 149	$ 360	$ 6
75		Commodity	COM	$ 699	$ 350	$ 220	$ 60	$ 65	$ 4
76		Total Rents		$ 35,043	$ 31,122	$ 3,022	$ 234	$ 653	$ 12
77	8820	Corporate & Div. Exp.							
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —
82		**Total Distr. & Trans. Op. Expense**							
83		Customer		$ 13,208,912	$ 12,268,331	$ 823,435	$ 11,601	$ 104,465	$ 1,080
84		Demand		$ 4,060,054	$ 2,888,716	$ 773,144	$ 115,112	$ 278,532	$ 4,550
85		Commodity		$ 408,716	$ 204,696	$ 128,651	$ 35,211	$ 37,847	$ 2,310
86		Total Distr. & Trans. Operations Exp.		$ 17,677,682	$ 15,361,743	$ 1,725,231	$ 161,923	$ 420,844	$ 7,940
87		**Distribution Maintenance Expenses**							
88	8850	**Maintenance Supervision and Engineering**							
89		Customer	887-893CUS	$ —	$ —	$ —	$ —	$ —	$ —
90		Demand	887-893DEM	$ —	$ —	$ —	$ —	$ —	$ —
91		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
92		Total Supervision and Engineering		$ —	$ —	$ —	$ —	$ —	$ —
93	8860	**Structures and Improvements**							
94		Customer	887-893CUS	$ 662,351	$ 630,116	$ 29,058	$ 151	$ 3,015	$ 12
95		Demand	887-893DEM	$ 527,429	$ 301,186	$ 149,333	$ 22,234	$ 53,798	$ 879
96		Commodity	COM	$ 13,054	$ 6,538	$ 4,109	$ 1,125	$ 1,209	$ 74
97		Total Structures and Improvements		$ 1,202,834	$ 937,839	$ 182,500	$ 23,509	$ 58,022	$ 964
98	8870	**Maintenance of Mains**							
99		Customer	CUS	$ 2,387,663	$ 2,278,654	$ 98,745	$ 452	$ 9,775	$ 36
100		Demand	DEM	$ 1,655,797	$ 1,194,024	$ 304,794	$ 45,380	$ 109,805	$ 1,794
101		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
102		Total Mains		$ 4,043,460	$ 3,472,678	$ 403,540	$ 45,832	$ 119,580	$ 1,830
103	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen.**							
104		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
105		Demand	DEM	$ 880,201	$ 634,728	$ 162,025	$ 24,124	$ 58,371	$ 953
106		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
107		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 880,201	$ 634,728	$ 162,025	$ 24,124	$ 58,371	$ 953
108	8890	**Odorization**							
109		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
110		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
111		Commodity	COM	$ 80,957	$ 40,546	$ 25,483	$ 6,974	$ 7,497	$ 458
112		Total Odorization		$ 80,957	$ 40,546	$ 25,483	$ 6,974	$ 7,497	$ 458
113	8900	**Meas. & Reg. Sta. Equip. - Ind.**							
114		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
115		Demand	NRDEM	$ 680,714	$ —	$ 449,307	$ 66,896	$ 161,867	$ 2,644
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Meas. & Reg. Sta. Eq.- Ind.		$ 680,714	$ —	$ 449,307	$ 66,896	$ 161,867	$ 2,644
118	8910	**Meas. & Reg. Sta. Eq.- City Gate**							
119		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
120		Demand	DEM	$ 54,194	$ 39,080	$ 9,976	$ 1,485	$ 3,594	$ 59
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Meas. & Reg. Sta. Eq.- City Gate		$ 54,194	$ 39,080	$ 9,976	$ 1,485	$ 3,594	$ 59

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
123	8920	**Services**							
124		Customer	SERCUS	$ 1,719,971	$ 1,629,070	$ 81,459	$ 484	$ 8,921	$ 37
125		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Services		$ 1,719,971	$ 1,629,070	$ 81,459	$ 484	$ 8,921	$ 37
128	8930	**Maintenance of Meters & House Regulators**							
129		Customer	MTRGCUS	$ —	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Meters & House Regulators		$ —	$ —	$ —	$ —	$ —	$ —
133	8940	**Maintenance of Other Equipment**							
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
137		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
138	8950	Clearing - Meter Shop - Small Meters							
139		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
141		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
142		**Total Clearing-Meter-Shop-Small Meters**		$ —	$ —	$ —	$ —	$ —	$ —
143	8960	Clearing - Meter Shop - Large Meters							
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
147		**Total Clearing-Meter Shop-Large Meters**		$ —	$ —	$ —	$ —	$ —	$ —
148		**Total Distr. Maintenance Expense**							
149		Customer		$ 4,769,984	$ 4,537,840	$ 209,262	$ 1,087	$ 21,710	$ 84
150		Demand		$ 3,798,335	$ 2,169,018	$ 1,075,434	$ 160,119	$ 387,434	$ 6,329
151		Commodity		$ 94,012	$ 47,084	$ 29,592	$ 8,099	$ 8,706	$ 531
152		Total Distr. Maintenance Expense		$ 8,662,331	$ 6,753,942	$ 1,314,289	$ 169,306	$ 417,850	$ 6,945
153		**Total Oper. & Maint. Expense**							
154		Customer		$ 17,978,897	$ 16,806,171	$ 1,032,698	$ 12,688	$ 126,175	$ 1,165
155		Demand		$ 7,858,389	$ 5,057,735	$ 1,848,578	$ 275,231	$ 665,966	$ 10,879
156		Commodity		$ 502,728	$ 251,780	$ 158,243	$ 43,310	$ 46,553	$ 2,842
157		Total Operations & Maint. Expense		$ 26,340,013	$ 22,115,685	$ 3,039,519	$ 331,229	$ 838,694	$ 14,885
158		**Customer Accounts Expense**							
159	901	Supervision							
160		Customer	902-904CUS	$ 296	$ 283	$ 12	$ 0	$ 1	$ 0
161		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
162		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
163		Total Supervision		$ 296	$ 283	$ 12	$ 0	$ 1	$ 0
164	902	**Meter Reading Expense**							
165		Customer	METCUS	$ 773,904	$ 711,353	$ 54,688	$ 795	$ 6,995	$ 74
166		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
167		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
168		Total Meter Reading Expense		$ 773,904	$ 711,353	$ 54,688	$ 795	$ 6,995	$ 74
169	903	**Customer Accounting**							
170		Customer	903CUS	$ 3,951,897	$ 3,840,746	$ 104,627	$ 283	$ 6,221	$ 20
171		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
172		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
173		Total Customer Accounting		$ 3,951,897	$ 3,840,746	$ 104,627	$ 283	$ 6,221	$ 20
174	904	**Bad Debt Expense**							
175		Customer	904CUS	$ 1,161,363	$ 1,076,852	$ 82,281	$ 2,023	$ 206	$ —
176		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Bad Debt Expense		$ 1,161,363	$ 1,076,852	$ 82,281	$ 2,023	$ 206	$ —
179	905	**Miscellaneous Customer Accounts**							
180		Customer	902-904CUS	$ 412,828	$ 394,721	$ 16,942	$ 217	$ 941	$ 7
181		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
182		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
183		Total Misc. Customer Accounts		$ 412,828	$ 394,721	$ 16,942	$ 217	$ 941	$ 7

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
184	907-910	**Customer Information Expense**							
185		Customer	CUS	$ 1,227,575	$ 1,171,530	$ 50,768	$ 233	$ 5,026	$ 18
186		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
188		Total Customer Information Expense		$ 1,227,575	$ 1,171,530	$ 50,768	$ 233	$ 5,026	$ 18
189		**Sales and Advertising Expense**							
190	911	Supervision							
191		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
192		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
193		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
194		**Total Supervision Expense**		$ —	$ —	$ —	$ —	$ —	$ —
195	912	**Demonstrating and Selling**							
196		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
197		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
198		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
199		Total Demon. and Selling Expense		$ —	$ —	$ —	$ —	$ —	$ —
200	913	**Advertising**							
201		Customer	CUS	$ 143,921	$ 137,351	$ 5,952	$ 27	$ 589	$ 2
202		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
203		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
204		Total Advertising		$ 143,921	$ 137,351	$ 5,952	$ 27	$ 589	$ 2
205	914	Employee Sales Referrals							
206		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
207		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
208		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
209		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —
210		Misc. Gas Sales Expense							
211	916	Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
212		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
213		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
214		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —
215		**Administrative & General Exp.**							
216	920-940	**Administrative & General Expenses**							
217		Customer	OPEXPCUS	$ 30,040,296	$ 28,329,962	$ 1,525,842	$ 15,347	$ 167,889	$ 1,256
218		Demand	OPEXPDEM	$ 4,081,032	$ 2,694,530	$ 915,164	$ 136,257	$ 329,696	$ 5,386
219		Commodity	COM	$ 261,077	$ 130,755	$ 82,179	$ 22,492	$ 24,176	$ 1,476
220		Total Administrative & General Exp.		$ 34,382,406	$ 31,155,246	$ 2,523,186	$ 174,095	$ 521,761	$ 8,118
221		**Depreciation & Amortization Expense**							
222	301-303	**Intangible Plant**							
223		Customer	CUS	$ 30,188	$ 28,810	$ 1,248	$ 6	$ 124	$ 0
224		Demand	DEM	$ 10,926	$ 7,879	$ 2,011	$ 299	$ 725	$ 12
225		Commodity	COM	$ 73	$ 37	$ 23	$ 6	$ 7	$ 0
226		Total Intangible Plant		$ 41,187	$ 36,726	$ 3,283	$ 311	$ 855	$ 13
227	365	**Land and Land Rights**							
228		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
229		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
230		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
231		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —
232	366	**Meas. and Reg. Station Structures**							
233		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
234		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
235		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
236		Total Measuring and Reg. Stat. Struct.		$ —	$ —	$ —	$ —	$ —	$ —
237	367	**Transmission Mains**							
238		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
239		Demand	DEM	$ 366,381	$ 264,204	$ 67,442	$ 10,041	$ 24,297	$ 397
240		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
241		Total Transmission Mains		$ 366,381	$ 264,204	$ 67,442	$ 10,041	$ 24,297	$ 397
242	368	**Compression Station Equipment**							
243		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
244		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
245		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
246		Total Compression Sta. Equipment		$ —	$ —	$ —	$ —	$ —	$ —
247	369	**Meas. & Reg. Station Equipment**							
248		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
249		Demand	DEM	$ 192,001	$ 138,455	$ 35,343	$ 5,262	$ 12,733	$ 208
250		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
251		Total Meas. & Reg. Stat. Equipment		$ 192,001	$ 138,455	$ 35,343	$ 5,262	$ 12,733	$ 208
252	369	**Odorization**							
253		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
254		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
255		Commodity	COM	$ 14,395	$ 7,209	$ 4,531	$ 1,240	$ 1,333	$ 81
256		Total Odorization		$ 14,395	$ 7,209	$ 4,531	$ 1,240	$ 1,333	$ 81
257	371	**Other Equipment**							
258		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
259		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
260		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
261		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
262	375	**Structures and Improvements**							
263		Customer	376-379CUS	$ 23,489	$ 22,417	$ 971	$ 4	$ 96	$ 0
264		Demand	DEM	$ 18,733	$ 13,509	$ 3,448	$ 513	$ 1,242	$ 20
265		Commodity	COM	$ 40	$ 20	$ 13	$ 3	$ 4	$ 0
266		Total Structures and Improvements		$ 42,262	$ 35,945	$ 4,432	$ 521	$ 1,342	$ 21
267	376	**Distribution Mains**							
268		Customer	CUS	$ 7,174,306	$ 6,846,763	$ 296,704	$ 1,359	$ 29,371	$ 108
269		Demand	DEM	$ 4,975,239	$ 3,587,732	$ 915,827	$ 136,356	$ 329,934	$ 5,389
270		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
271		Total Distribution Mains		$ 12,149,545	$ 10,434,495	$ 1,212,531	$ 137,715	$ 359,306	$ 5,498
272	376	**Odorization**							
273		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
274		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
275		Commodity	COM	$ 3,215	$ 1,610	$ 1,012	$ 277	$ 298	$ 18
276		Total Odorization		$ 3,215	$ 1,610	$ 1,012	$ 277	$ 298	$ 18
277	377	**Compressor Station Equipment**							
278		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
279		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
280		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
281		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —
282	378	**Meas. & Reg. Sta. Equip. - Gen.**							
283		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM	$ 491,339	$ 354,313	$ 90,444	$ 13,466	$ 32,583	$ 532
285		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Meas. & Reg. Sta. Eq.- Gen.		$ 491,339	$ 354,313	$ 90,444	$ 13,466	$ 32,583	$ 532
287	378	**Odorization Tank**							
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ 14,659	$ 7,342	$ 4,614	$ 1,263	$ 1,357	$ 83
291		Total Odorization Tank		$ 14,659	$ 7,342	$ 4,614	$ 1,263	$ 1,357	$ 83
292	379	**Meas.& Reg. Sta. Equip.- City Gate**							
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 133,844	$ 96,517	$ 24,638	$ 3,668	$ 8,876	$ 145
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Meas. & Reg. Sta. Eq.- City Gate		$ 133,844	$ 96,517	$ 24,638	$ 3,668	$ 8,876	$ 145
297	379	**Odorization Tank**							
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
300		Commodity	COM	$ 9,586	$ 4,801	$ 3,017	$ 826	$ 888	$ 54
301		Total Odorization Tank		$ 9,586	$ 4,801	$ 3,017	$ 826	$ 888	$ 54
302	380	**Services**							
303		Customer	SERCUS	$ 9,665,188	$ 9,154,382	$ 457,751	$ 2,720	$ 50,129	$ 207
304		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
306		Total Services		$ 9,665,188	$ 9,154,382	$ 457,751	$ 2,720	$ 50,129	$ 207
307	381	**Meters**							
308		Customer	METCUS	$ 3,335,369	$ 3,065,785	$ 235,692	$ 3,425	$ 30,147	$ 320
309		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
311		Total Meters		$ 3,335,369	$ 3,065,785	$ 235,692	$ 3,425	$ 30,147	$ 320
312	382	**Meter Installations**							
313		Customer	METCUS	$ 297	$ 273	$ 21	$ 0	$ 3	$ 0
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
316		Total Meter Installations		$ 297	$ 273	$ 21	$ 0	$ 3	$ 0
317	383	**House Regulators**							
318		Customer	REGCUS	$ 383,759	$ 335,258	$ 40,493	$ 1,188	$ 6,704	$ 116
319		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
321		Total House Regulators		$ 383,759	$ 335,258	$ 40,493	$ 1,188	$ 6,704	$ 116
322	385	**Meas. & Reg. Sta. Equip. - Ind.**							
323		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
324		Demand	NRDEM	$ 388,137	$ —	$ 256,191	$ 38,144	$ 92,295	$ 1,508
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Meas. & Reg. Stat. Eq.- Ind.		$ 388,137	$ —	$ 256,191	$ 38,144	$ 92,295	$ 1,508
327	385	**Odorization**							
328		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
329		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
330		Commodity	COM	$ 1,137	$ 570	$ 358	$ 98	$ 105	$ 6
331		Total Odorization		$ 1,137	$ 570	$ 358	$ 98	$ 105	$ 6
332	386	**Other Prop.- Customer Premises**							
333		Customer	CUS	$ 126,420	$ 120,649	$ 5,228	$ 24	$ 518	$ 2
334		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
336		Total Other Prop. - Customer Premises		$ 126,420	$ 120,649	$ 5,228	$ 24	$ 518	$ 2
337	387	**Other Equipment**							
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
341		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
342	389-398	**General Plant**							
343		Customer	GENPTCUS	$ 7,307,740	$ 6,931,763	$ 337,276	$ 2,300	$ 36,207	$ 194
344		Demand	DISPLTDEM	$ 1,236,027	$ 832,236	$ 266,523	$ 39,682	$ 96,017	$ 1,568
345		Commodity	COM	$ 8,186	$ 4,100	$ 2,577	$ 705	$ 758	$ 46
346		Total General Plant		$ 8,551,954	$ 7,768,099	$ 606,377	$ 42,687	$ 132,983	$ 1,808
347	389-398	**General Plant - Odorization**							
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 1,310	$ 656	$ 412	$ 113	$ 121	$ 7
351		Total General Plant - Odorization		$ 1,310	$ 656	$ 412	$ 113	$ 121	$ 7
352	40730	**Pension & FAS 106 Amort. Expense**							
353		Customer	CUS	$ (435,649)	$ (415,759)	$ (18,017)	$ (83)	$ (1,784)	$ (7)
354		Demand	DEM	$ (93,397)	$ (67,351)	$ (17,192)	$ (2,560)	$ (6,194)	$ (101)
355		Commodity	COM	$ (5,975)	$ (2,992)	$ (1,881)	$ (515)	$ (553)	$ (34)
356		Total Pension & FAS 106 Amort. Exp.		$ (535,021)	$ (486,102)	$ (37,090)	$ (3,157)	$ (8,530)	$ (142)
357		**Total Depreciation & Amort. Exp.**							
358		Customer		$ 27,611,108	$ 26,090,339	$ 1,357,369	$ 10,943	$ 151,515	$ 941
359		Demand		$ 7,719,230	$ 5,227,495	$ 1,644,675	$ 244,872	$ 592,508	$ 9,679
360		Commodity		$ 46,627	$ 23,352	$ 14,677	$ 4,017	$ 4,318	$ 264
361		Total Depreciation & Amort. Expense		$ 35,376,964	$ 31,341,186	$ 3,016,721	$ 259,832	$ 748,341	$ 10,883
362		**Taxes Other Than Income**							
363	4081	**Payroll and Other Taxes**							
364		Customer	OPEXPCUS	$ 2,546,607	$ 2,401,617	$ 129,350	$ 1,301	$ 14,232	$ 107
365		Demand	OPEXPDEM	$ 545,959	$ 360,473	$ 122,430	$ 18,228	$ 44,107	$ 720
366		Commodity	COM	$ 34,927	$ 17,492	$ 10,994	$ 3,009	$ 3,234	$ 197

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
367		Total Payroll and Other Taxes		$ 3,127,494	$ 2,779,583	$ 262,775	$ 22,538	$ 61,573	$ 1,024
368	4081	**Ad Valorem Taxes**							
369		Customer	CUS	$ 5,092,149	$ 4,859,667	$ 210,594	$ 965	$ 20,847	$ 77
370		Demand	DEM	$ 1,843,036	$ 1,329,045	$ 339,261	$ 50,512	$ 122,221	$ 1,996
371		Commodity	COM	$ 12,305	$ 6,163	$ 3,873	$ 1,060	$ 1,139	$ 70
372		Total Ad Valorem Taxes		$ 6,947,490	$ 6,194,875	$ 553,727	$ 52,536	$ 144,208	$ 2,143
373		**Revenue Related Taxes**							
374		Customer	TOTREVCUS	$ 219,750	$ 164,043	$ 45,874	$ 2,926	$ 6,800	$ 107
375		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
376		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
377		Total Revenue Related Taxes		$ 219,750	$ 164,043	$ 45,874	$ 2,926	$ 6,800	$ 107
378		**Total Taxes Other Than Income**							
379		Customer		$ 7,858,507	$ 7,425,327	$ 385,818	$ 5,192	$ 41,880	$ 290
380		Demand		$ 2,388,995	$ 1,689,519	$ 461,691	$ 68,740	$ 166,328	$ 2,717
381		Commodity		$ 47,232	$ 23,655	$ 14,867	$ 4,069	$ 4,374	$ 267
382		Total Taxes Other Than Income		$ 10,294,734	$ 9,138,501	$ 862,376	$ 78,001	$ 212,582	$ 3,274
383		**Excess Deferred Income Tax Amortization**							
384		Customer	CUS	$ (363,603)	$ (347,003)	$ (15,037)	$ (69)	$ (1,489)	$ (5)
385		Demand	DEM	$ (135,946)	$ (98,033)	$ (25,025)	$ (3,726)	$ (9,015)	$ (147)
386		Commodity	COM	$ (1,128)	$ (565)	$ (355)	$ (97)	$ (104)	$ (6)
387		**Total Excess Def. Income Tax Amortization**		$ (500,677)	$ (445,601)	$ (40,417)	$ (3,892)	$ (10,608)	$ (159)
388		**Interest on Customer Deposits**							
389		Customer	DEPCUS	$ 321,437	$ 156,646	$ 162,603	$ 1,745	$ 444	$ —
390		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
391		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
392		Total Interest on Cust. Deposits		$ 321,437	$ 156,646	$ 162,603	$ 1,745	$ 444	$ —
393		**Required Return**							
394		Customer	CUS	$ 46,546,269	$ 44,421,200	$ 1,924,992	$ 8,817	$ 190,559	$ 701
395		Demand	DEM	$ 17,403,058	$ 12,549,651	$ 3,203,503	$ 476,963	$ 1,154,089	$ 18,852
396		Commodity	COM	$ 144,395	$ 72,317	$ 45,451	$ 12,440	$ 13,371	$ 816
397		Tot. Req. Return		$ 64,093,722	$ 57,043,168	$ 5,173,946	$ 498,220	$ 1,358,019	$ 20,369
398		**Income Taxes**							
399		Customer	CUS	$ 9,606,130	$ 9,167,563	$ 397,276	$ 1,820	$ 39,327	$ 145
400		Demand	DEM	$ 3,591,610	$ 2,589,973	$ 661,133	$ 98,435	$ 238,179	$ 3,891
401		Commodity	COM	$ 29,800	$ 14,925	$ 9,380	$ 2,567	$ 2,760	$ 168
402		Total Income Taxes		$ 13,227,540	$ 11,772,460	$ 1,067,789	$ 102,822	$ 280,265	$ 4,204
403		**Total Cost of Service Before**							
404		**Revenue Credits**							
405		Customer		$ 147,270,825	$ 139,383,041	$ 7,086,829	$ 60,061	$ 736,279	$ 4,614
406		Demand		$ 42,906,367	$ 29,710,869	$ 8,709,720	$ 1,296,772	$ 3,137,751	$ 51,255
407		Commodity		$ 1,030,731	$ 516,218	$ 324,443	$ 88,798	$ 95,446	$ 5,826
408		**Total Cost of Service Before Revenue Credits**		$ 191,207,923	$ 169,610,129	$ 16,120,993	$ 1,445,630	$ 3,969,476	$ 61,695

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Cost Allocation Factors							
2								
3	Total Customers		326,442	311,538	13,500	62	1,336	5
4	**Total Customers Factor (CUS)**	CUS	1.00000	0.95435	0.04136	0.00019	0.00409	0.00002
5								
6	Services - Allocated Weighting			1.00000	1.15388	1.49682	1.27651	1.43131
7	Weighted Customers		328,921	311,538	15,578	93	1,706	7
8	**Weighted Services Customer Factor (SERCUS)**	SERCUS	1.00000	0.94715	0.04736	0.00028	0.00519	0.00002
9								
10	Meters - Allocated Weighting			1.00000	1.77405	5.62795	2.29224	6.61687
11	Weighted Customers		338,932	311,538	23,951	348	3,063	33
12	**Weighted Meters Customer Factor (METCUS)**	METCUS	1.00000	0.91917	0.07066	0.00103	0.00904	0.00010
13								
14	Regulators - Allocated Weighting			1.00000	2.78714	17.85294	4.66126	22.01461
15	Weighted Customers		356,607	311,538	37,628	1,104	6,230	108
16	**Weighted Regulators Customer Factor (REGCUS)**	REGCUS	1.00000	0.87362	0.10552	0.00310	0.01747	0.00030
17								
18	Meters and Regulators - Allocated Weighting			1.00000	1.95193	7.77448	2.70821	9.32049
19	Weighted Customers		342,036	311,538	26,352	481	3,619	46
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	MTRGCUS	1.00000	0.91083	0.07704	0.00141	0.01058	0.00013
21								
22	Non-Residential Customers		14,904	0	13,500	62	1,336	5
23	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.90585	0.00415	0.08967	0.00033
24								
25	Customer Cost Allocation Factors							
26								
27	Distribution Plant Customer Costs		$ 686,831,324	$ 649,495,014	$ 33,354,767	$ 259,392	$ 3,700,004	$ 22,147
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.94564	0.04856	0.00038	0.00539	0.00003
29								
30	Account 376-379 Customer Costs		$ 286,924,064	$ 273,824,552	$ 11,866,181	$ 54,351	$ 1,174,659	$ 4,321
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.95435	0.04136	0.00019	0.00409	0.00002
32								
33	Total Revenue (inc. cost of gas)		$ 257,245,398	$ 192,033,343	$ 53,701,147	$ 3,425,419	$ 7,960,482	$ 125,006
34	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.74650	0.20875	0.01332	0.03095	0.00049
35								
36	Mains - Customer Cost Factor		0.48499	0.46284	0.02006	0.00009	0.00199	0.00001
37	Services - Customer Cost Factor		0.51501	0.48780	0.02439	0.00014	0.00267	0.00001
38	**Mains & Svcs. Cust. Factor (MSCUS)**	MSCUS	1.00000	0.95064	0.04445	0.00024	0.00466	0.00002
39								
40	Total Plant Customer		$ 823,893,666	$ 780,299,778	$ 39,023,188	$ 285,355	$ 4,261,134	$ 24,211
41	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.94709	0.04736	0.00035	0.00517	0.00003
42								
43	Non-Intangible Plant Customer							
44	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 822,820,486	$ 785,254,634	$ 34,028,992	$ 155,863	$ 3,368,604	$ 12,393
45		NONINCUS	1.00000	0.95435	0.04136	0.00019	0.00409	0.00002
46								
47	Account 871-879 Customer Costs		$ 11,516,597	$ 10,696,522	$ 717,937	$ 10,114	$ 91,081	$ 942
48	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.92879	0.06234	0.00088	0.00791	0.00008
49								
50	Account 887-893 Customer Costs		$ 4,107,634	$ 3,907,724	$ 180,205	$ 936	$ 18,696	$ 73
51	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.95133	0.04387	0.00023	0.00455	0.00002
52								
53	Account 903 Customer		$ 3,951,897	$ 3,840,746	$ 104,627	$ 283	$ 6,221	$ 20
54	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.97187	0.02648	0.00007	0.00157	0.00001
55								
56	Customer Cost Allocation Factors							
57								
58	Account 904 Customer		$ 1,161,363	$ 1,076,852	$ 82,281	$ 2,023	$ 206	$ —
59	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.92723	0.07085	0.00174	0.00018	0.00000
60								
61	Accounts 902-904 Customer		$ 5,887,164	$ 5,628,951	$ 241,596	$ 3,101	$ 13,422	$ 94
62	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.95614	0.04104	0.00053	0.00228	0.00002
63								
64	Operating Expense Customer		$ 53,261,789	$ 50,229,346	$ 2,705,336	$ 27,210	$ 297,669	$ 2,228
65	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.94307	0.05079	0.00051	0.00559	0.00004
66								
67	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 90,514,165	$ 85,593,794	$ 4,395,663	$ 34,184	$ 487,606	$ 2,919
68	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 45,474,997	$ 43,398,837	$ 1,880,688	$ 8,614	$ 186,173	$ 685
69	Total General Plant Customer Costs		$ 135,989,162	$ 128,992,631	$ 6,276,350	$ 42,798	$ 673,779	$ 3,604
70	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.94855	0.04615	0.00031	0.00495	0.00003
71								

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
72	Customer Deposits		$ (6,613,930)	$ (3,223,171)	$ (3,345,736)	$ (35,898)	$ (9,126)	$ —
73	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.48733	0.50586	0.00543	0.00138	0.00000
74								
75	Demand Cost Allocation Factors							
76								
77	System Demand							
78	**System Demand Factor (DEM)**	DEM	1.00000	0.72112	0.18408	0.02741	0.06632	0.00108
79								
80	Non-Residential Demand							
81	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.66005	0.09827	0.23779	0.00388
82								
83	Distribution Plant Demand		$ 246,016,216	$ 165,646,486	$ 53,048,236	$ 7,898,240	$ 19,111,076	$ 312,178
84	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.67332	0.21563	0.03210	0.07768	0.00127
85								
86	Demand Cost Allocation Factors							
87								
88	Non-Intangible Plant Demand		$ 297,808,939	$ 214,755,265	$ 54,819,780	$ 8,162,002	$ 19,749,290	$ 322,603
89	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.72112	0.18408	0.02741	0.06632	0.00108
90								
91	Total Plant Demand		$ 298,197,362	$ 203,275,228	$ 62,653,585	$ 9,328,360	$ 22,571,484	$ 368,704
92	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.68168	0.21011	0.03128	0.07569	0.00124
93								
94	Operating Expense Demand		$ 15,577,618	$ 10,285,230	$ 3,493,254	$ 520,103	$ 1,258,474	$ 20,557
95	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.66026	0.22425	0.03339	0.08079	0.00132
96								
97	Acct. 887-893 Demand		$ 3,270,905	$ 1,867,833	$ 926,102	$ 137,885	$ 333,636	$ 5,450
98	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.57104	0.28313	0.04216	0.10200	0.00167
99								
100	Rate Base Demand		$ 220,817,480	$ 150,879,867	$ 46,162,491	$ 6,873,036	$ 16,630,428	$ 271,657
101	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.68328	0.20905	0.03113	0.07531	0.00123
102								
103	Commodity Cost Allocation Factors							
104								
105	Annual Distribution Volumes (Ccf)		200,820,622	100,576,461	63,212,213	17,300,748	18,596,127	1,135,073
106	**Distribution Commodity Factor (COM)**	COM	1.00000	0.50083	0.31477	0.08615	0.09260	0.00565

WKP Plant
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: PLANT WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1		**Distribution Plant Reserve**					
2	374	Land & Land Rights	$ (12,157)	DIS376-379	$ (6,757)	$ (5,389)	$ (11)
3	375	Structures and Improvements	$ (165,063)	DIS376-379	$ (91,742)	$ (73,165)	$ (156)
4	376	Distribution Mains	$ (92,558,158)	MAINS	$ (54,655,592)	$ (37,902,566)	$ —
5	376	Odorization	$ (9,564)	COM	$ —	$ —	$ (9,564)
6	377	Compressor Station Equipment	$ —	DEM	$ —	$ —	$ —
7	378	Meas. & Reg. Station Equip.- Gen.	$ (3,863,368)	DEM	$ —	$ (3,863,368)	$ —
8	378	Odorization Tank	$ (148,706)	COM	$ —	$ —	$ (148,706)
9	379	Meas. & Reg. Station Equip.- City Gate	$ (1,521,540)	DEM	$ —	$ (1,521,540)	$ —
10	379	Odorization Tank	$ (55,832)	COM	$ —	$ —	$ (55,832)
11	380	Services	$ (40,260,987)	CUS	$ (40,260,987)	$ —	$ —
12	381	Meters	$ (35,453,793)	CUS	$ (35,453,793)	$ —	$ —
13	382	Meter Installations	$ (2,791)	CUS	$ (2,791)	$ —	$ —
14	383	House Regulators	$ (4,883,641)	CUS	$ (4,883,641)	$ —	$ —
15	385	Meas. & Reg. Sta. Equip. -Ind.	$ (5,281,931)	DEM	$ —	$ (5,281,931)	$ —
16	385	Odorization	$ (6,037)	COM	$ —	$ —	$ (6,037)
17	386	Other Property - Customer Premises	$ (1,041,339)	DIS376-379	$ (578,778)	$ (461,580)	$ (982)
18	387	Other Equipment	$ —	DIS376-379	$ —	$ —	$ —
19		Total Distribution Plant Reserve	$ (185,264,906)		$ (135,934,080)	$ (49,109,538)	$ (221,288)
20							
21		**General Plant - Service Area Direct**					
22	389	Land & Land Rights	$ 8,347,674	DISPLT	$ 6,137,170	$ 2,198,274	$ 12,229
23	390	Structures & Improvements	$ 31,518,784	DISPLT	$ 23,172,462	$ 8,300,148	$ 46,175
24	391	Office Furniture and Equip.	$ 4,585,661	DISPLT	$ 3,371,356	$ 1,207,587	$ 6,718
25	392	Transportation Equipment	$ 25,015,559	DISPLT	$ 18,391,321	$ 6,587,590	$ 36,648
26	393	Stores Equipment	$ 123,761	DISPLT	$ 90,988	$ 32,591	$ 181
27	394	Tools, Shop & Garage	$ 15,361,664	DISPLT	$ 11,293,823	$ 4,045,336	$ 22,505
28	394	Odorization Tank	$ 19,654	COM	$ —	$ —	$ 19,654
29	395	CNG Equipment	$ —	DISPLT	$ —	$ —	$ —
30	396	Major Work Equipment	$ 3,532,069	DISPLT	$ 2,596,760	$ 930,134	$ 5,175
31	397	Communication Equipment	$ 34,624,291	DISPLT	$ 25,455,616	$ 9,117,951	$ 50,725
32	398	Miscellaneous General Plant	$ 6,349	DISPLT	$ 4,668	$ 1,672	$ 9
33		**General Plant - Shared Svcs. & Distrigas**					
34	389	Land & Land Rights	$ 209,039	CUS	$ 209,039	$ —	$ —
35	390	Structures & Improvements	$ 4,052,343	CUS	$ 4,052,343	$ —	$ —
36	391	Office Furniture and Equipment	$ 40,689,731	CUS	$ 40,689,731	$ —	$ —
37	392	Transportation Equipment	$ —	CUS	$ —	$ —	$ —
38	393	Stores Equipment	$ —	CUS	$ —	$ —	$ —
39	394	Tools, Shop & Garage	$ 125,849	CUS	$ 125,849	$ —	$ —
40	395	CNG Equipment	$ —	CUS	$ —	$ —	$ —
41	396	Major Work Equipment	$ —	CUS	$ —	$ —	$ —
42	397	Communication Equipment	$ 398,035	CUS	$ 398,035	$ —	$ —
43	398	Miscellaneous General Plant	$ —	CUS	$ —	$ —	$ —
44		**Total General Plant**					
45	389	Land & Land Rights	$ 8,556,713	GENPLT	$ 6,346,210	$ 2,198,274	$ 12,229
46	390	Structures & Improvements	$ 35,571,127	GENPLT	$ 27,224,805	$ 8,300,148	$ 46,175
47	391	Office Furniture and Equip.	$ 45,275,392	GENPLT	$ 44,061,087	$ 1,207,587	$ 6,718
48	392	Transportation Equipment	$ 25,015,559	GENPLT	$ 18,391,321	$ 6,587,590	$ 36,648
49	393	Stores Equipment	$ 123,761	GENPLT	$ 90,988	$ 32,591	$ 181
50	394	Tools, Shop & Garage	$ 15,487,513	GENPLT	$ 11,419,672	$ 4,045,336	$ 22,505
51	394	Odorization Tank	$ 19,654	COM	$ —	$ —	$ 19,654
52	395	CNG Equipment	$ —	GENPLT	$ —	$ —	$ —
53	396	Major Work Equipment	$ 3,532,069	GENPLT	$ 2,596,760	$ 930,134	$ 5,175
54	397	Communication Equipment	$ 35,022,327	GENPLT	$ 25,853,651	$ 9,117,951	$ 50,725
55	398	Miscellaneous General Plant	$ 6,349	GENPLT	$ 4,668	$ 1,672	$ 9
56		Total General Plant	$ 168,610,464		$ 135,989,162	$ 32,421,282	$ 200,020
57		**General Plant Depreciation Expense**					
58	389	Land & Land Rights	$ —		$ —	$ —	$ —

59	390	Structures & Improvements	$ 1,056,821		$ 808,851	$ 246,598	$ 1,372
60	391	Office Furniture and Equip.	$ 4,119,366		$ 4,008,882	$ 109,872	$ 611
61	392	Transportation Equipment	$ —		$ —	$ —	$ —
62	393	Stores Equipment	$ 8,251		$ 6,066	$ 2,173	$ 12
63	394	Tools, Shop & Garage	$ 1,032,501		$ 761,311	$ 269,689	$ 1,500
64	394	Tools, Shop & Garage - Odorization	$ 1,310		$ —	$ —	$ 1,310
65	395	CNG Equipment	$ —		$ —	$ —	$ —
66	396	Major Work Equipment	$ —		$ —	$ —	$ —
67	397	Communication Equipment	$ 2,334,592		$ 1,723,407	$ 607,804	$ 3,381
68	398	Miscellaneous General Plant	$ 423		$ 341	$ 81	$ 1
69		Total General Plant Depreciation Exp.	$ 8,553,264	GENDEP	$ 7,308,860	$ 1,236,217	$ 8,188
70		**General Plant**					
71		**Depreciation Reserve - Service Area Direct**					
72	389	Land & Land Rights	$ 4,733	DISPLT	$ 3,480	$ 1,246	$ 7
73	390	Structures & Improvements	$ (2,521,863)	DISPLT	$ (1,854,062)	$ (664,107)	$ (3,695)
74	391	Office Furniture and Equip.	$ (1,895,714)	DISPLT	$ (1,393,720)	$ (499,217)	$ (2,777)
75	392	Transportation Equipment	$ (9,718,895)	DISPLT	$ (7,145,286)	$ (2,559,371)	$ (14,238)
76	393	Stores Equipment	$ (7,599)	DISPLT	$ (5,587)	$ (2,001)	$ (11)
77	394	Tools, Shop & Garage	$ (4,554,994)	DISPLT	$ (3,348,810)	$ (1,199,511)	$ (6,673)
78	394	Odorization Tank	$ (4,241)	COM	$ —	$ —	$ (4,241)
79	395	CNG Equipment	$ 37,480	DISPLT	$ 27,555	$ 9,870	$ 55
80	396	Major Work Equipment	$ (1,344,194)	DISPLT	$ (988,245)	$ (353,980)	$ (1,969)
81	397	Communication Equipment	$ (14,072,660)	DISPLT	$ (10,346,153)	$ (3,705,890)	$ (20,617)
82	398	Miscellaneous General Plant	$ (4,308)	DISPLT	$ (3,167)	$ (1,134)	$ (6)
83			$ (34,082,254)		$ (25,053,995)	$ (8,974,094)	$ (54,165)
84		**General Plant**					
85		**Depreciation Reserve - Shared Svcs. & Distrigas**					
86	389	Land & Land Rights	$ —	CUS	$ —	$ —	$ —
87	390	Structures & Improvements	$ (922,965)	CUS	$ (922,965)	$ —	$ —
88	391	Office Furniture and Equipment	$ (18,688,284)	CUS	$ (18,688,284)	$ —	$ —
89	392	Transportation Equipment	$ —	CUS	$ —	$ —	$ —
90	393	Stores Equipment	$ —	CUS	$ —	$ —	$ —
91	394	Tools, Shop & Garage	$ (12,671)	CUS	$ (12,671)	$ —	$ —
92	395	CNG Equipment	$ —	CUS	$ —	$ —	$ —
93	396	Major Work Equipment	$ —	CUS	$ —	$ —	$ —
94	397	Communication Equipment	$ (251,591)	CUS	$ (251,591)	$ —	$ —
95	398	Miscellaneous General Plant	$ —	CUS	$ —	$ —	$ —
96			$ (19,875,510)		$ (19,875,510)	$ —	$ —
97		**General Plant**					
98		**Total Depreciation Reserve**					
99	389	Land & Land Rights	$ 4,733		$ 3,480	$ 1,246	$ 7
100	390	Structures & Improvements	$ (3,444,828)		$ (2,777,027)	$ (664,107)	$ (3,695)
101	391	Office Furniture and Equip.	$ (20,583,998)		$ (20,082,004)	$ (499,217)	$ (2,777)
102	392	Transportation Equipment	$ (9,718,895)		$ (7,145,286)	$ (2,559,371)	$ (14,238)
103	393	Stores Equipment	$ (7,599)		$ (5,587)	$ (2,001)	$ (11)
104	394	Tools, Shop & Garage	$ (4,567,665)		$ (3,361,481)	$ (1,199,511)	$ (6,673)
105	394	Odorization Tank	$ (4,241)		$ —	$ —	$ (4,241)
106	395	CNG Equipment	$ 37,480		$ 27,555	$ 9,870	$ 55
107	396	Major Work Equipment	$ (1,344,194)		$ (988,245)	$ (353,980)	$ (1,969)
108	397	Communication Equipment	$ (14,324,251)		$ (10,597,744)	$ (3,705,890)	$ (20,617)
109	398	Miscellaneous General Plant	$ (4,308)		$ (3,167)	$ (1,134)	$ (6)
110		Total General Plant Depr. Reserve	$ (53,957,765)	GENPLTRES	$ (44,929,505)	$ (8,974,094)	$ (54,165)

WKP Admin&Gen

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ADMINISTRATIVE AND GENERAL EXPENSE WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1	920	Salaries	$ 7,756,230	NONAGOPEXP	$ 5,849,517	$ 1,792,069	$ 114,645
2	921	Office Supplies & Expenses	$ 1,725,426	NONAGOPEXP	$ 1,301,265	$ 398,658	$ 25,503
3	922	Transferred Credit	$ (6,462,470)	NONAGOPEXP	$ (4,873,802)	$ (1,493,147)	$ (95,522)
4	923	Outside Services	$ 864,209	NONAGOPEXP	$ 651,761	$ 199,675	$ 12,774
5	924	Property Insurance	$ 327,803	NONAGOPEXP	$ 247,220	$ 75,739	$ 4,845
6	925	Injuries & Damages	$ 2,387,910	NONAGOPEXP	$ 1,800,890	$ 551,724	$ 35,296
7	926	Employee Pensions & Benefits	$ 7,301,118	NONAGOPEXP	$ 5,506,285	$ 1,686,915	$ 107,918
8	926	Distrigas	$ (177,617)	CUS	$ (177,617)	$ —	$ —
9	927	A&G Franchise Elections	$ —	NONAGOPEXP	$ —	$ —	$ —
10	928	Regulatory Commission Expenses	$ 968,792	NONAGOPEXP	$ 730,634	$ 223,838	$ 14,320
11	929	Duplicate Charges - Credit	$ —	NONAGOPEXP	$ —	$ —	$ —
12	930	Advertising	$ 107	NONAGOPEXP	$ 81	$ 25	$ 2
13	930	Other General	$ 1,830,627	NONAGOPEXP	$ 1,380,604	$ 422,964	$ 27,058
14	930	Distrigas	$ 16,896,955	CUS	$ 16,896,955	$ —	$ —
15	931	Rent	$ 690,591	NONAGOPEXP	$ 520,823	$ 159,560	$ 10,208
16	932	A&G Maintenance	$ 272,724	NONAGOPEXP	$ 205,681	$ 63,013	$ 4,031
17	940	Misc. General Expenses	$ —	NONAGOPEXP	$ —	$ —	$ —
18		Total Administrative & General Expense	$ 34,382,406	ADMINGEN	$ 30,040,296	$ 4,081,032	$ 261,077

WKP Selected Data
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER

	As Adjusted Test Year Bills/Meters	As Adjusted Volumes	As Adjusted Margin	Gas Costs at As Adjusted Volumes	As Adjusted Margin Plus Gas Costs	Unadjusted Sales Volumes (Excludes Transport)	As Adjusted Gas Sales Volumes (Excludes Transport)	Service Charges with Changes	Cost of Gas Revenue
Residential	3,738,454	100,576,461	$ 128,025,477	64,007,866	$ 192,033,343	96,594,749	100,576,461	$ 2,269,401	
Commercial	162,006	63,212,213	$ 24,405,808	29,295,339	$ 53,701,147	45,441,187	46,032,179	$ 58,030	
Industrial	742	17,300,748	$ 3,033,999	391,419	$ 3,425,419	447,904	615,043	$ 58	
Public Authority	16,037	18,596,127	$ 4,829,278	3,131,204	$ 7,960,482	4,782,978	4,920,106	$ 1,145	
Compressed Nat. Gas	59	1,135,073	$ 125,006	—	$ 125,006	—	—	$ 29	
Special Contract	154	59,125,140	$ 2,641,581	—	$ —	—	—	$ —	
Irrigation	25	269,338	$ 26,751	—	$ —	269,338	—	$ —	
Unmetered Gas Service	12	15,648	$ 1,964	—	$ —	15,648	—	$ —	
Total	3,917,490	260,230,748	$ 163,089,865	96,825,829	$ 257,245,398	147,551,803	152,143,789	$ 2,328,662	$ 93,904,159

COG Rate $ 0.63641

Customer Portion of Mains 59.05 %

Odorization Plant

Account	Original Cost	Reserve	Depr. Rate	Depr. Expense
369	$ 419,683	$ (10,016)	3.43%	$ 14,395
376	$ 144,153	$ (9,564)	2.23%	$ 3,215
378	$ 688,208	$ (148,706)	2.13%	$ 14,659
379	$ 486,607	$ (55,832)	1.97%	$ 9,586
385	$ 47,784	$ (6,037)	2.38%	$ 1,137
394	$ 19,654	$ (4,241)	6.67%	$ 1,310

Odorization Expense

Account	Cost
870	$ 67
874	$ 1,475
875	$ 87,890
880	$ 36
889	$ 80,957

Distrigas

Accounts	Per Book Allocated to TGS	Net Adjustments (with O&M Factor Applied)	Adjusted Allocated to TGS	Adjusted Allocated to Direct
926	$ (117,488)	$ (262,553)	$ (380,041)	$ (177,617)
930	$ 36,883,394	$ (729,502)	$ 36,153,892	$ 16,896,955

46.7362% Service Area Allocation Factor

	Residential	Commercial	Industrial	Public Authority	Compressed Nat. Gas
COSTS:					
Meters	1.00000	1.77405	5.62795	2.29224	6.61687
Regulators	1.00000	2.78714	17.85294	4.66126	22.01461
Services	1.00000	1.15388	1.49682	1.27651	1.43131
Meters & Regulators	1.00000	1.95193	7.77448	2.70821	9.32049
PEAK DEMANDS:					
Total System	0.72112	0.18408	0.02741	0.06632	0.00108
Account 385 Factor		0.66005	0.09827	0.23779	0.00388
OTHER ACCOUNTS:					
Account 903	0.97187	0.02648	0.00007	0.00157	0.00001
Account 904	0.92723	0.07085	0.00174	0.00018	0.00000
Customer Deposits	0.48733	0.50586	0.00543	0.00138	0.00000

	Residential	Commercial	Industrial	Public Authority	Compressed Nat. Gas
Base Revenue	$ 128,025,477	$ 24,405,808	$ 3,033,999	$ 4,829,278	$ 125,006
COG Revenue	$ 64,007,866	$ 29,295,339	$ 391,419	$ 3,131,204	$ —

903 Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: 903 FACTORS

	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	19,291	0.98589	75,954	0.97538	311,538	0.95435	0.97187
Commercial	274	0.01400	1,874	0.02407	13,500	0.04136	0.02648
Industrial	0	0.00000	2	0.00003	62	0.00019	0.00007
Public Authority	2	0.00010	41	0.00053	1,336	0.00409	0.00157
Compressed Nat. Gas	0	0.00000	0	0.00000	5	0.00002	0.00001

Source: Account 903.xlsx

904 Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: 904 FACTORS

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)
3-yr. avg.	$ 907,120	$ 841,110	$ 64,268	$ 1,580	$ 161	$ —
Factor	1.0000	0.92723	0.07085	0.00174	0.00018	0.00000

Source: Account 904.xlsx

Billing Determinants Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

BILLING DETERMINANTS SUMMARY

Gas Sales	Test Year Bills	Test Year Volumes	As Adjusted Bills	As Adjusted Volumes
Residential	3,718,632	96,594,749	3,738,454	100,576,461
Commercial	157,586	45,441,187	158,114	46,032,179
Industrial	223	447,904	295	615,043
Public Authority	10,008	4,684,889	9,972	4,804,679
Public Schs Space Htg.	71	98,089	83	115,427
Irrigation	25	269,338	25	269,338
Compressed Nat. Gas	17	0	11	0
Unmetered Gas Light	12	15,648	12	15,648
Gas Sales Total	3,886,575	147,551,803	3,906,967	152,428,775
Standard Transportation				
Commercial	3,892	17,180,034	3,892	17,180,034
Industrial	447	16,685,705	447	16,685,705
Public Authority	5,034	8,758,447	5,034	8,758,447
Public Schs Space Htg.	936	866,879	936	866,879
Compressed Nat. Gas	48	1,135,073	48	1,135,073
COGEN	12	4,050,695	12	4,050,695
Total Standard Transport	10,369	48,676,833	10,369	48,676,833
Transport - Special Contract	154	59,125,140	154	59,125,140
Total	3,897,098	255,353,776	3,917,490	260,230,748

Source: SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx

Customer Deposit Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: CUSTOMER DEPOSIT FACTORS

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	Compressed Nat. Gas
	$ 6,613,430	$ 3,222,927	$ 3,345,483	$ 35,895	$ 9,125	$ —
Factors		0.48733	0.50586	0.00543	0.00138	0.00000

Source: Customer Deposits.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

Size	Footage	Composition	Size	Plastic	Cost/Ft	LN (Cost/Ft)	Configured Cost
1	253,429	S	1	0	35.21	3.5612	8,253,309
2	6,497,014	S	2	0	38.85	3.6597	242,199,240
3	129,487	S	3	0	65.98	4.1894	5,525,508
4	2,500,967	S	4	0	50.22	3.9165	122,163,894
6	1,935,748	S	6	0	62.97	4.1426	123,896,685
8	387,013	S	8	0	83.37	4.4232	32,457,326
10	150,633	S	10	0	126.73	4.8421	16,553,242
12	293,045	S	12	0	199.58	5.2962	42,196,188
14	21,632	S	14	0	203.69	5.3166	4,081,448
16	46,939	S	16	0	249.87	5.5209	11,604,487
20	21,273	S	20	0	313.66	5.7483	9,029,699
1	180,064	P	1	1	20.92	3.0405	3,604,643
2	6,047,031	P	2	1	21.76	3.0799	138,568,946
3	190,566	P	3	1	23.95	3.1758	4,998,694
4	2,005,228	P	4	1	28.62	3.3540	60,209,268
6	1,208,212	P	6	1	37.86	3.6338	47,535,559
8	76,750	P	8	1	54.31	3.9946	3,956,674
12	2,138	P	12	1	101.18	4.6169	189,275
1	327	W	1	0	29.28	3.3769	10,661
2	3,733	W	2	0	31.10	3.4371	139,159
3	2,645	W	3	0	38.04	3.6386	112,880
4	101,006	W	4	0	41.82	3.7333	4,933,826
6	3,828	W	6	0	56.43	4.0330	245,009
8	818	W	8	0	73.62	4.2989	68,636
	22,059,528						882,534,257

SUMMARY OUTPUT

Regression Statistics			
Multiple R	0.979618106		
R Square	0.959651633		
Adjusted R Square	0.955808931	Best Fit	Log Linear Model
Standard Error	0.165450972		
Observations	24		

ANOVA

	df	SS	MS	F	Significance F
Regression	2	13.67242597	6.836212986	249.7335791	0.00000000000000229706
Residual	21	0.574854504	0.027374024		
Total	23	14.24728047			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.34815008	0.06238497	53.66917828	0.00000000	3.21841343	3.47788673
Size	0.13513400	0.00676694	19.96975055	0.00000000	0.12106138	0.14920661
Plastic	-0.48661745	0.07542485	-6.45168573	0.00000215	-0.64347202	-0.32976288

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	17.49	9,709,989	169,811,287		
Steel/Wrought Iron	28.45	12,349,540	351,345,083		
			521,156,369	882,534,257	59.05 %

Minimum System Study:

	Two-Inch Cost/Ft	Footage	Two Inch Cost	As Configured Cost	Customer Portion Portion
Plastic	21.76	9,709,989	211,249,858		
Steel/Wrought Iron	38.84	12,349,540	479,703,407		
			690,953,264	882,534,257	78.29 %
				w/Actual Cost	76.59 %

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

Source: Mains Study.xlsx

Meters & Regulator Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: METER AND REGULATOR FACTORS

Item	Meter	Meter Cost	Regulator	Regulator Cost	Cfh	Monthly Ccf (1)	Selected Monthly Break for Meter Selection
A	American AC 250	$ 257.39	1813-C 1 X 1 AB	$ 54.82	250	630	630
B	AL 425	$ 565.97	1813-C 1 X 1 AB	$ 86.36	425	1,071	1,075
C	AC 630	$ 1,408.06	1813-C 1 X 1 AB	$ 95.91	630	1,588	1,590
D	Dresser D-1000	$ 1,703.13	Itron CL34-IMR 1-1/4	$ 1,206.84	1,000	2,520	2,520

(1) Monthly Ccf is calculated based on assumed load factor of 35.%

Distribution of Meter and Regulator Sizes By Class

Item	Residential	Commercial	Industrial	Public Authority	Compressed Nat. Gas
A	100%	78%	13%	68%	0%
B	0%	9%	5%	10%	0%
C	0%	5%	2%	5%	0%
D	0%	8%	80%	17%	100%
Meter Cost	$ 257.39	$ 456.63	$ 1,448.59	$ 590.00	$ 1,703.13
Regulator Cost	$ 54.82	$ 152.79	$ 978.70	$ 255.53	$ 1,206.84
Meter and Regulator	$ 312.21	$ 609.42	$ 2,427.28	$ 845.53	$ 2,909.96
Weighted Factors					
Meters	1.00000	1.77405	5.62795	2.29224	6.61687
Regulators	1.00000	2.78714	17.85294	4.66126	22.01461
Meters & Regulators	1.00000	1.95193	7.77448	2.70821	9.32049

Source: Meter and Regulator.xlsx

Odorization Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: ODORIZATION PLANT AND EXPENSE SUMMARY

Odorization Equipment

Account	Book Cost	Allocated Reserve	Net Value
369	$ 419,683	$ 10,016	$ 409,667
376	$ 144,153	$ 9,564	$ 134,590
378	$ 688,208	$ 148,706	$ 539,502
379	$ 486,607	$ 55,832	$ 430,775
385	$ 47,784	$ 6,037	$ 41,747
394	$ 19,654	$ 4,241	$ 15,414
Total	$ 1,806,091	$ 234,396	$ 1,571,695

Source: Odorization Plant.xlsx

Odorization Expense

Account	Net Activity
8700	$ 67
8740	$ 1,475
8750	$ 87,890
8800	$ 36
8890	$ 80,957
Total	$ 170,426

Source: Odorization Expense.xlsx

Peak Demand

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: PEAK DEMAND SUMMARY

	Total	Residential	Commercial	Industrial	Public Authority	Compressed Nat. Gas
Total Est. Peak Usage	2,510,322	1,810,238	462,093	68,800	166,473	2,719
Peak Usage		0.72112	0.18408	0.02741	0.06632	0.00108
Non-Residential Demand			0.66005	0.09827	0.23779	0.00388

Source: Peak Demand.xlsx

Service Charges Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: SERVICE CHARGES SUMMARY

	Service Charge Revenue	%	As Adj. Test Year
Residential	$ 1,972,763	97.46%	$ 2,269,401
Commercial	50,445	2.49%	58,030
Public Authority	995	0.05%	1,145
Industrial	50	0.00%	58
Compressed Nat. Gas	25	0.00%	29
	$ 2,024,278		$ 2,328,662

Source: Service Charges.xlsx

Service Line Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS COST OF SERVICE STUDY: SERVICE LINE FACTOR SUMMARY

		Cost	Factor	Meters	Transporation Factor	Transportation Meters	Weighted Factor
Residential	$	1,549	1.00000	311,538	0.00000	0	1.00000
Commercial	$	1,775	1.14544	13,176	1.49682	324	1.15388
Public Authority	$	1,775	1.14544	838	1.49682	499	1.27651
Compressed Nat. Gas	$	1,775	1.14544	1	1.49682	4	1.43131
Industrial	$	2,319	1.49682	25	1.49682	37	1.49682
Transportation	$	2,319	1.49682				

Source: Service Lines.xlsx

As Adjusted Revenues Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

SUMMARY AS ADJUSTED REVENUES

Line No.	Revenue Class	CGSA Revenue	Removal of Cost of Gas	Remove Weather Normalization Dollars	Weather Normalization	Customer Growth Annualization	Remove Test Year GRIP Dollars	GRIP Annualizaton	Service Fee Annualization	Remove Interest on Storage	Remove Estimated Transport Revenue	As Adjusted Test Year Revenues
	Gas Sales											
1	Residential	$ 178,487,250	$ (63,413,979)	$ (2,450,383)	$ 1,071,232	$ 733,104	$ (21,617,196)	$ 35,215,449	$ —	$ —	$ —	$ 128,025,477
2	Commercial	45,403,381	(27,071,000)	(101,461)	53,123	72,592	(4,064,884)	6,736,801	—	—	—	21,028,552
3	Industrial	493,901	(276,120)	—	—	93,762	(89,292)	152,632	—	—	—	374,883
4	Public Authority	4,889,850	(2,952,230)	(50,366.62)	17,573	(8,333)	(481,306)	790,645	—	—	—	2,205,834
5	Public Schs Space Htg.	78,997	(55,798)	(300)	40	4,262	(3,514)	5,609	—	—	—	29,296
6	Irrigation	161,784	(135,032)	—	—	—	—	—	—	—	—	26,751
7	Compressed Nat. Gas	8,486	—	—	—	(4,888)	(5,212)	10,541	—	—	—	8,928
8	Unmetered Gas Light	1,964	—	—	—	—	—	—	—	—	—	1,964
9	Total Gas Sales Revenue	$ 229,525,612	$ (93,904,159)	$ (2,602,511)	$ 1,141,969	$ 890,498	$ (26,261,403)	$ 42,911,678	$ —	$ —	$ —	$ 151,701,685
	Transportation Revenue											
10	Commercial	$ 3,300,985	$ —	$ —	$ —	$ —	$ (90,105)	$ 166,376	$ —	$ —	$ —	$ 3,377,257
11	Industrial	2,489,421	—	0	—	—	(136,280)	305,975	—	—	—	2,659,116
12	Public Authority	1,867,873	—	0	—	—	(241,700)	397,698	—	—	—	2,023,870
13	Public Schs Space Htg.	351,538	—	0	—	—	(45,067)	73,944	—	—	—	380,415
14	Compressed Nat. Gas	102,214	—	0	—	—	(15,900)	29,764	—	—	—	116,078
15	COGEN	189,493	—	0	—	—	(578)	948	—	—	—	189,863
16	Special Contract	2,641,581	—	0	—	—	—	—	—	—	—	2,641,581
17	Estimated Revenue	(67,676)	—	—	—	—	—	—	—	—	67,676	—
18	Total Transport Revenue	$ 10,875,428	$ —	$ —	$ —	$ —	$ (529,628)	$ 974,705	$ —	$ —	$ 67,676	$ 11,388,180
19	Service Fee's - Acct 4880	$ 2,024,278	$ —	$ —	$ —	$ —	$ —	$ —	$ 304,384	$ —	$ —	$ 2,328,662
20	Utility Revenue - Acct 4950	806,701	—	—	—	—	—	—	—	(806,701)	—	—
21	Total Revenue	$ 243,232,019	$ (93,904,159)	$ (2,602,511)	$ 1,141,969	$ 890,498	$ (26,791,032)	$ 43,886,383	$ 304,384	$ (806,701)	$ 67,676	$ 165,418,527

Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx

Class Revenue Allocation

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	COMPRESSED NAT. GAS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Current Revenue-to-Cost Ratio (1)	0.8651	0.7822	1.5315	2.1127	1.2309	2.0406
2	Revenue Allocation One - Cost of Service Study Required Revenue Changes						
3	Revenue-to-Cost Ratio	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
4	Rate Design Revenue Change	$ 25,789,396	$ 36,946,576	$ (8,567,982)	$ (1,608,615)	$ (916,382)	$ (64,201)
5	% Increase - Non-Gas Revenue (2)	15.59%	27.85%	-34.70%	-52.67%	-18.76%	-51.00%
6	% Increase - Total Revenue (3)	9.83%	18.79%	-15.87%	-46.69%	-11.43%	-51.00%
7	% Total Revenue (for GRIP)	100.00 %	88.60 %	8.51 %	0.77 %	2.10 %	0.03 %
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)						
9	Revenue-to-Cost Ratio	1.0000	0.9474	1.4252	1.8902	1.1847	1.8325
10	Rate Design Revenue Change	$ 25,789,396	$ 28,020,832	$ (1,713,596)	$ (321,723)	$ (183,276)	$ (12,840)
11	% Increase - Non-Gas Revenue (2)	15.59%	21.12%	-6.94%	-10.53%	-3.75%	-10.20%
12	% Increase - Total Revenue (3)	9.83%	14.25%	-3.17%	-9.34%	-2.29%	-10.20%
13	% Total Revenue (for GRIP)	100.00 %	83.80 %	12.19 %	1.46 %	2.50 %	0.06 %
14	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)						
15	Revenue-to-Cost Ratio	1.0000	0.9342	1.5315	2.1127	1.2309	2.0406
16	Rate Design Revenue Change	$ 25,789,396	$ 25,789,396	$ —	$ —	$ —	$ —
17	% Increase - Non-Gas Revenue (2)	15.59%	19.44%	0.00%	0.00%	0.00%	0.00%
18	% Increase - Total Revenue (3)	9.83%	13.11%	0.00%	0.00%	0.00%	0.00%
19	% Total Revenue (for GRIP)	100.00 %	82.60 %	13.11 %	1.63 %	2.59 %	0.07 %

(1) Revenue-to-cost ratios are the ratios of each class' non-gas revenue (including revenue credits) to the cost of service.

(2) Non-gas revenue is the sum of as adjusted test year base revenue (i.e., revenue from recurring monthly charges resulting from as adjusted billing determinants), service charge revenue, special contract revenue, and other revenue credited to the cost of service for each class.

(3) Total revenue is the sum of non-gas revenue (see Note 2) and as adjusted gas costs. As adjusted gas costs are calculated by multiplying the test year average cost of gas (i.e., test year gas cost revenue divided by unadjusted sales service volumes) by as adjusted sales service volumes.

(4) For each class with a cost of service required revenue decrease, 20 percent of the required decrease is implemented. The benefit of implementing less than the required decrease is assigned to the residential class.

(5) No revenue change assigned to a class for which the cost of service required revenue change calls for a decrease. The resulting benefit from not implementing the required decease is assigned to the residential class.

Proof of Revenue

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROOF OF REVENUE

Line No.	Description	Bills	Volumes		Recommended Rates: Customer Charge	Recommended Rates: Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.	GRIP Allocation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential - Small	2,330,758			$ 25.50		$ 59,434,329				
2			All Ccf	39,439,549		0.69448	$ 27,389,978				
3	Residential - Large	1,407,697			$ 39.00		$ 54,900,183				
4			All Ccf	61,136,913		0.23425	$ 14,321,322				
5	Residential Total							$ 156,045,812	$ 156,046,309	$ (497)	83.80 %
6											
7	Commercial - Small	118,004			$ 85.00		$ 10,030,340				
8			All Ccf	7,271,449		0.15710	$ 1,142,345				
9	Commercial - Large	40,110			$ 100.00		$ 4,011,000				
10			All Ccf	38,760,730		0.10765	$ 4,172,593	$ 19,356,277			
11											
12	Commercial - Transport	3,892			297.51		$ 1,157,864				
13			All Ccf	17,180,034		0.12679	$ 2,178,256	$ 3,336,120			
14	Commercial Total							$ 22,692,397	$ 22,692,212	$ 185	12.19 %
15											
16	Industrial	295			$ 572.02		$ 168,746				
17			All Ccf	615,043		0.12707	$ 78,153	$ 246,899			
18											
19	Industrial - Transport	447			$ 772.02		$ 345,122				
20			All Ccf	16,685,705		0.12707	$ 2,120,253	$ 2,465,374			
21	Industrial Total							$ 2,712,274	$ 2,712,276	$ (2)	1.46 %
22											
23	Public Authority	10,055			$ 156.05		$ 1,569,109				
24			All Ccf	4,920,106		0.12549	$ 617,424	$ 2,186,533			
25											
26	Public Authority - Transport	5,970			$ 179.05		$ 1,068,955				
27			All Ccf	9,625,326		0.12549	$ 1,207,882	$ 2,276,837			
28	Public Authority Total							$ 4,463,370			
29											
30	Electric Cogeneration- Transport	12			$ 175.98		$ 2,112				
31			First 5,000 Ccf	60,000		0.07427	$ 4,456				
32			Next 35,000 Ccf	420,000		0.06590	$ 27,678				
33			Next 60,000 Ccf	720,000		0.05314	$ 38,261				
34			All over 100,000 Ccf	2,850,695		0.03864	$ 110,151				
35	Electric Cogeneration Total							$ 182,658	$ 4,646,002	$ 26	2.50 %
36											
37	Compressed Natural Gas	11			$ 594.88		$ 6,544				
38			All Ccf	0		0.06684	$ —	$ 6,544			
39											
40	Compressed Natural Gas - Transport	48			$ 619.88		$ 29,754				
41			All Ccf	1,135,073		0.06684	$ 75,868	$ 105,623			
42	Compressed Natural Gas Total							$ 112,166	$ 112,166		
43											
44	Total Revenue - All Classes										
45											
46	Recommended Rate Revenue							$ 186,208,676	$ 186,208,965		
47	Current Rate Revenue							$ 160,419,569	$ 160,419,569		
48	Revenue Change							$ 25,789,107	$ 25,789,396		
49											
50	Schedule A - Revenue Deficiency								$ 25,789,395		
									$ (0)		

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CURRENT AND RECOMMENDED RATES

Description		CGSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c)	(d)
Residential			Small	Large
Customer Charge		$25.47	$25.50	$39.00
Usage Rates	All Ccf	$0.32626	$0.69448	$0.23425
Commercial				
Customer Charge - Sales		$96.08	$85.00	$100.00
Usage Rates		$0.12679	$0.15710	$0.10765
Customer Charge - Transportation		$308.08	$297.51	
Usage Rates	All Ccf	$0.12679	$0.12679	
Industrial				
Customer Charge - Sales		$1,005.41	$572.02	
Usage Rates	All Ccf	$0.12707	$0.12707	
Customer Charge - Transportation		$1,205.41	$772.02	
Usage Rates	All Ccf	$0.12707	$0.12707	
Public Authority				
Customer Charge - Sales		$160.70	$156.05	
Usage Rates	All Ccf	$0.12549	$0.12549	
Customer Charge - Transportation		$183.70	$179.05	
Usage Rates	All Ccf	$0.12549	$0.12549	
Public Schools Space Heat - WITHDRAW				
Customer Charge - Sales		$213.70	$156.05	
Usage Rates	All Ccf	$0.10012	$0.12549	
Customer Charge - Transportation		$313.70	$179.05	
Usage Rates	All Ccf	$0.10012	$0.12549	
Electrical Generation				
Customer Charge - Sales		$183.70	$175.98	
Usage Rates	First 5,000 Ccf/Month	$0.07720	$0.07427	
	Next 35,000 Ccf/Month	$0.06850	$0.06590	
	Next 60,000 Ccf/Month	$0.05524	$0.05314	
	All Over 100,000 Ccf/Month	$0.04016	$0.03864	
Customer Charge - Transportation		$183.70	$175.98	
Usage Rates	First 5,000 Ccf/Month	$0.07720	$0.07427	
	Next 35,000 Ccf/Month	$0.06850	$0.06590	
	Next 60,000 Ccf/Month	$0.05524	$0.05314	
	All Over 100,000 Ccf/Month	$0.04016	$0.03864	
Compressed Natural Gas				
Customer Charge - Sales		$812.71	$594.88	
Usage Rates	All Ccf	$0.06684	$0.06684	
Customer Charge - Transportation		$837.71	$619.88	
Usage Rates	All Ccf	$0.06684	$0.06684	
Unmetered Gas Light				
Usage Rates	All Ccf	$0.12549	$0.12549	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

CURRENT AND RECOMMENDED RATES WORKPAPER

Gas Costs	CGSA	$0.63641
Transportation Gas Cost Savings Assumed		5 %

Description		CGSA Incorporated and Envrions Rates (1)	Recommended	
(a)		(b)	(d)	(e)
Residential			Small	Large
Customer Charge		$25.47	$25.50	$39.00
Usage Rates	All Ccf	$0.32626	$0.69448	$0.23425
Commercial				
Customer Charge - Sales		$96.08	$85.00	$100.00
Usage Rates	All Ccf	$0.12679	$0.15710	$0.10765
Customer Charge - Transportation		$308.08	$297.51	
Usage Rates	All Ccf	$0.12679	$0.12679	
Industrial				
Customer Charge - Sales		$1,005.41	$572.02	
Usage Rates	All Ccf	$0.12707	$0.12707	
Customer Charge - Transportation		$1,205.41	$772.02	
Usage Rates	All Ccf	$0.12707	$0.12707	
Public Authority				
Customer Charge - Sales		$160.70	$156.05	
Usage Rates	All Ccf	$0.12549	$0.12549	
Customer Charge - Transportation		$183.70	$179.05	
Usage Rates	All Ccf	$0.12549	$0.12549	
Public Schools Space Heating				
Customer Charge - Sales		$213.70	$156.05	
Usage Rates	All Ccf	$0.10012	$0.12549	
Customer Charge - Transportation		$313.70	$179.05	
Usage Rates	All Ccf	$0.10012	$0.12549	
Electrical Generation (2)				
Customer Charge - Sales		$183.70	$175.98	
Usage Rates	First 5,000 Ccf/Month	$0.07720	$0.07427	
	Next 35,000 Ccf/Month	$0.06850	$0.06590	
	Next 60,000 Ccf/Month	$0.05524	$0.05314	
	All Over 100,000 Ccf/Month	$0.04016	$0.03864	
Customer Charge - Transportation		$183.70	$175.98	
Usage Rates	First 5,000 Ccf/Month	$0.07720	$0.07427	
	Next 35,000 Ccf/Month	$0.06850	$0.06590	
	Next 60,000 Ccf/Month	$0.05524	$0.05314	
	All Over 100,000 Ccf/Month	$0.04016	$0.03864	
Compressed Natural Gas (3)				
Customer Charge - Sales		$812.71	$594.88	

		CGSA	Recommended
	Residential	CGSA	Recommended
Annual A	17	$ 41.76	$ 48.02
Annual B	43	$ 67.28	$ 76.81
	Commercial	CGSA	Recommended
Annual A	62	$ 143.11	$ 133.90
Annual B	966	$ 833.61	$ 819.03
Annual	4,414	$ 3,536.39	$ 3,525.82
	Industrial	CGSA	Recommended
Annual	2,085	$ 2,597.27	$ 2,163.88
Annual	37,325	$ 28,514.60	$ 28,081.21
	Pub. Auth.	CGSA	Recommended
Annual	489	$ 533.27	$ 528.62
Annual	1,612	$ 1,360.59	$ 1,355.94
	Public Schools Space Heat	CGSA	Recommended
Annual	1,391	$ 1,238.21	$ 1,215.85
Annual	926	$ 966.26	$ 855.10
	Electrical Cogeneration	CGSA	Recommended
Annual			
Annual	337,558	$ 219,905.95	$ 219,305.49
	Compressed Natural Gas	CGSA	Recommended
Annual	—	$ 812.71	$ 594.88

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CURRENT AND RECOMMENDED RATES WORKPAPER

Gas Costs	CGSA	$0.63641
Transportation Gas Cost Savings Assumed		5 %

Description		CGSA Incorporated and Envrions Rates (1)	Recommended	
(a)		(b)	(d)	(e)
Usage Rates	All Ccf	$0.06684	$0.06684	
Customer Charge - Transportation		$837.71	$619.88	
Usage Rates	All Ccf	$0.06684	$0.06684	
Unmetered Gas Light (4)				
Usage Rates	All Ccf	$0.12549	$0.12549	

Annual	23,647	$ 16,715.00	$ 16,497.17

	Unmetered Gas Light	CGSA	Recommended
Annual	1,304	$ 993.52	$ 993.52

Note 1: The volumetric and customer charge rates are the same for incorporated and environs customer classes. The Current rates reflect the proposed rates in Case 16275.
Note 2: There are currently no Electrical Generation gas sales customers.
Note 3: There are no volumes for the Compressed Natural Gas gas sales customer class.

Note 4: Rates shown are for Public Authority Unmetered Gas Light Service customers only, as there are no other customers on Residential, Commercial, or Industrial Unmetered Gas Light Service rates.

Customer Bill Impacts

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small (3)				
Incorporated	$41.76	$48.02	$6.26	15.0%
Environs	$41.76	$48.02	$6.26	15.0%
Residential - Large (3)				
Incorporated	$67.28	$76.81	$9.53	14.2%
Environs	$67.28	$76.81	$9.53	14.2%
Commercial - Small (3)				
Incorporated	$143.11	$133.90	-$9.21	-6.4%
Environs	$143.11	$133.90	-$9.21	-6.4%
Commercial - Large (3)				
Incorporated	$833.61	$819.03	-$14.58	-1.7%
Environs	$833.61	$819.03	-$14.58	-1.7%
Industrial				
Incorporated	$2,597.27	$2,163.88	-$433.39	-16.7%
Environs	$2,597.27	$2,163.88	-$433.39	-16.7%
Public Authority				
Incorporated	$533.27	$528.62	-$4.65	-0.9%
Environs	$533.27	$528.62	-$4.65	-0.9%
Public Schools Space Heating (4)				
Incorporated	$1,238.21	$1,215.85	-$22.36	-1.8%
Environs	$1,238.21	$1,215.85	-$22.36	-1.8%
Compressed Natural Gas				
Incorporated	$812.71	$594.88	-$217.83	-26.8%
Environs	$812.71	$594.88	-$217.83	-26.8%
Unmetered Gas Light				
Incorporated	$993.52	$993.52	$0.00	0.0%
Transportation Service: (5)				
Commercial Transportation				
Incorporated	$3,536.39	$3,525.82	-$10.57	-0.3%
Environs	$3,536.39	$3,525.82	-$10.57	-0.3%
Industrial Transportation				
Incorporated	$28,514.60	$28,081.21	-$433.39	-1.5%
Environs	$28,514.60	$28,081.21	-$433.39	-1.5%
Public Authority Transportation				
Incorporated	$1,360.59	$1,355.94	-$4.65	-0.3%
Environs	$1,360.59	$1,355.94	-$4.65	-0.3%
Public Schools Space Heating Transportation (4)				

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Incorporated	$966.26	$855.10	-$111.16	-11.5%
Environs	$966.26	$855.10	-$111.16	-11.5%
Electrical Cogeneration Transportation				
Incorporated	$219,905.95	$219,305.49	-$600.46	-0.3%
Environs	$219,905.95	$219,305.49	-$600.46	-0.3%
Compressed Natural Gas Transportation				
Incorporated	$16,715.00	$16,497.17	-$217.83	-1.3%
Environs	$16,715.00	$16,497.17	-$217.83	-1.3%

(1) Bill impacts are shown for those schedules with customers during the test year. The test year cost of gas is included in the bill calculations. Bills under current and recommended rates do not include revenue-related taxes. These taxes vary across different locations in the service area.

(2) Bills are based on the following average usage levels:

	Year-Round
Residential - Small	17
Residential - Large	43
Commercial - Small	62
Commercial - Large	966
Industrial	2,085
Public Authority	489
Public Schools Space Heat	1,391
Compressed Natural Gas	0

(3) Calculations for residential and commerical are based on usage at the Small and Large amounts shown in Note 2 (Residential: 17 Ccf for Small and 43 Ccf for Large/Commercial: 62 Ccf for Small and 966 for Large). See the individual rate design tabs for the source of these values.

(4) The gas sales and transportation Public School Space Heating tariffs will be discontinued. Customers will be consolidated into the Public Authority class.

(5) Transportation customers secure their own gas. While the Company has no way of knowing the customer's cost of gas, these bill comparisons assume that customers obtain their gas at a cost that is five percent less than the Company's gas cost. These transportation bill comparisons are only illustrations of the level of total bills and the percentage changes in those bills. Bills are based on the following average usage levels:

	Year-Round
Commercial Transportation	4,414
Industrial Transportation	37,325
Public Authority Transportation	1,612
Public Schools Space Heat Transportation	926
Electrical Cogeneration Transportation	337,558
Compressed Natural Gas Transportation	23,647

Residential Bill Impacts Existing Rates

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Small/Large Rate Relative to Existing Rates

								$ 25.50	$ 1.33089	$ 1.33089	Small					
			$ 25.47	$ 0.96267	$ 0.96267			$ 39.00	$ 0.87066	$ 0.87066	Large					
Consumption			Current Charges					Proposed Charges					Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	22	446	$ 305.64	$ —	$ 21.18	$ 305.64	$ 326.82	$ 306.00	$ —	$ 29.28	$ 306.00	$ 335.28	$ 0.03	$ 0.71	0%	3%
23	44	2,443	$ 305.64	$ 22.14	$ 42.36	$ 327.78	$ 348.00	$ 306.00	$ 30.61	$ 58.56	$ 336.61	$ 364.56	$ 0.74	$ 1.38	3%	5%
45	66	3,907	$ 305.64	$ 43.32	$ 63.54	$ 348.96	$ 369.18	$ 306.00	$ 59.89	$ 87.84	$ 365.89	$ 393.84	$ 1.41	$ 2.06	5%	7%
67	88	5,587	$ 305.64	$ 64.50	$ 84.71	$ 370.14	$ 390.35	$ 306.00	$ 89.17	$ 117.12	$ 395.17	$ 423.12	$ 2.09	$ 2.73	7%	8%
89	110	7,416	$ 305.64	$ 85.68	$ 105.89	$ 391.32	$ 411.53	$ 306.00	$ 118.45	$ 146.40	$ 424.45	$ 452.40	$ 2.76	$ 3.41	8%	10%
111	132	9,800	$ 305.64	$ 106.86	$ 127.07	$ 412.50	$ 432.71	$ 306.00	$ 147.73	$ 175.68	$ 453.73	$ 481.68	$ 3.44	$ 4.08	10%	11%
133	154	12,107	$ 305.64	$ 128.04	$ 148.25	$ 433.68	$ 453.89	$ 306.00	$ 177.01	$ 204.96	$ 483.01	$ 510.96	$ 4.11	$ 4.76	11%	13%
155	176	14,455	$ 305.64	$ 149.21	$ 169.43	$ 454.85	$ 475.07	$ 306.00	$ 206.29	$ 234.24	$ 512.29	$ 540.24	$ 4.79	$ 5.43	13%	14%
177	198	16,250	$ 305.64	$ 170.39	$ 190.61	$ 476.03	$ 496.25	$ 306.00	$ 235.57	$ 263.52	$ 541.57	$ 569.52	$ 5.46	$ 6.11	14%	15%
199	220	17,733	$ 305.64	$ 191.57	$ 211.79	$ 497.21	$ 517.43	$ 306.00	$ 264.85	$ 292.80	$ 570.85	$ 598.80	$ 6.14	$ 6.78	15%	16%
221	242	18,510	$ 305.64	$ 212.75	$ 232.97	$ 518.39	$ 538.61	$ 306.00	$ 294.13	$ 322.08	$ 600.13	$ 628.08	$ 6.81	$ 7.46	16%	17%
243	264	18,621	$ 305.64	$ 233.93	$ 254.14	$ 539.57	$ 559.78	$ 306.00	$ 323.41	$ 351.35	$ 629.41	$ 657.35	$ 7.49	$ 8.13	17%	17%
265	286	18,350	$ 305.64	$ 255.11	$ 275.32	$ 560.75	$ 580.96	$ 306.00	$ 352.69	$ 380.63	$ 658.69	$ 686.63	$ 8.16	$ 8.81	17%	18%
287	308	17,299	$ 305.64	$ 276.29	$ 296.50	$ 581.93	$ 602.14	$ 306.00	$ 381.97	$ 409.91	$ 687.97	$ 715.91	$ 8.84	$ 9.48	18%	19%
309	330	16,441	$ 305.64	$ 297.47	$ 317.68	$ 603.11	$ 623.32	$ 306.00	$ 411.25	$ 439.19	$ 717.25	$ 745.19	$ 9.51	$ 10.16	19%	20%
331	352	14,865	$ 305.64	$ 318.64	$ 338.86	$ 624.28	$ 644.50	$ 306.00	$ 440.52	$ 468.47	$ 746.52	$ 774.47	$ 10.19	$ 10.83	20%	20%
353	852	107,054	$ 305.64	$ 339.82	$ 820.19	$ 645.46	$ 1,125.83	$ 468.00	$ 307.34	$ 741.80	$ 775.34	$ 1,209.80	$ 10.82	$ 7.00	20%	7%
853	1352	7,616	$ 305.64	$ 821.16	$ 1,301.53	$ 1,126.80	$ 1,607.17	$ 468.00	$ 742.67	$ 1,177.13	$ 1,210.67	$ 1,645.13	$ 6.99	$ 3.16	7%	2%
1,353	1852	1,530	$ 305.64	$ 1,302.49	$ 1,782.86	$ 1,608.13	$ 2,088.50	$ 468.00	$ 1,178.00	$ 1,612.46	$ 1,646.00	$ 2,080.46	$ 3.16	$ (0.67)	2%	-0%
1,853	2352	516	$ 305.64	$ 1,783.83	$ 2,264.20	$ 2,089.47	$ 2,569.84	$ 468.00	$ 1,613.33	$ 2,047.79	$ 2,081.33	$ 2,515.79	$ (0.68)	$ (4.50)	-0%	-2%
2,353	2852	230	$ 305.64	$ 2,265.16	$ 2,745.53	$ 2,570.80	$ 3,051.17	$ 468.00	$ 2,048.66	$ 2,483.12	$ 2,516.66	$ 2,951.12	$ (4.51)	$ (8.34)	-2%	-3%
2,853	3352	102	$ 305.64	$ 2,746.50	$ 3,226.87	$ 3,052.14	$ 3,532.51	$ 468.00	$ 2,483.99	$ 2,918.45	$ 2,951.99	$ 3,386.45	$ (8.35)	$ (12.17)	-3%	-4%
3,353	3852	87	$ 305.64	$ 3,227.83	$ 3,708.20	$ 3,533.47	$ 4,013.84	$ 468.00	$ 2,919.32	$ 3,353.78	$ 3,387.32	$ 3,821.78	$ (12.18)	$ (16.01)	-4%	-5%
3,853	4352	47	$ 305.64	$ 3,709.17	$ 4,189.54	$ 4,014.81	$ 4,495.18	$ 468.00	$ 3,354.65	$ 3,789.11	$ 3,822.65	$ 4,257.11	$ (16.01)	$ (19.84)	-5%	-5%
4,353	4852	25	$ 305.64	$ 4,190.50	$ 4,670.87	$ 4,496.14	$ 4,976.51	$ 468.00	$ 3,789.98	$ 4,224.44	$ 4,257.98	$ 4,692.44	$ (19.85)	$ (23.67)	-5%	-6%
4,853	5352	24	$ 305.64	$ 4,671.84	$ 5,152.21	$ 4,977.48	$ 5,457.85	$ 468.00	$ 4,225.31	$ 4,659.77	$ 4,693.31	$ 5,127.77	$ (23.68)	$ (27.51)	-6%	-6%
5,353	5852	16	$ 305.64	$ 5,153.17	$ 5,633.54	$ 5,458.81	$ 5,939.18	$ 468.00	$ 4,660.64	$ 5,095.10	$ 5,128.64	$ 5,563.10	$ (27.51)	$ (31.34)	-6%	-6%
5,853	6352	8	$ 305.64	$ 5,634.51	$ 6,114.88	$ 5,940.15	$ 6,420.52	$ 468.00	$ 5,095.97	$ 5,530.43	$ 5,563.97	$ 5,998.43	$ (31.35)	$ (35.17)	-6%	-7%
6,353	6852	11	$ 305.64	$ 6,115.84	$ 6,596.21	$ 6,421.48	$ 6,901.85	$ 468.00	$ 5,531.30	$ 5,965.76	$ 5,999.30	$ 6,433.76	$ (35.18)	$ (39.01)	-7%	-7%
6,853	7352	6	$ 305.64	$ 6,597.18	$ 7,077.55	$ 6,902.82	$ 7,383.19	$ 468.00	$ 5,966.63	$ 6,401.09	$ 6,434.63	$ 6,869.09	$ (39.02)	$ (42.84)	-7%	-7%
7,353	42342	36	$ 305.64	$ 7,078.51	$ 40,761.37	$ 7,384.15	$ 41,067.01	$ 468.00	$ 6,401.96	$ 36,865.49	$ 6,869.96	$ 37,333.49	$ (42.85)	$ (311.13)	-7%	-9%

Residential Bill Impacts
New Rates
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO TRADITIONAL RATE STRUCTURE

Annual Residential Bill Impacts of Small/Large Rate Structure Compared to Traditional Rate Structure

								$ 25.50	$ 1.33089	$ 1.33089	Small					
			$ 41.61	$ 0.64116	$ 0.64116			$ 39.00	$ 0.87066	$ 0.87066	Large					
Consumption			Current Charges					Proposed Charges					Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	22	446	$ 499.32	$ —	$ 14.11	$ 499.32	$ 513.43	$ 306.00	$ —	$ 29.28	$ 306.00	$ 335.28	$ (16.11)	$ (14.85)	-39%	-35%
23	44	2,443	$ 499.32	$ 14.75	$ 28.21	$ 514.07	$ 527.53	$ 306.00	$ 30.61	$ 58.56	$ 336.61	$ 364.56	$ (14.79)	$ (13.58)	-35%	-31%
45	66	3,907	$ 499.32	$ 28.85	$ 42.32	$ 528.17	$ 541.64	$ 306.00	$ 59.89	$ 87.84	$ 365.89	$ 393.84	$ (13.52)	$ (12.32)	-31%	-27%
67	88	5,587	$ 499.32	$ 42.96	$ 56.42	$ 542.28	$ 555.74	$ 306.00	$ 89.17	$ 117.12	$ 395.17	$ 423.12	$ (12.26)	$ (11.05)	-27%	-24%
89	110	7,416	$ 499.32	$ 57.06	$ 70.53	$ 556.38	$ 569.85	$ 306.00	$ 118.45	$ 146.40	$ 424.45	$ 452.40	$ (10.99)	$ (9.79)	-24%	-21%
111	132	9,800	$ 499.32	$ 71.17	$ 84.63	$ 570.49	$ 583.95	$ 306.00	$ 147.73	$ 175.68	$ 453.73	$ 481.68	$ (9.73)	$ (8.52)	-20%	-18%
133	154	12,107	$ 499.32	$ 85.27	$ 98.74	$ 584.59	$ 598.06	$ 306.00	$ 177.01	$ 204.96	$ 483.01	$ 510.96	$ (8.47)	$ (7.26)	-17%	-15%
155	176	14,455	$ 499.32	$ 99.38	$ 112.84	$ 598.70	$ 612.16	$ 306.00	$ 206.29	$ 234.24	$ 512.29	$ 540.24	$ (7.20)	$ (5.99)	-14%	-12%
177	198	16,250	$ 499.32	$ 113.49	$ 126.95	$ 612.81	$ 626.27	$ 306.00	$ 235.57	$ 263.52	$ 541.57	$ 569.52	$ (5.94)	$ (4.73)	-12%	-9%
199	220	17,733	$ 499.32	$ 127.59	$ 141.06	$ 626.91	$ 640.38	$ 306.00	$ 264.85	$ 292.80	$ 570.85	$ 598.80	$ (4.67)	$ (3.46)	-9%	-6%
221	242	18,510	$ 499.32	$ 141.70	$ 155.16	$ 641.02	$ 654.48	$ 306.00	$ 294.13	$ 322.08	$ 600.13	$ 628.08	$ (3.41)	$ (2.20)	-6%	-4%
243	264	18,621	$ 499.32	$ 155.80	$ 169.27	$ 655.12	$ 668.59	$ 306.00	$ 323.41	$ 351.35	$ 629.41	$ 657.35	$ (2.14)	$ (0.94)	-4%	-2%
265	286	18,350	$ 499.32	$ 169.91	$ 183.37	$ 669.23	$ 682.69	$ 306.00	$ 352.69	$ 380.63	$ 658.69	$ 686.63	$ (0.88)	$ 0.33	-2%	1%
287	308	17,299	$ 499.32	$ 184.01	$ 197.48	$ 683.33	$ 696.80	$ 306.00	$ 381.97	$ 409.91	$ 687.97	$ 715.91	$ 0.39	$ 1.59	1%	3%
309	330	16,441	$ 499.32	$ 198.12	$ 211.58	$ 697.44	$ 710.90	$ 306.00	$ 411.25	$ 439.19	$ 717.25	$ 745.19	$ 1.65	$ 2.86	3%	5%
331	352	14,865	$ 499.32	$ 212.22	$ 225.69	$ 711.54	$ 725.01	$ 306.00	$ 440.52	$ 468.47	$ 746.52	$ 774.47	$ 2.92	$ 4.12	5%	7%
353	852	107,054	$ 499.32	$ 226.33	$ 546.27	$ 725.65	$ 1,045.59	$ 468.00	$ 307.34	$ 741.80	$ 775.34	$ 1,209.80	$ 4.14	$ 13.68	7%	16%
853	1352	7,616	$ 499.32	$ 546.91	$ 866.85	$ 1,046.23	$ 1,366.17	$ 468.00	$ 742.67	$ 1,177.13	$ 1,210.67	$ 1,645.13	$ 13.70	$ 23.25	16%	20%
1,353	1852	1,530	$ 499.32	$ 867.49	$ 1,187.43	$ 1,366.81	$ 1,686.75	$ 468.00	$ 1,178.00	$ 1,612.46	$ 1,646.00	$ 2,080.46	$ 23.27	$ 32.81	20%	23%
1,853	2352	516	$ 499.32	$ 1,188.07	$ 1,508.01	$ 1,687.39	$ 2,007.33	$ 468.00	$ 1,613.33	$ 2,047.79	$ 2,081.33	$ 2,515.79	$ 32.83	$ 42.37	23%	25%
2,353	2852	230	$ 499.32	$ 1,508.65	$ 1,828.59	$ 2,007.97	$ 2,327.91	$ 468.00	$ 2,048.66	$ 2,483.12	$ 2,516.66	$ 2,951.12	$ 42.39	$ 51.93	25%	27%
2,853	3352	102	$ 499.32	$ 1,829.23	$ 2,149.17	$ 2,328.55	$ 2,648.49	$ 468.00	$ 2,483.99	$ 2,918.45	$ 2,951.99	$ 3,386.45	$ 51.95	$ 61.50	27%	28%
3,353	3852	87	$ 499.32	$ 2,149.81	$ 2,469.75	$ 2,649.13	$ 2,969.07	$ 468.00	$ 2,919.32	$ 3,353.78	$ 3,387.32	$ 3,821.78	$ 61.52	$ 71.06	28%	29%
3,853	4352	47	$ 499.32	$ 2,470.39	$ 2,790.33	$ 2,969.71	$ 3,289.65	$ 468.00	$ 3,354.65	$ 3,789.11	$ 3,822.65	$ 4,257.11	$ 71.08	$ 80.62	29%	29%
4,353	4852	25	$ 499.32	$ 2,790.97	$ 3,110.91	$ 3,290.29	$ 3,610.23	$ 468.00	$ 3,789.98	$ 4,224.44	$ 4,257.98	$ 4,692.44	$ 80.64	$ 90.18	29%	30%
4,853	5352	24	$ 499.32	$ 3,111.55	$ 3,431.49	$ 3,610.87	$ 3,930.81	$ 468.00	$ 4,225.31	$ 4,659.77	$ 4,693.31	$ 5,127.77	$ 90.20	$ 99.75	30%	30%
5,353	5852	16	$ 499.32	$ 3,432.13	$ 3,752.07	$ 3,931.45	$ 4,251.39	$ 468.00	$ 4,660.64	$ 5,095.10	$ 5,128.64	$ 5,563.10	$ 99.77	$ 109.31	30%	31%
5,853	6352	8	$ 499.32	$ 3,752.71	$ 4,072.65	$ 4,252.03	$ 4,571.97	$ 468.00	$ 5,095.97	$ 5,530.43	$ 5,563.97	$ 5,998.43	$ 109.33	$ 118.87	31%	31%
6,353	6852	11	$ 499.32	$ 4,073.29	$ 4,393.23	$ 4,572.61	$ 4,892.55	$ 468.00	$ 5,531.30	$ 5,965.76	$ 5,999.30	$ 6,433.76	$ 118.89	$ 128.43	31%	32%
6,853	7352	6	$ 499.32	$ 4,393.87	$ 4,713.81	$ 4,893.19	$ 5,213.13	$ 468.00	$ 5,966.63	$ 6,401.09	$ 6,434.63	$ 6,869.09	$ 128.45	$ 138.00	32%	32%
7,353	42342	36	$ 499.32	$ 4,714.45	$ 27,148.00	$ 5,213.77	$ 27,647.32	$ 468.00	$ 6,401.96	$ 36,865.49	$ 6,869.96	$ 37,333.49	$ 138.02	$ 807.18	32%	35%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Bill Impacts of Small/Large Commercial Rate Relative to Existing Rates

								$ 85.00	$ 0.79351	$ 0.79351	Small					
			$ 96.08	$ 0.76320	$ 0.76320			$ 100.00	$ 0.74406	$ 0.74406	Large					
Consumption					Current Charges					Proposed Charges			Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	228	3,421	$ 1,152.96	$ —	$ 174.01	$ 1,152.96	$ 1,326.97	$ 1,020.00	$ —	$ 180.92	$ 1,020.00	$ 1,200.92	$ (11.08)	$ (10.50)	-12%	-9%
229	455	1,808	$ 1,152.96	$ 174.77	$ 347.26	$ 1,327.73	$ 1,500.22	$ 1,020.00	$ 181.71	$ 361.05	$ 1,201.71	$ 1,381.05	$ (10.50)	$ (9.93)	-9%	-8%
456	683	1,072	$ 1,152.96	$ 348.02	$ 521.27	$ 1,500.98	$ 1,674.23	$ 1,020.00	$ 361.84	$ 541.97	$ 1,381.84	$ 1,561.97	$ (9.93)	$ (9.35)	-8%	-7%
684	910	677	$ 1,152.96	$ 522.03	$ 694.51	$ 1,674.99	$ 1,847.47	$ 1,020.00	$ 542.76	$ 722.09	$ 1,562.76	$ 1,742.09	$ (9.35)	$ (8.78)	-7%	-6%
911	1138	538	$ 1,152.96	$ 695.28	$ 868.52	$ 1,848.24	$ 2,021.48	$ 1,020.00	$ 722.89	$ 903.01	$ 1,742.89	$ 1,923.01	$ (8.78)	$ (8.21)	-6%	-5%
1,139	1365	354	$ 1,152.96	$ 869.28	$ 1,041.77	$ 2,022.24	$ 2,194.73	$ 1,020.00	$ 903.81	$ 1,083.14	$ 1,923.81	$ 2,103.14	$ (8.20)	$ (7.63)	-5%	-4%
1,366	1593	323	$ 1,152.96	$ 1,042.53	$ 1,215.78	$ 2,195.49	$ 2,368.74	$ 1,020.00	$ 1,083.93	$ 1,264.06	$ 2,103.93	$ 2,284.06	$ (7.63)	$ (7.06)	-4%	-4%
1,594	1820	238	$ 1,152.96	$ 1,216.54	$ 1,389.02	$ 2,369.50	$ 2,541.98	$ 1,020.00	$ 1,264.85	$ 1,444.19	$ 2,284.85	$ 2,464.19	$ (7.05)	$ (6.48)	-4%	-3%
1,821	2048	248	$ 1,152.96	$ 1,389.79	$ 1,563.03	$ 2,542.75	$ 2,715.99	$ 1,020.00	$ 1,444.98	$ 1,625.11	$ 2,464.98	$ 2,645.11	$ (6.48)	$ (5.91)	-3%	-3%
2,049	2275	237	$ 1,152.96	$ 1,563.80	$ 1,736.28	$ 2,716.76	$ 2,889.24	$ 1,020.00	$ 1,625.90	$ 1,805.24	$ 2,645.90	$ 2,825.24	$ (5.90)	$ (5.33)	-3%	-2%
2,276	2503	197	$ 1,152.96	$ 1,737.04	$ 1,910.29	$ 2,890.00	$ 3,063.25	$ 1,020.00	$ 1,806.03	$ 1,986.16	$ 2,826.03	$ 3,006.16	$ (5.33)	$ (4.76)	-2%	-2%
2,504	2730	157	$ 1,152.96	$ 1,911.05	$ 2,083.54	$ 3,064.01	$ 3,236.50	$ 1,020.00	$ 1,986.95	$ 2,166.28	$ 3,006.95	$ 3,186.28	$ (4.76)	$ (4.18)	-2%	-2%
2,731	2958	148	$ 1,152.96	$ 2,084.30	$ 2,257.55	$ 3,237.26	$ 3,410.51	$ 1,020.00	$ 2,167.08	$ 2,347.20	$ 3,187.08	$ 3,367.20	$ (4.18)	$ (3.61)	-2%	-1%
2,959	3185	147	$ 1,152.96	$ 2,258.31	$ 2,430.79	$ 3,411.27	$ 3,583.75	$ 1,020.00	$ 2,348.00	$ 2,527.33	$ 3,368.00	$ 3,547.33	$ (3.61)	$ (3.04)	-1%	-1%
3,186	3413	138	$ 1,152.96	$ 2,431.56	$ 2,604.80	$ 3,584.52	$ 3,757.76	$ 1,020.00	$ 2,528.12	$ 2,708.25	$ 3,548.12	$ 3,728.25	$ (3.03)	$ (2.46)	-1%	-1%
3,414	3640	130	$ 1,152.96	$ 2,605.56	$ 2,778.05	$ 3,758.52	$ 3,931.01	$ 1,020.00	$ 2,709.04	$ 2,888.38	$ 3,729.04	$ 3,908.38	$ (2.46)	$ (1.89)	-1%	-1%
3,641	4640	530	$ 1,152.96	$ 2,778.81	$ 3,541.25	$ 3,931.77	$ 4,694.21	$ 1,200.00	$ 2,709.12	$ 3,452.44	$ 3,909.12	$ 4,652.44	$ (1.89)	$ (3.48)	-1%	-1%
4,641	5640	425	$ 1,152.96	$ 3,542.01	$ 4,304.45	$ 4,694.97	$ 5,457.41	$ 1,200.00	$ 3,453.18	$ 4,196.50	$ 4,653.18	$ 5,396.50	$ (3.48)	$ (5.08)	-1%	-1%
5,641	6640	354	$ 1,152.96	$ 4,305.21	$ 5,067.65	$ 5,458.17	$ 6,220.61	$ 1,200.00	$ 4,197.24	$ 4,940.56	$ 5,397.24	$ 6,140.56	$ (5.08)	$ (6.67)	-1%	-1%
6,641	7640	289	$ 1,152.96	$ 5,068.41	$ 5,830.85	$ 6,221.37	$ 6,983.81	$ 1,200.00	$ 4,941.30	$ 5,684.62	$ 6,141.30	$ 6,884.62	$ (6.67)	$ (8.27)	-1%	-1%
7,641	8640	252	$ 1,152.96	$ 5,831.61	$ 6,594.05	$ 6,984.57	$ 7,747.01	$ 1,200.00	$ 5,685.36	$ 6,428.68	$ 6,885.36	$ 7,628.68	$ (8.27)	$ (9.86)	-1%	-2%
8,641	9640	198	$ 1,152.96	$ 6,594.81	$ 7,357.25	$ 7,747.77	$ 8,510.21	$ 1,200.00	$ 6,429.42	$ 7,172.74	$ 7,629.42	$ 8,372.74	$ (9.86)	$ (11.46)	-2%	-2%
9,641	10640	144	$ 1,152.96	$ 7,358.01	$ 8,120.45	$ 8,510.97	$ 9,273.41	$ 1,200.00	$ 7,173.48	$ 7,916.80	$ 8,373.48	$ 9,116.80	$ (11.46)	$ (13.05)	-2%	-2%
10,641	11640	129	$ 1,152.96	$ 8,121.21	$ 8,883.65	$ 9,274.17	$ 10,036.61	$ 1,200.00	$ 7,917.54	$ 8,660.86	$ 9,117.54	$ 9,860.86	$ (13.05)	$ (14.65)	-2%	-2%
11,641	12640	129	$ 1,152.96	$ 8,884.41	$ 9,646.85	$ 10,037.37	$ 10,799.81	$ 1,200.00	$ 8,661.60	$ 9,404.92	$ 9,861.60	$ 10,604.92	$ (14.65)	$ (16.24)	-2%	-2%
12,641	13640	110	$ 1,152.96	$ 9,647.61	$ 10,410.05	$ 10,800.57	$ 11,563.01	$ 1,200.00	$ 9,405.66	$ 10,148.98	$ 10,605.66	$ 11,348.98	$ (16.24)	$ (17.84)	-2%	-2%
13,641	14640	96	$ 1,152.96	$ 10,410.81	$ 11,173.25	$ 11,563.77	$ 12,326.21	$ 1,200.00	$ 10,149.72	$ 10,893.04	$ 11,349.72	$ 12,093.04	$ (17.84)	$ (19.43)	-2%	-2%
14,641	15640	58	$ 1,152.96	$ 11,174.01	$ 11,936.45	$ 12,326.97	$ 13,089.41	$ 1,200.00	$ 10,893.78	$ 11,637.10	$ 12,093.78	$ 12,837.10	$ (19.43)	$ (21.03)	-2%	-2%
15,641	16640	70	$ 1,152.96	$ 11,937.21	$ 12,699.65	$ 13,090.17	$ 13,852.61	$ 1,200.00	$ 11,637.84	$ 12,381.16	$ 12,837.84	$ 13,581.16	$ (21.03)	$ (22.62)	-2%	-2%
16,641	17640	50	$ 1,152.96	$ 12,700.41	$ 13,462.85	$ 13,853.37	$ 14,615.81	$ 1,200.00	$ 12,381.90	$ 13,125.22	$ 13,581.90	$ 14,325.22	$ (22.62)	$ (24.22)	-2%	-2%
17,641	772618	506	$ 1,152.96	$ 13,463.61	$ 589,662.06	$ 14,616.57	$ 590,815.02	$ 1,200.00	$ 13,125.96	$ 574,874.15	$ 14,325.96	$ 576,074.15	$ (24.22)	$ (1,228.41)	-2%	-2%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO NEW RATES

Annual Bill Impacts of Small/Large Commercial Rate Relative to Traditional Rate Structure

								$ 85.00	$ 0.79351	$ 0.79351 Small						
			$ 85.51	$ 0.76320	$ 0.76320			$ 100.00	$ 0.74406	$ 0.74406 Large						
Consumption			Current Charges					Proposed Charges					Absolute Change		Percentage Change	
Low	High	Customers	Customer	Low Cons	High Cons	Low Total	High Total	Customer	Low Cons	High Cons	Low Total	High Total	Low	High	Low	High
0	228	3,421	$ 1,026.12	$ —	$ 174.01	$ 1,026.12	$ 1,200.13	$ 1,020.00	$ —	$ 180.92	$ 1,020.00	$ 1,200.92	$ (0.51)	$ 0.07	-1%	0%
229	455	1,808	$ 1,026.12	$ 174.77	$ 347.26	$ 1,200.89	$ 1,373.38	$ 1,020.00	$ 181.71	$ 361.05	$ 1,201.71	$ 1,381.05	$ 0.07	$ 0.64	0%	1%
456	683	1,072	$ 1,026.12	$ 348.02	$ 521.27	$ 1,374.14	$ 1,547.39	$ 1,020.00	$ 361.84	$ 541.97	$ 1,381.84	$ 1,561.97	$ 0.64	$ 1.22	1%	1%
684	910	677	$ 1,026.12	$ 522.03	$ 694.51	$ 1,548.15	$ 1,720.63	$ 1,020.00	$ 542.76	$ 722.09	$ 1,562.76	$ 1,742.09	$ 1.22	$ 1.79	1%	1%
911	1138	538	$ 1,026.12	$ 695.28	$ 868.52	$ 1,721.40	$ 1,894.64	$ 1,020.00	$ 722.89	$ 903.01	$ 1,742.89	$ 1,923.01	$ 1.79	$ 2.36	1%	1%
1,139	1365	354	$ 1,026.12	$ 869.28	$ 1,041.77	$ 1,895.40	$ 2,067.89	$ 1,020.00	$ 903.81	$ 1,083.14	$ 1,923.81	$ 2,103.14	$ 2.37	$ 2.94	1%	2%
1,366	1593	323	$ 1,026.12	$ 1,042.53	$ 1,215.78	$ 2,068.65	$ 2,241.90	$ 1,020.00	$ 1,083.93	$ 1,264.06	$ 2,103.93	$ 2,284.06	$ 2.94	$ 3.51	2%	2%
1,594	1820	238	$ 1,026.12	$ 1,216.54	$ 1,389.02	$ 2,242.66	$ 2,415.14	$ 1,020.00	$ 1,264.85	$ 1,444.19	$ 2,284.85	$ 2,464.19	$ 3.52	$ 4.09	2%	2%
1,821	2048	248	$ 1,026.12	$ 1,389.79	$ 1,563.03	$ 2,415.91	$ 2,589.15	$ 1,020.00	$ 1,444.98	$ 1,625.11	$ 2,464.98	$ 2,645.11	$ 4.09	$ 4.66	2%	2%
2,049	2275	237	$ 1,026.12	$ 1,563.80	$ 1,736.28	$ 2,589.92	$ 2,762.40	$ 1,020.00	$ 1,625.90	$ 1,805.24	$ 2,645.90	$ 2,825.24	$ 4.67	$ 5.24	2%	2%
2,276	2503	197	$ 1,026.12	$ 1,737.04	$ 1,910.29	$ 2,763.16	$ 2,936.41	$ 1,020.00	$ 1,806.03	$ 1,986.16	$ 2,826.03	$ 3,006.16	$ 5.24	$ 5.81	2%	2%
2,504	2730	157	$ 1,026.12	$ 1,911.05	$ 2,083.54	$ 2,937.17	$ 3,109.66	$ 1,020.00	$ 1,986.95	$ 2,166.28	$ 3,006.95	$ 3,186.28	$ 5.81	$ 6.39	2%	2%
2,731	2958	148	$ 1,026.12	$ 2,084.30	$ 2,257.55	$ 3,110.42	$ 3,283.67	$ 1,020.00	$ 2,167.08	$ 2,347.20	$ 3,187.08	$ 3,367.20	$ 6.39	$ 6.96	2%	3%
2,959	3185	147	$ 1,026.12	$ 2,258.31	$ 2,430.79	$ 3,284.43	$ 3,456.91	$ 1,020.00	$ 2,348.00	$ 2,527.33	$ 3,368.00	$ 3,547.33	$ 6.96	$ 7.53	3%	3%
3,186	3413	138	$ 1,026.12	$ 2,431.56	$ 2,604.80	$ 3,457.68	$ 3,630.92	$ 1,020.00	$ 2,528.12	$ 2,708.25	$ 3,548.12	$ 3,728.25	$ 7.54	$ 8.11	3%	3%
3,414	3640	130	$ 1,026.12	$ 2,605.56	$ 2,778.05	$ 3,631.68	$ 3,804.17	$ 1,020.00	$ 2,709.04	$ 2,888.38	$ 3,729.04	$ 3,908.38	$ 8.11	$ 8.68	3%	3%
3,641	4640	530	$ 1,026.12	$ 2,778.81	$ 3,541.25	$ 3,804.93	$ 4,567.37	$ 1,200.00	$ 2,709.12	$ 3,452.44	$ 3,909.12	$ 4,652.44	$ 8.68	$ 7.09	3%	2%
4,641	5640	425	$ 1,026.12	$ 3,542.01	$ 4,304.45	$ 4,568.13	$ 5,330.57	$ 1,200.00	$ 3,453.18	$ 4,196.50	$ 4,653.18	$ 5,396.50	$ 7.09	$ 5.49	2%	1%
5,641	6640	354	$ 1,026.12	$ 4,305.21	$ 5,067.65	$ 5,331.33	$ 6,093.77	$ 1,200.00	$ 4,197.24	$ 4,940.56	$ 5,397.24	$ 6,140.56	$ 5.49	$ 3.90	1%	1%
6,641	7640	289	$ 1,026.12	$ 5,068.41	$ 5,830.85	$ 6,094.53	$ 6,856.97	$ 1,200.00	$ 4,941.30	$ 5,684.62	$ 6,141.30	$ 6,884.62	$ 3.90	$ 2.30	1%	0%
7,641	8640	252	$ 1,026.12	$ 5,831.61	$ 6,594.05	$ 6,857.73	$ 7,620.17	$ 1,200.00	$ 5,685.36	$ 6,428.68	$ 6,885.36	$ 7,628.68	$ 2.30	$ 0.71	0%	0%
8,641	9640	198	$ 1,026.12	$ 6,594.81	$ 7,357.25	$ 7,620.93	$ 8,383.37	$ 1,200.00	$ 6,429.42	$ 7,172.74	$ 7,629.42	$ 8,372.74	$ 0.71	$ (0.89)	0%	-0%
9,641	10640	144	$ 1,026.12	$ 7,358.01	$ 8,120.45	$ 8,384.13	$ 9,146.57	$ 1,200.00	$ 7,173.48	$ 7,916.80	$ 8,373.48	$ 9,116.80	$ (0.89)	$ (2.48)	-0%	-0%
10,641	11640	129	$ 1,026.12	$ 8,121.21	$ 8,883.65	$ 9,147.33	$ 9,909.77	$ 1,200.00	$ 7,917.54	$ 8,660.86	$ 9,117.54	$ 9,860.86	$ (2.48)	$ (4.08)	-0%	-0%
11,641	12640	129	$ 1,026.12	$ 8,884.41	$ 9,646.85	$ 9,910.53	$ 10,672.97	$ 1,200.00	$ 8,661.60	$ 9,404.92	$ 9,861.60	$ 10,604.92	$ (4.08)	$ (5.67)	-0%	-1%
12,641	13640	110	$ 1,026.12	$ 9,647.61	$ 10,410.05	$ 10,673.73	$ 11,436.17	$ 1,200.00	$ 9,405.66	$ 10,148.98	$ 10,605.66	$ 11,348.98	$ (5.67)	$ (7.27)	-1%	-1%
13,641	14640	96	$ 1,026.12	$ 10,410.81	$ 11,173.25	$ 11,436.93	$ 12,199.37	$ 1,200.00	$ 10,149.72	$ 10,893.04	$ 11,349.72	$ 12,093.04	$ (7.27)	$ (8.86)	-1%	-1%
14,641	15640	58	$ 1,026.12	$ 11,174.01	$ 11,936.45	$ 12,200.13	$ 12,962.57	$ 1,200.00	$ 10,893.78	$ 11,637.10	$ 12,093.78	$ 12,837.10	$ (8.86)	$ (10.46)	-1%	-1%
15,641	16640	70	$ 1,026.12	$ 11,937.21	$ 12,699.65	$ 12,963.33	$ 13,725.77	$ 1,200.00	$ 11,637.84	$ 12,381.16	$ 12,837.84	$ 13,581.16	$ (10.46)	$ (12.05)	-1%	-1%
16,641	17640	50	$ 1,026.12	$ 12,700.41	$ 13,462.85	$ 13,726.53	$ 14,488.97	$ 1,200.00	$ 12,381.90	$ 13,125.22	$ 13,581.90	$ 14,325.22	$ (12.05)	$ (13.65)	-1%	-1%
17,641	772618	506	$ 1,026.12	$ 13,463.61	$ 589,662.06	$ 14,489.73	$ 590,688.18	$ 1,200.00	$ 13,125.96	$ 574,874.15	$ 14,325.96	$ 576,074.15	$ (13.65)	$ (1,217.84)	-1%	-2%

Residential

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

RESIDENTIAL CLASS RATE DESIGN

Select class revenue allocation (1, 2, or 3) and recommended customer charge.
The class revenue allocation selected on this sheet flows to all classes.

		Proposed Revenue		Class Revenue Alloc.
		$ 156,046,309		2

	Determinants	Recommended		
Bills	3,738,454	Customer Charge	$	41.61
Volumes	100,576,461	Usage Rate	$	0.00475
		Calculated Revenue	$	156,034,828
		Rounding	$	(11,481)

Small/Large Rates:

Small	*	2,330,758	Customer Charge	$	25.50
	*	39,439,549	Usage Rate	$	0.69448
		17			
Large	*	1,407,697	Customer Charge	$	39.00
	*	61,136,913	Usage Rate	$	0.23425
		43			
			Calculated Revenue	$	156,045,812
			Rounding	$	(497)

*Source: resrslt.xlsx

Commercial

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
CENTRAL-GULF SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2023

COMMERCIAL CLASS RATE DESIGN

Select class revenue allocation (1, 2, or 3) and recommended customer charge.
The class revenue allocation selected on this sheet flows to all classes.

	Current Revenue		Proposed Revenue		Class Revenue Alloc.
Commercial	$	21,028,552	$	22,692,212	2
Comm. Transport	$	3,377,257			
Total	$	24,405,808		92.98 %	

Commercial	Determinants	Recommended		$212 delta
Bills	158,114	Customer Charge	$	85.51
Volumes	46,032,179	Usage Rate	$	0.12679
Comm. Transport				
Bills	3,892	Customer Charge	$	297.51
Volumes	17,180,034	Usage Rate	$	0.12679
		Calculated Revenue	$	22,692,867.51
		Rounding	$	655.69

Small/Large Rates:

Small	*	118,004	Customer Charge	$	85.00
	*	7,271,449	Usage Rate	$	0.15710
		61.62			
Large	*	40,110	Customer Charge	$	100.00
	*	38,760,730	Usage Rate	$	0.10765
		966.36			
			Calculated Revenue	$	22,692,397
			Rounding	$	185

*Source: comrslt.xlsx

Industrial

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

INDUSTRIAL CLASS RATE DESIGN

The class revenue allocation selected on this sheet flows to all classes.

	Current Revenue	Proposed Revenue	Class Revenue Alloc.
Industrial	$ 374,883	$ 2,712,276	2
Industrial Transport	$ 2,659,116		
Total	$ 3,033,999	89 %	

Industrial	Determinants	Recommended	$200 delta
Bills	295	Customer Charge	$ 572.02
Volumes	615,043	Usage Rate	0.12707
Industrial Transport			
Bills	447	Customer Charge	$ 772.02
Volumes	16,685,705	Usage Rate	0.12707
		Calculated Revenue	$ 2,712,273.77
		Rounding	(2.46)

Public Authority

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

PUBLIC AUTHORITY CLASS RATE DESIGN

The class revenue allocation selected on this sheet flows to all classes.

	Current Revenue	Proposed Revenue	Class Revenue Alloc.
Public Authority	2,205,834	2122119.80	2
Pub. Auth Transport	2,023,870	1947062.25	
Pub. Sch. Spc. Htg.	29,296	28184.11	
Public Sch. Spc. Htg. Transport	380,415	365977.85	
Cogeneration Transport	189,863	182657.59	
Total	4,829,278	$ 4,646,002	

Public Authority	Determinants	Recommended	$23 delta	
Bills	10,055	Customer Charge	156.05	
Volumes	4,920,106	Usage Rate	0.12549	
Pub. Auth Transport				
Bills	5,970	Customer Charge	$179.05	
Volumes	9,625,326	Usage Rate	$ 0.12549	
			4,463,369.55	
			394,187.50	
Cogeneration Sales			Equal % Change	
Bills	—	Customer Charge	$ 175.98	
	—	First 5,000	$ 0.07427	
Volumes	—	Next 35,000	$ 0.06590	
	—	Next 60,000	$ 0.05314	
	—	All Over 100,000	$ 0.03864	
	—			
Cogeneration Transport				
Bills	12	Customer Charge	$ 175.98	
	60,000	First 5,000	$ 0.07427	
Volumes	420000	Next 35,000	$ 0.06590	
	720,000	Next 60,000	$ 0.05314	
	2,850,695	All Over 100,000	$ 0.03864	
	4,050,695			
			182,657.61	
			$ 0.03	
		Calculated Revenue	$ 4,646,027.17	$ 182,657.61
		Rounding	$ 25.57	$ (4,463,343.98)

Compressed Nat. Gas

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

CENTRAL-GULF SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2023

COMPRESSED NATURAL GAS CLASS RATE DESIGN

The class revenue allocation selected on this sheet flows to all classes.

	Current Revenue	Proposed Revenue	Class Revenue Alloc.
CNG	8,928	$ 112,166	2
CNG Transport	116,078		
	125,006		

CNG	Determinants	Recommended	$25 delta
Bills	11	Customer Charge	$ 594.88
Volumes	—	Usage Rate	0.06684
CNG Transport			
Bills	48	Customer Charge	$ 619.88
Volumes	1,135,073	Usage Rate	$ 0.06684
		Calculated Revenue	$ 112,166.20
		Rounding	$ 0.24

SCHEDULE WORKPAPERS

Schedule Workpapers are voluminous and are being provided in electronic format.

Confidential and/or Highly Sensitive Schedule Workpapers will be provided pursuant to the terms of the Protective Agreement in this proceeding or Protective Order issued in OS-24-00017471.

TESTIMONY WORKPAPERS

Testimony Workpapers are being provided in electronic format.

Confidential and/or Highly Sensitive Testimony Workpapers will be provided pursuant to the terms of the Protective Agreement in this proceeding or Protective Order issued in OS-24-00017471.