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June 30, 2025

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DOCKET SERVICES
RAILROAD COMMISSION OF TEXAS

Mr. Mark Evarts
Interim Director, Oversight & Safety Division
Railroad Commission of Texas
1701 N. Congress Ave., 9th Floor
Austin, Texas 78701

Re: Case No. 00028202; *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, West North and Rio Grande Valley Service Areas*

Dear Mr. Evarts:

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, West North, and Rio Grande Valley Service Areas, 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. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS

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 ("SOI"), 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 areas[1] served by the Company, which are listed in **Appendix A** hereto, and incorporated by reference.

As part of this SOI, the Company proposes to consolidate its currently designated service areas, which are the: Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA"), and West North Service Area ("WNSA") into a single statewide jurisdiction. Consistent with this request to consolidate the service areas, the Company's proposed rates were developed based on the cost of providing service to the entirety of TGS's footprint in Texas.[2]

The Company requests that the proposed rate schedules and tariffs for TGS, attached to this SOI as **Exhibit A**, and incorporated herein by reference, become effective on August 19, 2025,

[1] This pleading uses the terms "unincorporated areas" and "environs" interchangeably.

[2] Contemporaneously, with this filing, TGS is also filing a SOI to change rates for the incorporated areas of CGSA, RGVSA, and WNSA with the Cities.

which is 50 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 systemwide cost of providing service to all customers within the incorporated and unincorporated areas served by TGS.[3] The new rates will affect all customers served by TGS. Current rate schedules include small and large residential, small and large commercial,[4] commercial transportation, industrial, industrial transportation, public authority, public authority transportation, irrigation, compressed natural gas, compressed natural gas transportation, electrical generation, electrical generation transportation, and unmetered gas light service.

For the 12-month period ended December 31, 2024, the Company's overall, combined revenue requirement for TGS, on a systemwide basis, totaled approximately $458.8 million, as adjusted. The total revenue TGS received during the test year was approximately $417.8 million, leaving a revenue deficiency on a combined basis of approximately $41.1 million.

If approved, the requested rates will increase TGS's revenues by $41.1 million, which is an increase of 7.07% (including gas costs), or 9.83% (excluding gas costs). Because the proposed changes will increase TGS's total aggregate revenues 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 SOI, the Company is requesting: (1) Commission approval of new depreciation rates for Direct and Division distribution and general plant; (2) a finding that the

[3] The Company's cost to serve Fort Bliss was included in the calculation of the Company's revenue requirement; however, those costs are fully allocated to Fort Bliss and recovered under the Company's existing contracts with Fort Bliss. Therefore, the proposed systemwide rates do not include any costs incurred to serve Fort Bliss.
[4] The currently designated WNSA has a single Commercial Customer class.

expenses for 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 Texas through December 31, 2024, including capital investment in the Company's Interim Rate Adjustment ("IRA") filings made since the last rate cases in the CGSA, RGVSA, and WNSA, pursuant to Texas Utilities Code § 104.301; (4) approval of the form of notice for the proposed Rate Schedule PIT; 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. The proposed TGS rate schedules and tariffs would be applicable to all incorporated and unincorporated areas served by TGS, if consolidation is approved.

If the new tariffs are approved, the Company will need to withdraw the existing CGSA, RGVSA, and WNSA tariffs to reflect the new TGS rates and/or related changes necessary to reflect consolidation. Additionally, the Company is proposing: (1) a new Customer Assistance rate design and related rate schedules; (2) revisions to the Rules of Service and T-Terms to include new definitions; (3) revisions to the Cost of Gas clause for consistency with all Company areas of service; (4) additional revisions to the Company's rate schedules and tariffs as proposed and detailed in Section E of this Statement of Intent; and, (5) combining the Commercial, Industrial, Public Authority and Compressed Natural Gas ("CNG") rate on the Transportation Schedule into one Transportation rate and adding a new Electric Generation rate design and rate schedule.

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 § 103.001, the cities have original jurisdiction to set the rates

TGS requests for customers within their respective incorporated areas. 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 TGS.

III. CONSOLIDATION OF SERVICE AREAS

The Company is proposing to consolidate the existing service areas into a single statewide jurisdiction served by TGS. The CGSA, RGVSA, and WNSA are currently separate service areas comprised of the incorporated areas listed in **Appendix A** to this SOI and their associated environs. While the Company's past practice has been to develop separate rates based on the individual costs of service of the CGSA, RGVSA, and WNSA, the Company seeks in this SOI (consistent with several prior Commission decisions for TGS), to consolidate these three service areas and to use a systemwide cost of service for TGS. The Company's proposed rates for all of its customers are based on the systemwide cost of providing service to customers throughout the entirety of Texas.

If the Company's consolidation request is not approved, the Company requests approval of new base rates for the CGSA, RGVSA, and WNSA based on the separate cost of service schedules for each service area that are included in this SOI filing.

IV. DETAILS OF PROPOSED CHANGES

A. Rate Filing Package

In addition to this SOI, 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, as set forth in this SOI and Rate Filing Package, is based on the 12-month period ended December 31, 2024, 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 meters read on and after August 19, 2025.

D. Class and Number of Customers Affected

The proposed changes to the Company's rate schedules will affect all TGS customers. 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		RGVSA Customers		WNSA Customers	
	Incorporated	Environs	Incorporated	Environs	Incorporated	Environs
Small Residential	202,594	24,158	33,788	2,029	154,319	18,003
Large Residential	78,883	9,406	22,042	1,324	107,323	12,521
Commercial	—	—	—	—	16,057	1,105
Small Commercial	9,576	359	2,610	114	—	—
Large Commercial	3,104	116	1,282	56	—	—
Industrial	19	1	22	15	32	3
Public Authority	758	53	442	53	1,276	146
Unmetered Gas Light	1	—	—	—	—	—
Commercial Transportation	296	11	23	4	21	—
Industrial Transportation	17	11	16	17	9	4
Public Authority Transportation	481	10	3	3	10	—
Compressed Natural Gas Transportation	3	1	—	—	4	—
Electric Generation Transportation	1	—	—	—	—	—

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

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

1. Proposed addition of new Rate Schedules 16 and 1W. These schedules create a Customer Assistance tariff for residential customers who qualify for a reduced rate.

2. Proposed Rate Schedules 20, 25, 2Y and 2Z designate 20 and 2Z as Small Commercial, and 25 and 2Y Large Commercial rate schedules, applicable statewide.

3. Proposed rate schedules include rate changes as reflected in the direct testimony of Company witness Paul H. Raab.

4. All proposed TGS rate schedules include revisions to reflect statewide application to all incorporated and unincorporated areas served by the Company and to reflect a Common Billing Pressure for all customers of 14.65 pounds per square inch (psi).

5. All proposed Incorporated TGS rate schedules for General Sales and Transportation Customers include revisions to the "Other Adjustments" section to:

    a. reference the Economic Development Rate (EDR) that is applicable only to the cities of: Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Clint, Crane, Dell City, El Paso, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, McCamey, Millsap, Mineral Wells, Monahans, Pecos, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Wickett, Willow Park and Wink, Texas; and

    b. remove references to Rate Schedules CAC and 1C applicable only in the existing CGSA, Rate Schedule URI-RIDER applicable only in the existing WNSA, and Rate Schedules EEP and 1EE applicable only in the existing RGVSA.

6. The Cost of Gas Clauses 1-INC and 1-ENV have been updated to: add clarifying language to the Cost of Gas definition to specify that the Customer Rate Relief Component is not applicable to some areas and that the "revenue associated fee" is applicable to Weatherford, Texas only; add clarifying language to the Cost of Purchased Gas definition in the incorporated schedules to specify that it shall also include the cost of gas withdrawn from storage; add clarifying language to the Customer Rate Relief Component definition to specify that this rate is not applicable to some areas; add definitions for "FERC Intervention Costs," "Non-Utility Transactions" and "Uncollectible Cost of Gas"; add new Section G, Non-Utility Transactions; and, to add a reference to the FERC Intervention Costs to Section I. Annual Reconciliation Report.

7. Transportation Rate Schedules T-1 and T-1-ENV: include rate changes as reflected in the testimony of Mr. Raab; update the Cost of Service Rate to include all Transportation customers (excluding Electric Generation) and to remove references to the individual rates for Commercial Transportation, Industrial Transportation, Public Authority Transportation, Compressed Natural Gas Transportation and Electric Generation Transportation customers; and include recovery of any applicable local taxes or fees paid to the cities.

8. Transportation Rate Schedules T-EGEN and T-EGEN-ENV are proposed to create an Electric Generation Transportation rate design and rate tariff, separate from Rate Schedules T-1 and T-1-ENV; include a demand charge based upon the customer's maximum daily quantity; and include a requirement for customers to install and maintain electronic flow measurement equipment.

9. Transportation Rate Schedule T-Terms are updated to include applicability to all incorporated cities and unincorporated areas served by TGS and definitions are updated to reflect the addition of CNG Service and Public Authority Service.

10. Rate Schedule WNA contains an update to include applicability for Residential Customer Assistance Service, Rate Schedules 16 and 1W; update of the weather factors for each class consistent with the weather normalization calculation proposed in this case; and clarifying language to help customers understand the applicability of Weather Factors (WF).

11. Rate Schedules RCE-TGS and RCE-TGS-ENV are updated to provide a mechanism to recover all reasonable rate case expenses incurred by the Company and participating cities in connection with SOI filings made with the cities and the Commission.

12. Rate Schedule CRR, "Customer Rate Relief" contains an updated Applicability section and header to show applicability statewide, with the exception of specified areas, which has already been approved by the Commission in Docket No. OS-21-00007061.

13. 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.

14. Rules of Service: Proposed Rules of Service reflect the existing, approved versions of the Rules of Service in the Company's currently designated service areas and reflect the following additional Company proposals:

    a. Updating the cover page and § 1.1 (Tariff Applicability) to include all incorporated and unincorporated areas served by the Company;

    b. Updating § 1.3 (Definitions) to include definitions and terminology in the Rules of Service for the terms: Atmospheric Pressure, Common Billing Pressure, Compressed Natural Gas Service, Constant Factor, Public Authority Service, Safe Access and Standard Serving Pressure. The definition for "Electric

Generation Service" was expanded to now apply to a larger group of non-residential customers and the definition for "Service Area" was removed;

c. Addition of § 4.2 (Use of Natural Gas Equipment and Appliances) to include language for the "Use of Natural Gas Equipment" and "Appliances;"

d. Revisions to § 5.5 (Fees and Charges) to add clarifying language regarding to the Company's ability to provide Expedited Service at the customer's request;

e. Revisions to § 6.1 (Compliance by Applicant) to add clarifying language regarding the Company's ability to refuse service in any situation that is unsafe for personnel, customers or the general public;

f. Revisions to §§ 4.1 (Provision of Service), 6.1 (Compliance by Applicant), 7.4 (Reasons for Disconnection), 7.9 (Right of Entry to Disconnect Service), 10.2 (Customer Owned Facilities), 12.3 (Meter Location) and 12.7 (Access to the Meter) to reflect the requirement that Company personnel have Safe Access to Company assets;

g. Revisions to § 9.3 (Estimated Bills) to expand Company and customer options for capturing meter reads when the meter is not accessible;

h. Additions to § 10.2 (Company-Owned Facilities) to enhance language regarding: the prohibition against tampering with any Company-owned facilities and the requirement for reasonable precautions when engaging in activities around or near Company-owned facilities. This update also includes the requirement for customers to call 811 before any customer-initiated digging projects;

i. Revisions to § 10.6 (Materials or Equipment Furnished by the Applicant) to add clarifying language;

j. Additions to § 10.7 (Relocation of Company Facilities) to clarify responsibility for relocation expenses due to customer encroachment;

k. Revisions to § 10.8 to add clarifying language regarding the replacement of Customer-owned piping;

l. Additions to § 11 (Extension of Facilities) include language regarding cost justifications for line extensions and cost treatment for residential multi-family line extensions; the addition of clarifying language regarding the construction of facilities in §§ 11.5 and 11.6; updates and clarifying language regarding advances and refunds in §§ 11.7, 11.8 and 11.9;

m. Revisions to § 13 (Pressure) to add language regarding "Common Billing Pressure" and an update to the table in § 13.1 to now include the "Constant Factor" for all incorporated and unincorporated jurisdictions;

n. Revisions to § 15 (Service Fees and Deposits Amounts) to update service fees and deposits to reflect recent approvals among the Company's service areas and to move fees closer to actual Company costs; and

o. Addition of § 16 (Tapping Fees) to be consistent with the approved Quality of Service Rules in the existing WNSA.

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 all customers:

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	Proposed TGS Rates
Residential							
No. of Small Customers Affected	202,594	24,158	33,788	2,029	154,319	18,003	—
Small Customer Charge	$21.36	$21.36	$23.64	$23.64	$21.85	$21.85	$29.50
Small Volumetric Charge (per Ccf)	$0.87646	$0.87646	$2.02007	$2.02007	$0.46668	$0.46668	$0.67553
No. of Large Customers Affected	78,883	9,406	22,042	1,324	107,323	12,521	—
Large Customer Charge	$33.36	$33.36	$38.64	$38.64	$38.35	$38.35	$39.50
Large Volumetric Charge (per Ccf)	$0.46737	$0.46737	$0.63545	$0.63545	$0.01668	$0.01668	$0.31189
Customer Assistance Program (Up to 30,000 qualifying customers)							
No. of Customers Affected	—	—	—	—	—	—	—
Customer Charge	—	—	—	—	—	—	$22.13
Volumetric Charge (per Ccf)	—	—	—	—	—	—	$0.55000

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	Proposed TGS Rates
Commercial							
Customers Affected[5]	—	—	—	—	16,057	1,105	
Customer Charge					$92.73	$92.73	
Volumetric Charge (per Ccf)					$0.09394	$0.09394	
No. of Small Customers Affected	9,576	359	2,610	114	—	—	—
Small Customer Charge	$72.88	$72.88	$120.32	$120.32	-	-	$75.00
Small Volumetric Charge (per Ccf)	$0.27930	$0.27930	$0.63855	$0.63855	-	-	$0.43589
No. of Large Customers Affected	3,104	116	1,282	56	—	—	—
Large Customer Charge	$87.88	$87.88	$275.32	$275.32	-	-	$150.00
Large Volumetric Charge (per Ccf)	$0.22985	$0.22985	$0.26655	$0.26655	-	-	$0.13589
Commercial Transportation							
No. of Customers Affected	296	11	23	4	21	—	—
Customer Charge	$320.96	$320.96	$545.32	$545.32	$517.73	$517.73	$500.00
Volumetric Charge (per Ccf)	$0.12679	$0.12679	$0.10770	$0.10770	$0.09394	$0.09394	$0.08831
Industrial							
No. of Customers Affected	19	1	22	15	32	3	—
Customer Charge	$1,033.21	$1,033.21	$1,234.53	$1,234.53	$1,295.93	$1,295.93	$1,250.00
Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.28220	$0.28220	$0.11486	$0.11486	$0.11849

[5] WNSA currently has only one Commercial customer class, and TGS proposes to create Small and Large Commercial Customer classes with the rates noticed herein.

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	Proposed TGS Rates
Industrial Transportation							
No. of Customers Affected	17	11	16	17	9	4	—
Customer Charge	$1,233.21	$1,233.21	$1,384.53	$1,384.53	$1,495.93	$1,495.93	$500.00
Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.08722	$0.08722	$0.11486	$0.11486	$0.08831
Public Authority							
No. of Customers Affected	758	53	442	53	1,276	146	—
Customer Charge	$181.93	$181.93	$243.91	$243.91	$253.05	$253.05	$200.00
Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.16208	$0.16208	$0.13511	$0.13511	$0.13745
Public Authority Transportation							
No. of Customers Affected	481	10	3	3	10	—	—
Customer Charge	$204.93	$204.93	$2,543.91	$2,543.91	$553.05	$553.05	$500.00
Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.00840	$0.00840	$0.13511	$0.13511	$0.08831
Electric Generation Transportation							
No. of Customers Affected	1	—	—	—	—	—	—
Customer Charge	$201.64	$201.64	$545.32	$545.32	$717.73	$717.73	$1,000.00
Demand Charge MDQ/month							$0.72542
Volumetric Charge (per Ccf)							
Usage Rates (Year-Round)							
All Ccf	—	—	$0.10770	$0.10770	—	—	$0.02000
First 5,000 Ccf	$0.07724	$0.07724	—	—	—	—	—
Next 35,000	$0.06853	$0.06853	—	—	—	—	—
Next 60,000	$0.05527	$0.05527	—	—	—	—	—
All Over 100,000	$0.04018	$0.04018	—	—	—	—	—
Volumetric Charge (per Ccf)							
Usage Rates (October - April)							
All Ccf	—	—	—	—	—	—	—

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	Proposed TGS Rates
First 5,000 Ccf	—	—	—	—	$0.05260	$0.05260	—
Next 95,000	—	—	—	—	$0.04260	$0.04260	—
Next 300,000	—	—	—	—	$0.03260	$0.03260	—
All Over 400,000	—	—	—	—	$0.02260	$0.02260	—
Volumetric Charge (per Ccf)							
Usage Rates (May-September)							
All Ccf	—	—	—	—	—	—	—
First 5,000 Ccf	—	—	—	—	$0.04259	$0.04259	—
Next 95,000	—	—	—	—	$0.03258	$0.03258	—
Next 300,000	—	—	—	—	$0.02259	$0.02259	—
All Over 400,000	—	—	—	—	$0.01258	$0.01258	—
Compressed Natural Gas							
No. of Customers Affected	—	—	—	—	—	—	—
Customer Charge	$746.15	$746.15	—	—	$1,955.67	$1,955.67	$320.00
Volumetric Charge (per Ccf)	$0.07817	$0.07817	—	—	$0.08643	$0.08643	$0.08831
Compressed Natural Gas Transportation							
No. of Customers Affected	3	1	—	—	4	—	—
Customer Charge	$771.15	$771.15	—	—	$2,255.67	$2,255.67	$500.00
Volumetric Charge (per Ccf)	$0.07817	$0.07817	—	—	$0.08643	$0.08643	$0.08831
Unmetered Gas Light							
No. of Customers Affected	1	—	—	—	—	—	—
Customer Charge	—	—	—	—	—	—	—
Residential Volumetric Charge (per Ccf)	$0.87646	$0.87646	$2.02007	$2.02007	$0.46668	$0.46668	$0.67553
Commercial Volumetric Charge (per Ccf)	$0.27930	$0.27930	$0.63855	$0.63855	$0.09394	$0.09394	$0.43589

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	Proposed TGS Rates
Industrial Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.28220	$0.28220	$0.11486	$0.11486	$0.11849
Public Authority Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.16208	$0.16208	$0.13511	$0.13511	$0.13745

Exhibit C shows the average bill impact by customer class.

G. Witness Testimony

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

- ***Jeff Husen*** **- Vice-President of Rates and Regulatory Affairs for ONE Gas.** Mr. Husen provides an overview of the SOI filing, including an explanation of the relief TGS is requesting; supports the proposed consolidation of the TGS service areas into a single Texas jurisdiction; addresses the Company's proposed revisions to customer assistance and related tariff options; addresses proposed revisions to the line extension policy in the Rules of Service; 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*** **- Vice-President of Operations for TGS.** Mr. Limón provides an overview of operations in Texas; supports the proposed consolidation of the TGS service areas into a single statewide jurisdiction; addresses the reasonableness and necessity of capital investment and Operations and Maintenance (O&M) expenses; addresses ONE Gas' response to COVID-19; and addresses the Company's Pipeline Integrity Testing Program.

- ***Anthony Brown*** **- Manager of Rates and Regulatory Analysis for TGS.** Mr. Brown 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 request for recovery of rate case expenses; and describes the proposed TGS rate schedules and tariffs, as well as rate schedules and tariffs currently in effect for the CGSA, RGVSA, and WNSA.

- ***Stacey McTaggart*** **- Rates and Regulatory Director for TGS.** Ms. McTaggart addresses the Company's request to consolidate all of its existing service areas—CGSA, RGVSA,

and WNSA—to implement statewide rates and tariffs; describes the Company's request for an expanded customer assistance program and tariff and the recovery of associated costs; supports the Company's request for recovery of credit card processing fees; addresses regulatory asset treatment of cloud-based computing costs; and revisions to the line extension policy in the Rules of Service.

- ***Eric Sanford*** **- Manager of Rates and Regulatory Compliance for ONE Gas.** Mr. Sanford supports certain TGS Division and Corporate capital investment that is included in the revenue requirement as well as Corporate depreciation and amortization expense.

- ***Keara Downum*** **- Rates Analyst II of Rates and Regulatory Compliance for ONE Gas.** Ms. Downum addresses the cost allocation methodology used to determine TGS's share of allocated costs; discusses certain Corporate expense adjustments; and explains the Direct, TGS Division and Corporate expense adjustments related to payroll, employee benefits, and incentive compensation.

- ***Megan Gough*** **- Director of Compensation for ONE Gas.** Ms. Gough addresses the reasonableness of ONE Gas' compensation philosophy and structure, as well as the related costs for base pay, incentive plans, and benefits.

- ***Cyndi King*** **- 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*** **- Director of Risk and Insurance for ONE Gas**. Ms. Shelton describes ONE Gas' captive insurance company, UIC.

- ***Kenneth Eakens*** **- Director of Tax Compliance and Financial Reporting for ONE Gas.** Mr. Eakens describes how the Internal Revenue Service's Natural Gas Safe Harbor Method impacts the Company's taxes and addresses the treatment of the Company's Excess Deferred Income Taxes (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 statewide study of the depreciation rates for TGS plant located in Texas and for common facilities used by TGS throughout the state.

- ***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* - Rates Specialist for TGS.** Ms. Serna describes the class cost of service study and supports TGS's proposed class revenue allocation.
- ***Zane Drummond* - Rates Analyst for TGS.** Mr. Drummond supports TGS's revenue adjustments.
- ***Paul H. Raab* is an independent economic consultant.** Mr. Raab describes and supports TGS's proposed rate design.

V. RATE CASE EXPENSES

Pursuant to Texas Utilities Code § 104.051 and Commission Substantive 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.

VI. 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 Substantive Rules §§ 7.230 and 7.235. The public notice that the Company proposes to provide regarding the proposed change in rates for TGS, is attached as **Exhibit E,** to the SOI. TGS asks that the Commission's Examiners and Administrative Law Judge approve its form of notice prior to publication or distribution to customers. The Company will submit proof of notice promptly upon completion thereof.

VII. COMPANY REPRESENTATIVES FOR NOTIFICATION

TGS's authorized representatives are:

Judy Jenkins Hitchye
Stacey L. McTaggart
Marie Michels
Texas Gas Service Company
Barton Skyway IV
1301 S. Mopac, Suite 400
Austin, Texas 78746
512-370-8354
Judy.Hitchye@onegas.com
Stacey.McTaggart@onegas.com
Marie.Michels@onegas.com

and

Kate Norman
C. Glenn Adkins
Gene Montes
Shelley Morgan
Norman Santos P.C.
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512-985-9399
kate.norman@normansantos.com
glenn.adkins@normansantos.com
gene.montes@normansantos.com
shelley.morgan@normansantos.com

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

VIII. 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 SOI, a proposed Protective Order and respectfully requests that the Commission issue an order approving the Protective Order. TGS will provide confidential material as applicable, upon execution of Exhibit A attached to the Protective Order.

IX. CONCLUSION

TGS requests that: (1) rates are approved for TGS consistent with those proposed herein, to become effective for meters read on and after August 19, 2025; (2) consolidation of the existing CGSA, RGVSA, and the WNSA is approved; (3) the Commission approve new depreciation rates for Direct and Division distribution and general plant; (4) the Commission find that expenses for COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (5) capital investment made through December 31, 2024, including capital investment in the Company's IRA filings made since the last rate cases in the CGSA, RGVSA, and the WNSA pursuant to Texas Utilities Code § 104.301, is deemed prudent; (6) the form of

notice for the proposed Rate Schedule PIT be approved; (7) approval of the proposed expansion of Customer Assistance Programs is granted; (8) all reasonable rate case expenses incurred in connection with this SOI filing are authorized for recovery by the Company; and (9) for such further relief to which the Company may be entitled.

Respectfully submitted,

By: Kate Norman

Judy Jenkins Hitchye
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Barton Skyway IV
1301 S. Mopac, Suite 400
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512-370-8229

Kate Norman
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512-410-4668 (fax)

ATTORNEYS FOR TEXAS GAS SERVICE COMPANY

TGS SOI -Appendix A

Incorporated Cities, Environs and Unincorporated areas served by Texas Gas Service

Incorporated Cities & Environs

Alamo
Aledo
Alton
Andrews
Anthony
Austin
Barstow
Bayou Vista
Beaumont
Bee Cave
Borger
Breckenridge
Brownsville
Bryson
Buda
Cedar Park
Clint
Combes
Crane
Cuero
Dell City
Donna
Dripping Springs
Edcouch
Edinburg
El Paso
Elsa
Galveston
Georgetown
Gonzales
Graford
Graham
Groves
Harlingen
Hidalgo
Horizon City
Hudson Oaks
Hutto
Jacksboro
Jamaica Beach
Jarrell
Kyle
La Feria
La Joya
La Villa
Laguna Vista
Lakeway
Lockhart
Los Fresnos
Luling
Lyford
Marble Falls
McAllen
McCamey
Mercedes
Millsap
Mineral Wells
Mission
Monahans
Mustang Ridge
Nederland
Nixon
Palm Valley
Palmhurst
Palmview
Pecos
Penitas
Pflugerville
Pharr
Port Arthur
Port Isabel
Port Neches
Primera
Progreso
Pyote
Rancho Viejo
Raymondville
Rio Hondo
Rollingwood
San Benito
San Elizario
San Juan
Santa Rosa
Shiner
Skellytown
Socorro
Sunset Valley
Thorntonville
Vinton
Weatherford
Weslaco
West Lake Hills
Wickett
Willow Park
Wink
Yoakum

Environs only

Bastrop

Unincorporated Areas

Bayview
Canutillo
Fabens
Jermyn
Jim Hogg County
Jonah
Laguna Heights
Monte Alto
Olmito
Palo Pinto
Perrin
Possum Kingdom
Punkin Center
San Carlos
Starr County
Whitt

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 10**
Page 1 of 2

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 structure 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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$29.50 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.67553 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 331 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 331 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)

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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

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

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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 15**
Page 1 of 2

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 structure 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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$39.50 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.31189 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 331 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 331 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)

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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 16**
Page 1 of 2

CUSTOMER ASSISTANCE RESIDENTIAL SERVICE RATE
PILOT PROGRAM

APPLICABILITY

Applicable to a residential customer in a single dwelling, or in a dwelling unit of a multiple dwelling structure or residential apartment, for domestic purposes.

Natural gas service under this rate schedule is available only to those customers whose household receives assistance from: Comprehensive Energy Assistance Program (CEAP); Low Income Home Energy Assistance Program (LIHEAP); Supplemental Security Income Program (SSI); Medicaid; Supplemental Nutritional Assistance Program (SNAP); the Children's Health Insurance Program (CHIP); Veterans Affairs Supportive Housing (VASH); federal, state, or local housing rental assistance vouchers; and/or such other federal, state, and local government entitlement programs that verify Customer's household income is at or below the 200 percent Federal Poverty Income Level (FPIL).

Eligible residential customers may apply via partner agency or website (www.texasgasservice.com/cares) and must provide documentation to show that the customer's household currently receives one or more of the approved assistance programs listed above, or demonstrates a household income at or below 200 percent Federal Poverty Income Level (FPIL). The Company shall have the right to determine and confirm from time to time, that the customer meets the criteria contained herein.

Participation in this pilot program is available to the first 30,000 eligible customers who apply as outlined above. The results of the pilot program will be assessed at the next full rate case.

TERRITORY

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$22.13 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.55000 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

Initial Rate Schedule	Meters Read On and After
	TBD

CUSTOMER ASSISTANCE RESIDENTIAL SERVICE RATE
PILOT PROGRAM (Continued)

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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 20**
Page 1 of 2

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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$75.00 plus
All Ccf metered @14.65 psi* during the per monthly billing period @	$0.43589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 3,001 Ccf	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,001 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.

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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 25**
Page 1 of 2

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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$150.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.13589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 3,001 Ccf	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,001 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.

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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**
Page 1 of 2

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

TERRITORY

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$1,250.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.11849 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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

INDUSTRIAL SERVICE RATE (Continued)

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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 40**
Page 1 of 2

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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$200.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.13745 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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.

PUBLIC AUTHORITY SERVICE RATE (Continued)

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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 70**
Page 1 of 2

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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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	$0.67553 per Ccf metered @ 14.65 psi*
Commercial	$0.43589 per Ccf metered @ 14.65 psi*
Industrial	$0.11849 per Ccf metered @ 14.65 psi*
Public Authority	$0.13745 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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.

Supersedes Rate Schedule Dated	Meters Read On and After
November 27, 2024 (Central-Gulf) January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park) February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park) August 26, 2024 (Rio Grande Valley)	TBD

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 at 1-800-700-2443 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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1Z**
Page 1 of 2

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 structure 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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$29.50, plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.67553 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 331 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 331 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.

SMALL RESIDENTIAL SERVICE RATE (Continued)

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

Taxes: Plus applicable taxes and fees related to above.

Weather Normalization Adjustment: The billing shall reflect adjustments in accordance with 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 1Y**
Page 1 of 2

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 structure 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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$39.50 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.31189 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 331 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 331 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.

LARGE RESIDENTIAL SERVICE RATE (Continued)

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1W**
Page 1 of 2

CUSTOMER ASSISTANCE RESIDENTIAL SERVICE RATE
PILOT PROGRAM

APPLICABILITY

Applicable to a residential customer in a single dwelling, or in a dwelling unit of a multiple dwelling structure or residential apartment, for domestic purposes.

Natural gas service under this rate schedule is available only to those customers whose household receives assistance from: Comprehensive Energy Assistance Program (CEAP); Low Income Home Energy Assistance Program (LIHEAP); Supplemental Security Income Program (SSI); Medicaid; Supplemental Nutritional Assistance Program (SNAP); the Children's Health Insurance Program (CHIP); Veterans Affairs Supportive Housing (VASH); federal, state, or local housing rental assistance vouchers; and/or such other federal, state, and local government entitlement programs that verify Customer's household income is at or below the 200 percent Federal Poverty Income Level (FPIL).

Eligible residential customers may apply via partner agency or website (www.texasgasservice.com/cares) and must provide documentation to show that the customer's household currently receives one or more of the approved assistance programs listed above, or demonstrates a household income at or below 200 percent Federal Poverty Income Level (FPIL). The Company shall have the right to determine and confirm from time to time, that the customer meets the criteria contained herein.

Participation in this pilot program is available to the first 30,000 eligible customers who apply as outlined above. The results of the pilot program will be assessed at the next full rate case.

TERRITORY

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$22.13 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.55000 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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.

Initial Rate Schedule	Meters Read On and After
	TBD

CUSTOMER ASSISTANCE RESIDENTIAL SERVICE RATE
PILOT PROGRAM (Continued)

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.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Z**
Page 1 of 2

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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$75.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.43589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 3,001 Ccf	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,001 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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Y**
Page 1 of 2

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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$150.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.13589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 3,001 Ccf	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,001 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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE-ENV, if applicable.

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 3Z**
Page 1 of 2

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

TERRITORY

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$1,250.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.11849 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE-ENV, if applicable.

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated	Meters Read On and After
May 27, 2025 (Central-Gulf and West-North) August 25, 2025 (Rio Grande Valley)	TBD

INDUSTRIAL SERVICE RATE (Continued)

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 4Z**
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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$200.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.13745 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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	Meters Read On and After
May 27, 2025 (Central-Gulf and West-North) August 25, 2025 (Rio Grande Valley)	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 7Z**
Page 1 of 2

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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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	$0.67553 per Ccf metered @ 14.65 psi*
Commercial	$0.43589 per Ccf metered @ 14.65 psi*
Industrial	$0.11849 per Ccf metered @ 14.65 psi*
Public Authority	$0.13745 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 at 1-800-700-2443 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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE CNG-1**
Page 1 of 2

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

All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$320.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.08831 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

Supersedes Rate Schedule Dated	Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)	TBD

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE CNG-1-ENV**
Page 1 of 2

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

All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	$320.00 plus
All Ccf metered @14.65 psi* during the monthly billing period @	$0.08831 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 Schedules PIT and PIT-Rider.

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 Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated	Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)	TBD

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1-INC**
Page 1 of 6

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 served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

B. DEFINITIONS

1. **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.

2. **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 (applicable to all areas except the incorporated and unincorporated areas of: Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas), the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, FERC Intervention Costs, Non-Utility Transactions and the revenue associated fees (including franchise fees) and taxes.

   Applicable in the incorporated area of Weatherford, Texas, only: The "revenue associated fees" as defined herein, shall expressly include the full amount necessary for the Company to recover the franchise fees payable upon both the base rates and gas costs of its gas sales customers in accordance with the applicable franchise ordinance. Additionally, the franchise fees collected by the Company from its customers and to be remitted to the City in accordance with the franchise ordinance shall not be included as part of the Reconciliation Audit set forth in Section B.6 or the Cost of Gas Statement set forth in Section H.

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 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

COST OF GAS CLAUSE (Continued)

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). This component is not applicable to customers in the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas.

5. **FERC Intervention Costs** - Costs incurred from outside vendors and attorneys for the purpose of protecting the interest of sales customers in connection with negotiating Federal Energy Regulatory Commission ("FERC") related issues with upstream pipelines or intervention and participation in proceedings at the FERC. FERC Intervention Costs may also include incurred internal travel expenses related to this purpose.

6. **Non-Utility Transactions** - for the purposes of this section only, "non-utility transactions" shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. "Non-utility Transactions" shall not include any transaction conducted by any affiliate of the company.

7. **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.

8. **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; (f) the total amount of FERC Intervention Costs; and (g) 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. **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; (f) the total amount of FERC Intervention Costs; and (g) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

10. **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.

11. **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.

12. **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. All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

COST OF GAS CLAUSE (Continued)

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.

G. NON-UTILITY TRANSACTIONS

The aggregate net margins generated by the company from all Non-Utility Transactions shall be credited 100% to sales customers in the month during which the transaction closes.

COST OF GAS CLAUSE (Continued)

For purposes of this provision, "Non-Utility Transactions" shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. "Non-utility Transactions" shall not include any transaction conducted by any affiliate of the company.

For purposes of this provision, "Net Margins" shall mean revenues from the aggregate of all Non-Utility Transactions, less the costs to the Company of such transactions, including related taxes, commissions, transaction fees, and transfer fees. The Net Margins shall be credited to the ratepayers once per year through an adjustment of the Reconciliation Account as determined in the Annual Reconciliation filing. This provision does not permit the Company to include in the calculation of gas cost, any storage or gas stored except as prudently and necessarily needed to serve sales customers.

H. 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 (excluding customers in the the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas); (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.

The Company shall include in its monthly Cost of Gas Statement filed pursuant to the Cost of Gas Clause the separate cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

I. 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 including but not limited to the purchase cost of natural gas, renewable gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas, by month for the 12 months ending June 30.

COST OF GAS CLAUSE (Continued)

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 tabulation of any FERC Intervention activities performed and associated costs incurred on behalf of sales customers.

5. 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.

6. A description of the imbalance payments made to and received from the Company's transportation customers, 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.

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

8. A tabulation of cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

   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 1-ENV**
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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 and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

B. DEFINITIONS

1. **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.

2. **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 (applicable to all areas except the incorporated and unincorporated areas of: Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas), the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, FERC Intervention Costs, Non-Utility Transactions and the revenue associated fees and taxes.

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 gas withdrawn from storage. 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.

COST OF GAS CLAUSE (Continued)

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). This component is not applicable to customers in the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas.

5. **FERC Intervention Costs** - Costs incurred from outside vendors and attorneys for the purpose of protecting the interest of sales customers in connection with negotiating Federal Energy Regulatory Commission ("FERC") related issues with upstream pipelines or intervention and participation in proceedings at the FERC. FERC Intervention Costs may also include incurred internal travel expenses related to this purpose.

6. **Non-Utility Transactions** - for the purposes of this section only, "non-utility transactions" shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. "Non-utility Transactions" shall not include any transaction conducted by any affiliate of the company.

7. **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 psi. 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. **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; (f) the total amount of FERC Intervention Costs; and (g) 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. **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; (f) the total amount of FERC Intervention Costs; and (g) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

10. **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.

11. **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.

12. **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. All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

COST OF GAS CLAUSE (Continued)

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.

G. NON-UTILITY TRANSACTIONS

The aggregate net margins generated by the company from all Non-Utility Transactions shall be credited 100% to sales customers in the month during which the transaction closes.

Supersedes Rate Schedules Dated	Meters Read On and After
November 27, 2024 (Central-Gulf)	TBD
January 30, 2024 (Rio Grande Valley)	
January 27, 2023 (Rate Sched. 1-ENV-WTX for environs Andrews, Anthony, Barstow, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett and Wink)	
September 26, 2023 (Rate Sched. 1-ENV-NTX for environs Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Jermyn, Millsap, Mineral Wells, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, Weatherford Whitt and Willow Park)	
September 26, 2023 (Rate Sched. 1-ENV-BorgSk for environs Borger and Skellytown)	

COST OF GAS CLAUSE (Continued)

For purposes of this provision, "Non-Utility Transactions" shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. "Non-utility Transactions" shall not include any transaction conducted by any affiliate of the company.

For purposes of this provision, "Net Margins" shall mean revenues from the aggregate of all Non-Utility Transactions, less the costs to the Company of such transactions, including related taxes, commissions, transaction fees, and transfer fees. The Net Margins shall be credited to the ratepayers once per year through an adjustment of the Reconciliation Account as determined in the Annual Reconciliation filing. This provision does not permit the Company to include in the calculation of gas cost, any storage or gas stored except as prudently and necessarily needed to serve sales customers.

H. 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 (excluding customers in the the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas); (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.

The Company shall include in its monthly Cost of Gas Statement filed pursuant to the Cost of Gas Clause the separate cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

I. 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 including but not limited to the purchase cost of natural gas, renewable gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas, by month for the 12 months ending June 30.

COST OF GAS CLAUSE (Continued)

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 tabulation of any FERC Intervention activities performed and associated costs incurred on behalf of sales customers.

5. 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.

6. A description of the imbalance payments made to and received from the Company's transportation customers, 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.

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

8. A tabulation of cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

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 CRR**
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CUSTOMER RATE RELIEF RATE SCHEDULE

Applicable to all Sales Customers excluding the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and the unincorporated areas of Canutillo and Fabens, Texas for the purpose of collecting and remitting customer rate relief charges as authorized by the Railroad Commission of Texas (Commission) in accordance with Chapter 104, Subchapter I of the Texas Utilities Code and the Commission Financing Order issued in Docket No. OS-21-00007061.

A. ABBREVIATIONS AND DEFINITIONS

1) Authority – The Texas Public Finance Authority, together with any successor to its duties and functions.

2) Bonds or Customer Rate Relief ("CRR") Bonds – The "Texas Natural Gas Securitization Finance Corporation Customer Rate Relief Bonds, Series 2023" and any additional or different designation or title by which each series of Bonds shall be known as determined by the Issuer Entity.

3) Ccf and Mcf – For Ccf, one hundred (100) standard cubic feet of gas, where one (1) standard cubic foot of gas is the amount of gas contained in one (1) cubic foot of space at a standard pressure of fourteen point sixty-five (14.65) pounds per square inch, absolute and a standard temperature of sixty (60) degrees Fahrenheit; and, for Mcf, 1,000 standard cubic feet of gas.

4) Central Servicer – The entity engaged in accordance with the terms of the Financing Order to, amongst other things, engage the Participating Gas Utilities as collection agents for the purposes of facilitating collection and remittance of CRR Charges by Participating Gas Utilities, and perform the other services required of it under the Servicing Agreement (as defined in the Financing Order).

5) Commission – The Railroad Commission of Texas, including its staff or delegate.

6) CRR Charge True-Up Adjustment – A True-Up Adjustment (as defined in the Financing Order).

7) CRR Charge True-Up Charge Adjustment Letter – A true-up adjustment letter substantially in the form of Exhibit 3 to the Financing Order.

8) CRR Scheduled Adjustment Date – January 1 and July 1 of each applicable year, provided that the CRR Scheduled Adjustment Date and any other deadlines or target dates related thereto, shall be subject to modification prior to the date the Bonds so as to reflect the terms of the Servicing Agreement.

9) Customer Rate Relief ("CRR") Charge – A nonbypassable charge as defined in Tex. Util. Code § 104.362(7).

10) Financing Order – The order adopted under Tex. Util. Code § 104.366 approving the issuance of CRR Bonds and the creation of Customer Rate Relief Property and associated CRR Charges for the recovery of regulatory assets, including extraordinary costs, related financing costs, and other costs authorized by the Financing Order.

11) Gas Utility – Texas Gas Service Company, a Division of ONE Gas, Inc. and its successors and assignees, an operator of natural gas distribution pipelines that delivers and sells natural gas to the public and that is subject to the Commission's jurisdiction under Tex. Util. Code § 102.001, or an operator that transmits, transports,

delivers, or sells natural gas or synthetic natural gas to operators of natural gas distribution pipelines and whose rates for those services are established by the Commission in a rate proceeding filed under Chapter 104 of the Utilities Code, within the service area.

12) Irrevocable – The Financing Order, together with the Customer Rate Relief Property as defined by Tex. Util. Code § 104.362(8) and the CRR Charges authorized by the Financing Order, are irrevocable and not subject to reduction, impairment, or adjustment by further action of the Commission, except in connection with true-ups authorized by the Financing Order.

13) Issuer Entity – Texas Natural Gas Securitization Finance Corporation, a Texas nonprofit public corporation established by the Authority, or any successor created pursuant to Tex. Gov't Code § 1232.1072.

14) Large Participating Gas Utility – Atmos Energy Corporation on behalf of its Mid-Tex Division and West Texas Division; CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas; Texas Gas Service Company, a Division of ONE Gas, Inc., excluding the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and the unincorporated areas of Canutillo and Fabens, Texas; and any Participating Gas Utility or Successor Utility (as defined in the Financing Order) each of whose Normalized Sales Volumes exceed 2.0% of the total aggregate Normalized Sales Volumes among all Participating Gas Utilities. Any calculation performed in connection with the preceding sentence shall be made on the basis of the most recently reported Normalized Sales Volumes and such calculation shall be performed by the Central Servicer annually no later than one (1) month after Normalized Sales Volumes are reported as regularly scheduled under Paragraph H hereof; provided that the Commission and/or Central Servicer may perform such calculation without any limitation in order to give effect to any merger, acquisition, disposition, divesture, spin-off or other transaction that would impact a Participating Gas Utility's share of the total aggregate Normalized Sales Volumes. The Commission or the Central Servicer shall promptly thereafter provide written notice to a Participating Gas Utility that subsequently becomes a Large Participating Gas Utility, which change shall take effective beginning on January 1 of the following calendar year.

15) Nonbypassable – CRR Charges must be paid by all existing or future customers receiving service from a Participating Gas Utility or such gas utility's successors or assigns.

16) Normalized Sales Volumes –
   a) For Large Participating Gas Utilities: All natural gas volumes projected to be billed for the upcoming twelve (12) month period in conjunction with the operation of a Participating Gas Utility's Purchased Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs. For the avoidance of doubt, only the Normalized Sales Volumes of Large Participating Gas Utilities shall be aggregated to calculate the CRR Charges.

   b) For other Participating Gas Utilities: All natural gas volumes billed in the preceding calendar year in conjunction with the operation of a Participating Gas Utility's Purchased Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs and normalized according to the methodology utilized in each Participating Gas Utility's application filed in Docket No. OS-21- 00007061, *Consolidated Applications For Customer Rate Relief and Related Regulatory Asset Determinations In Connection With The February 2021 Winter Storm.*

      For the avoidance of doubt, only the Normalized Sales Volumes of Large Participating Gas Utilities shall be aggregated in order to calculate the CRR Charges.

17) Participating Gas Utilities – Atmos Energy Corporation on behalf of its Mid-Tex Division and West Texas Division; Rockin' M Gas LLC d/b/a Bluebonnet Natural Gas LLC; CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas; Corix Utilities (Texas) Inc.; EPCOR Gas Texas Inc.; SiEnergy, LP; Summit Utilities Arkansas, Inc.[1], Texas Gas Service Company, a Division of ONE Gas, Inc., excluding the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and the unincorporated areas of Canutillo and Fabens, Texas; and Universal Natural Gas, LLC d/b/a Universal Natural Gas, Inc. or any Successor Utility (as defined in the Financing Order).

18) Sales Customer(s) – All active customers taking service under a Participating Gas Utility's Purchased Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs.

B. APPLICABILITY

This rate schedule sets out the rate, terms and conditions under which the CRR Charge shall be billed and collected by Texas Gas Service Company, a Division of ONE Gas, Inc. as a Participating Gas Utility for all Texas Gas Service customers, excluding those in the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and in the unincorporated areas of Canutillo and Fabens, Texas under the terms of the Financing Order. Each individual Sales Customer is responsible for paying the CRR Charge billed to it in accordance with the terms of this rate schedule. Payment is to be made by an individual Sales Customer to the Participating Gas Utility of which it is a customer. The Participating Gas Utility is obligated to apply amounts collected from customers to pay any outstanding CRR Charges prior to applying such amounts for any other purpose. The Participating Gas Utility, as collection agent, shall remit collections of the CRR Charges to the Indenture Trustee in accordance with the terms of the Financing Order and any servicing or other similar agreement that is contemplated by the Financing Order.

C. TERM

This rate schedule shall remain in effect until the CRR Charges have been collected and remitted to the Indenture Trustee in an amount sufficient to satisfy all obligations in regard to paying principal and interest on the CRR Bonds together with all other financing costs, bond administrative expenses and other costs as provided in the Financing Order. This rate schedule and the CRR Charge are irrevocable and nonbypassable.

D. SALES CUSTOMERS

For the purposes of billing the CRR Charges, all Sales Customers of the Participating Gas Utility, excluding those in the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and in the unincorporated areas of Canutillo and Fabens, Texas shall be assessed the uniform volumetric charge identified below.

E. CRR CHARGE

The CRR Charge will be a monthly volumetric rate of $0.118/Ccf. The CRR Charge is calculated in accordance with and subject to the provisions set forth in the Financing Order and will be adjusted at least annually based upon the CRR Charge true- up adjustment procedure. The CRR Charge shall be included in the Participating Gas

[1] Summit Utilities Arkansas, Inc. is the Successor Utility of CenterPoint Energy Arkla as of January 10, 2022.

Utility's Purchase Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs. Participating Gas Utilities may reflect the CRR Charge according to the delivery pressures defined in Participating Gas Utilities' applicable tariffs. Such delivery pressure specific charges shall be equivalent to the CRR Charge as determined below at 14.65 per square inch, as defined above.

F. DETERMINATION OF CUSTOMER RATE RELIEF CHARGE

The CRR Charge will be adjusted no less frequently than annually, in accordance with the terms of the Servicing Agreement (as defined in the Financing Order), to ensure that the expected collection of CRR Charges is adequate to pay when due, pursuant to the expected amortization schedule, principal and interest on the CRR Bonds and together with all other financing costs, bond administrative expenses and other costs, as provided in the Financing Order, on a timely basis. The CRR Charge shall be computed according to the formula described below.

Step 1: Determination of Normalized Sales Volumes
(A) Total Large Participating Gas Utility Normalized Sales Volumes (Mcf)
(B) Assumed % of uncollectible sales
(C) Total Normalized Sales Volumes Billed and Collected: ***(A * (1 – B))***

For the avoidance of doubt, Normalized Sales Volumes are assumed to be calculated without giving effect to volumes anticipated from Participating Gas Utilities making up less than two percent (2.0%) of the total Normalized Sales Volumes of all Participating Gas Utilities.

Step 2: Determination of CRR Charge
(D) Total CRR Charge Rate Revenue Requirement for Applicable Period
(E) CRR Charge per Normalized Sales Volumes (Mcf): ***(D / C)***
Thereof: CRR Charge for Sales Customers

G. CRR CHARGE TRUE-UP

Changes to the CRR Charge will be effected through the filing of CRR Charge True-Up Adjustment Letters by the Central Servicer to the Commission as authorized by the Financing Order and in accordance with the Servicing Agreement. Not less than fifteen (15) days prior to each CRR Scheduled Adjustment Date and more frequently as required by the Central Servicer, the Central Servicer will submit the CRR Charge True-Up Adjustment Letter in the form of Exhibit 3 to the Financing Order to ensure that CRR Charge collections are sufficient to make all scheduled payments of CRR Bond principal and interest and meet other Ongoing Financing Costs (as defined in the Financing Order) on a timely basis during the payment period.

In addition to the foregoing, the Central Servicer shall be authorized to file CRR Charge True-Up Adjustment Letters with the Commission that adjust the CRR Charge more frequently (but not more often than quarterly) as required under the provisions of the Servicing Agreement (as defined in the Financing Order).

H. CRR CHARGE TRUE-UP PROCEDURE

Texas Gas Service Company, a Division of ONE Gas, Inc. shall annually file with the Commission and the Central Servicer by June 1 of each year its Normalized Sales Volumes; each Large Participating Gas Utility shall

include projected volumes for each of the future twelve (12) months beginning July 1, and each other Participating Gas Utility shall include its Normalized Sales Volumes for the prior calendar year. Such filing and/or reporting may be more frequent to the extent required under the Servicing Agreement and applicable Collection and Reporting Arrangements. If Texas Gas Service Company, a Division of ONE Gas, Inc. is a Large Participating Gas Utility, the Participating Gas Utility shall, upon the request of the Central Servicer, provide the Commission and the Central Servicer updated Normalized Sales Volumes for the succeeding twelve (12) month period no later than the fifteenth (15th) day following such request to allow the Central Servicer to make Interim True-Up Adjustments. Each Participating Gas Utility shall have the right to provide the foregoing information to the Central Servicer on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). The Central Servicer shall submit to the Commission and the Participating Gas Utilities, not less than fifteen (15) days prior to the CRR Scheduled Adjustment Date, a CRR Charge True-Up Adjustment Letter applying the CRR Charge True-Up Adjustment based on Normalized Sales Volumes and other mathematical factors and requesting administrative approval from the Commission as provided for in the Servicing Agreement. The Commission's review and approval of the True-Up Adjustment Letter shall be as set forth in the Servicing Agreement (it being understood such review is limited to determining if any mathematical or clerical errors are present in the application of the CRR Charge True-Up Adjustment relating to the appropriate amount of any over-collection or under-collection of CRR Charges and the amount of an adjustment).

If any CRR Charge True-Up Adjustment that is an Interim True-Up Adjustment is necessary, (i) the Central Servicer may request and the Large Participating Gas Utilities shall provide revised Normalized Sales Volumes for each of the immediately succeeding twelve (12) months and related data and (ii) within fifteen (15) days of receipt of such data, the Central Servicer shall file a revision to the CRR Rate Schedule in a True-Up Charge Adjustment Letter setting forth the adjusted CRR Charge to be effective for the upcoming period, in accordance with the Servicing Agreement. Texas Gas Service Company, a Division of ONE Gas, Inc. shall have the right to provide such information on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). A CRR Charge resulting from a true-up adjustment will become effective on the first (1st) billing cycle that is not less than fifteen (15) days following the making of the CRR Charge True-Up Adjustment filing.

I. TAXABILITY

The receipt of CRR Charges by a Participating Gas Utility is exempt from state and local sales and use taxes and utility gross receipts taxes and assessments and is excluded from revenue for purposes of franchise tax under Tex. Tax Code § 171.1011.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE PIT**
Page 1 of 3

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 Company gas sales and standard transportation rate schedules within the incorporated and unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: Rate Schedules 10, 15, 16, 20, 25, 30, 40, CNG-1, 1Z, 1Y, 1W, 2Z, 2Y, 3Z, 4Z, CNG-1-ENV, T-1, T-EGEN, T-1-ENV and T-EGEN-ENV.

QUALIFYING EXPENSES

This Rider applies only to the legally mandated safety testing of the Company's transmission lines in the Company's areas of service 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

PIPELINE INTEGRITY TESTING (PIT) RIDER (Continued)

pipelines in the Company's areas of service. Neither capital expenditures by the Company, nor the labor cost of Company employees, shall be recovered under this Rider.

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 Company's areas of service. 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 Cities served by the Company 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 Cities served by the Company (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 Cities served by the Company 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.

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 incorporated and unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: Rate Schedules 10, 15, 16, 20, 25, 30, 40, CNG-1, 1Z, 1Y, 1W, 2Z, 2Y, 3Z, 4Z, CNG-1-ENV, T-1, T-EGEN, T-1-ENV and T-EGEN-ENV.

B. PIT RATE

$TBD per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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. **RATE SCHEDULE WNA**
Page 1 of 3

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") within the incorporated and unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: Rate Schedules 10, 15, 16, 1Z, 1Y, 1W, 20, 25, 2Z, 2Y, 40, and 4Z. The WNA shall be effective during the September through May billing cycles.

PURPOSE

The WNA adjusts customer bills to address variations in weather experienced during the billing period that are above or below the 'normal' weather range established in the Company's most recent rate filing. The WNA refunds over-collections or surcharges of revenue due to colder than normal weather or under-collections of revenue due to 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 (at 14.65 psi) 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:

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.

Supersedes Rate Schedule Dated	Meters Read On and After
November 27, 2024 (Central-Gulf) January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park) February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park) January 30, 2024 (Rio Grande Valley)	TBD

WEATHER NORMALIZATION ADJUSTMENT CLAUSE (Continued)

CB = Number of customers billed for the billing period.

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

The Weather Factors (WF) and associated weather station for each applicable incorporated or environs area are established as follows:

Austin, Bastrop (environs only), Bee Cave, Buda, Cedar Park, Dripping Springs, Georgetown, Hutto, Jarrell, Jonah (environs only), Kyle, Lakeway, Marble Falls, Mustang Ridge, Pflugerville, Rollingwood, Sunset Valley, and West Lake Hills:

Residential 0.14202; Commercial 0.48000; Public Authority 2.06571
Weather Station: KATT

Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum:

Residential 0.12176; Commercial 0.18681; Public Authority 0.97873
Weather Station: KSAT

Bayou Vista, Galveston, and Jamaica Beach:

Residential 0.19431; Commercial 0.42720; Public Authority 2.91772
Weather Station: KGLS

Beaumont, Groves, Nederland, Port Arthur, and Port Neches:

Residential 0.14652; Commercial 0.29381; Public Authority 1.09440
Weather Station: KBPT

Alamo, Alton, Brownsville, Combes, Donna, Edcouch, Edinburg, Elsa, Harlingen, Hidalgo, La Feria, La Joya, La Villa, Laguna Vista, Los Fresnos, Lyford, McAllen, Mercedes, Mission, Palm Valley, Palmhurst, Palmview, Penitas, Pharr, Port Isabel, Primera, Progreso, Rancho Viejo, Raymondville, Rio Hondo, San Benito, San Juan, Santa Rosa, and Weslaco, Texas, the unincorporated cities of Bayview, Laguna Heights, Monte Alto, Olmito, and San Carlos and the unincorporated areas of Jim Hogg and Starr counties:

Residential 0.07609; Commercial 1.29246; Public Authority 2.52362
Weather Station: KBRO

WEATHER NORMALIZATION ADJUSTMENT CLAUSE (Continued)

Borger and Skellytown:

Residential 0.14039; Commercial 0.64194; Public Authority 2.24684
Weather Station: KAMA

Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Jermyn, Millsap, Mineral Wells, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, Weatherford, Whitt, and Willow Park:

Residential 0.13605; Commercial 0.46630; Public Authority 2.16192
Weather Station: KABI

Anthony, Canutillo, Clint, El Paso, Fabens, Horizon City, San Elizario, Socorro, and Vinton:

Residential 0.14485; Commercial 0.51375; Public Authority 3.33692
Weather Station: KELP

Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett, and Wink:

Residential 0.11833; Commercial 0.51375; Public Authority 1.51545
Weather Station: KMAF

Dell City:

Residential 0.14485; Commercial 0.51375; Public Authority 3.33692
Weather Station: KELP

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 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

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE E5

FORT BLISS SERVICE RATE

APPLICABILITY

Applicable to the United States Government for all purposes at Fort Bliss, William Beaumont General Hospital, Biggs Field, Logan Heights, The First Calvary Brigade Area, the Station Hospital, Permanent Troop Housing and Supporting Facilities and AFF Board No. 4 and Guided Missile Group and Training Facilities located east of Jeb Stuart Road.

COST OF SERVICE RATE

During each monthly billing period the sum of items 1 and 2 below:

1. Cost of Service Charge:

   All Gas @ $ 0.07476 per Ccf @ 14.9 PSIA.

2. Cost of Gas Charge: In addition to the Cost of Service set forth above, Ft. Bliss billing shall include an amount equal to the Cost of Gas per billing month as determined in accordance with Rate Schedule No. 1-INC. Cost per Ccf will be determined at 14.9 PSIA and multiplied by total Ccf consumed during the billing month.

CONDITIONS

1. In case of shortage of natural gas supply, or any other emergency not due to fault of the Company, deliveries of gas hereunder may be curtailed in accordance with Company's program of curtailment applicable to its customers in the incorporated and unincorporated areas of El Paso, Texas.

2. Volume of gas shown by meter readings will be corrected to 14.9 pounds per square inch absolute. Atmospheric pressure is agreed to be 12.8 pounds.

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE EDR

ECONOMIC DEVELOPMENT RATE

A. APPLICABILITY

This Economic Development Rate ("EDR") rate schedule shall apply to the following rate schedules for the incorporated areas of the Cities of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro, and Vinton, Texas: 10, 15, 16, 20, 25, 30, 40, CNG-1, T-1 and T-EGen.

B. TERRITORY

The Cities of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

C. PURPOSE

This rate schedule provides for the recovery of costs that Texas Gas Service Company, a Division of ONE Gas, Inc. incurs related to economic development in the cities mentioned above. Successful economic development will only occur to the extent that the community and its corporate partners provide the necessary support to attract new businesses and industries to this region. New businesses and industries will increase employment, spur growth and local business expansion, create a more robust economy and improve the quality of life for the region.

D. EDR RATE

The EDR rate during each Monthly Billing Period:

All Ccf metered @14.65 psi* during the monthly billing period @ $ 0.002 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

All applicable fees and taxes (including franchise fees) will be added to the EDR rates.

D. BILLING

1. The EDR rate shall be added to the applicable cost of service usage charge (per Ccf rate) for rate schedules: 10, 15, 16, 20, 25, 30, 40, CNG-1, T-1 and T-EGen.

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

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 all incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: 10, 15, 16, 20, 25, 30, 40, 60, CNG-1, T-1 and T-EGEN.

B. RCE RATE

All Ccf metered @14.65 psi* during the monthly billing period @ $TBD per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 $TBD in actual expense and no more than $TBD in estimated expense. The Rate Case Expense Surcharge will be a separate line item on the bill.

C. OTHER ADJUSTMENTS

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. **RATE SCHEDULE RCE-TGS-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. TBD: Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated areas of Texas Gas Service, 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 all unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: 1Z, 1Y, 1W, 2Z, 2Y, 3Z, 4Z, 6Z, CNG-1-ENV, T-1-ENV, and T-EGEN-ENV.

B. RCE RATE

All Ccf metered @14.65 psi* during the monthly billing period @ $ TBD per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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 $TBD in actual expense and up to $TBD in estimated expenses. The Rate Case Expense Surcharge will be a separate line item on the bill.

C. OTHER ADJUSTMENTS

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. TBD 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

Initial Rate Schedule — Meters Read On and After
TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE T-1**
Page 1 of 2

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 distribution system which includes all incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1. 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, the Cost of Service Rate shall be comprised of a customer charge per meter per month as follows:

All Transportation Customers (excluding Electric Generation)	$500.00 per month

Plus – A delivery charge per monthly billing period as follows:

All Transportation Customers (excluding Electric Generation)	$0.08831 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

OTHER ADJUSTMENTS

Gas Utility Pipeline Taxes: 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.

Taxes: A charge will be made each month to recover the cost of any applicable taxes and fees, including franchise fees paid to the cities.

TRANSPORTATION SERVICE RATE (Continued)

Rate Case Expense Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE, if applicable.

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.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

Other Charges: 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 served by the Company, 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.

SUBJECT TO

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

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.

ELECTRIC GENERATION TRANSPORTATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any non-residential customer who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company"), to use natural gas for the purpose of electric generation. Electric generation is defined as bulk power system assets, co-generation facilities, distributed generation, and or backup power systems. 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 distribution system which includes all incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1. 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, the Cost of Service Rate shall be comprised of:

Electric Generation customer charge per meter	$1,000.00 per month plus
A Demand charge of	$0.72542 per Ccf MDQ per month plus
A Delivery charge of	$0.02000 per Ccf metered @14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

MONTHLY MDQ DEMAND CHARGE

The Monthly MDQ Demand Charge is the demand charge associated with reserving pipeline capacity to meet the maximum daily usage (hereinafter "maximum daily quantity" or "MDQ") for an individual customer. If the use of electronic flow measurement (EFM), as defined in the Company's Rules of Service (Rate Schedule Number QSR-TGS), has established an MDQ for a customer during the prior twelve (12)-month period, the MDQ derived from the EFM data shall be utilized. For customers who have not established an MDQ through the use of EFM, the MDQ shall be calculated by using the connected load and applying a diversity factor appropriate for the

ELECTRIC GENERATION TRANSPORTATION SERVICE RATE (Continued)

operations conducted at the facilities. The MDQ in Ccf shall then be multiplied by each applicable Monthly MDQ Demand Charge to determine the amount to be charged to the customer for each billing period. The MDQ may be adjusted at any time for any known and quantifiable additions of equipment or removal of equipment at the customer's facilities.

Except as allowed by the Company, customers shall not be entitled to receive gas from Company on any day in excess of the MDQ amount established for such customer pursuant to the foregoing provisions. Periods of maximum usage may not be within a calendar month due to variations in billing periods. The Monthly MDQ Demand Charge shall not be prorated.

OTHER ADJUSTMENTS

Gas Utility Pipeline Taxes: 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.
Taxes: A charge will be made each month to recover the cost of any applicable taxes and fees, including franchise fees paid to the cities.

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

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.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

Other Charges: 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 Company's area of service, 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.

SUBJECT TO

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

ELECTRIC GENERATION TRANSPORTATION SERVICE RATE (Continued)

2. Customers taking service under this rate schedule will be required to obtain EFM equipment from the Company. If the locations of customer's facilities or other factors interfere with the ability to communicate EFM volume data using Company's available cellular telephone technology, customer will be required to provide and maintain, at its own expense, a dedicated telephone line through which communications may be transmitted. The EFM equipment shall remain the property of the Company and at no time may the customer take possession of the EFM equipment without written consent by an authorized representative of the Company.

3. 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.

4. 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.

5. The Agreement shall be interpreted under Texas law.

Texas Gas Service Company, a Division of ONE Gas, Inc **RATE SCHEDULE T-1-ENV**
Page 1 of 2

TRANSPORTATION SERVICE RATE

APPLICABILITY

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

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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 distribution system, which includes all unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1. 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

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All Transportation Customers (excluding Electric Generation)	$500.00 per month

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*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

OTHER ADJUSTMENTS

Gas Utility Pipeline Taxes: 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.

Taxes: A charge will be made each month to recover the cost of any applicable taxes and fees.

TRANSPORTATION SERVICE RATE (Continued)

Rate Case Expense Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

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.

Other Charges: 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 unincorporated areas served by the Company, 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.

SUBJECT TO

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

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.

ELECTRIC GENERATION TRANSPORTATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any non-residential customer who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company"), to use natural gas for the purpose of electric generation. Electric generation is defined as bulk power system assets, co-generation facilities, distributed generation, and or backup power systems. 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 distribution system, which includes all unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1. 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, the Cost of Service Rate shall be comprised of:

Electric Generation customer charge per meter	$1,000.00 per month plus
A Demand charge of	$0.72542 per Ccf MDQ per month plus
A Delivery charge of	$0.02000 per Ccf metered @14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

MONTHLY MDQ DEMAND CHARGE

The Monthly MDQ Demand Charge is the demand charge associated with reserving pipeline capacity to meet the maximum daily usage (hereinafter "maximum daily quantity" or "MDQ") for an individual customer. If the use of electronic flow measurement (EFM), as defined in the Company's Rules of Service (Rate Schedule Number QSR-TGS), has established an MDQ for a customer during the prior twelve (12)-month period, the MDQ derived from the EFM data shall be utilized. For customers who have not established an MDQ through the use of EFM, the MDQ shall be calculated by using the connected load and applying a diversity factor appropriate for the

ELECTRIC GENERATION TRANSPORTATION SERVICE RATE (Continued)

operations conducted at the facilities. The MDQ in Ccf shall then be multiplied by each applicable Monthly MDQ Demand Charge to determine the amount to be charged to the customer for each billing period. The MDQ may be adjusted at any time for any known and quantifiable additions of equipment or removal of equipment at the customer's facilities.

Except as allowed by the Company, customers shall not be entitled to receive gas from Company on any day in excess of the MDQ amount established for such customer pursuant to the foregoing provisions. Periods of maximum usage may not be within a calendar month due to variations in billing periods. The Monthly MDQ Demand Charge shall not be prorated.

OTHER ADJUSTMENTS

Gas Utility Pipeline Taxes: 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.

Taxes: A charge will be made each month to recover the cost of any applicable taxes and fees.

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

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.

Other Charges: 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 unincorporated areas of the Company's area of service, 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.

SUBJECT TO

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

2. Customers taking service under this rate schedule will be required to obtain EFM equipment from the Company. If the locations of customer's facilities or other factors interfere with the ability to communicate EFM volume data using Company's available cellular telephone technology, customer will be required to provide and maintain, at its own expense, a dedicated telephone line through which communications may be transmitted. The EFM equipment shall remain the property of the Company and at no time may the customer take possession of the EFM equipment without written consent by an authorized representative of the Company.

ELECTRIC GENERATION TRANSPORTATION SERVICE RATE (Continued)

3. 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.

4. 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.

5. The Agreement shall be interpreted under Texas law.

GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE

1.1 REQUIREMENTS FOR TRANSPORTATION SERVICE

This rate schedule shall apply to Customers who have elected Transportation Service through the Company's distribution system within the incorporated and unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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.

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 degrees Fahrenheit and at the standard pressure base of the applicable 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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

Commercial Service: Service to Customers 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.

Compressed Natural Gas (CNG) Service: Service to Customers where the Customer purchases Natural Gas to be compressed and used as a motor fuel. This rate does not include compression by the Company beyond normal meter sales pressure.

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 (1) calendar day and ending at 9:00 a.m. Central Standard Time the following calendar day.

Dekatherm (Dth): Shall mean one million (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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

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 TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

Industrial Service: Service to Customers 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 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.

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.

Public Authority Service: Service to Customers that are 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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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 Company's 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.
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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

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).

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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;

c) Customer must provide Company with a signed Transportation Form identifying its Qualified Supplier. Customer may designate no more than one (1) 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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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 (1) PDA methodology shall be applied per allocation period.

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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

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.

RULES OF SERVICE

TEXAS GAS SERVICE ALL CUSTOMERS

Incorporated and environs areas of: Alamo, Aledo, Alton, Andrews, Anthony, Austin, Barstow, Bayou Vista, Beaumont, Bee Cave, Borger, Breckenridge, Brownsville, Bryson, Buda, Cedar Park, Clint, Combes, Crane, Cuero, Dell City, Donna, Dripping Springs, Edcouch, Edinburg, El Paso, Elsa, Galveston, Georgetown, Gonzales, Graford, Graham, Groves, Harlingen, Hidalgo, Horizon City, Hudson Oaks, Hutto, Jacksboro, Jamaica Beach, Jarrell, Kyle, La Feria, La Joya, La Villa, Laguna Vista, Lakeway, Lockhart, Los Fresnos, Luling, Lyford, Marble Falls, McAllen, McCamey, Mercedes, Millsap, Mineral Wells, Mission, Monahans, Mustang Ridge, Nederland, Nixon, Palm Valley, Palmhurst, Palmview, Pecos, Penitas, Pflugerville, Pharr, Port Arthur, Port Isabel, Port Neches, Primera, Progreso, Pyote, Rancho Viejo, Raymondville, Rio Hondo, Rollingwood, San Benito, San Elizario, San Juan, Santa Rosa, Shiner, Skellytown, Socorro, Sunset Valley, Thorntonville, Vinton, Weatherford, Weslaco, West Lake Hills, Wickett, Willow Park, Wink, and Yoakum, Texas; the environs of Bastrop, Texas; and the unincorporated areas of: Bayview, Canutillo, Fabens, Jermyn, Jim Hogg County, Jonah, Laguna Heights, Monte Alto, Olmito, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, San Carlos, Starr County, and Whitt, Texas.

Effective for Meters Read 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 West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park (January 27, 2023), Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park (February 27, 2023), Rio Grande Valley (January 30, 2024), and Central-Gulf (November 27, 2024)

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – ALL CUSTOMERS

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Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – ALL CUSTOMERS

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 areas served by the Company comprised of the incorporated and environs areas of: Alamo, Aledo, Alton, Andrews, Anthony, Austin, Barstow, Bayou Vista, Beaumont, Bee Cave, Borger, Breckenridge, Brownsville, Bryson, Buda, Cedar Park, Clint, Combes, Crane, Cuero, Dell City, Donna, Dripping Springs, Edcouch, Edinburg, El Paso, Elsa, Galveston, Georgetown, Gonzales, Graford, Graham, Groves, Harlingen, Hidalgo, Horizon City, Hudson Oaks, Hutto, Jacksboro, Jamaica Beach, Jarrell, Kyle, La Feria, La Joya, La Villa, Laguna Vista, Lakeway, Lockhart, Los Fresnos, Luling, Lyford, Marble Falls, McAllen, McCamey, Mercedes, Millsap, Mineral Wells, Mission, Monahans, Mustang Ridge, Nederland, Nixon, Palm Valley, Palmhurst, Palmview, Pecos, Penitas, Pflugerville, Pharr, Port Arthur, Port Isabel, Port Neches, Primera, Progreso, Pyote, Rancho Viejo, Raymondville, Rio Hondo, Rollingwood, San Benito, San Elizario, San Juan, Santa Rosa, Shiner, Skellytown, Socorro, Sunset Valley, Thorntonville, Vinton, Weatherford, Weslaco, West Lake Hills, Wickett, Willow Park, Wink, and Yoakum, Texas; the environs of Bastrop, Texas; and the unincorporated areas of: Bayview, Canutillo, Fabens, Jermyn, Jim Hogg County, Jonah, Laguna Heights, Monte Alto, Olmito, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, San Carlos, Starr County, and Whitt, Texas.

Service under this Tariff is subject to the original jurisdiction of the municipalities in the Company's area of service and the Railroad Commission of Texas. The Company will provide service to any person and/or business within its areas of service 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 (1) rate is applicable. A Customer assigned to a rate schedule shall remain on that schedule for a minimum of one (1) 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 of 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.
Atmospheric Pressure:	The pressure exerted by the weight of the atmosphere, which at sea level has a mean value of roughly 14.70 pounds per square inch (psi). A table containing the average Atmospheric Pressure of each location served by the Company is shown in Section 13.
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 (1) 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 60 degrees Fahrenheit and at the standard pressure base of the applicable 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.
Common Billing Pressure:	A Common Billing Pressure of 14.65 psi is used to determine an equitable measurement of volume of Natural Gas consumed for Customers who live in areas with varying Atmospheric Pressure.
Compressed Natural Gas (CNG) Service:	Service to any non-residential Customer of the Company for usage where the Customer purchases Natural Gas which will be compressed and used as a motor fuel. This service will be separately metered and does not include compression by the Company beyond normal meter sales pressure.
Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Constant Factor:	A factor that is calculated by dividing the Standard Serving Pressure by a Common Billing Pressure of 14.65 psi. This factor will be further adjusted for non-residential Customers who have requested an elevated meter pressure above the Standard Serving Pressure. The Constant Factor is multiplied by the change in

	meter readings shown on the Customer's bill to calculate a Billed Ccf volume also shown on the Customer's bill. A table containing the Constant Factor of each location served by the Company is shown in Section 13.
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 (1) calendar day and ending at 9:00 a.m. Central Standard Time the following calendar day.
Dekatherm (Dth):	Shall mean one million (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 non-residential Customers operating electric generation assets 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 the 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 event 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 the 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 (1) 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.
Public Authority Service:	Service to Customers that are 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.
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 Company's area of service, or the Railroad Commission of Texas, as applicable.
Safe Access:	This term, used throughout the Company's Rules of Service, shall mean that Company representatives shall have free access to Company-owned assets, including but not limited to meters, service lines, and all other equipment relating to Company's service and the Company shall upon request, also have access to Customer Natural Gas appliances and equipment to perform safety inspections as may be deemed necessary by the Company during the performance of routine maintenance and/or in response to emergency situations without threat or harm from the Customer, Customer representatives or animals on the property.
Special Rate Schedule:	A rate schedule designed for a specific Customer.
Standard Serving Pressure:	The Standard Serving Pressure at a Customer's meter shall be 4 ounces (0.25 psi) or 7" Water Column above the standard Atmospheric Pressure in the area served. A table containing the Standard Serving Pressure of each location served by the Company is shown in Section 13.
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 (2) 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 365 consecutive Days, or 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.

Texas Gas Service Company, a Division of ONE Gas, Inc.
Rules of Service – ALL CUSTOMERS

SECTION 4 — CONDITIONS OF SERVICE

4.1 PROVISION OF SERVICE

The Company will provide Gas service to any person or organization located within the Company's 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 Safe Access for the Company to provide service to Customer's property or the premises of the Consumer.

4.2 USE OF NATURAL GAS EQUIPMENT AND APPLIANCES

The Customer shall provide notice to the Company of the installation of any Natural Gas appliance or equipment located on the Customer's property upon the Company's request. Customer notice shall be provided electronically or verbally when requested. Appliances and Equipment may include, but not be limited to: furnace, clothes dryer, water heater, tankless water heater, stove/oven, generator, pool heater, fireplace, fire pit, grill, commercial/industrial boilers, etc.

4.3 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.

4.4 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.

4.5 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 (4) 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.

4.6 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.

4.7 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.

4.8 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 (1) year subsequent to the final disposition of the complaint.

4.9 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.

4.10 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 the 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 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 (2) forms of verifiable identification: (1) a government-issued identification card bearing a photograph of Applicant; and (2) 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 area of service as rapidly as practical. As a general policy, those applications not involving line extensions, service lines or new facilities should be filled within seven (7) working days. Those applications for individual residential service requiring line extensions or service lines 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. However, the Company shall not be obligated to provide Expedited Service when the personnel and resources to do so are not reasonably available. 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 (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 the Company or Company’s representatives Safe Access to or entry for observation of Customer-owned Natural Gas facilities or appliances and/or whose Natural Gas facilities or appliances 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.

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 (6) 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.

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

f) Five (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 five (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 of 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 five (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 five (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 (6) 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 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 a.m. or after 7:00 p.m. 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.

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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
		$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 areas of service. 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 areas of service. 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 (1) year or more, the request for service shall be treated as a new application. When service has been disconnected for less than one (1) 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 (1) 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, with Safe Access, 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.

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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 (1) 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 (2) 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 (1) 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 (2) 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 (1/6) 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 Company's area of service 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 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 two (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.

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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 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 (6) 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 or phone call, and request that the Customer read the meter and return the card or a picture of the meter dial 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 (2) 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 five percent (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 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

i) The Average Payment Plan ("Plan") is available to residential and qualifying non-residential 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. Requests for participation can be made by telephone or in writing.

ii) 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.

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

b) AVERAGE PAYMENT AMOUNT

i) 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, the Company may estimate the missing months in order to determine the appropriate average payment amount.

ii) The average payment amount is identified as a separate item on the Gas bill so the participating Consumer will know the amount to pay.

iii) 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, with Safe Access, 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.

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

b) The Customer shall take all reasonable precautions when excavating, digging or constructing around or near Company-owned Natural Gas facilities to include calling 811 to identify the location of buried Natural Gas lines prior to digging or constructing in the vicinity of Natural Gas facilities.

c) 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, including but not limited to the failure to call 811 to identify the location of Gas lines before digging, 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.

10.3 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 not installed by the Company 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.

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, to include any 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 any portions of the service line and meter set not furnished by the Company, as described in Section 10.5.

b) The Applicant shall be responsible for the adequacy, safety and compliance with applicable codes and ordinances of piping, conversion equipment and appliances. No action of the Company, in accordance with this Tariff, shall release the Applicant of the responsibility for the Customer-owned facilities, equipment or appliances 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 local rules, and shall be properly designed for the pressures and volumes to be handled. Where there are no applicable local, state or federal requirements, the most current International Fuel Gas Code shall apply.

10.7 RELOCATION OF COMPANY FACILITIES

a) A charge of not more than the 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.

c) If the Company shall change the Point of Delivery or change the location of its equipment on private property due to encroachment by Customer-owned property, the Customer 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 Natural Gas 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 then own and be responsible for all service piping from the main line up to the Company's meter. The Customer will then own and be responsible for all piping from the meter to and within the building.

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

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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.

c) Determination of whether a proposed extension is cost justified shall be made based on the following economic model: the Maximum Allowable Investment (MAI) shall be equal to the expected number of new premises times the annual base revenue per new premise based on current Tariff rates times ten; or MAI = Expected New Premises x Annual Base Revenue x 10. The calculation of the MAI shall reflect the impact of related economic factors including, but not limited to, future residential growth, future commercial growth and operational efficiencies.

d) If the cost of a proposed extension is lower than the MAI, the Company may at its sole discretion provide the Applicant a payment to offset some or all of the cost of Customer or developer infrastructure including but not limited to the cost of installing Natural Gas piping from the meter to the Natural Gas appliance as well as required venting for each Natural Gas appliance. This payment shall be based on the actual cost of Natural Gas piping and venting and shall not cause the total cost of the proposed extension to exceed the MAI. Any such payments will be treated as an investment in intangible plant and amortized over a ten-year period.

e) The Company may pay to Applicant reasonable costs related to acquiring necessary right-of-way and reasonable costs related to the management of facility installation activities.

11.2 RESIDENTIAL MULTI-UNIT LINE EXTENSION AND CONSTRUCTION CHARGES

a) The Company shall install the necessary facilities to provide service to Applicants for residential multi-unit projects pursuant to the provisions in Section 11.1 above.

b) The Company will provide Applicants for residential multi-unit projects a payment to offset some or all of the cost of Customer or developer infrastructure including but not limited to the cost of installing Natural Gas piping from the meter to the Natural Gas appliance as well as required venting for each Natural Gas appliance. This payment shall be based on the actual cost of Natural Gas piping and venting and shall not exceed the MAI as calculated in Section 11.1(c) above. Any such payments will be treated as an investment in intangible plant and amortized over a ten-year period.

c) Multi-unit structures are defined as having four (4) or more individual units under one (1) roof.

d) To be eligible for this payment, each unit must, at a minimum, contain either a Natural Gas water heater or Natural Gas furnace, plus one (1) other Natural Gas appliance for a total of two (2) installed Natural Gas appliances.

11.3 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.

11.4 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.

11.5 ADVANCES

The mutually agreed upon terms will determine the amount and term of any 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.

11.6 CONSTRUCTION OF FACILITIES

As soon as practical after the advance has been paid or it has been determined that no advance will be required, and the permits for construction have been obtained, 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.

11.7 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 each subsequent anniversary of the 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.

11.8 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 term, any remaining amount of the advance shall be retained by the Company as a contribution in aid of construction.

11.9 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 (6) months following expiration of the term 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 (2) 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 (2) 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, with Safe Access, 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, disconnection or replacement. 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 five (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 or her.

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 two percent (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 (6) 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 (3) 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 six (6) months for 0-500 Mcf/d; every three (3) months for volumes 500-2,000 Mcf/d; and every month for volumes 2,000 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 (1) 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 (1) 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).

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SECTION 13 — GAS MEASUREMENT

13.1 PRESSURE

The standard serving and measurement pressure at Customer meters shall be 4 ounces (0.25 psi) or 7" Water Column above the standard Atmospheric Pressure in the area served.

To achieve a common pressure base throughout the state for Customer billing, the Company will convert the Customer's Standard Serving Pressure to a Common Billing Pressure by multiplying by a Constant Factor, shown below. The Constant Factor is determined by dividing the Customer's Standard Serving Pressure by 14.65. For Customers with the Standard Serving Pressure of 4 ounces at their meter, the Constant Factor shown below will be on their monthly bill as a component of calculating the billed volumes. For Customers with a serving pressure more than 4 ounces at their meter, the Constant Factor will be adjusted to accommodate the increased pressure at the meter. The Atmospheric Pressure and Standard Serving Pressure, determined to be the average in the cities and environs of the Company's area of service, are listed below:

Cities and their Environs	Atmospheric Pressure PSI	Standard Serving Pressure PSI	Constant Factor
Alamo	14.40	14.65	1.0000
Aledo	14.40	14.65	1.0000
Alton	14.40	14.65	1.0000
Andrews	13.10	13.35	0.9113
Anthony	12.80	13.05	0.8908
Austin	14.40	14.65	1.0000
Barstow	13.50	13.75	0.9386
Bastrop	14.40	14.65	1.0000
Bayou Vista	14.70	14.95	1.0205
Bayview	14.40	14.65	1.0000
Beaumont	14.70	14.95	1.0205
Bee Cave	14.40	14.65	1.0000
Borger	13.10	13.35	0.9113
Breckenridge	14.40	14.90	1.0171
Brownsville	14.40	14.65	1.0000
Bryson	14.40	14.65	1.0000
Buda	14.40	14.65	1.0000
Canutillo	12.80	13.05	0.8908
Cedar Park	14.40	14.65	1.0000
Clint	12.80	13.05	0.8908
Combes	14.40	14.65	1.0000
Crane	13.50	13.75	0.9386
Cuero	14.48	14.73	1.0055
Dell City	12.80	13.05	0.8908
Donna	14.40	14.65	1.0000
Dripping Springs	14.40	14.65	1.0000
Edcouch	14.40	14.65	1.0000
Edinburg	14.40	14.65	1.0000

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El Paso	12.80	13.05	0.8908
Elsa	14.40	14.65	1.0000
Fabens	12.80	13.05	0.8908
Galveston	14.70	14.95	1.0205
Georgetown	14.40	14.65	1.0000
Gonzales	14.48	14.73	1.0055
Graford	14.40	14.65	1.0000
Graham	14.40	14.90	1.0171
Groves	14.70	14.95	1.0205
Harlingen	14.40	14.65	1.0000
Hidalgo	14.40	14.65	1.0000
Horizon City	12.80	13.05	0.8908
Hudson Oaks	14.40	14.65	1.0000
Hutto	14.40	14.65	1.0000
Jacksboro	14.40	14.65	1.0000
Jamaica Beach	14.70	14.95	1.0205
Jarrell	14.40	14.65	1.0000
Jermyn	14.40	14.65	1.0000
Jim Hogg County	14.40	14.65	1.0000
Jonah	14.40	14.65	1.0000
Kyle	14.40	14.65	1.0000
La Feria	14.40	14.65	1.0000
La Joya	14.40	14.65	1.0000
La Villa	14.40	14.65	1.0000
Laguna Heights	14.40	14.65	1.0000
Laguna Vista	14.40	14.65	1.0000
Lakeway	14.40	14.65	1.0000
Lockhart	14.48	14.73	1.0055
Los Fresnos	14.40	14.65	1.0000
Luling	14.48	14.73	1.0055
Lyford	14.40	14.65	1.0000
Marble Falls	14.40	14.65	1.0000
McAllen	14.40	14.65	1.0000
McCamey	13.50	13.75	0.9386
Mercedes	14.40	14.65	1.0000
Millsap	14.40	14.65	1.0000
Mineral Wells	14.40	14.65	1.0000
Mission	14.40	14.65	1.0000
Monahans	13.50	13.75	0.9386
Monte Alto	14.40	14.65	1.0000
Mustang Ridge	14.40	14.65	1.0000
Nederland	14.70	14.95	1.0205

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Nixon	14.48	14.73	1.0055
Olmito	14.40	14.65	1.0000
Palm Valley	14.40	14.65	1.0000
Palmhurst	14.40	14.65	1.0000
Palmview	14.40	14.65	1.0000
Palo Pinto	14.40	14.65	1.0000
Pecos	13.50	13.75	0.9386
Penitas	14.40	14.65	1.0000
Perrin	14.40	14.65	1.0000
Pflugerville	14.40	14.65	1.0000
Pharr	14.40	14.65	1.0000
Port Arthur	14.70	14.95	1.0205
Port Isabel	14.40	14.65	1.0000
Port Neches	14.70	14.95	1.0205
Possum Kingdom	14.40	14.65	1.0000
Primera	14.40	14.65	1.0000
Progreso	14.40	14.65	1.0000
Punkin Center	14.40	14.65	1.0000
Pyote	13.50	13.75	0.9386
Rancho Viejo	14.40	14.65	1.0000
Raymondville	14.40	14.65	1.0000
Rio Hondo	14.40	14.65	1.0000
Rollingwood	14.40	14.65	1.0000
San Benito	14.40	14.65	1.0000
San Carlos	14.40	14.65	1.0000
San Elizario	12.80	13.05	0.8908
San Juan	14.40	14.65	1.0000
Santa Rosa	14.40	14.65	1.0000
Shiner	14.48	14.73	1.0055
Skellytown	13.02	13.27	0.9058
Socorro	12.80	13.05	0.8908
Starr County	14.40	14.65	1.0000
Sunset Valley	14.40	14.65	1.0000
Thorntonville	13.50	13.75	0.9386
Vinton	12.80	13.05	0.8908
Weatherford	14.40	14.65	1.0000
Weslaco	14.40	14.65	1.0000
West Lake Hills	14.40	14.65	1.0000
Whitt	14.40	14.65	1.0000
Wickett	13.50	13.75	0.9386
Willow Park	14.40	14.65	1.0000
Wink	13.50	13.75	0.9386

Yoakum	14.48	14.73	1.0055

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 ten percent (10%) 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 (100) cubic feet (Ccf). A cubic foot shall be defined as the amount of Gas which occupies a volume of one (1) 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 Common Billing 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 Common Billing Pressure. The index of the meter shall be the sole determinant of volumes passing through the meter. 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 (1) cubic foot of Gas at a pressure of 14.73 psi 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 psi 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 the Company's billing purposes.

SECTION 14 — QUALITY OF GAS

14.1 HEATING VALUE

Gas delivered to Consumers in all 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 psi 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 Company's area of service 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.

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Rules of Service – ALL CUSTOMERS

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 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.	$40.00
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.	$20.00
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.	$20.00

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		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.	$75.00
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 1,500 cubic feet per hour Over 1,500 cubic feet per hour --- Orifice Meters All sizes	 $165.00 $230.00 --- $200.00
f)	Payment Re-processing Fee	A fee will be charged to the Customer for the recovery of costs associated to the reprocessing of any payment, including paper check, electronic transfer payment and debit/credit card payment that has been rejected or returned by the bank for any reason.	$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.	$20.00
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	$40.00 $55.00 $75.00
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 Customer's convenience.	$200.00
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). May be charged in tandem with Unauthorized Consumption Fee in situations that include both Tampering and Unauthorized Consumption.	$200.00

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l)	Unauthorized Consumption Fee	Charges for the replacement of an illegally broken meter seal or locking device, and/or a bypass of the meter, to the Customer who could be reasonably expected to benefit from Gas service received through said meter. May be charged in tandem with Meter Tampering Fee in situations that include both Tampering and Unauthorized Consumption.	$32.00 plus expenses
m)	No Access Fee	A fee charged to a Customer who schedules an appointment but fails to appear.	$20.00
n)	Meter Removal Fee	A fee will be charged to the Customer to remove the meter due to tampering, accessibility issues, and other reasons deemed necessary by the Company in accordance with this Tariff.	$28.00
o)	Account Research Fee	An hourly fee will be charged for Customer account information requiring research of accounting/billing information.	$25.00
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	A deposit will be required from any new or current residential Customer to mitigate credit exposure. Current Customers may be assessed deposits due to delinquent bill payment behavior.	Minimum $125.00
c)	Non-Residential Customer Deposit	A deposit will be required from any new or current non-residential Customer to mitigate credit exposure. Current Customers may be assessed deposits due to delinquent bill payment behavior.	Minimum $250.00

Texas Gas Service Company, a Division of ONE Gas, Inc.
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SECTION 16 — TAPPING FEES

16.1 TAPPING FEES

The Company may, at its option, extend lines to serve a group of new Customers outside or inside the incorporated by the use of Contribution In Aid of Construction (CIAC). Unless not economical or reasonable, the Company shall allow payment of the CIAC amount in the form of a monthly Tapping Fee charged to the existing and subsequent Customers in the area to be served. The fee will continue to be charged to all Customers connecting to the Extension of Facilities each month until the Company recovers the amount of CIAC required to serve the area. At least fifty percent (50%) of the existing homes in the area must be under contract for service for this type of Extension of Facilities to be available to the area.

The monthly per Customer Tapping Fee will be equal to the Monthly Amortization of the CIAC divided by the number of Customers participating in the program.

The Tapping Fee will usually be set within the first six (6) months of billing the first Customer receiving Gas from this extension. In some cases, this period could be extended.

In order to calculate the monthly Amortization of the CIAC, the following steps are to be followed:

1. Calculate the Required Rate Base

   Required Rate Base = Cost of Mains, services and yard lines

2. Calculate the Revenue Requirement

   Revenue Requirement = (Required Rate Base x return on capital) + related Federal Income Taxes + Depreciation

   Note: Depreciation = Required Rate Base x currently authorized rate by Component

3. Calculate the Annual Revenues to be received from Customers

   Annual Revenue = Number of Customers x the average annual revenue per Customer
   Note: The Number of Customers includes Customers connected to the System and Customers contracted to connect to the System within the first six (6) months of billing the first Customers receiving Gas from the System.

4. Calculate the Justified Rate Base

   The Justified Rate Base is the Rate Base that is backed into by using the revenue requirement model described in Step 2 above. The model backs into the Justified Rate Base by calculating the return, Federal Income Taxes and Depreciation for a given investment level, such that the sum of the return, Federal Income Taxes and Depreciation equals the Annual Revenues calculated in Step 3 above.

5. Calculate the Contribution In Aid of Construction (CIAC)

   CIAC = Required Rate Base – Justified Rate Base

6. Calculate the CIAC monthly payment

CIAC monthly payment is determined by using an amortization table. The variables include number of payments, interest rate and the outstanding CIAC.

7. Calculate the Monthly Tapping Fee

   Monthly Tapping Fee = CIAC monthly payment divided by the number of Customers used in Step 3 above.

8. If the Monthly Tapping fee is not economical or reasonable, a one-time lump sum CIAC amount may be required. This CIAC amount would then reduce the amount in Step 5 above, and the Monthly Tapping Fee would then be re-calculated less the one-time fee.

CIAC will change overtime based upon additional capital investments (principally to tie in new Customers) and for reductions based upon the tapping fee payments. The interest rate changes annually and is based upon Chase Bank (or its successors prime rate plus two percent).

For each project undertaken, the Company will file with the respective Regulatory Authority an initial Tapping Fee Rider showing the amount and calculation of the Tapping Fee. For each project undertaken, the Company will file with the Regulatory Authority an annual reconciliation report, detailing the application of the Tapping Fee to principal and interest and the outstanding CIAC balance.

Texas Administrative Code

TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 7	GAS SERVICES
SUBCHAPTER D	CUSTOMER SERVICE AND PROTECTION
RULE §7.455	Curtailment Standards

(a) Definitions. The following words and terms, when used in this section, shall have the following meanings, unless the context clearly indicates otherwise.

(1) Balancing authority--The Electric Reliability Council of Texas or other responsible entity that integrates resource plans ahead of time, maintains electricity demand and resource balance within a balancing authority area, and supports interconnection frequency in real time for a power region in Texas.

(2) Commission--The Railroad Commission of Texas.

(3) Curtailment event--When a gas utility determines that its ability to deliver gas may become inadequate to support continuous service to firm customers on its system and it reduces deliveries to one or more firm customers. For the purposes of this section, an interruption of delivery or service to interruptible gas customers does not constitute a curtailment event. Prior to reducing deliveries to one or more firm customers, a gas utility interrupts deliveries to interruptible customers pursuant to mutually agreed upon contracts and/or tariffs.

(4) Electric generation facilities--Facilities registered with the applicable balancing authority including bulk power system assets, co-generation facilities, distributed generation, and backup power systems.

(5) Firm or firm deliveries--Natural gas deliveries that are described as firm under a contract or tariff.

(6) Gas utility--An entity that operates a natural gas transmission pipeline system or a local distribution company that is subject to the Commission's jurisdiction as defined in Texas Utilities Code, Title 3.

(7) Human needs customers--Residences, hospitals, water and wastewater facilities, police, fire, military and civil defense facilities, and locations where people may congregate in an emergency such as schools and places of worship. A human needs customer also includes small commercial customers that cannot practicably be curtailed without curtailing human needs.

(8) Interruptible or interruptible deliveries--Natural gas deliveries that are not described as firm under a contract or tariff.

(b) Applicability. This section takes effect on September 1, 2022. This section applies when any gas utility experiences a curtailment event affecting intrastate service on any of its intrastate natural gas pipelines. When a gas utility experiences a curtailment event, the gas utility shall curtail deliveries according to the priorities listed

in subsection (c) of this section unless and until the gas utility has an approved curtailment plan pursuant to subsection (d) of this section. The curtailment priorities in this section apply to sales of natural gas owned by a gas utility and/or deliveries utilizing a gas utility's transportation capacity. The priorities in this section do not apply to sales of gas owned by an entity that is not a gas utility. The term "deliveries" in this section includes sales and/or transportation service.

(c) Priorities.

(1) Unless a gas utility has an approved curtailment plan pursuant to subsection (d) of this section, a gas utility shall apply the following priorities in descending order during a curtailment event:

(A) firm deliveries to human needs customers and firm deliveries of natural gas to local distribution systems which serve human needs customers;

(B) firm deliveries to electric generation facilities;

(C) firm deliveries to industrial and commercial users of the minimum natural gas required to prevent physical harm and/or ensure critical safety to the plant facilities, to plant personnel, or the public when such protection cannot be achieved through the use of an alternate fuel;

(D) firm deliveries to small industrials and regular commercial loads that use less than 3,000 Mcf per day;

(E) firm deliveries to large industrial and commercial users for fuel or as a raw material where an alternate fuel or raw material cannot be used and operation and plant production would be curtailed or shut down completely when natural gas is curtailed;

(F) firm deliveries to large industrial and commercial users for fuel or as a raw material where an alternate fuel or raw material can be used and operation and plant production would be curtailed or shut down completely when natural gas is curtailed; and

(G) firm deliveries to customers that are not covered by the priorities listed in subparagraphs (A) - (F) of this paragraph.

(2) Deliveries to customers within the same priority on the portion of the system which is subject to curtailment shall be curtailed to the extent practicable on a pro rata basis according to scheduled quantities. If a customer's end-use requirements fall under two or more priorities, then such requirements must be treated separately when applying this schedule of priorities to the extent practicable. Transportation customers have equivalent end-use priorities as sales customers.

(3) When applying the priorities of this section, a gas utility may rely on the representations of its customers and/or their end users regarding the nature of customers' deliveries.

(d) Curtailment plans. Order 489 and any curtailment plan approved by the Commission prior to the effective date of this section is superseded by this section. A gas utility may file its own curtailment plan for approval with the Oversight and Safety Division. A gas utility shall follow the priorities listed in subsection (c) of this section unless and until the gas utility has an approved curtailment plan on file with the Commission. The first three priorities in any individual curtailment plan must be consistent with the first three priorities listed in subsection

(c)(l)(A) - (C) and (2) of this section. A gas utility shall provide to its customers notice of an application for a curtailment plan. A gas utility shall provide notice on the same day the gas utility files its application with the Commission. The gas utility may provide notice by hand delivery, by first class, certified, registered mail, commercial delivery service, electronic methods, or by such other manner as the Commission may require. The notice shall be in the form prescribed by the Commission. The Oversight and Safety Division may administratively approve the curtailment plan if no request for hearing is filed within thirty days of such notice. The Commission shall set the matter for hearing if it receives a timely request for hearing from a customer of the gas utility.

(e) Required tariff filings. Within 90 days of the effective date of this section, each gas utility shall electronically file with the Commission, in the manner prescribed by the Commission, tariffs that shall include either:

(1) the curtailment priorities as specified in this section; or

(2) a curtailment plan approved by the Commission as specified in subsection (d) of this section.

(f) Curtailment emergency contact information. Each gas utility shall maintain current curtailment emergency contact information with the Commission and shall submit curtailment emergency contact information on or before November 1 of each year.

Source Note: The provisions of this §7.455 adopted to be effective July 29, 2002, 27 TexReg 6687; amended to be effective May 14, 2018, 43 TexReg 2997; amended to be effective September 1, 2022, 47 TexReg 2516

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE TF-IS

TAPPING FEE RATES

A. APPLICABILITY

The Tapping Fee rates, as set forth in Section (C) below and pursuant to the Rules of Service, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the incorporated areas of Burbridge Acres, Cotton Valley Estates, and Jones Subdivision Colonias.

B. TERRITORY

Burbridge Acres Colonia in the City of Clint, TX.
Cotton Valley Estates Colonia in the City of Socorro, TX.
Jones Subdivision in the City of Socorro, TX.

C. CURRENT RATES

The Tapping Fee rates for the colonias listed below will continue to be charged to all customers connecting to the extension of facilities each month until the Company recovers the amount of Contribution In Aid of Construction (CIAC) required to serve the area. During each monthly billing period:

A tapping fee charge per meter per month of $ 7.22 applicable to the Burbridge Acres Colonia in the City of Clint, TX.

A tapping fee charge per meter per month of $ 8.41 applicable to the Cotton Valley Estates Colonia in the City of Socorro, TX.

A tapping fee charge per meter per month of $ 7.82 applicable to the Jones Subdivision in the City of Socorro, TX.

Supersedes Rate Schedule Dated	Meters Read On and After
January 27, 2023 (Burbridge Acres, Cotton Valley Estates, and Jones Subdivision) February 8, 2023 (withdrawn Haciendas del Valle Colonia)	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE TF-OS**
Page 1 of 1

TAPPING FEE RATES

A. APPLICABILITY

The Tapping Fee rates, as set forth in Section (C) below and pursuant to the Rules of Service, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the unincorporated areas of Agua Dulce, Burbridge Acres, Panorama Village, and Westway Colonias.

B. TERRITORY

Agua Dulce Colonia in the environs of El Paso, TX.
Burbridge Acres Colonia in the environs of El Paso, TX.
Panorama Village Colonia in the environs of El Paso, TX.
Westway Colonia in the environs of the El Paso, TX.

C. CURRENT RATES

The Tapping Fee rates for the colonias listed below will continue to be charged to all customers connecting to the extension of facilities each month until the Company recovers the amount of Contribution In Aid of Construction (CIAC) required to serve the area. During each monthly billing period:

A tapping fee charge per meter per month of $ 8.82 applicable to the Agua Dulce Colonia in the environs of El Paso, TX.

A tapping fee charge per meter per month of $ 7.22 applicable to the Burbridge Acres Colonia in the environs of El Paso, TX.

A tapping fee charge per meter per month of $ 4.85 applicable to the Panorama Village Colonia in the environs of El Paso, TX.

A tapping fee charge per meter per month of $ 26.33 applicable to the Westway Colonia in the environs of El Paso, TX.

D. ANNUAL RECONCILIATION REPORT

Per the Company's Rules of Service, Section 16.1 Tapping Fees, the Company shall file with the Railroad Commission of Texas ("Commission") an annual reconciliation report detailing the application of the tapping fee for each colonia to principal and interest and the outstanding CIAC balance.

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 27, 2023	TBD

Recommended Rates

Line No.	Description	Bills	Volumes (Ccf)	Customer Charge	Usage Charges	Recommended Revenue	Assigned Revenue	Rounding Diff.	Test Year As Adjusted Revenue	Revenue Change
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential - Small									
2	Incorporated	4,290,357	71,290,753	$29.50	$0.67553	$174,724,588	$174,724,361	$227	$158,499,294	$16,225,067
3	Environs	483,088	10,612,464			$21,420,120	21,420,092	28	19,431,002	1,989,090
4		4,773,445	81,903,217			$196,144,708	$196,144,453	$255	$177,930,297	$18,214,157
5										
6	Residential - Large									
7	Incorporated	2,573,465	113,729,207	$39.50	$0.31189	$137,122,866	$137,122,688	$178	$124,389,347	$12,733,340
8	Environs	289,768	16,929,925			$16,726,115	16,726,093	22	15,172,892	1,553,201
9		2,863,233	130,659,132			$153,848,980	$153,848,781	$200	$139,562,240	$14,286,541
10										
11	Customer Assistance Program	360,000	10,020,372	$22.13	$0.55000	**$13,478,004**	**$13,478,004**	$0	$0	**$13,478,004**
12										
13	Total Residential									
14	Incorporated	7,187,389	193,741,960			$311,847,454	$311,847,049	$405	$282,888,642	$28,958,407
15	Environs	809,289	28,840,760			38,146,234	38,146,185	50	34,603,895	3,542,290
16	**Total Residential**	**7,996,677**	**222,582,720**			**$349,993,688**	**$ 349,993,234**	**$454**	**$317,492,536**	**$32,500,697**
17	Commercial - Small									
18	Incorporated	288,529	13,004,923	$75.00	$0.43589	$27,308,374	$27,308,149	$225	$29,383,265	$(2,075,116)
19	Environs	15,481	598,686			$1,422,054	1,422,042	12	1,530,101	(108,059)
20		304,010	13,603,609			$28,730,427	$28,730,191	$236	$30,913,366	$(2,183,175)
21										
22	Commercial - Large									
23	Incorporated	103,023	93,193,182	$150.00	$0.13589	$28,117,503	$28,117,272	$231	$30,253,872	$(2,136,600)
24	Environs	5,528	4,290,182			$1,412,161	1,412,149	12	1,519,457	(107,308)
25		108,551	97,483,364			$29,529,664	$29,529,422	$243	$31,773,329	$(2,243,908)
26	Total Commercial									
27	Incorporated	391,552	106,198,105			$55,425,877	$55,425,421	$456	$59,637,137	$(4,211,716)
28	Environs	21,009	4,888,869			2,834,215	2,834,191	23	3,049,558	(215,367)
29	**Total Commercial**	**412,561**	**111,086,974**			**$58,260,091**	**$ 58,259,612**	**$479**	**$62,686,696**	**$(4,427,083)**
30	Industrial									
31	Incorporated	877	2,801,242	$1,250.00	$0.11849	$1,428,272	$1,428,255	$16	$1,670,678	$(242,422)
32	Environs	220	1,676,681			474,043	474,037	5	554,497	(80,460)
33	**Total Industrial**	**1,097**	**4,477,922**			**$1,902,314**	**$ 1,902,293**	**$22**	**$2,225,175**	**$(322,882)**
34	Public Authority									
35	Incorporated	29,710	16,103,760	$200.00	$0.13745	$8,155,395	$8,155,396	$(1)	$8,559,302	$(403,906)
36	Environs	3,025	1,871,911			862,392	862,392	(0)	905,103	(42,711)
37	**Total Public Authority**	**32,735**	**17,975,671**			**$9,017,787**	**$ 9,017,789**	**$(1)**	**$9,464,406**	**$(446,617)**
38	Compressed Natural Gas									
39	Incorporated	12	—	$320.00	$0.00000	$3,840	$3,816	$24	$4,533	$(716)
40	Environs	—	—			0	0	0	0	0
41	**Total Compressed Natural Gas**	**12**	**0**			**$3,840**	**$ 3,816**	**$24**	**$4,533**	**$(716)**
42	General Transportation									
43	Incorporated	10,597	65,984,598	$500.00	$0.08831	$11,125,525	$11,125,273	$251	$11,394,903	$(269,630)
44	Environs	728	13,407,196			1,548,035	1,548,000	35	1,585,517	(37,517)
45	**Total General Transportation**	**11,325**	**79,391,794**			**$12,673,560**	**$ 12,673,274**	**$286**	**$12,980,421**	**$(307,147)**
46	Electric Generation Transportation									
47	Incorporated	12		$1,000.00		$12,000	$207,911	$0	$197,869	$10,041
	MDQ		12,709		$0.72542	110,632				
	All Ccf		4,263,918		$0.02000	85,278				
48	Environs	—	—			0	0	0	0	0
49	**Total Electric Generation**	**12**	**4,276,627**			**$207,911**	**$ 207,911**	**$0**	**$197,869**	**$10,041**
50	**Fort Bliss**								**$2,478,665**	**$585,611**

	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)
51 Proposed TGS Revenue									
52 Incorporated	$400,203,293	$400,202,143	$1,150	$366,831,729	$36,434,690	$9,216,506	$144,047,446	9.7 %	7.0 %
53 Environs	$45,333,903	$45,333,790	$113	$40,698,571	$4,635,219	1,012,579	18,763,780	11.1 %	7.7 %
54 **Total Revenue**	**$445,537,196**	**$445,535,933**	**$1,263**	**$407,530,300**	**$41,069,909**	**$10,229,085**	**$162,811,227**	**9.8 %**	**7.1 %**

Combined recommended revenue:	$455,766,281	
The total revenue received during the test year	$417,759,385	
revenue deficiency	$41,069,909	
rates will increase TGS's revenues by	$41.1	Million
which is an increase of including the cost of gas	7.07 %	
which is an increase of excluding the cost of gas	9.83 %	

Exhibit C

Average Bill Impact By Class
(Including Cost of Gas)

Customer Class and Location	Current Average Monthly Bill Including Cost of Gas	Poposed Average Monthly Bill Including Cost of Gas	Proposed Monthly Dollar Change	Proposed Percentage Change with Cost of Gas
Sales Service: (1) (2)				
Residential - Small				
CGSA Incorporated and Environs	$ 44.88	$ 48.82	$ 3.94	8.8%
WNSA Incorporated and Environs	$ 38.44	$ 48.82	$ 10.38	27.0%
RGVSA Incorporated and Environs	$ 62.53	$ 48.82	$ (13.71)	-21.9%
Residential - Large				
CGSA Incorporated and Environs	$ 77.29	$ 74.30	$ (2.99)	-3.9%
WNSA Incorporated and Environs	$ 59.66	$ 74.30	$ 14.64	24.5%
RGVSA Incorporated and Environs	$ 78.89	$ 74.30	$ (4.59)	-5.8%
Customer Assistance				
CGSA Incorporated and Environs	$ 44.88	$ 39.30	$ (5.58)	-12.4%
WNSA Incorporated and Environs	$ 38.44	$ 39.30	$ 0.86	2.2%
RGVSA Incorporated and Environs	$ 62.53	$ 39.30	$ (23.23)	-37.2%
Commercial - Small				
CGSA Incorporated and Environs	$ 107.56	$ 114.67	$ 7.11	6.6%
WNSA Incorporated and Environs	$ 117.47	$ 114.67	$ (2.80)	-2.4%
RGVSA Incorporated and Environs	$ 159.93	$ 114.67	$ (45.26)	-28.3%
Commercial - Large				
CGSA Incorporated and Environs	$ 739.73	$ 676.72	$ (63.01)	-8.5%
WNSA Incorporated and Environs	$ 589.26	$ 676.72	$ 87.46	14.8%
RGVSA Incorporated and Environs	$ 736.13	$ 676.72	$ (59.41)	-8.1%
Industrial				
CGSA Incorporated and Environs	$ 3,652.60	$ 3,572.33	$ (80.27)	-2.2%
WNSA Incorporated and Environs	$ 3,646.91	$ 3,572.33	$ (74.58)	-2.0%
RGVSA Incorporated and Environs	$ 3,392.24	$ 3,572.33	$ 180.09	5.3%
Public Authority				
CGSA Incorporated and Environs	$ 530.03	$ 522.93	$ (7.10)	-1.3%
WNSA Incorporated and Environs	$ 581.78	$ 522.93	$ (58.85)	-10.1%
RGVSA Incorporated and Environs	$ 468.32	$ 522.93	$ 54.61	11.7%
Compressed Natural Gas				
CGSA Incorporated and Environs	$ 746.15	$ 320.00	$ (426.15)	-57.1%
WNSA Incorporated and Environs	N/A	N/A	N/A	N/A
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A
Transportation Service: (3)				
Commercial Transportation				
CGSA Incorporated and Environs	$ 3,807.64	$ 3,886.69	$ 79.05	2.1%
WNSA Incorporated and Environs	$ 4,161.74	$ 3,886.69	$ (275.05)	-6.6%
RGVSA Incorporated and Environs	$ 3,915.94	$ 3,886.69	$ (29.25)	-0.7%
Industrial Transportation				
CGSA Incorporated and Environs	$ 20,758.98	$ 18,816.36	$ (1,942.62)	-9.4%
WNSA Incorporated and Environs	$ 22,028.20	$ 18,816.36	$ (3,211.84)	-14.6%
RGVSA Incorporated and Environs	$ 18,887.56	$ 18,816.36	$ (71.20)	-0.4%
Public Authority Transportation				
CGSA Incorporated and Environs	$ 1,477.92	$ 1,711.73	$ 233.81	15.8%
WNSA Incorporated and Environs	$ 1,964.16	$ 1,711.73	$ (252.43)	-12.9%
RGVSA Incorporated and Environs	$ 3,516.89	$ 1,711.73	$ (1,805.16)	-51.3%
Compressed Natural Gas Transportation				
CGSA Incorporated and Environs	$ 29,828.01	$ 31,556.20	$ 1,728.19	5.8%
WNSA Incorporated and Environs	$ 35,169.78	$ 31,556.20	$ (3,613.58)	-10.3%
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A
Electric Generation Transportation				
CGSA Incorporated and Environs	$ 184,636.19	$ 185,400.48	$ 764.29	0.4%
WNSA Incorporated and Environs	N/A	N/A	N/A	N/A
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A

(1) Bill impacts are shown for those schedules with customers during the test year. The test year cost of gas in each area 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) Current and recommended bills are based on the following average monthly usage levels at local pressure and at 14.65 psi, respectively.

	CGSA	WNSA	RGVSA	CGSA	WNSA	RGVSA
	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure
Residential - Small	17	17	17	17	19	17
Residential - Large	46	46	46	46	51	46
Commercial - Small	45	45	45	45	50	45
Commercial - Large	898	898	898	896	998	898
Industrial	4,081	4,081	4,081	4,070	4,533	4,081
Public Authority	549	549	549	548	610	549
Compressed Natural Gas	0	N/A	N/A	0	N/A	N/A

(3) 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. Current and recommended bills are based on the following usage levels at local pressure and at 14.65 psi, respectively.

	CGSA	WNSA	RGVSA	CGSA	WNSA	RGVSA
	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure
Commercial Transportation	6,558	6,558	6,558	6,541	7,285	6,558
Industrial Transportation	35,469	35,469	35,469	35,376	39,400	35,469
Public Authority Transportation	2,346	2,346	2,346	2,340	2,607	2,346
Compressed Natural Gas Transportation	60,139	60,139	N/A	59,982	66,805	N/A
Electric Generation Transportation	355,327	355,327	N/A	355,327	N/A	N/A

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JEFFREY J. HUSEN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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LIST OF EXHIBITS

EXHIBIT JJH-1	List of Witnesses and Testimony Topics
EXHIBIT JJH-2	Cost of Service Schedules Table of Contents
EXHIBIT JJH-3	Central-Gulf Service Area Investment Reports for January 2024 – December 2024
EXHIBIT JJH-4	Rio Grande Valley Service Area Investment Reports for January 2023 – December 2024
EXHIBIT JJH-5	West North Service Area Investment Reports for January 2022 – December 2024

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 Nos. 10739, 10766, 10928 and Docket Nos. OS-22-00009896 ("Docket No. 9896"), OS-23-00014399 ("Docket No. 14399"), and OS-24-00017471 ("Docket No. 17471"). 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. My testimony will summarize and introduce the following issues:

1. Explain the issues that are driving the timing of the Company's filing and the relief TGS seeks through this case;

2. Identify the witnesses who are providing testimony in support of this SOI;

3. Discuss the Company's request to consolidate the Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA") and West North Service Area ("WNSA") into a single TGS division;

4. Address the annual capital investment reports for the existing CGSA,[1] RGVSA,[2] and WNSA[3] that TGS has filed with the Commission as part of its Interim Rate Adjustment ("IRA" or "GRIP") filings since the last associated rate cases, which supports the Company's request for a determination that the Direct, TGS Division and Corporate capital investment made through December 31, 2024, is used and useful and was prudently incurred;

5. Summarize the Company's proposal to continue the use of small and large rate design that the Commission has previously approved in the currently designated service areas (recognizing the differing usage characteristics of customers in the residential and commercial classes); however, this rate design would be new for commercial customers in WNSA;

6. Introduce the Company's proposals to assist income-qualified customers through a discounted rate design and an expansion of the Company's Share the Warmth customer assistance program; and

[1] The Company last filed a rate case with the CGSA cities and Commission on June 3, 2024 (*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*, Docket No. OS-24-00017471 consol., Final Order (Nov. 19, 2024)).

[2] The Company last filed a rate case with the RGVSA cities and Commission on June 30, 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 (Jan. 30, 2024)).

[3] The Company last filed a rate case with the WNSA cities and Commission on June 30, 2022 (*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., Final Order (Jan. 18, 2023)).

7. Summarize the revisions the Company proposes to its Line Extension Policy within its Rules of Service.

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

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

II. OVERVIEW OF THE STATEMENT OF INTENT FILING

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, 950 of which are in Texas. As a 100% regulated company focused solely on delivering natural gas safely and reliably, all costs ONE Gas incurs are from activities that support providing this service to its customers.

Q. WHAT TEST YEAR WAS USED IN THIS SOI?

A. The Company's SOI is based on the financial results for the test year ended December 31, 2024, with adjustments for some known and measurable changes as discussed in the direct testimonies of Company witnesses Anthony Q. Brown, Eric S. Sanford, Keara J. Downum and Stacey L. McTaggart.

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 $41,069,909. 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 10.40%. TGS is requesting recovery of reasonable and necessary operating and maintenance ("O&M") costs it incurred in 2022 as a result of COVID-19 that have not previously been authorized for recovery, consistent with the Regulatory Asset Notice the Commission issued in April 2020.[4] 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. Downum. The Company is also requesting new depreciation rates, as discussed in the testimony of Company witness Dr. Ronald E. White.

In addition to the rate relief requested in this SOI, TGS is also seeking approval to consolidate the existing CGSA, RGVSA and WNSA into a single TGS division. The Company is also proposing to continue 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 WNSA in Docket No. 9896 and for residential and

[4] 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.

commercial customers in the RGVSA in Docket No. 14399 and in the CGSA in Docket No. 17471.

Finally, TGS is requesting a prudence determination finding that the capital investment made since the last rate cases in the existing CGSA, RGVSA, and WNSA cities and environs 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 Cost of Service schedules, which lists all the schedules and workpapers in this filing, along with the sponsor(s).

Q. WHY IS TGS FILING A SOI AT THIS TIME?

A. The Company's current base rates within the existing CGSA, RGVSA and WNSA cities and environs were established in November 2024, January 2024 and January 2023, respectively. Rate cases are significant undertakings that are time- and resource-intensive. As such, the Company carefully scrutinizes its cost of service to determine if it needs to file a rate case. Inflationary pressures continue to impact the Company's cost of providing service, not unlike most other businesses. Although the Company has been able to update rates with annual GRIP filings with the cities and Commission since that last rate cases, the Company's rates are not sufficient to recover the cost of providing service at this time.

This rate case gives TGS the opportunity to request rates that more accurately reflect the current and expected costs of providing service to TGS customers at the time new rates will go into effect and to continue its efforts to achieve efficiencies through regulatory service area consolidation, which the Commission has consistently been approving since 2016. The filing is intended to

explain the changes in expenses (including depreciation expense), support the recovery of investments in the Company's distribution system, address the accumulation of deferred taxes since the last rate case, better align each customer class's contribution to the overall revenue requirement based on the cost of providing service and expand programs to support income-qualified customers in need of assistance.

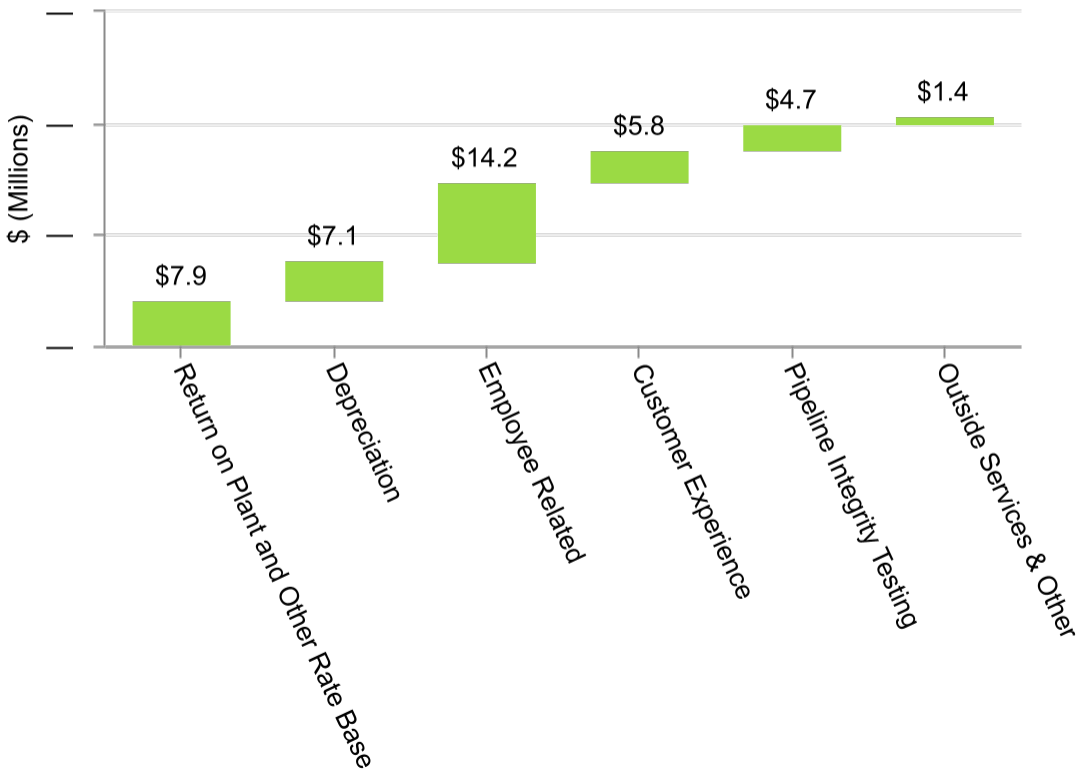
The Company's top priority is maintaining a safe and reliable natural gas system, the operation of which requires annual investments to improve the natural gas system and the incurring of expenses in order to operate safely and reliably. Since the last rate cases in each service area, the Company's net plant has increased over $338 million as the result of investments in its natural gas distribution system. These investments were necessary to replace aging infrastructure and support the safe and reliable delivery of natural gas to residential and business customers, including costs of extending service to new customers. This case provides an opportunity to realign rates to support current and future investments, allowing the Company to continue to provide safe and reliable service to our customers and to update the Company's tariffs accordingly.

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

A. In terms of revenue requirement, the Company's cost of service calculations show that TGS is experiencing a revenue deficiency driven primarily by the need to recover costs for employee-related expenses, the cost of capital on the Company's plant investment, related depreciation, and the Company's ongoing efforts to

comply with all regulatory and safety requirements. Table JJH-1 below, illustrates the drivers of the $41.1 million revenue deficiency.

Table JJH-1
Drivers of Revenue Deficiency



Q. ARE THE COSTS TGS SEEKS TO RECOVER, WHICH ARE DRIVING THE REVENUE DEFICIENCY, REASONABLE, NECESSARY AND PRUDENT?

A. Yes. In addition to an increase of over $338 million in net plant since base rates were last changed, 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.

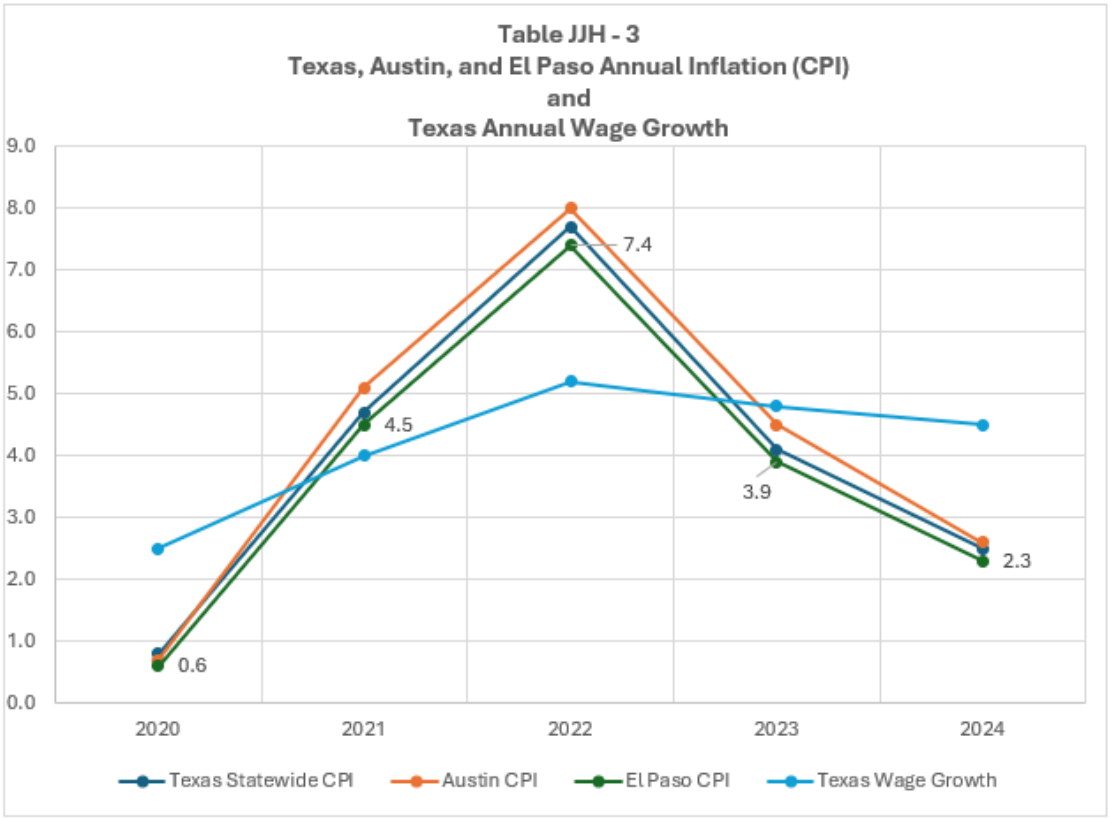
TGS also made additional capital investments in its natural gas distribution system for technology that provides critical services supporting all employees in their efforts to provide service safely and reliably to customers. The Company continues to incur these types of costs annually due to aging infrastructure; 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 investments and expenses 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, inflationary pressures are also affecting the Company's costs to provide service. As there can be a significant lag due to the inflationary impact on expenses, the proposed rate increase is not out of line with U.S. inflation that has had an average cumulative effect of approximately 21% since the pandemic that began in 2020. Please see Table JJH-2 below for the inflation rates by month from 2020 through 2024, as published by the Bureau of Labor Statistics.

Table JJH-2													
U.S. INFLATION RATES													
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**AVG**
2024	3.1%	3.2%	3.5%	3.4%	3.3%	3.0%	2.9%	2.4%	2.6%	2.7%	2.9%	2.9%	2.9%
2023	6.4%	6.0%	5.0%	4.9%	4.0%	3.0%	3.2%	3.7%	3.7%	3.2%	3.1%	3.4%	4.1%
2022	7.5%	7.9%	8.5%	8.3%	8.6%	9.1%	8.5%	8.3%	8.2%	7.7%	7.1%	6.5%	8.0%
2021	1.4%	1.7%	2.6%	4.2%	5.0%	5.4%	5.4%	5.3%	5.4%	6.2%	6.8%	7.0%	4.7%
2020	2.5%	2.3%	1.5%	0.3%	0.1%	0.6%	1.0%	1.3%	1.4%	1.2%	1.2%	1.4%	1.2%

As shown in Table JJH-3 below, Texas has not been immune to the impacts of inflation.



Sources: U.S. Bureau of Labor Statistics; Federal Reserve Bank of Dallas; and Texas Workforce Commission

Table JJH-3 summarizes the year-over-year inflation rate for Texas statewide and specifically for the Austin and El Paso markets for 2020 through 2024, along with the wage growth in Texas for that same time period. As can be

seen in the table, inflation rates are consistent with the national trends noted in Table JJH-2. Texas statewide inflation had a cumulative impact of approximately a 19% increase since 2020.

Wage growth in the state of Texas over the last five years has contributed to the inflationary increases previously discussed. As shown in Table JJH-3, the inflationary pressures have begun to decrease, but wage growth continues to remain consistent over the past four years. Over the past five years, annual wage increases have increased to 4.5% in 2024 from 2.5% in 2020, with a peak of 5.2% in 2022.

Accordingly, 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. Since the Company's previous rate cases, prices for equipment, materials, supplies, employee labor and contractor services have increased. These external factors contribute to the need to increase rates to be able to continue to provide safe and reliable service.

Q. HAS THE COMPANY FOLLOWED PRIOR COMMISSION DECISIONS IN PREPARING THIS SOI?

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, the use of the Company's actual capital structure, and requests to consolidate service areas. 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 currently designated service territories 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 an 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?

A. The proposed rate increase will result in changes to the average monthly bills for the 598,949 residential customers in the incorporated areas and the 67,441 residential customers in the environs areas, as shown in Table JJH-4 below.[5]

Table JJH-4

Line No.	Description	Current	Recommended	Change Dollars	Change %
	(a)	(b)	(c)	(d)	(e)
1	**Residential - Small**				
2	CGSA Incorporated and Environs	$44.88	$48.82	$3.94	8.78%
3	WNSA Incorporated and Environs	$38.44	$48.82	$10.38	27.00%
4	RGVSA Incorporated and Environs	$62.53	$48.82	$(13.71)	(21.93)%
5	**Residential - Large**				
6	CGSA Incorporated and Environs	$77.29	$74.30	$(2.99)	(3.87)%
7	WNSA Incorporated and Environs	$59.66	$74.30	$14.64	24.54%
8	RGVSA Incorporated and Environs	$78.89	$74.30	$(4.59)	(5.82)%

The proposed rates for all rate classes are also identified in Mr. Raab's direct testimony and are reflected in the tariffs sponsored by Mr. Brown. In addition, the Company proposes revised service fees and updated language in its transportation tariffs and Rules of Service.

[5] The changes in year-round average bills shown in Column (d) and (e) vary due to differences in current rates and the timing of prior rate cases.

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 60% 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 now able to submit pledges online and to 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 events such as 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 32,000 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 the reading of a meter. This initiative reduced on-site visits to customer locations by approximately 82,000 visits in 2024, and avoided an estimated cost of $1.3 million.

2. The Company has implemented three Picarro mobile leak survey units in Texas in recent years. In these early years of implementation, efficiency savings are at least partially offset by the increase in leaks that are found by the technology. Over time, mobile leak survey is expected to provide increased safety along with cost benefits.

3. The Company has added additional employees to transition a significant portion of line locating costs from contractor to employee labor. This transition will allow the Company to reduce reliance on contractors, as well as, assess performance in comparing internal versus external labor. In addition, the Company has begun filtering line locate tickets from 811 to identify those that are only requesting an extension of the locate already performed. This process reduced ticket volume by approximately 10.5% in 2024, and avoided an estimated cost of $1.1 million.

4. 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 2024 test year that is approximately 30% less ($838,000) than pre-pandemic levels in 2019.

5. Several HR and Benefit initiatives are producing savings and projected to continue to create O&M savings through benefits design changes and active vendor management totaling approximately $159,400 in savings.

III. CONSOLIDATION

Q. WHAT DOES TGS PROPOSE IN THIS RATE CASE REGARDING CONSOLIDATION?

A. TGS proposes to consolidate the existing CGSA, RGVSA, and WNSA to form a single TGS division.

Q. WHY IS THE COMPANY REQUESTING CONSOLIDATION OF ALL EXISTING SERVICE AREAS IN TEXAS?

A. The request in this case for a single set of rates that would apply to the entire TGS division is the culmination of the Company's efforts since 2015 to consolidate service areas. This regulatory treatment aligns with the reality that TGS has been operating in a consolidated manner for approximately a decade. Our technicians cross service area boundaries to conduct leak detection activities and to repair and replace equipment, and our Service Centers serve customers in multiple areas of the state without regard to service area boundaries. Operation of TGS as a single division has been a practical reality for years due to the Company's functional operating model, operational efficiencies that have occurred over the years and population growth that occurs regardless of geographic boundaries. As the Commission has recognized in prior TGS consolidation cases, a single set of base rates and tariffs will reflect these realities and reduce rate case expenses and other administrative costs. Instead of the need for three rate cases to adjust base rates and/or tariffs, TGS will incur rate case expenses associated with only one base rate proceeding in the future. Similarly, if consolidation is approved, the Company will reduce the number of GRIP filings from the three it currently files, to only one GRIP.

Q. WILL CONSOLIDATION REQUIRE CHANGES TO HOW TGS OPERATES ITS SYSTEM?

A. No, the operational changes necessary to operate in a coordinated manner have already occurred. The consolidation actually better reflects TGS's existing

centralized operations, management, and decision-making processes. The existing regulatory service areas are not operated in isolation from each other. Instead, TGS operates and maintains its system, including all of the existing service areas, in a coordinated way, along with managing those activities at the TGS and ONE Gas levels.

TGS's currently designated service areas have been the result of historical factors. The boundaries of the Company's service areas are arbitrary from an operations perspective and have been the result of acquisitions of existing gas utility systems throughout the state starting approximately 90 years ago. Boundaries that may appear on maps were not the result of an intentional choice of the Company to identify geographic boundaries around the gas distribution systems TGS operates. TGS's system is centralized at the corporate or statewide levels so there is no need or basis for separate geographic service areas.

Q. PLEASE ELABORATE ON HOW TGS CURRENTLY OPERATES THE SYSTEM.

A. The existing CGSA, RGVSA and WNSA already share personnel for certain services and rely on centralized management of certain functions and operations. Many of the same people, myself included, are regularly involved in the coordinated operation, maintenance and management of the Company's system throughout the state, including for the currently designated service areas that TGS seeks to consolidate. The centralization resulting from the functional operating model allows for the efficient and timely use of materials, supplies, and other Company resources, including personnel. For example, the Company's

centralization of the Customer Information Center located in El Paso means that all TGS customers receive uniform responses to similar inquiries concerning payment activity, establishing or changing service, and service or payment disputes. Similarly, our centralized dispatch allows for efficient deployment of field operation employees in Texas to provide timely service to customers. The centralization of functions such as leak survey, pressure control and measurement, and cathodic protection on a statewide basis promotes efficiency and consistency, allowing the Company to monitor the status of its assets more effectively.

Q. HAS THE COMMISSION APPROVED CONSOLIDATION FOR OTHER TGS SERVICE AREAS?

A. Yes. Between 2016 and 2023, the Commission approved consolidation of service areas in five TGS rate cases. As a result, the number of service areas has gone down from ten to three regulatory service areas. The consolidation TGS requests in this rate case is similar to the other service area consolidations the Commission approved for TGS because the way TGS operates the system has not changed. The same operational, regulatory and administrative factors that supported prior consolidation requests also support consolidation in this rate case. As Ms. McTaggart explains in detail in her testimony, the Administrative Law Judge in Docket No. 9896 explained, it is not logical to require gas utilities like TGS to create efficiencies in operations while also preventing them from consolidating service areas. My testimony has addressed the operational efficiencies that support consolidation, and Ms. McTaggart addresses Commission policy and the many prior decisions that support consolidation from a regulatory perspective.

Q. IS THE CONSOLIDATION REQUEST APPROPRIATE AND IN THE PUBLIC INTEREST?

A. Yes. TGS already operates the CGSA, RGVSA and WNSA in a centralized and coordinated manner. Further, decisions regarding incurring O&M expense and making capital investment are also handled in a centralized approach. Consolidation will lead to more consistent and equal cost impacts on customers because there will be a larger, single group of customers in TGS, instead of three distinct customer bases in three different service areas. Consolidation is also appropriate because any geographic boundaries of the service areas are arbitrary from an operations perspective and not relevant to the way the Company has operated and will continue to operate its system. Ms. McTaggart also addresses why consolidation is appropriate and in the public interest from a rates and administrative perspective.

IV. 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 since the last rate cases in each currently designated service area in the amount of approximately $338 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. Company witnesses Alejandro Limón, Mr. Brown and Mr. Sanford address these investments in more detail in their direct testimonies. As addressed by Mr. Brown and Mr. Sanford, 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.

Q. IS TGS INCLUDING CAPITAL INVESTMENT FROM GRIP FILINGS IN THIS RATE CASE?

A. Yes. The Company has made annual GRIP filings in each service area since the last rate cases. TGS has included GRIP investment since January 1, 2022, for the WNSA, January 1, 2023, for the RGVSA, and January 1, 2024, for the CGSA.

Q. IN ADDITION TO YOURS AND MR. LIMÓN'S TESTIMONY, WHAT SUPPORT IS THE COMPANY PROVIDING FOR THE ANNUAL CAPITAL INVESTMENT AMOUNTS?

A. In Exhibits JJH-3 through JJH-5, 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 each service area.

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 allocated

Corporate capital investment amounts. Therefore, the ongoing capital investment is a necessary and critical aspect of the Company's ability to provide service.

V. SMALL AND LARGE RATE DESIGN

Q. PLEASE DESCRIBE THE COMPANY'S SMALL AND LARGE RATE DESIGN PROPOSAL.

A. The Company proposes to continue a rate design that has been previously approved by the Commission and 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. If approved, this will be a new rate design for commercial customers in the current WNSA. 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	$29.50	$75.00
Volumetric Rate (All Ccf)	$0.67553	$0.43589

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	$39.50	$150.00
Volumetric Rate (All Ccf)	$0.31189	$0.13589

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-5 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, consistent with the Commission's approval of existing small/large rate structures, 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."[6] The customer will have the option to contact the

[6] *See* 16 TAC § 7.45(2)(A)(ii).

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 ALL 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 in Docket No. 9896, which was fully litigated, 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;[7]
- 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;[8] and
- the two-tier rate design will give small usage customers more control over their bill and will give large usage customers more stable bills.[9]

This analysis supports the finding in the Final Order in Docket No. 9896 that the two-tiered rate structure for residential customers is just and reasonable.[10]

[7] Docket No. OS-22-00009896 consol., Amended Proposal for Decision at 61 (Jan. 11, 2023).
[8] *Id.* at 62.
[9] *Id.*
[10] *See* Docket No. OS-22-00009896 consol., Final Order at Findings of Fact No. 103 (Jan. 18, 2023).

VI. CUSTOMER ASSISTANCE

Q. WHAT OPTIONS DOES TGS CURRENTLY PROVIDE TO ASSIST CUSTOMERS WITH PAYING THEIR BILLS?

A. The Company provides several plans and programs to assist customers, including:

1. Small & Large Rate Design - As discussed previously in this testimony, TGS offers rate design options that recognize the differing usage characteristics of customers and allows customers who desire it, some amount of choice in how they are billed for gas service.

2. Average Payment Plan - The Average Payment Plan is based on a 12-month rolling average of a customer's natural gas bill. This plan reduces the volatility of seasonal energy expenses by spreading the average annual cost of natural gas service throughout the year which makes budgeting easier.

3. Pay arrangements - In addition to offering convenient forms of payment such as automatic payments and the ability to pay online from the website or mobile application, customers who have been notified that their service may be disconnected can access options to establish convenient payment plans through either the website or by contacting a customer service agent.

4. Access to Customer Assistance programs - In addition to financial contributions to programs like Share the Warmth, the Company works with customers to find options to pay their bills through programs like 2-1-1 Texas and the Low Income Home Energy Assistance Program (LIHEAP).

Q. WHAT NEW OR EXPANDED CUSTOMER ASSISTANCE PROGRAMS DOES TGS PROPOSE?

A. As more fully explained by Ms. McTaggart, the Company proposes an expanded Share the Warmth program and a Customer Assistance residential rate schedule pilot program for qualifying customers. The Company recognizes that an important public policy interest is served by ensuring qualified customers have resources to help pay their utility bills, and TGS supports continued efforts to ensure resources are available through rate design or in amounts necessary to meet the ongoing needs.

Q. PLEASE BRIEFLY EXPLAIN THE SHARE THE WARMTH PROGRAM.

A. Share the Warmth is a program that allows customers to voluntarily contribute their own money to provide financial assistance for fellow customers who need help paying their natural gas bills. In addition to customer contributions, the Company agreed in prior rate cases affecting Central Texas and Gulf Coast customers to make matching contributions to Share the Warmth beginning in 2017. In 2024, the Company agreed to match Share the Warmth contributions up to $200,000 annually.

Q. WHY IS THE COMPANY PROPOSING TO EXPAND THE SHARE THE WARMTH PROGRAM?

A. TGS believes it is important for the Share the Warmth program to provide sufficient support for customers in need of assistance. To meet that need, however, funding beyond that currently provided by customers and the Company would be required at a significantly higher level than the past. We believe Share the Warmth funding represents a reasonable and necessary expense in TGS's cost of service. As Ms. McTaggart explains in more detail in her testimony, TGS proposes a new statewide program with an available amount of $2 million per year to replace the existing $200,000 CGSA contribution. The program funds would be distributed to partner agencies statewide. In addition, customers would continue to have the option of making contributions to the program.

Q. WHAT IS THE COMPANY'S RATE DESIGN PROPOSAL TO ASSIST CUSTOMERS?

A. The Company proposes a pilot program for up to 30,000 active income qualifying residential customers to receive service at reduced rates (customer charge and volumetric rate) that are approximately 25% lower than the proposed rates for small residential customers. A customer served under this rate schedule would be responsible for the full cost of any associated rate schedules or riders such as the Cost of Gas Clause, PIT Rider or Rate Case Expense Rider. Ms. McTaggart and Mr. Raab provide additional details of the Company's proposal.

VII. PROPOSED REVISIONS TO LINE EXTENSION POLICY

Q. IS THE COMPANY CONTINUING TO SEE DEMAND FOR NATURAL GAS SERVICE?

A. Yes, the Company continues to experience requests for natural gas service for residential, commercial and industrial sales and transport customers throughout the state. The following Table JJH-5, highlights the number of new meters installed by the Company over the last three years.

Table JJH-5
NEW METER SETS

2024	9,293
2023	9,757
2022	10,698

In addition to the customers added, TGS had approximately 31,000 meter requests at December 31, 2024, from individuals or entities that are interested in receiving service from the Company in the future.

Q. ARE THERE BENEFITS OF MAKING INVESTMENTS TO SERVE NEW CUSTOMERS?

A. Yes, other than the obvious benefits of being responsive to the residential, business, and economic needs of the Company's customers, the addition of new customers provides access to cost effective energy resources to Texas residents and businesses. According to the American Gas Association, natural gas is 3.5 times more affordable than electricity in the United States.[11] Without a cost effective way to connect new customers to natural gas service through an interconnected, safe and reliable pipeline network, the cost benefits of natural gas as an energy source will be diminished, which will ultimately raise costs for customers. Without the ability to provide natural gas as an energy source, customers' increased energy needs will further burden electric grids that are already resource constrained. Lastly, the addition of new customers also provides a wider base over which to spread fixed system costs, specifically the costs to operate and maintain the system.

Q. HOW DOES THE COMPANY ENSURE THAT EXISTING CUSTOMERS' RATES ARE NOT UNDULY AFFECTED BY EXTENDING SERVICE TO NEW CUSTOMERS?

A. The Company's goal is to ensure that existing customers' rates are not unduly affected due to investment for new customer additions. To that end, each project is evaluated to determine if the future customers to be served by the new project will produce revenue sufficient to cover the additional cost of service resulting from the capital expenditures necessary to extend or build a new part of the Company's

[11] *See* https://playbook.aga.org/affordable.

system. In cases where there will not be sufficient revenues covering the additional cost of service, the Company will require a contribution from the entity (or person) who is requesting the line extension to make the extension cost justified.

Q. WHAT REVISIONS DOES THE COMPANY PROPOSE TO ITS LINE EXTENSION POLICY IN THE RULES OF SERVICE?

A. TGS proposes revisions to the Line Extension Policy in the Rules of Service to align with our existing practices for the formula by which the Company determines if a line extension is cost justified, to enhance our ability to provide service by identifying certain instances when the Company may include in invested capital some or all of the cost of customer piping and venting, and to add language clarifying the recoverability of certain costs associated with right of way and facility installation management, consistent with a recent Commission decision in Docket No. OS-24-00018879 ("Docket No. 18879"). Ms. McTaggart explains the details of these revisions in her direct testimony.

Q. WILL CUSTOMERS BENEFIT FROM THE COMPANY'S REVISIONS TO THE LINE EXTENSION POLICY IN TGS'S RULES OF SERVICE?

A. Yes, the Company's revisions will more clearly delineate the process by which it evaluates customer growth investments, enhance the components of what may be included in invested capital and align our policies with the recent Commission decision in Docket No. 18879. This additional clarity will allow customers and the Commission to understand how the Company determines the prudency of investments related to customer growth.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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; supports the proposed consolidation of the TGS service areas into a single Texas jurisdiction; addresses the Company's proposed revisions to customer assistance and related tariff options; addresses proposed revisions to the line extension policy in the Rules of Service; 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	Vice-President of Operations for TGS	Provides an overview of operations in Texas; supports the proposed consolidation of the TGS service areas into a single statewide jurisdiction; addresses the reasonableness and necessity of capital investment and Operations and Maintenance ("O&M") expenses; addresses ONE Gas' response to COVID-19; and addresses the Company's Pipeline Integrity Testing Program.
Anthony Q. Brown	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 request for recovery of rate case expenses; and describes the proposed TGS rate schedules and tariffs, as well as rate schedules and tariffs currently in effect for the CGSA, RGVSA, and WNSA.
Stacey L. McTaggart	Rates and Regulatory Director for TGS	Addresses the Company's request to consolidate all of its existing service areas - CGSA, RGVSA, and WNSA - to implement statewide rates and tariffs; describes the Company's request for an expanded customer assistance program and tariff and the recovery of associated costs; supports the Company's request for recovery of credit card processing fees; addresses regulatory asset treatment of cloud-based computing costs; and revisions to the line extension policy in the Rules of Service.
Eric S. Sanford	Manager of Rates and Regulatory Compliance for ONE Gas	Supports certain TGS Division and Corporate capital investment that is included in the revenue requirement as well as Corporate depreciation and amortization expense.
Keara J. Downum	Rates Analyst II of Rates and Regulatory Compliance for ONE Gas	Addresses the cost allocation methodology used to determine TGS's share of allocated costs; discusses certain Corporate expense adjustments; and explains the Direct, TGS Division and Corporate expense adjustments related to payroll, employee benefits, and incentive compensation.
Megan Z. Gough	Director of Compensation for ONE Gas	Addresses the reasonableness of ONE Gas' compensation philosophy and structure, as well as the related costs for base pay, incentive plans, and benefits.
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 how the Internal Revenue Service's Natural Gas Safe Harbor Method impacts the Company's taxes and addresses the treatment of the Company's Excess Deferred Income Taxes ("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 statewide study of the depreciation rates for TGS plant located in Texas and for common facilities used by TGS throughout the state.
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 D. 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.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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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 11 day of June 2025.

M. BETH WILLIAMS NOTARY # 13002055 EXP. 03/01/29 PUBLIC STATE OF OKLAHOMA

M Beth Williams
Notary Public in and for the State of Oklahoma

My commission expires: 3/1/2029

WORKPAPERS

TO

DIRECT TESTIMONY

OF

JEFFREY J. HUSEN

Workpapers to the Direct Testimony of Jeffrey J. Husen are being provided in electronic format.

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

ALEJANDRO LIMÓN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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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. 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 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 ("WNSA")) 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, Docket No. OS-23-00014399 ("Docket No. 14399") and Docket No. OS-24-00017471 ("Docket No. 17471").

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 Texas and explains how the costs TGS incurs are necessary for maintaining a safe and reliable natural gas distribution system. In addition, my testimony supports the Company's request to consolidate the existing Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA") and WNSA into a single statewide jurisdiction. 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

Texas through December 31, 2024. 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, used and useful. I also support 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 and tight labor market.

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 in Texas. I have attached a map of the areas that TGS serves to my testimony as Exhibit AL-1. TGS and its predecessor utilities have served these areas for nearly 120 years. Operational decisions for TGS are made at the statewide level in coordination with ONE Gas corporate level management 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 existing regulatory service area boundaries do not represent the full scope of employees responsible for the activities and workload associated with its actual operations in Texas. Instead, the centralized approach means that the existing 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, 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 OPERATIONS IN TEXAS.

A. TGS provides natural gas distribution service to approximately 700,000 customers[1] and operates approximately 11,285 miles of distribution mains, approximately 253.86 miles of transmission mains, and approximately 5,913 miles of service lines. These system assets combined represent more than $1,887 million in net investment. As of the end of 2024, the Company directly employed approximately 220 TGS Division and 737 Direct personnel in Texas with a combined annual payroll of over $71 million. The Company remitted approximately $17.9 million in annual property taxes to each of the local taxing authorities within the TGS territories.

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] TGS serves customers in the Incorporated and environs areas of: Alamo, Aledo, Alton, Andrews, Anthony, Austin, Barstow, Bayou Vista, Beaumont, Bee Cave, Borger, Breckenridge, Brownsville, Bryson, Buda, Cedar Park, Clint, Combes, Crane, Cuero, Dell City, Donna, Dripping Springs, Edcouch, Edinburg, El Paso, Elsa, Galveston, Georgetown, Gonzales, Graford, Graham, Groves, Harlingen, Hidalgo, Horizon City, Hudson Oaks, Hutto, Jacksboro, Jamaica Beach, Jarrell, Kyle, La Feria, La Joya, La Villa, Laguna Vista, Lakeway, Lockhart, Los Fresnos, Luling, Lyford, Marble Falls, McAllen, McCamey, Mercedes, Millsap, Mineral Wells, Mission, Monahans, Mustang Ridge, Nederland, Nixon, Palm Valley, Palmhurst, Palmview, Pecos, Penitas, Pflugerville, Pharr, Port Arthur, Port Isabel, Port Neches, Primera, Progreso, Pyote, Rancho Viejo, Raymondville, Rio Hondo, Rollingwood, San Benito, San Elizario, San Juan, Santa Rosa, Shiner, Skellytown, Socorro, Sunset Valley, Thorntonville, Vinton, Weatherford, Weslaco, West Lake Hills, Wickett, Willow Park, Wink, and Yoakum, Texas; the environs of Bastrop, Texas; and the unincorporated areas of: Bayview, Canutillo, Fabens, Jermyn, Jim Hogg County, Jonah, Laguna Heights, Monte Alto, Olmito, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, San Carlos, Starr County, and Whitt, Texas.

(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 for the last 9 years. TGS has also 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. CONSOLIDATION OF TEXAS GAS SERVICE

Q. WHAT DOES TGS PROPOSE IN THIS RATE CASE REGARDING CONSOLIDATION?

A. TGS proposes to consolidate the existing CGSA, RGVSA and WNSA into a single statewide jurisdiction.

Q. WILL CONSOLIDATION REQUIRE CHANGES TO HOW TGS OPERATES ITS SYSTEM?

A. No, the operational changes necessary to operate in a coordinated manner have already occurred. The service area consolidation requested in this filing will actually better reflect TGS's existing centralized operations, management, and decision-making processes. The existing regulatory service areas are not operated in isolation from each other. Instead, TGS operates and maintains its system, including all of the existing service areas, in a coordinated way, along with managing those activities at the TGS and ONE Gas levels.

TGS's current service areas have been the result of historical factors, particularly those existing prior to the three consolidations beginning in 2016.[2] The boundaries of the Company's service areas are arbitrary from an operations perspective and have been the result of acquisitions of existing gas utility systems throughout the state starting approximately 120 years ago. Boundaries that may appear on maps were not the result of an intentional choice to identify geographic boundaries around the gas distribution systems TGS operated. TGS's system is

[2] In 2016, TGS began the process of consolidating its original ten service areas by the submission of a series of rate case filings seeking regulatory approval for the initial consolidation of service areas into the three existing territories today - the Central-Gulf Coast Service Area, the West North Service Area, and the Rio Grande Valley Service Area.

now centralized at the corporate and statewide levels so there is no need or basis for continued separate geographic service areas.

Q. PLEASE ELABORATE ON HOW TGS CURRENTLY OPERATES THE SYSTEM.

A. The existing CGSA, RGVSA and WNSA already share personnel for certain services and rely on centralized management of certain other functions and operations. Many of the same people, myself included, are regularly involved in the coordinated operation, maintenance and management of the Company's system throughout the state, which includes the service areas that TGS seeks to consolidate.

The centralization resulting from the Company's functional operating model allows for the efficient and timely use of materials, supplies, and other Company resources, including personnel. For example, the centralization of the Customer Information Center located in El Paso, provides all customers within Texas with uniform responses to similar inquiries concerning payment activity, the establishment or changes to service, and responses to service or payment disputes. Similarly, a centralized dispatch center allows for efficient deployment of field operation employees in Texas to provide timely service to customers. Further, the centralization of functions such as leak survey, pressure control and measurement, and cathodic protection on a statewide basis promotes efficiency and consistency, and allows the Company to monitor the status of its assets more effectively within Texas.

Q. HAS THE COMMISSION APPROVED CONSOLIDATION FOR OTHER TGS SERVICE AREAS?

A. Yes. Between 2016 and 2023, the Commission approved consolidation of service areas in five TGS rate cases. As a result, the number of service areas has been reduced from ten to three regulatory service areas. The consolidation TGS requests in this rate case is similar to the other service area consolidations the Commission has previously approved for TGS.

Q. HAS THE MANNER IN WHICH TGS OPERATES ITS SYSTEM CHANGED SINCE THE MOST RECENT APPROVED TERRITORY CONSOLIDATION?

A. No. The same operational, regulatory and administrative factors that supported prior consolidation requests also support consolidation in this rate case. As Company witness Stacey McTaggart explains in detail in her testimony, the Administrative Law Judge in GUD No. 10506 explained, it is not logical to require gas utilities like TGS to create efficiencies in operations while also preventing them from consolidating service areas. My testimony has addressed the operational efficiencies that support consolidation, and Ms. McTaggart addresses Commission policy and many prior decisions that support consolidation from a regulatory perspective.

Q. IS THE CONSOLIDATION REQUEST APPROPRIATE AND IN THE PUBLIC INTEREST?

A. Yes. TGS already operates the existing CGSA, RGVSA and WNSA in a centralized and coordinated manner. Further, decisions regarding incurring O&M

expense and capital investment are also handled in a centralized approach. Consolidation will lead to more consistent or equal cost impacts on customers because there will be a larger, single group of customers TGS serves throughout the state, as opposed to the current three separate customer bases in three different service areas. Consolidation is also appropriate because any geographic boundaries of the service areas are arbitrary from an operations perspective and not relevant to the way the Company has and will continue to operate its system. Ms. McTaggart also addresses why consolidation is appropriate and in the public interest from a rates and administrative perspective.

IV. 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

[3] *See generally,* 49 Code of Federal Regulations ("C.F.R.") § 192.1001-.10015 (2025) (distribution integrity management standards).

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 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 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.

Q. IS THE O&M EXPENSE REQUESTED FOR RECOVERY IN THIS RATE CASE REASONABLE AND NECESSARY?

A. Yes. TGS is requesting recovery of nearly $163 million of O&M expense that was incurred during the test year. Approximately $88 million of O&M expense was directly incurred within the areas TGS serves in Texas, which Company witness Anthony Q. Brown also addresses in his direct testimony. Company witness Keara J. Downum also addresses the TGS O&M costs of approximately $26 million and ONE Gas Corporate allocated O&M costs in the amount of approximately $49 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

[4] 16 Texas Administrative Code ("TAC") §§ 8.101, 8.209 and 49 C.F.R. §§ 192.937, 192.1001.

efficient service to customers. The O&M costs in this rate case are the annual amount of costs incurred for TGS and Corporate employees to perform the day-to-day functions necessary to operate the TGS system.

V. CAPITAL INVESTMENT

Q. WHAT IS CAPITAL INVESTMENT?

A. The term "capital investment" refers to the funds TGS spends to acquire or install equipment or facilities that are used and useful in the provision of 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 to provide safe and reliable service to our customers and for the maintenance and expansion of the utility system.

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 South Austin, a system reinforcement was completed along SH45 and installed 7,850 feet of 12" high-pressure steel pipeline to improve system pressure in order to increase deliverability during extremely cold weather.
- In West Austin, 1,000 feet of high and medium pressure mains were relocated due to encroachment of road enhancements along N. Capital of Texas HWY and Courtyard Drive.
- In Nederland, Texas, 2,800 feet of obsolete steel main pipeline was replaced with polyethylene pipe in a residential community to improve system integrity.

- In Harlingen, Texas 2,200 feet of 2-inch polyethylene medium pressure main pipeline was installed to serve the Paso Real Coves residential subdivision.

- In McAllen, Texas 2,250 feet of deteriorated 4-inch steel low pressure main pipeline was replaced with 1,800 feet of 2-inch polyethylene medium pressure pipeline in the downtown district.

- In El Paso, Texas a complete replacement and re-configuration of the Belvidere Regulation Station was done to increase system sustainability, reliability and ease to maintain and operate.

- In Fabens, Texas, 15,350 feet of 8-inch steel main to replace 4-inch pipe that feeds to the town of Fabens and other customers in the unincorporated areas of El Paso County to improve safety, capacity and system reliability.

- In Monahans, Texas a system reinforcement was completed on West 15th Street with the installation of 4,000 feet of 6-inch polyethylene pipe to increase gas deliverability during 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 by TGS since the last rate cases in the existing CGSA, RGVSA, and WNSA in the amount of approximately $338 million. 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, 2024, which Company witnesses Jeffrey J. Husen, Eric S. Sanford and Mr. Brown address in their direct testimony.

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 next steps in the Company's capital budgeting process include consideration of 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, Company required managerial

approvals are obtained. TGS senior management also meets on a regular basis to review capital spending levels and to 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 to improve customer service.

Q. WHAT AMOUNT OF INVESTMENT HAS TGS MADE INTO ITS SYSTEM SINCE THE LAST RATE CASES IN THE EXISTING WNSA, CGSA AND RGVSA?

A. Since the last rate cases, the Company has, on a combined basis, invested a total of $338 million throughout the state. This increase is related to capital investment the Company 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 the Company 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 necessary, prudent, and reasonable in investment amount for the maintenance, safety and reliability of the system and to provide an appropriate level and quality of gas utility service to our customers. This is also true for the TGS Division and Corporate capital investment amounts that are allocated to Texas and contribute to the Company's ability to provide service in Texas. These capital costs are necessary for the Company's operations and are reasonable and prudent.

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 253.86 miles of gas transmission mains in Texas 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.[5] 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. Mr. Brown 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"), 14399 and 17471.

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. Mr. Brown 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.

[5] 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. 17471, the Commission approved TGS's request to recover all of its requested PIT expenses through a separate rider.[6] As Mr. Brown notes in his direct testimony, the Commission also approved PIT Riders in TGS rate cases in GUD Nos. 9988, 10506, 10526, 10656, 10739, 10928 and Docket Nos. 9896 and 14399.

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 under unprecedented conditions, including COVID-19, 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 2022. Likewise, a national emergency was declared on March 13, 2020, due to COVID-19 on a federal level.[7] This major event and labor market issues, affected the Company's operations and required TGS to incur costs that are included in this rate case.

[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 Rio Grande Valley Service Area,* Docket No. OS-23-00014399 consol., Final Order at Finding of Fact No. 40 (Jan. 30, 2024).

[7] Declaring a National Emergency Concerning the Novel Coronavirus Disease (COVID-19) Outbreak, Proclamation 9994 of March 13, 2020, 85 Fed. Reg. 15,337 (Mar. 18, 2020), Continuation of the National Emergency Concerning the Coronavirus Disease 2019 (COVID-19) Pandemic, 87 Fed. Reg. 10,289 (Feb. 23, 2022) (notice).

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.
- 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.

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.

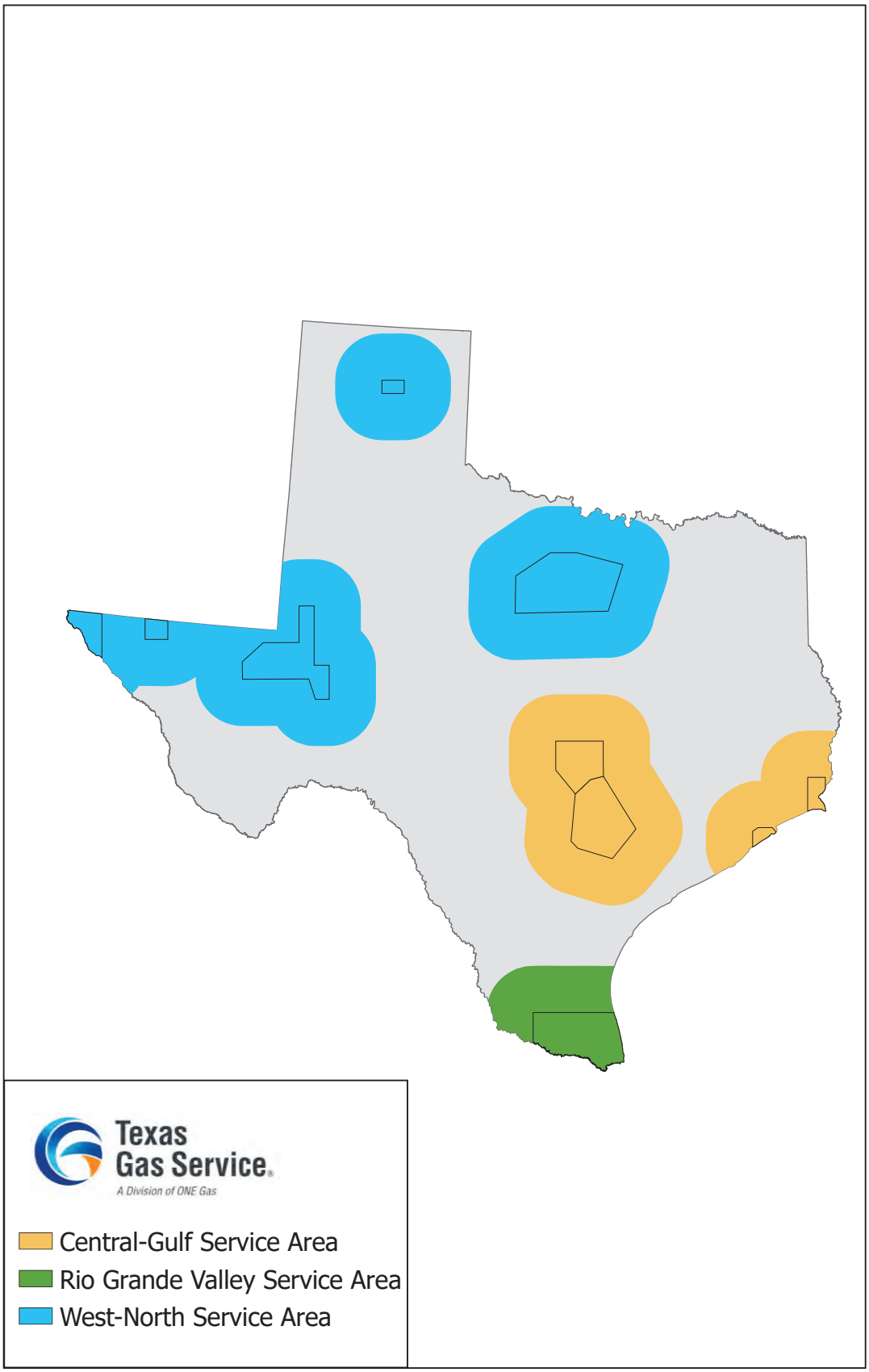
Q. WHAT COSTS DID THE COMPANY INCUR RELATED TO COVID-19 THAT ARE INCLUDED IN THIS RATE CASE?

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, changing air filters monthly and sanitizing spray service. Mr. Brown describes the nature of these costs in his testimony.

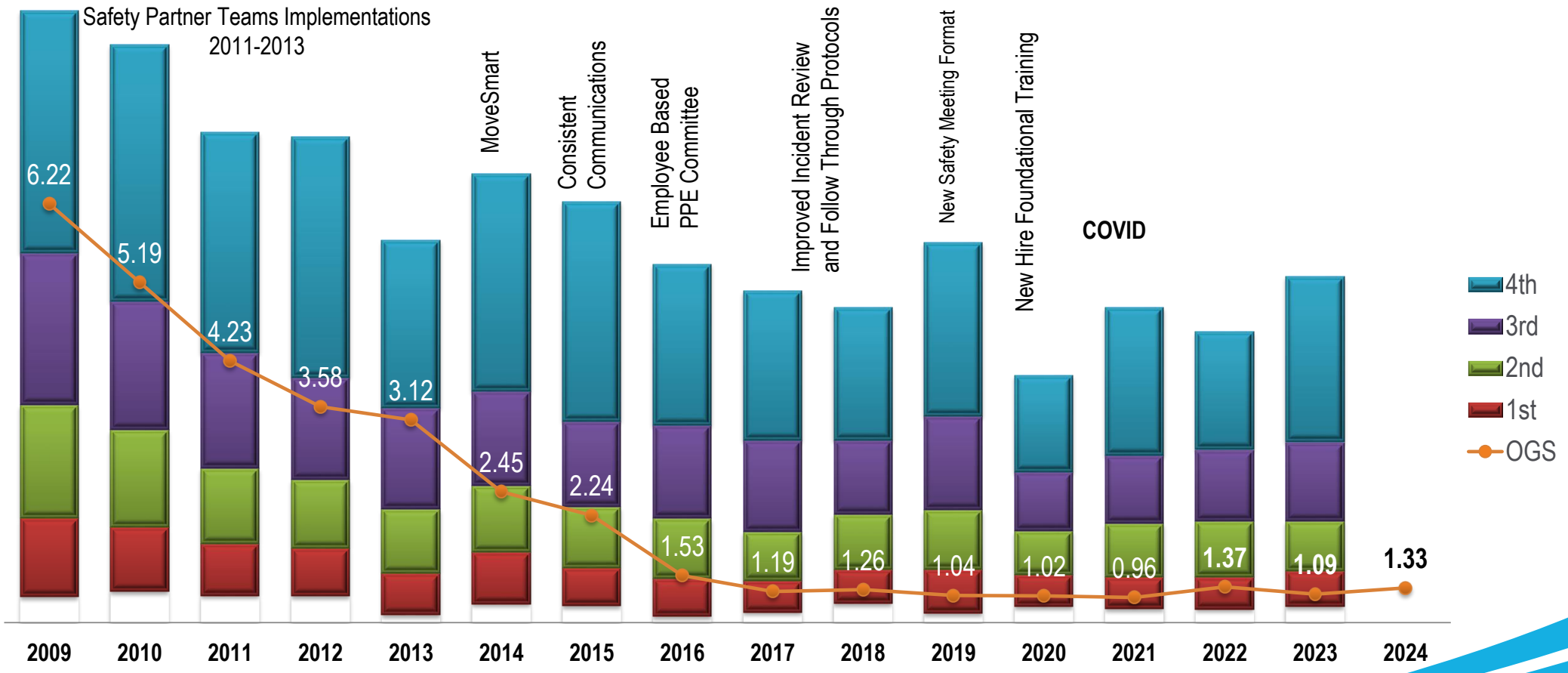
VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

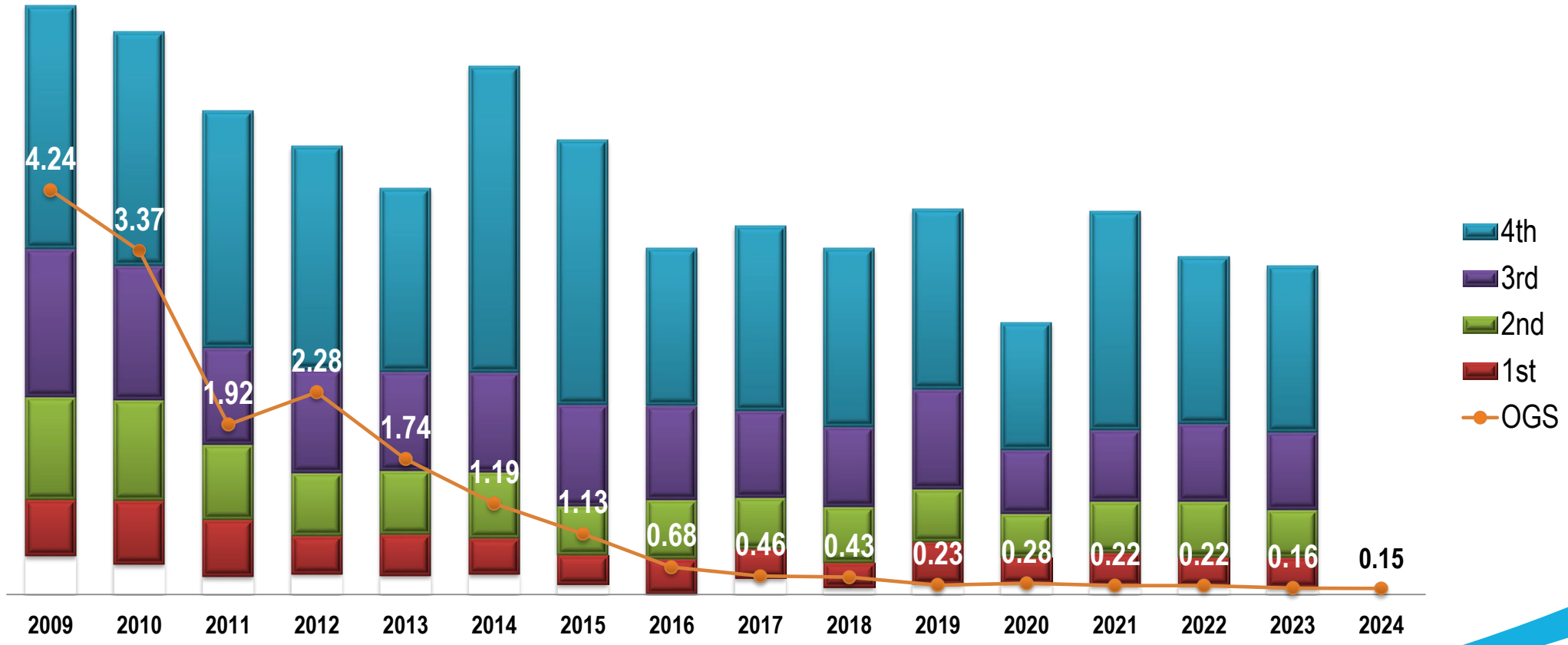
A. Yes, it does.


Texas
Gas Service
A Division of ONE Gas
Central-Gulf Service Area
Rio Grande Valley Service Area
West-North Service Area

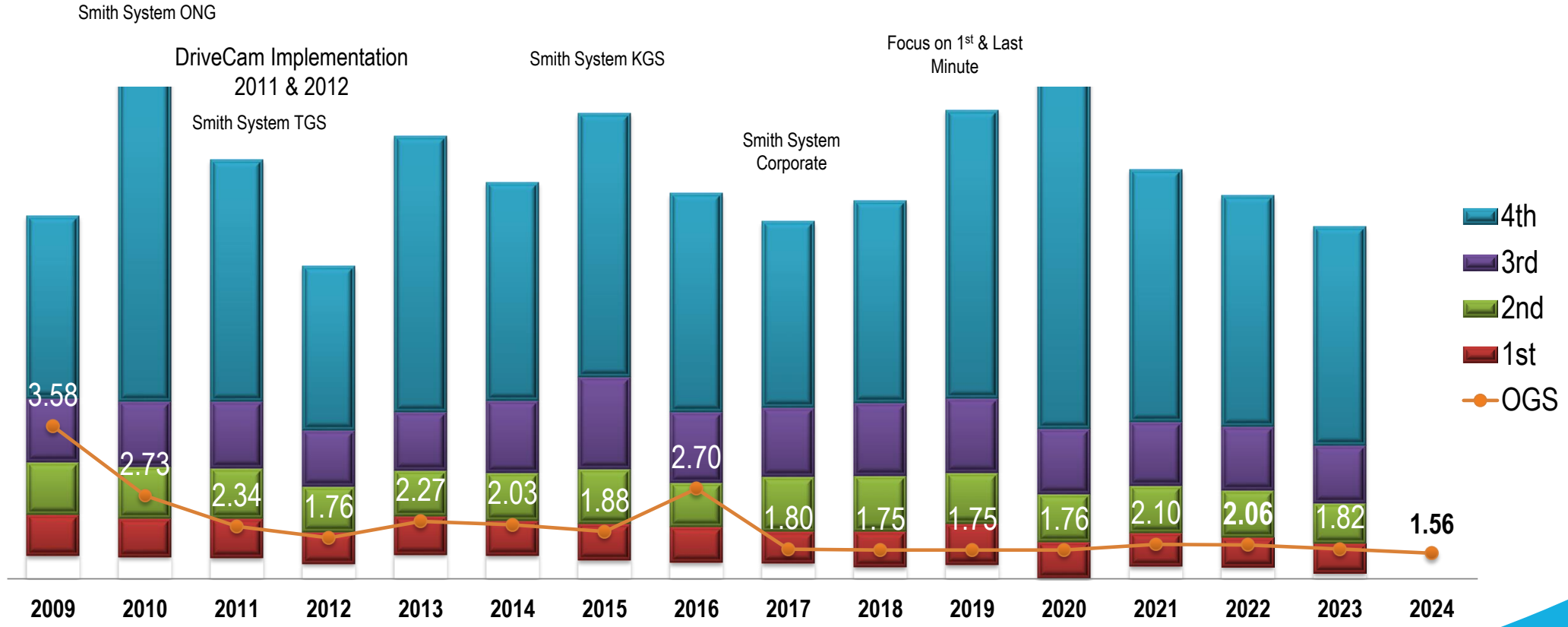
TRIR Historical Performance & Supporting Programs



DART Historical Performance



PVIR Historical Performance & Supporting Programs



STATE OF TEXAS §
§
COUNTY OF EL PASO §

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.

Alejandro Limón

SUBSCRIBED AND SWORN TO BEFORE ME by the said Alejandro Limón on this 10 day of JUNE 2025.

Notary Public in and for the State of Texas

My commission expires: FEBRUARY 14, 2028

MARIA GUADALUPE ARREOLA
Notary ID #134764352
My Commission Expires
February 14, 2028

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

ANTHONY Q. BROWN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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DIRECT TESTIMONY OF ANTHONY Q. BROWN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Anthony Q. Brown, 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 am a licensed Certified Public Accountant with a Bachelor of Business Administration with a major in Finance from Angelo State University in 2013 and Master's in Business Administration from Angelo State University in 2015. I began my career with TGS in September 2015 as a Rate Analyst I. In July 2019, I was promoted to Rate Specialist. I began serving in my current position as a Manager of Rates and Regulatory in May 2022.

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 in which the Company is proposing to consolidate all of its existing service areas:

1. Compliance with certain Railroad Commission of Texas ("Commission") rules and statutory requirements, including affiliate cost recovery issues related to Utility Insurance Company ("UIC");

2. Support the Direct costs attributed in the Company's cost of service calculation that demonstrate the Company's need for a rate change. I also describe the portion of the Company's requested rate base amounts related to Direct costs;

3. Support the Company's recovery of Pipeline Integrity Testing ("PIT") costs;

4. Support the Company's recovery of rate case expenses; and

5. Describe the rate schedules and tariffs currently in effect for the existing Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA"), and West North Service Area ("WNSA"), and describe the proposed rate schedules and tariffs that TGS is requesting the Commission approve in this case, including a new Residential Customer Assistance tariff.

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 Eric S. Sanford
Schedule B-1 M&S	Co-Sponsor with Eric S. Sanford
Schedule B-2 Prepayments	Co-Sponsor with Eric S. Sanford
Schedule B-3 8.209 Reg Asset	Sponsoring
Schedule B-4 Pension & 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
Schedule B-11 Regulatory Assets	Sponsoring
Schedule C Plant	Co-Sponsor with Eric S. Sanford
Schedule C-1 CCNC	Co-Sponsor with Eric S. Sanford
Schedule D Reserves	Co-Sponsor with Eric S. Sanford
Schedule F Federal Income Tax	Sponsoring

OPERATING INCOME:	
Schedule G Summary of Operating Revenue & Expense Adj	Co-Sponsor with Zane M. Drummond and Keara J. Downum
Schedule G-7 Amortization of Pension and Other Post Employment Benefits	Sponsoring
Schedule G-9 Miscellaneous Adjustments	Co-Sponsor with Keara J. Downum
Schedule G-10 Rents	Co-Sponsor with Keara J. Downum
Schedule G-11 Interest on Customer Deposits	Sponsoring
Schedule G-12 Uncollectible Expense	Sponsoring
Schedule G-14 Advertising Expense	Co-Sponsor with Keara J. Downum
Schedule G-15 Depreciation & Amortization	Co-Sponsor with Eric S. Sanford

OPERATING INCOME:	
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	Sponsoring
Schedule G-23 PIT	Sponsoring
Schedule G-24 EDIT	Co-Sponsor with Kenneth E. Eakens
Schedule G-25 CC Processing	Co-Sponsor with Stacey L. McTaggart
Schedule G-26 Customer Assistance	Co-Sponsor with 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 have filed testimony on behalf of TGS before this Commission in Gas Utilities Docket ("GUD") Nos. 10739, 10766, 10928, and Docket Nos. OS-23-00014883 ("Docket No. 14883") and OS-23-00014399 ("Docket No. 14399").

II. 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.

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:

[1] *See* 16 Texas Administrative Code ("TAC") § 7.310.

- 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 2025, 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. This confirmation was based on the officers' 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 on the effectiveness of these controls as of the end of the period covered by the financial statements, in its Form 10-K filed with the

Securities and Exchange Commission ("SEC"). 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, as filed with the SEC on February 20, 2025. The report concluded that our disclosure controls and procedures, and our internal control over financial reporting, were effective at December 31, 2024.[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. Further, 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,

[2] *See* ONE Gas Form 10-K for the fiscal year ended December 31, 2024 at 36 (Item 8) (Feb. 20, 2025).

on February 20, 2025. 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 as of December 31, 2024, 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]

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 complies with Commission Rule § 7.503. Accordingly, the Company is entitled to the presumption that costs

[3] *Id.*
[4] *See* 16 TAC § 7.503.

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.[5] 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.

[5] *See* 16 TAC § 7.501.

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 included profits or losses resulting from the sale or lease of appliances, fixtures, equipment or other merchandise 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 TGS is $(184,129,691), 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 TGS 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 0.022% of gross receipts. Specifically, Schedule G-14 (Advertising Expense) shows that the Company's cost of service includes $135,305, 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 Gas Utility Regulatory Act ("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 Keara J. Downum 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 Docket No. OS-24-00017471 ("Docket No. 17471") and Docket No. 14399, which were resolved through settlement agreements and approved by the Commission. The Commission also approved TGS's request to recover UIC affiliate costs in Docket No. OS-22-00009896 ("Docket No. 9896"), a case that was fully litigated.[6]

[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, 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); *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*, Docket No. OS-24-00017471 consol., Final Order at FoF No. 50 (Nov. 19, 2024).

III. OVERVIEW OF COST OF SERVICE CALCULATION

Q. HOW DID THE COMPANY CALCULATE THE REQUESTED RATES?

A. In calculating the requested rates, the Company used the cost of providing service to all TGS customers so that rates within each customer class in the incorporated and unincorporated areas will be consistent across the entire State. Exhibit G to the Statement of Intent ("SOI") contains the cost of service schedules that, taken together, show the calculation of the Company's revenue requirement. 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.[7]

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, 2024, with adjustments for some known and measurable

[7] *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. Downum's direct testimony, and the direct testimony of Company witnesses Eric S. Sanford and 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 Texas.

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 $151,258,518. 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 $458,219,242.

A comparison of this revenue requirement to adjusted revenues, from Schedule G, demonstrates that the Company's current rates produce a level of revenues that is $40,459,857 lower (before gross-up for additional uncollectible expense and Texas franchise tax) than the Company's cost of providing service. After gross-up for additional uncollectible expense and Texas franchise tax, the

revenue deficiency on a systemwide basis is $41,069,909, as shown on Schedule A, line 19.

IV. 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. 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.[8] 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

[8] *See* 16 TAC § 7.115(9).

with the treatment of CCNC that has been approved in prior proceedings, including Docket Nos. 9896, 14399, and 17471.[9]

Q. PLEASE DESCRIBE THE FORT BLISS PLANT WORKPAPERS.

A. WKP C.a Direct Plant and WKP C-1.a Direct CCNC, contain the per book balance and adjustments for all Direct plant excluding plant associated with Fort Bliss. WKP C.a.1 Fort Bliss and WKP C-1.a.1 Fort Bliss, contains the per book balance and adjustments for plant associated with Fort Bliss. The Fort Bliss plant is shown separately in order to facilitate the presentation of proforma depreciation expense, as explained in the Operating Revenue and Expenses section of my testimony.

Q. PLEASE EXPLAIN THE CALCULATION OF THE GROSS PIS AND CCNC BALANCES SHOWN ON SCHEDULE B.

A. The adjusted TGS Gross PIS balance of $2,235,332,639 on Schedule B, is the sum of the adjusted plant balances shown on Schedule C (Plant), through the test year ended December 31, 2024, for: (1) Direct TGS plant; (2) TGS Division plant balances; and (3) allocated ONE Gas corporate plant balances. The adjusted CCNC balance of $315,722,339 on Schedule B, is the sum of the adjusted CCNC balances shown on Schedule C-1 through the test year ended December 31, 2024, for: (1) Direct TGS balances; (2) TGS Division balances; and (3) allocated ONE Gas Corporate CCNC balances.

[9] *See 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, Final Order (Dec. 14, 2010); *Statement of Intent of 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; Docket No. OS-23-00014399 consol., Final Order; and Docket No. OS-24-00017471 consol., Final Order.

Q. PLEASE EXPLAIN HOW THE PER BOOK BALANCE OF PIS WAS CALCULATED.

A. The Per Book PIS balance as of December 31, 2024, of $2,241,035,995 on Schedule C (line 4), results from three component parts: (1) $2,141,645,122, the per book balance of TGS Direct PIS; (2) $11,817,307, TGS Division per book PIS; and (3) $87,573,566, the allocated portion of ONE Gas Corporate per book PIS. Mr. Sanford sponsors the TGS Division and the ONE Gas Corporate amounts, and the reasonableness of these amounts in his direct testimony.

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 TGS Direct PIS balance. The following adjustments were made to:

1. remove $181 for meal and hotel adjustments; and
2. remove $754,986 to adjust for miscoded additions and transfers.

The total amount of adjustments made to the TGS Direct per book PIS balance, equals $(755,167). The Company also adjusted TGS Division and ONE Gas Corporate per book PIS balances as identified and sponsored by Mr. Sanford in his direct testimony.

Q. PLEASE EXPLAIN THE CALCULATION OF THE ADJUSTED TEST YEAR PIS BALANCE AS SHOWN ON SCHEDULE C.

A. The adjusted TGS PIS balance of $2,235,332,639 on Schedule C (line 4), results from three components: (1) $2,140,889,955, the adjusted TGS Direct PIS balance; (2) 11,430,339, the adjusted TGS Division PIS balance; and (3) 83,012,346, the

allocated portion of the adjusted ONE Gas Corporate PIS balance. Mr. Sanford sponsors the TGS Division and ONE Gas Corporate allocated amounts and their reasonableness in his 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 $317,458,391 on Schedule C-1 (line 4), results from three component parts at December 31, 2024: (1) $307,645,733, the per book balance of TGS Direct CCNC; (2) $231,863, the TGS Division PIS balance; and (3) $9,580,795, the allocated portion of ONE Gas Corporate per book CCNC. Mr. Sanford 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 TGS Direct CCNC balance. The following adjustments were made to:

1. remove $2,317 for meal & hotel adjustments;
2. remove $1,234,908 to adjust for miscoded additions and transfers; and
3. a $0 (net-zero) adjustment to reclassify FERC 382 to FERC 381.

The total amount of adjustments to the TGS Direct per book CCNC balance equals $(1,237,226). Accordingly, the Company also adjusted TGS Division and ONE Gas Corporate, per book CCNC balances as identified and sponsored by Mr. Sanford in his direct testimony.

Q. PLEASE EXPLAIN THE IMPACT OF THE FERC RECLASSIFICATION ON THE PER BOOK PIS BALANCES.

A. The total costs associated with FERC 382, Meter installations, were reclassified to FERC 381, Meters, on WKP C.a Direct Plant, to assign costs to the appropriate FERC account. This reclassification has no impact on the Per Book PIS balance.

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, 2024, of $(501,603,193), on Schedule D contains: (1) $(447,357,983), the per book TGS Direct Reserve balance; (2) $(3,906,441), the TGS Division reserve balance; and (3) $(50,338,769), the TGS allocated portion of the ONE Gas Corporate reserve balance. Adjustments were made to the per book TGS Direct Reserve balance to remove plant additions, transfers or retirements mistakenly coded to TGS, to reclassify assets in FERC 381 to FERC 382, and to rebalance reserves as recommended by Company witness Ronald E. White, Ph.D. Total adjustments to the TGS Direct per book reserves equal $(59,117). Mr. Sanford testifies 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 $2,054,324,164. This is the sum of the adjusted test year balances for PIS of $2,235,332,639, plus CCNC of 315,722,339 and, Reserves of $(496,730,814).

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, Alejandro Limón, and Mr. Sanford.

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:

- Negative acquisition amount on One Gas Pipeline Company ("OPC") Assets;
- Materials and Supplies inventory;
- Prepayments, which are addressed by Mr. Sanford in his direct testimony;
- Amounts deferred in accordance with Commission Rule § 8.209;
- Requested Regulatory Assets;
- Pension and Other Post Employment Benefits ("OPEB") Regulatory Assets;

- 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. PLEASE DESCRIBE OPC.

A. In 2019, ONE Gas acquired a pipeline from ONEOK, Inc. ("ONEOK") and created an affiliate (referred to as OPC), to hold the pipeline assets, which are located in the area currently designated as 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.[10] With Commission approval, at the conclusion of GUD No. 10928, the Company dissolved OPC and recorded the assets on TGS's books.

Q. PLEASE EXPLAIN THE CALCULATION OF THE NEGATIVE ACQUISITION ADJUSTMENT ON OPC ASSETS.

A. The OPC assets were purchased from ONEOK below the book value, giving rise to a $2,481,514 negative acquisition adjustment. In accordance with GUD No. 10928, TGS began amortizing the negative acquisition adjustment over 20 years in September 2020.[11] The unamortized negative acquisition adjustment balance of $(1,949,023), is included as a reduction to rate base.

Q. 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 TGS Direct Materials and Supplies Inventory and Stores Load, as well

[10] GUD No. 10928 consol., Final Order at FoF Nos. 62-65.
[11] *Id.* at FoF No. 63.

as ONE Gas Measurement Assets ("OMA"). Mr. Sanford addresses the OMA inventory balance of materials and supplies in his direct testimony. 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 TGS. 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 in past Commission decisions),[12] a thirteen-month average was used and results in a $26,639,992 balance to be included in rate base. An average thirteen-month balance normalizes the fluctuations that may occur during the test year.

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

[12] *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; GUD No. 10526, Final Order; GUD No. 10656, Final Order; GUD No. 10739, Final Order; GUD No. 10766, Final Order; Docket No. OS-22-00009896 consol., Final Order; Docket No. OS-23-00014399, consol., Final Order.

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. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE ASSOCIATED WITH PREPAYMENTS?

A. The Company has included a 13-month average of prepayments of $11,080,303. This asset is included on Schedule B, line 6 and detailed on Schedule B-2 (Prepayments). Mr. Sanford addresses prepayments in his direct testimony.

Q. WHAT AMOUNT HAS 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, 2024. 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 weighted average 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 $4,757,745, and includes monthly deferred DIMP costs from January 2024 through December 2024. This asset is included on Schedule B, line 7 and detailed on Schedule B-3 (8.209 Reg Asset). 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.[13] In addition, the cities within the TGS territory have also approved the Company's request to recover deferred amounts related to Rule § 8.209.[14]

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.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE FOR THE PENSION AND OPEB REGULATORY ASSET?

A. The Company has included $(6,518,193), for a Pension and OPEB regulatory asset, as shown on Schedule B-4. GURA § 104.059 states that if a gas utility establishes

[13] Docket No. OS-22-00009896 consol., Final Order; Docket No. OS-23-00014399 consol., Final Order; Docket No. OS-24-00017471 consol., Final Order.

[14] In 2022, 2023, and 2024, cities in the TGS territory approved the recovery of Rule § 8.209 amounts in the Company's GRIP filings.

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 cases for the existing CGSA and WNSA (Docket Nos. 17471 and 9896), 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 $(2,658,757). In addition, since Docket Nos. 9896, 14399, and 17471, 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, 2024, those deferrals total (4,262,484), 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 $44,728,624. 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 $(13,403,426) (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 ASSETS OR LIABILITIES?

A. The Company has included a requested regulatory asset amount totaling $2,118,256. This amount is included on Schedule B, line 9, and detailed on Schedule B-11, and is comprised of the following:

- Unamortized balance of Regulatory Assets from Docket No. 17471, which includes COVID-19 operations and maintenance ("O&M") expenses and Winter Storm Uri expenses, less the 12 months of amortization that will occur during the preparation and review process of this SOI;
- Unamortized balance of Regulatory Assets from Docket No. 9896, which includes COVID-19 O&M expenses and Winter Storm Uri expenses, less the 12 months of amortization that will occur during the preparation and review process of this SOI;
- Unamortized balance of Regulatory Assets from Docket No. 14399, which includes COVID-19 O&M expenses and Winter Storm Uri expenses, less the 12 months of amortization that will occur during the preparation and review process of this SOI;
- Refund to customers for recovering line locating costs from a TGS contractor;
- O&M expenses incurred during Winter Storm Gerri;
- Expenses, primarily legal, incurred in response to Docket No. 14883; and
- Direct TGS Shared Service and Allocated Corporate COVID O&M expenses incurred after the test year for Docket No. 9896.

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 INCLUSION OF WINTER STORM GERRI EXPENSES AS A REGULATORY ASSET.

A. The Company's gas system modeling software has identified gas pressure deficiencies in Southwest Austin during periods of extreme cold weather. In January 2024, in response to Winter Storm Gerri, the Company implemented proactive measures to ensure the continuity and reliability of the gas supply to customers in the affected area. The Winter Storm Gerri regulatory asset includes expenses for Company labor, contract labor, and direct materials necessary to install 500 feet of 6-inch temporary polyethylene main above ground to maintain adequate gas pressure to customers.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED TGS'S REQUEST TO RECOVER WINTER STORM COSTS BOOKED TO A REGULATORY ASSET?

A. Yes. In Docket Nos. 9896, 14399 and 17471, TGS requested recovery of similar costs related to Winter Storm Uri that were booked to a regulatory asset and the Commission approved TGS's request.[15]

[15] Docket No. OS-22-00009896 consol., Final Order at FoF No. 46; Docket No. OS-23-00014399 consol., Final Order at FoF No. 53; Docket No. OS-24-000017471 consol., Final Order at FoF No. 49.

Q. PLEASE EXPLAIN WHY TGS IS SEEKING RECOVERY OF COSTS IT INCURRED RELATED TO DOCKET NO. 14883.

A. On August 16, 2023, TGS filed with the Commission an appeal of municipal action taken by the City of El Paso related to the city's decision ordering the Company to issue Gas Reliability Infrastructure Program ("GRIP") refunds. On June 25, 2024, the Commission ruled that TGS acted lawfully, reversed El Paso's refund actions in their entirety and sustained the Company's appeal. The Commission also denied the City of El Paso's Motion for Rehearing on August 15, 2024. The Company incurred reasonable and necessary costs related to outside legal counsel and required attendance at an El Paso city council meeting. In addition, the Company's request for these costs in this rate case is consistent with the Final Order in Docket No. 14883, in which the Commission ordered that TGS is not precluded from renewing its request for recovery of legal costs associated with the appeal in the future, after the appellate docket is concluded.[16]

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.

[16] *Petition for Review of Municipal Actions of the City of El Paso's Show cause and Refund Orders Regarding Texas Gas Service Company, a Division of ONE Gas, Inc.'s Collection of Revenues for an Interim Rate Adjustment for Calendar Year 2021*, Docket No. OS-23-00014883, Final Order at Ordering Paragraph No. 3 (Jun. 25, 2024).

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, 14399 and 17471, TGS requested recovery of similar costs related to COVID-19 that were booked to a regulatory asset and the Commission approved TGS's request.[17]

Q. DESCRIBE THE COSTS INCLUDED IN THE COVID-19 REGULATORY ASSET.

A. The COVID-19 regulatory asset includes 2022 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. Mr. Limón describes the nature of these costs in more detail in his direct testimony.

[17] Docket No. OS-22-00009896 consol., Final Order at FoF No. 44; Docket No. OS-23-00014399 consol., Final Order at FoF No. 52; and Docket No. OS-24-00017471 consol., Final Order at FoF No. 49.

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 13 through 16. Lines 13 and 14, are the balances at the test year end for customer deposits and customer advances, respectively. In addition, the ADIT balance shown on line 15 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 Excess Deferred Income Taxes ("EDIT") balance shown on line 16 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 TGS per book balances of customer deposits and customer advances as of December 31, 2024. The total Customer Deposits (line 13) are $(16,329,640). The total Customer Advances (line 14) are $(6,534,399).

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 15), is $(184,129,691), and the EDIT balance (line 16), is $(27,872,376). These balances are treated for ratemaking purposes as offsets to the Company's invested capital (rate base).[18]

Q. PLEASE SUMMARIZE THE COMPANY'S RATE BASE AS CALCULATED ON SCHEDULE B.

A. The total rate base that is included in the cost of service calculation is $1,886,912,337. This total amount includes all the component parts described above. Mr. Sanford's direct testimony provides details for Corporate and Division rate base items.

[18] 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.

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, AND THAT ARE REASONABLE AND NECESSARY FOR PROVIDING SERVICE TO CUSTOMERS?

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 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.

V. 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.[19] This method 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

[19] Railroad Commission of Texas, Oversight and Safety Division - Gas Services, Natural Gas Rate Review Handbook at 38-39 (Sept. 2017).

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,[20] 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,[21] 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 disallowance. The specific mechanics of computing federal income tax expense using the Return

[20] 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.

[21] Qualified Transportation Fringe, Transportation and Commuting Expenses Under Section 274, 85 Fed. Reg. 81,391 (Dec. 16, 2020), https://www.federalregister.gov/documents/2020/12/16/2020-27505/qualified-transportation-fringe-transportation-and-commuting-expenses-under-section-274.

Method are shown on Schedule F. The adjusted test year federal income tax expense included in the Company's revenue requirement is $31,312,410.

VI. 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 contains a summary of the adjustments to revenues and expenses, which are identified in greater detail in Schedules G-1 through G-26. 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. Downum and Mr. Sanford.

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 TGS, the Company incurs "allocable" expenses for Shared Services provided to TGS customers from various ONE Gas departments. A portion of these reasonable and necessary expenses must

be allocated to TGS to determine the total cost TGS incurs to provide service to TGS customers. For example, during the test year, personnel from various departments provided management, accounting, human resources, customer service and engineering services to TGS, and generated a variety of expenses that are directly charged or causally allocated to TGS.

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 TGS operations. TGS's portion of test year costs charged to the allocable cost centers described above, are included in the TGS's per book costs on Schedule G, column (a). The Company's allocation methodologies are discussed by Ms. Downum 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 $(6,518,193) includes amortization of: (1) the deferred annual Pension and OPEB expense that has occurred since the approved rates in Docket Nos. 9896, 14399, and 17471 were implemented; and (2) the remaining portion of the pension and OPEB regulatory asset approved in Docket Nos. 9896 and 17471 that will not be fully amortized when proposed TGS rates are 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 expense over $25 per person, exclusive of taxes and tip amounts, and hotel stays over $175 per night, exclusive of taxes, were removed. Ms. Downum 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 TGS interest on customer deposits has been calculated by applying the current 2025 Commission-required interest rate of 5.05%,[22] to the adjusted balance of TGS 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.

[22] *See, e.g.,* Railroad Commission of Texas, Bulletin No. 1248 § 6(B)(1) (Mar. 31, 2025) (citing 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 TGS 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 TGS, are divided by total TGS 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.[23] 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.

[23] *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 Appeal of Texas Gas Service Company from the Actions of the Cities of Lockhart, Luling, Cuero, Gonzales, Nixon, Shiner and Yoakum; and the Statement of Intent Filed to Increase Rates in the Unincorporated Areas of the South Texas Service Area*, GUD No. 9770, Final Order (Apr. 24, 2008); GUD No. 9988, Final Order; GUD No. 10217, Final Order; *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 (Nov. 26, 2013); GUD No. 10488, Final Order; GUD No. 10506 consol., Final Order; GUD No. 10526, Final Order; GUD No. 10656, Final Order; GUD No. 10928 consol., Final Order; Docket No. OS-22-00009896 consol., Final Order; Docket No. OS-23-00014399 consol., Final Order; and Docket No. OS-24-00017471 consol., Final Order.

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 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. Schedule G-14 demonstrates that total adjusted advertising expense included in the proposed revenue requirement is $135,305, and is less than the allowable amount of $3,117,973.

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, 2024, DIMP deferral balance, is included and is calculated using the TGS depreciation rates for mains and services.[24]

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 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 to the depreciation expense account on the Company's books. As a result, adjusted

[24] *See* 16 TAC § 8.209(j).

depreciation for TWE equipment is included as part of the TWE clearing adjustment on Schedule G-19. Mr. Sanford 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 Direct plant depreciation rates were developed in the 2025 depreciation study conducted by Dr. White for this rate case. Please note that Fort Bliss and TGS Direct plant have different depreciation rates as approved in Docket No. 9896.[25] 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. Adjusted property tax expense is computed by multiplying net PIS included in rate base by an effective property tax rate. The effective tax rate is computed by dividing the property taxes paid in January 2025, by net PIS as of January 1, 2024. Net PIS as of January 1, 2024, is used for the denominator of the effective rate because that is the valuation assessment date upon which the property taxes were computed. Test year property tax expense is subtracted from adjusted property tax expense to calculate the adjustment to test year expense.

[25] Docket No. OS-22-00009896 consol., Final Order at FoF No. 87

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 TGS. Instead, the Company includes on Schedule G-17, the franchise tax amount paid by the Company on May 15, 2025.

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 TGS stores costs that were under-cleared relative to TGS 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 TGS stores clearing account were less than actual cost incurred during the test year. Thus, an adjustment to increase the test year amount cleared is necessary. This adjustment is shown on Schedule G-18, lines 1 through 3.

The second category of adjustments relate to the level of costs that was charged into the TGS stores clearing account during the test year. As shown on lines 4 through 7, adjustments were made to reflect the difference between TGS 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 TGS 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 TGS TWE during the test year were more than the TGS 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 TGS 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 TGS 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 TGS 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 be included in base rates, if the Company's request for a PIT 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 of $(2,272,038), which is detailed in the direct testimony of Mr. Eakens.

Q. PLEASE EXPLAIN THE CREDIT CARD PROCESSING ADJUSTMENT REFLECTED ON SCHEDULE G-25.

A. Schedule G-25 reflects the adjustment to include annualized credit card processing fees of $3,681,255 in the cost of service, which is detailed in the direct testimony of Ms. McTaggart.

Q. PLEASE EXPLAIN THE CUSTOMER ASSISTANCE PROGRAMS ADJUSTMENT REFLECTED ON SCHEDULE G-26.

A. Schedule G-26 reflects a $2,627,000 adjustment for Customer Assistance programs. TGS's proposed programs include "Share the Warmth" and "Customer Assistance Residential Service Rate Pilot Program" and are discussed in the direct testimony of Ms. McTaggart.

VII. CURRENT RATE SCHEDULES

Q. WHEN WAS THE LAST SOI TO CHANGE BASE RATES FILED IN THE CGSA?

A. On June 3, 2024, TGS filed a SOI requesting to increase rates with each city within the CGSA and the associated environs areas. The case was docketed as Docket

No. 17471, at the Commission. A Unopposed Settlement Agreement was entered into by and between TGS, Staff of the Commission, TGS Cities, and the Steering Committee of Cities. The Commission approved the settlement agreement on November 19, 2024.

Q. HAS THE COMPANY FILED INTERIM RATE ADJUSTMENTS ("IRAS") IN THE CGSA?

A. Yes. Pursuant to GURA § 104.301 and Commission Rule § 7.7101 (the "GRIP rule"), the Company filed the following IRA 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, 2025	00020233	January 1 to December 31, 2024	May 13, 2025

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE CGSA ENVIRONS AND CITIES?

A. As shown in Exhibit AQB-1, the rates in effect for customers in the CGSA environs and cities are the base rates approved in Docket No. 17471, and the IRA addressed above.

Q. WHEN WAS THE LAST SOI TO CHANGE BASE RATES FILED IN THE RGVSA?

A. On June 30, 2023, TGS filed a SOI, requesting to increase rates with each city within the RGVSA and the associated environs areas. The case was docketed as Docket No. 14399, at the Commission. A Unanimous Settlement Agreement was entered into by and between TGS, Staff of the Commission, and Intervenor Cities

Served by Texas Gas Service Company. The Commission approved the settlement agreement on January 30, 2024.

Q. HAS THE COMPANY FILED IRAS IN THE RGVSA?

A. Yes. Pursuant to GURA § 104.301 and the GRIP rule, the Company filed the following IRAs within the RGVSA incorporated and environs areas:

IRA Filing Date	Case No. for Environs Filing	Plant Investment Period	Environs Interim Order Issue Date
May 13, 2024	00017353	January 1 to December 31, 2023	August, 15, 2024
April 25, 2025	00027662	January 1 to December 31, 2024	Pending

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE RGVSA ENVIRONS AND CITIES?

A. As shown in Exhibit AQB-1, the rates in effect for customers in the RGVSA environs and cities are the base rates approved in Docket No. 14399, and the first of the two IRAs addressed above. At the time of this filing, the second IRA addressed above remains pending.

Q. WHEN WAS THE LAST SOI TO CHANGE BASE RATES FILED IN THE WNSA?

A. On June 30, 2022, TGS filed a SOI, requesting to increase rates within each city and the environs of the WNSA. The case was docketed as Docket No. 9896, at the Commission. In addition to TGS, the parties in the case were the City of El Paso, the City of Borger and Commission Staff. Following a hearing on the merits in November 2022, the Administrative Law Judge issued an Amended Proposal for Decision on January 11, 2023. The Commission issued a Final Order on January 18, 2023.

Q. HAS THE COMPANY FILED IRAS IN THE WNSA?

A. Yes. Pursuant to GURA § 104.301 and the GRIP rule, the Company filed the following IRAs within the WNSA incorporated and environs areas:

IRA Filing Date	Case No. for Environs Filing	Plant Investment Period	Environs Interim Order Issue Date
March 10, 2023	00012849	January 1 to December 31, 2022	June 13, 2023
March 8, 2024	00016546	January 1 to December 31, 2023	June 25, 2024
February 11, 2025	00020234	January 1 to December 31, 2024	May 13, 2025

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE WNSA ENVIRONS AND CITIES?

A. As shown in Exhibit AQB-1, the rates in effect for customers in the WNSA environs and cities are the base rates approved in Docket No. 9896, and the IRAs addressed above.

VIII. PROPOSED RATE SCHEDULES AND TARIFFS

Q. WHAT TARIFFS ARE PROPOSED BY THE COMPANY IN THIS SOI?

A. The proposed statewide tariffs, attached as Exhibit A to the SOI, are as follows:

- Rate Schedules 10, 15, 16, 20, 25, 30, 40, 70 and CNG-1 for gas sales service;
- Rate Schedules 1Z, 1Y, 1W, 2Z, 2Y, 3Z, 4Z, 7Z, 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-EGEN, T-EGEN-ENV, T-TERMS for transportation service;
- Rate Schedule WNA for weather normalization adjustment ("WNA");
- Rate Schedules PIT and PIT-Rider for recovery of annually approved PIT expenses;
- Rate Schedules RCE-TGS and RCE-TGS-ENV for recovery of approved rate case expenses in this filing;

- Rate Schedule EDR for the economic development rate for the incorporated areas in Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro, and Vinton;
- Rate Schedule CRR, "Customer Rate Relief;" and
- Incorporated and environs Rules of Service.

The proposed rate schedules accurately reflect all the changes requested by the Company in this filing. Exhibit AQB-2 provides the existing rate schedules in redline format to identify the changes the Company proposes for TGS. If consolidation is approved, the proposed statewide tariffs would supersede the corresponding tariffs that currently exist in the service areas.

Q. ARE THERE ANY EXISTING TARIFFS FOR WHICH THE COMPANY IS NOT PROPOSING CHANGES IN THIS SOI?

A. Yes. The Company proposes no changes to Rate Schedules TF, "Tapping Fee Rates," Rate Schedule E5, "Fort Bliss Service Rate," Rate Schedule PSF, "Pipeline Safety and Regulatory Program Fees," Rate Schedules RCE-Rider-RGV "Rate Case Expense Surcharges" and the Curtailment Plan Rate Schedule, all of which are currently in effect for one or more of the currently designated CGSA, RGVSA, and WNSA.

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, Docket No. 17471 for the CGSA.[26] Next, the RGVSA and WNSA

[26] Docket No. OS-24-00017471 consol., Final Order at Conclusion of Law ("CoL") No. 26; Docket No. OS-22-00009896 consol., Final Order at FoF No. 110; and Docket No. OS-23-00014399 consol., Final Order at CoL No. 27.

tariffs and rate schedules were reviewed to identify applicable tariff provisions and language appropriate for inclusion in the newly proposed TGS tariffs. If consolidation is approved in this SOI, the overall number of tariffs that must be maintained and administered by TGS (and its regulators) will be reduced to 38. Without consolidation, TGS and regulators would need to maintain and administer 98 tariffs.

A. Gas Sales Service Tariffs

Q. PLEASE DESCRIBE THE TGS GAS SALES RATE SCHEDULES.

A. Rate Schedules 10, 15, 16, 20, 25, 30, 40, 70, 1Z, 1Y, 1W, 2Z, 3Z, 4Z and 7Z, are based on the currently designated CGSA, RGVSA, and WNSA gas sales rate schedules, with revisions made to:

1. include rate changes as reflected in the direct testimony of Company witness Paul H. Raab;
2. add language to all gas sales tariffs, to reflect the applicability of each tariff to all incorporated and unincorporated areas served by TGS (as may be appropriate);
3. update language in the 'Other Adjustments' section on all gas sales tariffs, to remove references to a Winter Storm Uri rider that was applicable only to certain areas;
4. update language in the 'Other Adjustments' section on all incorporated gas sales tariffs, to remove references to CA, CAC, and EE (Conservation and Energy Efficiency program riders that were only applicable to certain areas);
5. update language in the 'Other Adjustments' section on all incorporated gas sales tariffs to add EDR;
6. create Rate Schedules 16 and 1W Customer Assistance Residential Service Rate Pilot Program;
7. add language to specify that monthly volumetric usage will be converted to a Common Billing Pressure volume on customer bills;

8. add references to proposed new tariffs, such as the Rate Case Expense Surcharge Riders, Rate Schedules RCE-TGS and RCE-TGS-ENV; and

9. add clarifying language to improve readability and help customers understand the charges on their bill.

The proposed gas sales rates referenced in the tariffs are consistent with the recommendations of Mr. Raab.

Q. PLEASE EXPLAIN THE PROPOSED RESIDENTIAL TARIFFS FOR CUSTOMER ASSISTANCE.

A. As discussed in Mr. Raab's and Ms. McTaggart's direct testimonies, the Company proposes a rate design that includes a Customer Assistance Residential Service Rate Pilot Program to be available for qualifying residential customers. The addition of Rate Schedules 16 and 1W reflect the Company's request.

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 Nos. 14399 and 17471.

Q. PLEASE DESCRIBE THE COMPANY'S COST OF GAS CLAUSE TARIFFS.

A. Proposed Rate Schedules 1-INC and 1-ENV are based on the existing Company cost of gas clauses with revisions to:

1. update Section A, in the incorporated and environs tariffs to reflect applicability to all incorporated cities and unincorporated areas served by TGS;

2. add clarifying language to definitions in Section B:

    a. the Cost of Gas definition in the incorporated and environs tariffs was revised to specify that the Customer Rate Relief Component is not applicable to some areas;

    b. the Cost of Gas definition in the incorporated tariffs was revised to specify that the "revenue associated fee" is applicable to Weatherford, Texas only;

    c. the Cost of Purchased Gas definition in the incorporated tariffs, was revised to specify that it shall also include the cost of gas withdrawn from storage;

    d. the Customer Rate Relief Component definition was revised to specify that this rate is not applicable to some areas; and

    e. definitions for 'Intervention Costs,' 'Non-Utility Transactions' and 'Uncollectible Cost of Gas' were added;

3. Section G, Non-Utility Transactions, was added to credit aggregate net margins to sales customers in the month during which the transaction closes; and

4. add clarifying language to Section I. Annual Reconciliation Report to include FERC Intervention costs.

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 currently in effect, as well as to add clarifying language to help customers understand the charges on their bill.

Q. PLEASE DESCRIBE THE CHANGES TO THE CUSTOMER RATE RELIEF RATE SCHEDULE.

A. There are no substantive changes to this rate schedule; however, the Applicability section and the header have been updated to show applicability statewide, with the exception of specified areas, which has already been approved by the Commission in Docket No. OS-21-00007061.

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 transportation rate schedules approved in Docket Nos. 9896, 14399 and 17471. Consistent with the final order in Docket No. 17471, TGS proposes to combine the existing rate classes into one general transportation rate.

Proposed Rate Schedules T-EGen and T-EGen-ENV are new tariffs applicable to Electric Generation Transportation customers only. Electric Generation service is substantially different from other transportation service and therefore requires a unique rate structure.

Additional material differences between the proposed transportation tariffs and the tariffs currently in effect for the incorporated and environs areas are revisions made to:

1. include rate changes as reflected in the testimony of Mr. Raab;
2. combine the existing four transportation rates for Commercial, Industrial, Public Authority and CNG customers into one general transportation rate;
3. add clarifying language to specify that monthly volumetric usage will be converted to a Common Billing Pressure volume on their bill;
4. include recovery of any applicable local taxes or fees paid to the cities;
5. proposed Rate Schedules T-EGen and T-EGen-ENV include a demand charge based upon the customer's maximum daily quantity ("MDQ"), to offset the costs of maintaining 'on-demand gas supply.' These schedules also include language clarifying the MDQ; and
6. proposed Rate Schedules T-EGen and T-EGen-ENV include a requirement for customers to agree to the installation of electronic flow measurement equipment.

In addition to the revisions above, proposed Rate Schedules T-1 and T-1-ENV, include a number of non-substantive language revisions to add clarifying language to help customers understand the charges on their bill.

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 existing Rate Schedule T-TERMS approved in Docket Nos. 9896, 14399 and 17471 with revisions made to:

1. update Section 1.1, to reflect applicability to all incorporated cities and unincorporated areas served by TGS; and
2. include definitions for "Compressed Natural Gas (CNG) Service" and "Public Authority Service" under Section 1.2.

In addition to the revisions above, proposed Rate Schedule T-TERMS includes revisions to specify the T-TERMS rate schedules are applicable to all areas the Company serves.

C. Tariff Riders

Q. HOW HAS THE COMPANY REVISED THE WEATHER NORMALIZATION CLAUSE PROPOSED IN THIS CASE?

A. The 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 Residential Customer Assistance Service, Rate Schedules 16 and 1W to the "Applicability" section;

2. reflect updated weather factors for each class consistent with Mr. Drummond's weather normalization calculation in this case; and

3. add clarifying language to help customers understand the applicability of Weather Factors (WF).

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 potential 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, 14399 and 17471, and in GUD Nos. 9988, 10506, 10526, 10656, 10739 and 10928. To continue the treatment approved by the Commission in previous cases, the Company requests approval of revised Rate Schedules PIT and PIT-Rider, as applicable to all gas sales and standard transportation customers 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, 14399 and 17471, the Commission ordered that PIT expense in the Company's existing WNSA, RGVSA and CGSA, 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."[27]

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 integrity 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, both before and since, the last rate cases in each currently designated service area. However, if the proposed Rate Schedule PIT is not approved, the PIT expenses should be included in the calculation of base rates, as discussed in the Operating Revenue and Expenses 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 Company rate schedules with revisions made to:

1. add Customer Assistance Residential Service, Rate Schedules 16 and 1W to the "Territory" and "Applicability" sections;
2. specify applicability to all incorporated and unincorporated areas served by TGS; and
3. specify that monthly volumetric usage will be converted to a Common Billing Pressure volume on customer bills.

[27] Docket No. OS-22-00009896 consol., Final Order at FoF No. 88; Docket No. OS-23-00014399 consol., Final Order FoF No. 40; and Docket No. OS-24-00017471 consol., Final Order at FoF No. 45.

Additionally, Rate Schedule PIT requires initial regulatory approval of the form of notice. Accordingly, in this case, the Company seeks formal approval of the form of notice included in Exhibit AQB-4.

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-TGS and RCE-TGS-ENV, to enable the Company to recover (via surcharge) all rate case expenses determined to be reasonable. Proposed Rate Schedules RCE-TGS and RCE-TGS-ENV, are based on previously approved rate case expense

riders with a language update to clarify that monthly volumetric usage will be converted to a Common Billing Pressure volume on customer bills.

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 TGS by starting with the CGSA incorporated and environs Rules of Service, which were updated and approved in 2024. Sections impacted by these conforming revisions include:

1. § 1.3, addition of definitions for Electric Generation (previously known as Electric Cogeneration) and Firm Service, Force Majeure;
2. § 7, Discontinuance of Service; and
3. § 9.9, Average Payment Plan.

Additional material differences between the proposed TGS Rules of Service and existing Rules of Service for the service areas include:

1. Updates to the areas listed on page 1 and Section 1.1, to include all incorporated and unincorporated areas served by TGS;
2. Updates to § 1.3, Definitions, to include "Atmospheric Pressure," "Common Billing Pressure," "Constant Factor" and "Standard Serving Pressure" to provide clarity for billing processes; add definition for "Safe Access" to reflect the requirement that Company personnel have Safe Access to Company assets; add definition for "Compressed Natural Gas (CNG) Service" and "Public Authority Service" to include these services provided by the Company; and, revisions to the definition for "Electrical Cogeneration Service" to be applicable to non-residential customers only;
3. Revisions to §§ 4.1, 6.1, 7.4, 7.9, 10.2, 12.3 and 12.7 to include language to reflect the requirement that Company personnel have Safe Access to Company assets;
4. Addition of § 4.2 to clarify the requirement to disclose Customer use of certain natural gas equipment and appliances;

5. Addition of § 5.5 to clarify the Company shall not be obligated to provide Expedited Service when the personnel and resources are not reasonably available;

6. Revisions to § 6.1 to add clarifying language regarding the Company's right to refuse service if the Customer does not allow Company representatives to observe Customer-owned natural gas facilities or appliances, and/or whose natural gas facilities or appliances do not comply with the tariff;

7. Revisions to § 9.3 to provide for a phone call to request that the Customer read the meter and return a post card (if provided) or a picture of the meter dial to facilitate an estimated bill;

8. Revisions to § 10.2 to add clarifying language regarding Customer responsibilities around Company-owned facilities;

9. Revisions to § 10.6 to add clarifying language regarding Customer responsibilities for Customer-owned materials and equipment including piping, installations, appliances and conversions;

10. Revisions to § 10.7 to add clarifying language regarding the relocation of the Company delivery point of natural gas;

11. Revisions to § 10.8 to add clarifying language regarding the replacement of Customer-owned piping;

12. Revisions to § 11.1 and addition of § 11.2, to clarify the Company's policies regarding line extensions to be cost-justified by calculating the Maximum Allowable Investment (MAI);

13. Making administrative corrections to § 11.5, clarifying language regarding the construction of facilities in § 11.6, updates and clarifying language regarding advances and refunds in §§ 11.7, 11.8 and 11.9;

14. Revisions to § 13 to provide clarity for billing processes regarding the Common Billing Pressure of 14.65 psi and the Constant Factors that will be displayed on Customer bills;

15. Revisions to the table shown in § 13.1 to include all incorporated and unincorporated jurisdictions served by TGS with their corresponding Atmospheric Pressure, Standard Pressure and Constant Factors;

16. Revisions to § 15 (Service Fees and Deposits Amounts), to update service fees and deposits to reflect recent approvals among the Company's service areas and to move fees closer to actual Company costs; and

17. Addition of § 16 Tapping Fees, on a statewide basis, consistent with the approved Quality of Service Rules in the existing WNSA.

The proposed changes provide clarity regarding the Company's current policies and procedures. Having a single set of Rules of Service for all customers 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 AQB-3 identifies the current and proposed service fees. The proposed fees were established by completing a comprehensive service fee study to determine the actual cost of each function. In addition, language was revised for the description of service fees to be more clear. 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. HOW WILL EXISTING TARIFFS BE TREATED IF THE PROPOSED CONSOLIDATED TARIFFS ARE NOT APPROVED ?

A. If consolidation is not approved, the following changes would apply to existing service area tariffs:

1. withdraw Rate Schedules C-1 and C-1-ENV, Electric Generation Service;
2. withdraw Cost of Gas Rate Schedules: 1-INC-NTX, 1-ENV-NTX, 1-INC-BS and 1-ENV-BS to consolidate all Customers in the existing WNSA, to be on a single Cost of Gas Rate Schedule 1-INC-WTX for incorporated customers, and 1-ENV-WTX for environs customers; and
3. the remaining proposed changes in the TGS Rate Schedules would apply to the corresponding tariffs that currently exist in the service areas.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Incorporated and Unincorporated/Environs Current Rates							
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Residential							
Small Customers Affected	202,594	24,158	33,788	2,029	154,319	18,003	-
Small Customer Charge	$21.36	$21.36	$23.64	$23.64	$21.85	$21.85	$29.50
Small Volumetric Charge (per Ccf)	$0.87646	$0.87646	$2.02007	$2.02007	$0.46668	$0.46668	$0.67553
Large Customers Affected	78,883	9,406	22,042	1,324	107,323	12,521	-
Large Customer Charge	$33.36	$33.36	$38.64	$38.64	$38.35	$38.35	$39.50
Large Volumetric Charge (per Ccf)	$0.46737	$0.46737	$0.63545	$0.63545	$0.01668	$0.01668	$0.31189
Customer Assistance Program (Up to 30,000 qualifying customers)							
Customers Affected	-	-	-	-	-	-	-
Customer Charge	-	-	-	-	-	-	$22.13
Volumetric Charge (per Ccf)	-	-	-	-	-	-	$0.55000
Commercial							
Small Customers Affected	9,576	359	2,610	114	-	-	-
Small Customer Charge	$72.88	$72.88	$120.32	$120.32	$92.73	$92.73	$75.00
Small Volumetric Charge (per Ccf)	$0.27930	$0.27930	$0.63855	$0.63855	$0.09394	$0.09394	$0.43589
Large Customers Affected	3,104	116	1,282	56	-	-	-
Large Customer Charge	$87.88	$87.88	$275.32	$275.32	$92.73	$92.73	$150.00
Large Volumetric Charge (per Ccf)	$0.22985	$0.22985	$0.26655	$0.26655	$0.09394	$0.09394	$0.13589
Commercial Transportation							
Customers Affected	296	11	23	4	21	-	-
Customer Charge	$320.96	$320.96	$545.32	$545.32	$517.73	$517.73	$500.00
Volumetric Charge (per Ccf)	$0.12679	$0.12679	$0.10770	$0.10770	$0.09394	$0.09394	$0.08831
Industrial							
Customers Affected	19	1	22	15	32	3	-
Customer Charge	$1,033.21	$1,033.21	$1,234.53	$1,234.53	$1,295.93	$1,295.93	$1,250.00
Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.28220	$0.28220	$0.11486	$0.11486	$0.11849

Incorporated and Unincorporated/Environs Current Rates							
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Industrial Transportation							
Customers Affected	17	11	16	17	9	4	-
Customer Charge	$1,233.21	$1,233.21	$1,384.53	$1,384.53	$1,495.93	$1,495.93	$500.00
Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.08722	$0.08722	$0.11486	$0.11486	$0.08831
Public Authority							
Customers Affected	758	53	442	53	1,276	146	-
Customer Charge	$181.93	$181.93	$243.91	$243.91	$253.05	$253.05	$200.00
Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.16208	$0.16208	$0.13511	$0.13511	$0.13745
Public Authority Transportation							
Customers Affected	481	10	3	3	10	-	-
Customer Charge	$204.93	$204.93	$2,543.91	$2,543.91	$553.05	$553.05	$500.00
Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.00840	$0.00840	$0.13511	$0.13511	$0.08831
Electric Generation Transportation							
Customers Affected	1	-	-	-	-	-	-
Customer Charge	$201.64	$201.64	$545.32	$545.32	$717.73	$717.73	$1,000.00
Demand Charge (per MDQ per month)							0.72542
Volumetric Charge (per Ccf)							
Usage Rates (Year-Round)							
All Ccf	-	-	$0.10770	$0.10770	-	-	$0.02000
First 5,000 Ccf	$0.07724	$0.07724	-	-	-	-	
Next 35,000	$0.06853	$0.06853	-	-	-	-	
Next 60,000	$0.05527	$0.05527	-	-	-	-	
All Over 100,000	$0.04018	$0.04018	-	-	-	-	
Volumetric Charge (per Ccf)							
Usage Rates (October - April)							
All Ccf	-	-	-	-	-	-	-
First 5,000 Ccf	-	-	-	-	$0.05260	$0.05260	-
Next 95,000	-	-	-	-	$0.04260	$0.04260	-
Next 300,000	-	-	-	-	$0.03260	$0.03260	-
All Over 400,000	-	-	-	-	$0.02260	$0.02260	-
Volumetric Charge (per Ccf)							
Usage Rates (May-September)							
All Ccf	-	-	-	-	-	-	-
First 5,000 Ccf	-	-	-	-	$0.04259	$0.04259	-
Next 95,000	-	-	-	-	$0.03258	$0.03258	-
Next 300,000	-	-	-	-	$0.02259	$0.02259	-
All Over 400,000	-	-	-	-	$0.01258	$0.01258	-

Incorporated and Unincorporated/Environs Current Rates							
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Compressed Natural Gas							
Customers Affected	-	-	-	-	-	-	-
Customer Charge	$746.15	$746.15	-	-	$1,955.67	$1,955.67	$320.00
Volumetric Charge (per Ccf)	$0.07817	$0.07817	-	-	$0.08643	$0.08643	$0.08831
Compressed Natural Gas Transportation							
Customers Affected	1	-	-	-	-	-	-
Customer Charge	$771.15	$771.15	-	-	$2,255.67	$2,255.67	$500.00
Volumetric Charge (per Ccf)	$0.07817	$0.07817	-	-	$0.08643	$0.08643	$0.08831
Unmetered Gas Light							
Customers Affected	1	-	-	-	-	-	-
Customer Charge	-	-	-	-	-	-	-
Residential Volumetric Charge (per Ccf)	$0.87646	$0.87646	$2.02007	$2.02007	$0.46668	$0.46668	$0.67553
Commercial Volumetric Charge (per Ccf)	$0.27930	$0.27930	$0.63855	$0.63855	$0.09394	$0.09394	$0.43589
Industrial Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.28220	$0.28220	$0.11486	$0.11486	$0.11849
Public Authority Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.16208	$0.16208	$0.13511	$0.13511	$0.13745

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 10**
~~**Central Gulf Service Area**~~
Page 1 of 2

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 structure 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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$18.00~~ $29.50 plus
~~Interim Rate Adjustments (IRA)~~	~~$3.36 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$21.36 per month~~

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~8764~~67553 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~331	Small Residential, Rate Schedule 10
Annual Normalized Volume ~~352~~331 Ccf or	Large Residential, Rate Schedule 15

Supersedes Rate ~~Schedule~~Schedules Dated ~~November 27, 2024~~ | Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 10**

~~**Central Gulf Service Area**~~

Page 2 of 2

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~~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~~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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

CONDITIONS

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

~~Footnote 1: 2024 IRA - $3.36 (Gas Utilities Case No. 00020233)~~

Supersedes Rate ~~Schedule~~Schedules Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 15**
~~**Central Gulf Service Area**~~
Page 1 of 2

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 structure 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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of ~~$30.00~~ $39.50 plus
~~Interim Rate Adjustments (IRA) $3.36 per month (Footnote 1)~~
~~Total Customer Charge $33.36 per month~~

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~4673~~31189 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~331	Small Residential, Rate Schedule 10
Annual Normalized Volume ~~352~~331 Ccf or	Large Residential, Rate Schedule 15

Supersedes Rate Schedule Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 15**
~~**Central Gulf Service Area**~~
Page 2 of 2

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~~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~~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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

CONDITIONS

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

~~Footnote 1: 2024 IRA - $3.36 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 20**
~~**Central Gulf Service Area**~~
Page 1 of 2

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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$60~~ $75.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$12.88 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$72.88 per month~~

All Ccf metered @14.65 psi* during the per monthly billing period @ $0.~~2793~~43589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~001	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,~~640~~001 Ccf or	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~~customer's next scheduled bill.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 20**

~~**Central Gulf Service Area**~~

Page 2 of 2

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.~~

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~~.

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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

CONDITIONS

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

~~Footnote 1: 2024 IRA - $12.88 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 25**

~~**Central Gulf Service Area**~~

Page 1 of 2

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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$75~~ $150.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$12.88 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$87.88 per month~~

All Ccf ~~per~~ metered @14.65 psi* during the monthly billing period @ $0.~~22985~~13589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~001	Small Commercial, Rate Schedule 20
Annual Normalized Volume 3,~~640~~001 Ccf or	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~~customer's next scheduled bill.

OTHER ADJUSTMENTS

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf) TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 25**

~~**Central Gulf Service Area**~~

Page 2 of 2

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.~~

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~~.

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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

CONDITIONS

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

~~Footnote 1: 2024 IRA - $12.88 (Gas Utilities Case No. 00020233)~~

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

Page 1 of ~~1~~2

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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$571.38~~	$1,250.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$461.83 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$1,033.21 per month~~	

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~14569~~11849 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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~~Schedules PIT and PIT-Rider~~, if applicable~~.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 30**

~~**Central Gulf Service Area**~~

Page 2 of ~~1~~2

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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

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

INDUSTRIAL SERVICE RATE (Continued)

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

CONDITIONS

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

~~Footnote 1: 2024 IRA - $461.83 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

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

Page 1 of ~~1~~2

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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$155.97~~ $200.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$25.96 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$181.93 per month~~

All Ccf ~~per~~ metered @14.65 psi* during the monthly billing period @ $0.~~13768~~13745 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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~~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, if applicable.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 40**

~~**Central Gulf Service Area**~~

Page 2 of ~~1~~2

Rate Case Expense ~~Rider~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

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.

PUBLIC AUTHORITY SERVICE RATE (Continued)

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

CONDITIONS

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

~~Footnote 1: 2024 IRA - $25.96 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE 70
~~**Central Gulf Service Area**~~
Page 1 of 2

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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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.~~8764~~67553 per Ccf metered @ 14.65 psi*
Commercial	$0.~~2793~~43589 per Ccf metered @ 14.65 psi*
Industrial	$0.~~1456~~911849 per Ccf metered @ 14.65 psi*
Public Authority	$0.~~1376~~813745 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

OTHER ADJUSTMENTS

~~Initial~~Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~	November 27, 2024 (Central-Gulf)
TBD	January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)
	February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)
	August 26, 2024 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE 70
~~**Central-Gulf Service Area**~~ **Page 2 of 2**

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~~at 1-800-700-2443 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.

~~Initial~~Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~ November 27, 2024 (Central-Gulf)	
TBD	
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
August 26, 2024 (Rio Grande Valley)	

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

Page 1 of 2

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 structure 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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$18.00~~ $29.50,	plus
~~Interim Rate Adjustments (IRA)~~	~~$3.36 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$21.36 per month~~	

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~8764~~67553 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~331	Small Residential, Rate Schedule 1Z
Annual Normalized Volume ~~352~~331 Ccf or	Large Residential, Rate Schedule 1Y

Supersedes Rate ~~Schedule~~Schedules Dated ~~November 27, 2024~~ Meters Read On and After

May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1Z**
~~**Central Gulf Service Area**~~
Page 2 of 2

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~~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.

SMALL RESIDENTIAL SERVICE RATE (Continued)

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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

~~Footnote 1: 2024 IRA -$3.36 (Gas Utilities Case No. 00020233)~~

Supersedes Rate ~~Schedule~~Schedules Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1Y**
~~**Central Gulf Service Area**~~

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 structure 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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$30.00~~ $39.50	plus
~~Interim Rate Adjustments (IRA)~~	~~$3.36 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$33.36 per month~~	

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~4673~~31189 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~331	Small Residential, Rate Schedule 1Z
Annual Normalized Volume ~~352~~331 Ccf or	Large Residential, Rate Schedule 1Y

Supersedes Rate Schedule Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 1Y**

~~**Central Gulf Service Area**~~

Page 2 of 2

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~~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.

LARGE RESIDENTIAL SERVICE RATE (Continued)

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.

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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

~~Footnote 1: 2024 IRA - $3.36 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Z**
~~**Central Gulf Service Area**~~
Page 1 of 2

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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$60~~ $75.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$12.88 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$72.88 per month~~

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~2793~~43589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~001	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,~~640~~001 Ccf or	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~~customer's next scheduled bill.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	May 27, 2025 (Central-Gulf and West-North) TBD August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Z**
~~**Central Gulf Service Area**~~
Page 2 of 2

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~~Schedules 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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

~~Footnote 1: 2024 IRA - $12.88 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Y**
~~**Central Gulf Service Area**~~

Page 1 of 2

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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$75~~ $150.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$12.88 per month (Footnote 1)~~
~~Total Customer Charge~~	~~$87.88 per month~~

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~22985~~13589 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

The Company will initially assign each ~~Customer~~customer to the rate schedule that is the most economical based on the annual normalized volume at the ~~Customer's~~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~~001	Small Commercial, Rate Schedule 2Z
Annual Normalized Volume 3,~~640~~001 Ccf or	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~~customer's next scheduled bill.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	May 27, 2025 (Central-Gulf)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 2Y**
~~**Central Gulf Service Area**~~
Page 2 of 2

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~~Schedules 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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE-ENV, if applicable.

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.

~~Footnote 1: 2024 IRA - $12.88 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 3Z**
~~**Central Gulf Service Area**~~

Page 1 of ~~1~~2

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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$571.38~~	$1,250.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$461.83 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$1,033.21 per month~~	

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~14569~~11849 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 3Z**
~~**Central Gulf Service Area**~~
Page 2 of ~~1~~2

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~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE-ENV, if applicable.

Taxes: Plus applicable taxes and fees related to above.

INDUSTRIAL 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: 2024 IRA - $461.83 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
August 25, 2025 (Rio Grande Valley)	

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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$155.97~~	$200.00 plus
~~Interim Rate Adjustments (IRA)~~	~~$25.96 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$181.93 per month~~	

All Ccf ~~per~~ metered @14.65 psi* during the monthly billing period @ $0.~~1376~~13745 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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~~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, if applicable.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	
	May 27, 2025 (Central-Gulf and West-North)
	TBD
	August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 4Z**
~~**Central Gulf Service Area**~~
Page 2 of 1

Rate Case Expense ~~Rider~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

~~Footnote 1: 2024 IRA - $25.96 (Gas Utilities Case No. 00020233)~~

Supersedes Rate Schedule Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 7Z**
~~**Central Gulf Service Area**~~
Page 1 of 2

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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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.~~8764~~67553 per Ccf metered @ 14.65 psi*
Commercial	$0.~~2793~~43589 per Ccf metered @ 14.65 psi*
Industrial	$0.~~1456~~11849 per Ccf metered @ 14.65 psi*
Public Authority	$0.~~1376~~13745 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE 7Z**

~~**Central Gulf Service Area**~~

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~~at 1-800-700-2443 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.

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE CNG-1
~~**Central Gulf Service Area**~~

~~**Page 1 of 2**~~

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.~~
All incorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$594.55~~ $320.00	plus
~~Interim Rate Adjustments (IRA)~~	~~$151.60 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$746.15 per month~~	

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~07817~~08831 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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~~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, if applicable.

Rate Case Expense ~~Rider~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

Supersedes Rate Schedule Dated	Meters Read On and After
~~November 27, 2024~~	May 27, 2025 (Central-Gulf and West-North)
TBD	

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE CNG-1
~~**Central-Gulf Service Area**~~

~~**Page 2 of 2**~~

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

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

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.

~~Footnote 1: 2024 IRA - $151.60 (Gas Utilities Case No. 00020233)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE CNG-1-ENV**
~~**Central Gulf Service Area**~~
Page 1 of 2

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.~~
All unincorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

COST OF SERVICE RATE

During each monthly billing period, the Cost of Service Rate shall be comprised of:

A customer charge per meter per month of	~~$594.55~~ $320.00	plus
~~Interim Rate Adjustments (IRA)~~	~~$151.60 per month (Footnote 1)~~	
~~Total Customer Charge~~	~~$746.15 per month~~	

All Ccf ~~per~~metered @14.65 psi* during the monthly billing period @ $0.~~07817~~08831 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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~~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, if applicable.

Supersedes Rate Schedule Dated
~~November 27, 2024~~ TBD (Central-Gulf and West-North)

Meters Read On and After
May 27, 2025

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE CNG-1-ENV**
~~**Central Gulf Service Area**~~
Page 2 of 2

Rate Case Expense ~~Rider~~Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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.

~~Footnote 1: 2024 IRA - $151.60 (Gas Utilities Case No. 00020233)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ **RATE SCHEDULE 1-INC**

~~Central Gulf Service Area~~ **Page 1 of ~~56~~**

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~~served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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~~1. **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.

2. **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 (applicable to all areas except the incorporated and unincorporated areas of: Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas), the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, FERC Intervention Costs, Non-Utility Transactions and the revenue associated fees (including franchise fees) and taxes.

   Applicable in the incorporated area of Weatherford, Texas, only: The "revenue associated fees" as defined herein, shall expressly include the full amount necessary for the Company to recover the franchise fees payable upon both the base rates and gas costs of its gas sales customers in accordance with the applicable franchise ordinance. Additionally, the franchise fees collected by the Company from its customers and to be remitted to the City in accordance with the franchise ordinance shall not be included as part of the Reconciliation Audit set forth in Section B.6 or the Cost of Gas Statement set forth in Section H.

Supersedes Rate ~~Schedule~~Schedules Dated
~~January 15, 2024~~
TBD
January 30, 2024 (Rio Grande Valley)
January 27, 2023 (Rate Sched. 1-INC-WTX for incorporated Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett and Wink)
September 26, 2023 (Rate Sched. 1-INC-NTX for incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford Whitt and Willow Park)
September 26, 2023 (Rate Sched. 1-INC-BorgSk for incorporated Borger and Skellytown)

Meters Read On and After
November 27, 2024 (Central-Gulf)

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ **RATE SCHEDULE 1-INC**

~~Central Gulf Service Area~~ **Page 2 of ~~5~~6**

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 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

COST OF GAS CLAUSE (Continued)

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). This component is not applicable to customers in the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas.

~~5. 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. 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~~ 5. **FERC Intervention Costs** - Costs incurred from outside vendors and attorneys for the purpose of protecting the interest of sales customers in connection with negotiating Federal Energy Regulatory Commission ("FERC") related issues with upstream pipelines or intervention and participation in proceedings at the FERC. FERC Intervention Costs may also include incurred internal travel expenses related to this purpose.

6. **Non-Utility Transactions** - for the purposes of this section only, "non-utility transactions" shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. "Non-utility Transactions" shall not include any transaction conducted by any affiliate of the company.

~~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~~

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~

RATE SCHEDULE 1-INC

~~Central Gulf Service Area~~ **Page 3 of ~~5~~6**

~~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.~~

7. **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.

~~8. 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.~~

~~9.~~ 8. **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~~(f) the total amount of FERC Intervention Costs; and (g) 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)

~~10. Uncollectible Cost of Gas~~

9. **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; (f) the total amount of FERC Intervention Costs; and (g) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

10. **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.

11. **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.

12. **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. All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

COST OF GAS CLAUSE (Continued)

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,

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~

RATE SCHEDULE 1-INC

~~Central Gulf Service Area~~ **Page 5 of ~~5~~6**

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.

~~G~~G. NON-UTILITY TRANSACTIONS

The aggregate net margins generated by the company from all Non-Utility Transactions shall be credited 100% to sales customers in the month during which the transaction closes.

COST OF GAS CLAUSE (Continued)

For purposes of this provision, “Non-Utility Transactions” shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. “Non-utility Transactions” shall not include any transaction conducted by any affiliate of the company.

For purposes of this provision, “Net Margins” shall mean revenues from the aggregate of all Non-Utility Transactions, less the costs to the Company of such transactions, including related taxes, commissions,

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~

RATE SCHEDULE 1-INC

~~Central Gulf Service Area~~ **Page 6 of ~~5~~6**

transaction fees, and transfer fees. The Net Margins shall be credited to the ratepayers once per year through an adjustment of the Reconciliation Account as determined in the Annual Reconciliation filing. This provision does not permit the Company to include in the calculation of gas cost, any storage or gas stored except as prudently and necessarily needed to serve sales customers.

H. 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;~~refund; (d) the Customer Rate Relief Component (excluding customers in the the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas); (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.

The Company shall include in its monthly Cost of Gas Statement filed pursuant to the Cost of Gas Clause the separate cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

~~H~~I. 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 including but not limited to the purchase cost of natural gas, renewable gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas, by month for the 12 months ending June 30.

COST OF GAS CLAUSE (Continued)

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.

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~

RATE SCHEDULE 1-INC

~~Central Gulf Service Area~~ **Page 7 of ~~5~~6**

~~4~~4. A tabulation of any FERC Intervention activities performed and associated costs incurred on behalf of sales customers.

5. 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~~6. 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~~7. A tabulation of Uncollectible Cost of Gas during the period and its effect on the Cost of Gas Clause to date.

~~7.~~ 8. A tabulation of cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

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**~~ **RATE SCHEDULE 1-ENV**
~~**Central Gulf Service Area**~~ **Page 1 of ~~5~~6**

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~~and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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~~1. **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.

2. **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 (applicable to all areas except the incorporated and unincorporated areas of: Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas), the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, FERC Intervention Costs, Non-Utility Transactions and the revenue associated fees and taxes.

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 gas withdrawn from storage. 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.

COST OF GAS CLAUSE (Continued)

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). This component is not applicable to customers in the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas.

~~5. 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.~~

~~5~~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.

~~7. 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.~~

~~8~~5. **FERC Intervention Costs** - Costs incurred from outside vendors and attorneys for the purpose of protecting the interest of sales customers in connection with negotiating Federal Energy Regulatory Commission ("FERC") related issues with upstream pipelines or intervention and participation in proceedings at the FERC. FERC Intervention Costs may also include incurred internal travel expenses related to this purpose.

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~**Rate Schedule**~~ **RATE SCHEDULE 1-ENV**
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6. **Non-Utility Transactions** - for the purposes of this section only, "non-utility transactions" shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. "Non-utility Transactions" shall not include any transaction conducted by any affiliate of the company.

7. **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~~psi. 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.~~ 8. **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 (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) the total amount of FERC Intervention Costs; and (g) 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. **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. ~~10. Uncollectible Cost of Gas~~ 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; (f) the total amount of

FERC Intervention Costs; and (g) an adjustment, if necessary, to remove lost and unaccounted for gas costs during the period for volumes in excess of 5 percent of purchases.

10. **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.

11. **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.

12. **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. All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

COST OF GAS CLAUSE (Continued)

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.

~~G~~G. NON-UTILITY TRANSACTIONS

The aggregate net margins generated by the company from all Non-Utility Transactions shall be credited 100% to sales customers in the month during which the transaction closes.

COST OF GAS CLAUSE (Continued)

For purposes of this provision, “Non-Utility Transactions” shall mean the following transactions to the extent that such transactions pertain to natural gas supplies, storage, and transportation capacity allocated to sales customers: excess sales of natural gas and releases of transportation or storage capacity. “Non-utility Transactions” shall not include any transaction conducted by any affiliate of the company.

For purposes of this provision, “Net Margins” shall mean revenues from the aggregate of all Non-Utility Transactions, less the costs to the Company of such transactions, including related taxes, commissions, transaction fees, and transfer fees. The Net Margins shall be credited to the ratepayers once per year through an adjustment of the Reconciliation Account as determined in the Annual Reconciliation filing. This provision does

not permit the Company to include in the calculation of gas cost, any storage or gas stored except as prudently and necessarily needed to serve sales customers.

H. 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~~;~~ (excluding customers in the the incorporated and unincorporated areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas and in the environs areas of Canutillo and Fabens, Texas); (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 ~~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.

The Company shall include in its monthly Cost of Gas Statement filed pursuant to the Cost of Gas Clause the separate cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

~~H~~I. 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 including but not limited to the purchase cost of natural gas, renewable gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas, by month for the 12 months ending June 30.

COST OF GAS CLAUSE (Continued)

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~~4. A tabulation of any FERC Intervention activities performed and associated costs incurred on behalf of sales customers.

5. 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~~6. 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~~7. A tabulation of Uncollectible Cost of Gas during the period and its effect on the Cost of Gas Clause to date.

~~7.~~ 8. A tabulation of cost of each type of purchased gas, including but not limited to the purchase cost of natural gas, renewable natural gas, hydrogen, and any other type of gas included in the Cost of Purchased Gas.

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.

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CUSTOMER RATE RELIEF RATE SCHEDULE

Applicable to all Sales Customers excluding the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and the unincorporated areas of Canutillo and Fabens, Texas for the purpose of collecting and remitting customer rate relief charges as authorized by the Railroad Commission of Texas (Commission) in accordance with Chapter 104, Subchapter I of the Texas Utilities Code and the Commission Financing Order issued in Docket No. OS-21-00007061.

A. ABBREVIATIONS AND DEFINITIONS

1) Authority – The Texas Public Finance Authority, together with any successor to its duties and functions.

2) Bonds or Customer Rate Relief ("CRR") Bonds – The "Texas Natural Gas Securitization Finance Corporation Customer Rate Relief Bonds, Series 2023" and any additional or different designation or title by which each series of Bonds shall be known as determined by the Issuer Entity.

3) Ccf and Mcf – For Ccf, one hundred (100) standard cubic feet of gas, where one (1) standard cubic foot of gas is the amount of gas contained in one (1) cubic foot of space at a standard pressure of fourteen point sixty-five (14.65) pounds per square inch, absolute and a standard temperature of sixty (60) degrees Fahrenheit; and, for Mcf, 1,000 standard cubic feet of gas.

4) Central Servicer – The entity engaged in accordance with the terms of the Financing Order to, amongst other things, engage the Participating Gas Utilities as collection agents for the purposes of facilitating collection and remittance of CRR Charges by Participating Gas Utilities, and perform the other services required of it under the Servicing Agreement (as defined in the Financing Order).

5) Commission – The Railroad Commission of Texas, including its staff or delegate.

6) CRR Charge True-Up Adjustment – A True-Up Adjustment (as defined in the Financing Order).

7) CRR Charge True-Up Charge Adjustment Letter – A true-up adjustment letter substantially in the form of Exhibit 3 to the Financing Order.

8) CRR Scheduled Adjustment Date – January 1 and July 1 of each applicable year, provided that the CRR Scheduled Adjustment Date and any other deadlines or target dates related thereto, shall be subject to modification prior to the date the Bonds so as to reflect the terms of the Servicing Agreement.

9) Customer Rate Relief ("CRR") Charge – A nonbypassable charge as defined in Tex. Util. Code § 104.362(7).

10) Financing Order – The order adopted under Tex. Util. Code § 104.366 approving the issuance of CRR Bonds and the creation of Customer Rate Relief Property and associated CRR Charges for the recovery of regulatory assets, including extraordinary costs, related financing costs, and other costs authorized by the Financing Order.

Supersedes Rate Schedule Dated	Meters Read On and After
~~September 26, 2023~~	September 25, 2024
TBD	

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11) Gas Utility – Texas Gas Service Company, a Division of ONE Gas, Inc. and its successors and assignees, an operator of natural gas distribution pipelines that delivers and sells natural gas to the public and that is subject to the Commission's jurisdiction under Tex. Util. Code § 102.001, or an operator that transmits, transports, delivers, or sells natural gas or synthetic natural gas to operators of natural gas distribution pipelines and whose rates for those services are established by the Commission in a rate proceeding filed under Chapter 104 of the Utilities Code, within the service area.

12) Irrevocable – The Financing Order, together with the Customer Rate Relief Property as defined by Tex. Util. Code § 104.362(8) and the CRR Charges authorized by the Financing Order, are irrevocable and not subject to reduction, impairment, or adjustment by further action of the Commission, except in connection with true-ups authorized by the Financing Order.

13) Issuer Entity – Texas Natural Gas Securitization Finance Corporation, a Texas nonprofit public corporation established by the Authority, or any successor created pursuant to Tex. Gov't Code § 1232.1072.

14) Large Participating Gas Utility – Atmos Energy Corporation on behalf of its Mid-Tex Division and West Texas Division; CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas; Texas Gas Service Company, a Division of ONE Gas, Inc., excluding the ~~West Texas Service Area~~incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and the unincorporated areas of Canutillo and Fabens, Texas; and any Participating Gas Utility or Successor Utility (as defined in the Financing Order) each of whose Normalized Sales Volumes exceed 2.0% of the total aggregate Normalized Sales Volumes among all Participating Gas Utilities. Any calculation performed in connection with the preceding sentence shall be made on the basis of the most recently reported Normalized Sales Volumes and such calculation shall be performed by the Central Servicer annually no later than one (1) month after Normalized Sales Volumes are reported as regularly scheduled under Paragraph H hereof; provided that the Commission and/or Central Servicer may perform such calculation without any limitation in order to give effect to any merger, acquisition, disposition, divesture, spin-off or other transaction that would impact a Participating Gas Utility's share of the total aggregate Normalized Sales Volumes. The Commission or the Central Servicer shall promptly thereafter provide written notice to a Participating Gas Utility that subsequently becomes a Large Participating Gas Utility, which change shall take effective beginning on January 1 of the following calendar year.

15) Nonbypassable – CRR Charges must be paid by all existing or future customers receiving service from a Participating Gas Utility or such gas utility's successors or assigns.

16) Normalized Sales Volumes –

a) For Large Participating Gas Utilities: All natural gas volumes projected to be billed for the upcoming twelve (12) month period in conjunction with the operation of a Participating Gas Utility's Purchased Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs. For the avoidance of doubt, only the Normalized Sales Volumes of Large Participating Gas Utilities shall be aggregated to calculate the CRR Charges.

b) For other Participating Gas Utilities: All natural gas volumes billed in the preceding calendar year in conjunction with the operation of a Participating Gas Utility's Purchased Gas Adjustment, Cost of Gas

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Clause, or other equivalent tariff established for the collection of natural gas costs and normalized according to the methodology utilized in each Participating Gas Utility's application filed in Docket No. OS-21- 00007061, *Consolidated Applications For Customer Rate Relief and Related Regulatory Asset Determinations In Connection With The February 2021 Winter Storm*.

For the avoidance of doubt, only the Normalized Sales Volumes of Large Participating Gas Utilities shall be aggregated in order to calculate the CRR Charges.

17) Participating Gas Utilities – Atmos Energy Corporation on behalf of its Mid-Tex Division and West Texas Division; Rockin' M Gas LLC d/b/a Bluebonnet Natural Gas LLC; CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas; Corix Utilities (Texas) Inc.; EPCOR Gas Texas Inc.; SiEnergy, LP; Summit Utilities Arkansas, Inc.[1], Texas Gas Service Company, a Division of ONE Gas, Inc., excluding the ~~West Texas Service Area~~incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and the unincorporated areas of Canutillo and Fabens, Texas; and Universal Natural Gas, LLC d/b/a Universal Natural Gas, Inc. or any Successor Utility (as defined in the Financing Order).

18) Sales Customer(s) – All active customers taking service under a Participating Gas Utility's Purchased Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs.

B. APPLICABILITY

This rate schedule sets out the rate, terms and conditions under which the CRR Charge shall be billed and collected by Texas Gas Service Company, a Division of ONE Gas, Inc. as a Participating Gas Utility for all ~~Incorporated and Unincorporated Areas of the Central Gulf~~Texas Gas Service ~~Area, Rio Grande Valley Service Area, North Texas Service Area~~customers, excluding those in the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and ~~Borger/Skellytown Service Area~~Wink, Texas, and in the unincorporated areas of Canutillo and Fabens, Texas under the terms of the Financing Order. Each individual Sales Customer is responsible for paying the CRR Charge billed to it in accordance with the terms of this rate schedule. Payment is to be made by an individual Sales Customer to the Participating Gas Utility of which it is a customer. The Participating Gas Utility is obligated to apply amounts collected from customers to pay any outstanding CRR Charges prior to applying such amounts for any other purpose. The Participating Gas Utility, as collection agent, shall remit collections of the CRR Charges to the Indenture Trustee in accordance with the terms of the Financing Order and any servicing or other similar agreement that is contemplated by the Financing Order.

C. TERM

This rate schedule shall remain in effect until the CRR Charges have been collected and remitted to the Indenture Trustee in an amount sufficient to satisfy all obligations in regard to paying principal and interest on the CRR Bonds together with all other financing costs, bond administrative expenses and other costs as provided in the Financing Order. This rate schedule and the CRR Charge are irrevocable and nonbypassable.

[1] Summit Utilities Arkansas, Inc. is the Successor Utility of CenterPoint Energy Arkla as of January 10, 2022.

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D. SALES CUSTOMERS

For the purposes of billing the CRR Charges, all Sales Customers of the Participating Gas ~~Utility's Central Gulf Service Area, Rio Grande Valley Service Area, North Texas Service Area and Borger/Skellytown Service Area~~Utility, excluding those in the incorporated and environs areas of Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas, and in the unincorporated areas of Canutillo and Fabens, Texas shall be assessed the uniform volumetric charge identified below.

E. CRR CHARGE

The CRR Charge will be a monthly volumetric rate of $0.118/Ccf. The CRR Charge is calculated in accordance with and subject to the provisions set forth in the Financing Order and will be adjusted at least annually based upon the CRR Charge true- up adjustment procedure. The CRR Charge shall be included in the Participating Gas Utility's Purchase Gas Adjustment, Cost of Gas Clause, or other equivalent tariff established for the collection of natural gas costs. Participating Gas Utilities may reflect the CRR Charge according to the delivery pressures defined in Participating Gas Utilities' applicable tariffs. Such delivery pressure specific charges shall be equivalent to the CRR Charge as determined below at 14.65 per square inch, as defined above.

F. DETERMINATION OF CUSTOMER RATE RELIEF CHARGE

The CRR Charge will be adjusted no less frequently than annually, in accordance with the terms of the Servicing Agreement (as defined in the Financing Order), to ensure that the expected collection of CRR Charges is adequate to pay when due, pursuant to the expected amortization schedule, principal and interest on the CRR Bonds and together with all other financing costs, bond administrative expenses and other costs, as provided in the Financing Order, on a timely basis. The CRR Charge shall be computed according to the formula described below.

Step 1: Determination of Normalized Sales Volumes
(A) Total Large Participating Gas Utility Normalized Sales Volumes (Mcf)
(B) Assumed % of uncollectible sales
(C) Total Normalized Sales Volumes Billed and Collected: ***(A * (1 – B))***

For the avoidance of doubt, Normalized Sales Volumes are assumed to be calculated without giving effect to volumes anticipated from Participating Gas Utilities making up less than two percent (2.0%) of the total Normalized Sales Volumes of all Participating Gas Utilities.

Step 2: Determination of CRR Charge
(D) Total CRR Charge Rate Revenue Requirement for Applicable Period
(E) CRR Charge per Normalized Sales Volumes (Mcf): ***(D / C)***
Thereof: CRR Charge for Sales Customers

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G. CRR CHARGE TRUE-UP

Changes to the CRR Charge will be effected through the filing of CRR Charge True-Up Adjustment Letters by the Central Servicer to the Commission as authorized by the Financing Order and in accordance with the Servicing Agreement. Not less than fifteen (15) days prior to each CRR Scheduled Adjustment Date and more frequently as required by the Central Servicer, the Central Servicer will submit the CRR Charge True-Up Adjustment Letter in the form of Exhibit 3 to the Financing Order to ensure that CRR Charge collections are sufficient to make all scheduled payments of CRR Bond principal and interest and meet other Ongoing Financing Costs (as defined in the Financing Order) on a timely basis during the payment period.

In addition to the foregoing, the Central Servicer shall be authorized to file CRR Charge True-Up Adjustment Letters with the Commission that adjust the CRR Charge more frequently (but not more often than quarterly) as required under the provisions of the Servicing Agreement (as defined in the Financing Order).

H. CRR CHARGE TRUE-UP PROCEDURE

Texas Gas Service Company, a Division of ONE Gas, Inc. shall annually file with the Commission and the Central Servicer by June 1 of each year its Normalized Sales Volumes; each Large Participating Gas Utility shall include projected volumes for each of the future twelve (12) months beginning July 1, and each other Participating Gas Utility shall include its Normalized Sales Volumes for the prior calendar year. Such filing and/or reporting may be more frequent to the extent required under the Servicing Agreement and applicable Collection and Reporting Arrangements. If Texas Gas Service Company, a Division of ONE Gas, Inc. is a Large Participating Gas Utility, the Participating Gas Utility shall, upon the request of the Central Servicer, provide the Commission and the Central Servicer updated Normalized Sales Volumes for the succeeding twelve (12) month period no later than the fifteenth (15th) day following such request to allow the Central Servicer to make Interim True-Up Adjustments. Each Participating Gas Utility shall have the right to provide the foregoing information to the Central Servicer on a confidential basis if reasonably necessary to ensure compliance with applicable securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). The Central Servicer shall submit to the Commission and the Participating Gas Utilities, not less than fifteen (15) days prior to the CRR Scheduled Adjustment Date, a CRR Charge True-Up Adjustment Letter applying the CRR Charge True-Up Adjustment based on Normalized Sales Volumes and other mathematical factors and requesting administrative approval from the Commission as provided for in the Servicing Agreement. The Commission's review and approval of the True-Up Adjustment Letter shall be as set forth in the Servicing Agreement (it being understood such review is limited to determining if any mathematical or clerical errors are present in the application of the CRR Charge True-Up Adjustment relating to the appropriate amount of any over-collection or under-collection of CRR Charges and the amount of an adjustment).

If any CRR Charge True-Up Adjustment that is an Interim True-Up Adjustment is necessary, (i) the Central Servicer may request and the Large Participating Gas Utilities shall provide revised Normalized Sales Volumes for each of the immediately succeeding twelve (12) months and related data and (ii) within fifteen (15) days of receipt of such data, the Central Servicer shall file a revision to the CRR Rate Schedule in a True-Up Charge Adjustment Letter setting forth the adjusted CRR Charge to be effective for the upcoming period, in accordance with the Servicing Agreement. Texas Gas Service Company, a Division of ONE Gas, Inc. shall have the right to provide such information on a confidential basis if reasonably necessary to ensure compliance with applicable

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securities laws (subject to any (i) legal requirements necessitating the disclosure of such information, including compliance with (A) applicable securities laws and (B) other generally applicable laws and (ii) certain customary restrictions and exceptions to be agreed). A CRR Charge resulting from a true-up adjustment will become effective on the first (1st) billing cycle that is not less than fifteen (15) days following the making of the CRR Charge True-Up Adjustment filing.

I. TAXABILITY

The receipt of CRR Charges by a Participating Gas Utility is exempt from state and local sales and use taxes and utility gross receipts taxes and assessments and is excluded from revenue for purposes of franchise tax under Tex. Tax Code § 171.1011.

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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 Company 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~~served by the Company, as listed in the ~~environs area of Bastrop, Texas:~~Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: Rate Schedules 10, 15, 16, 20, 25, 30, 40, ~~C-1,~~ CNG-1, 1Z, 1Y, 1W, 2Z, 2Y, 3Z, 4Z, ~~C-1-ENV,~~ CNG-1-ENV, T-1, ~~and~~T-EGEN, T-1-ENV and T-EGEN-ENV.

QUALIFYING EXPENSES

This Rider applies only to the legally mandated safety testing of the Company's transmission lines in the ~~CGSA~~Company's areas of service 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;

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~ November 27, 2024 (Central-Gulf)	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

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~~**Central Gulf Service Area**~~
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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

PIPELINE INTEGRITY TESTING (PIT) RIDER (Continued)

pipelines in the ~~CGSA~~Company's areas of service. Neither capital expenditures by the Company, nor the labor cost of Company employees, shall be recovered under this Rider.

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.~~Company's areas of service. 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.

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~ November 27, 2024 (Central-Gulf)	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE PIT
~~**Central Gulf Service Area**~~
Page 3 of 3

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 served by the Company 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 served by the Company (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

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~ November 27, 2024 (Central-Gulf)	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE PIT
~~Central-Gulf Service Area~~
Page 4 of 3

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 served by the Company 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.

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~ November 27, 2024 (Central-Gulf)	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

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~~served by the Company, as listed in the ~~environs area of Bastrop, Texas:~~ Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1: Rate Schedules 10, 15, 16, 20, 25, 30, 40, ~~C-1,~~ CNG-1, ~~T-1,~~ 1Z, 1Y, 1W, 2Z, 2Y, 3Z, 4Z, ~~C-1-ENV,~~ CNG-1-ENV, T-1, T-EGEN, T-1-ENV and T-~~1~~EGEN-ENV.

B. PIT RATE

$~~0.00010~~TBD per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

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.

Supersedes Rate Schedule Dated	Meters Read On and After
~~March 27, 2024~~	~~March 27, 2025~~
March 27, 2025 (Central-Gulf, Rio Grande Valley, and West-North)	TBD

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE WNA**
~~**Central Gulf Service Area**~~
Page 1 of ~~23~~

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~~within the incorporated and unincorporated areas served ~~in~~by the ~~Central Gulf~~Company, as listed in the Company's Rules of 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 Schedule Number QSR-TGS), Section 1.1: Rate Schedules 10, 15, 16, 1Z, 1Y, 1W, 20, 25, 2Z, 2Y, 40, and 4Z. The WNA shall be effective during the September through May billing cycles.

PURPOSE

The WNA adjusts customer bills to address variations in weather experienced during the billing period that are above or below the 'normal' weather range established in the Company's most recent rate filing. The WNA refunds over-collections or surcharges of revenue due to colder than normal weather or 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 (at 14.65 psi) for the billing period.

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~	
	November 27, 2024 (Central-Gulf)
	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE WNA**
~~**Central Gulf Service Area**~~
Page 2 of ~~23~~

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

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.

WEATHER NORMALIZATION ADJUSTMENT CLAUSE (Continued)

CB = Number of customers billed for the billing period.

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

The Weather Factors (WF) and associated weather station for each applicable incorporated or environs area are established as follows:

Austin, Bastrop (environs only), Bee Cave, Buda, Cedar Park, Dripping Springs, Georgetown, Hutto, Jarrell, Jonah (environs only), Kyle, Lakeway, Marble Falls, Mustang Ridge, Pflugerville, Rollingwood, Sunset Valley, and West Lake Hills:

Residential 0.~~14945~~14202; Commercial 0.~~46174~~48000; Public Authority ~~1.91573~~2.06571
Weather Station: KATT

Cuero, Gonzales, Lockhart, Luling, Nixon, Shiner, and Yoakum:

Residential 0.~~13893~~12176; Commercial 0.~~24380~~18681; Public Authority 0.~~82469~~97873
Weather Station: KSAT

Bayou Vista, Galveston, and Jamaica Beach:

Residential 0.~~19840~~19431; Commercial 0.~~50668~~42720; Public Authority ~~5.12822~~2.91772
Weather Station: KGLS

Beaumont, Groves, Nederland, Port Arthur, and Port Neches:

Residential 0.~~14683~~14652; Commercial 0.~~21018~~29381; Public Authority 1.~~04076~~09440

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~	
	November 27, 2024 (Central-Gulf)
	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE WNA
~~**Central-Gulf Service Area**~~
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Weather Station: KBPT

Alamo, Alton, Brownsville, Combes, Donna, Edcouch, Edinburg, Elsa, Harlingen, Hidalgo, La Feria, La Joya, La Villa, Laguna Vista, Los Fresnos, Lyford, McAllen, Mercedes, Mission, Palm Valley, Palmhurst, Palmview, Penitas, Pharr, Port Isabel, Primera, Progreso, Rancho Viejo, Raymondville, Rio Hondo, San Benito, San Juan, Santa Rosa, and Weslaco, Texas, the unincorporated cities of Bayview, Laguna Heights, Monte Alto, Olmito, and San Carlos and the unincorporated areas of Jim Hogg and Starr counties:

Residential 0.07609; Commercial 1.29246; Public Authority 2.52362
Weather Station: KBRO

WEATHER NORMALIZATION ADJUSTMENT CLAUSE (Continued)

Borger and Skellytown:

Residential 0.14039; Commercial 0.64194; Public Authority 2.24684
Weather Station: KAMA

Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Jermyn, Millsap, Mineral Wells, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, Weatherford, Whitt, and Willow Park:

Residential 0.13605; Commercial 0.46630; Public Authority 2.16192
Weather Station: KABI

Anthony, Canutillo, Clint, El Paso, Fabens, Horizon City, San Elizario, Socorro, and Vinton:

Residential 0.14485; Commercial 0.51375; Public Authority 3.33692
Weather Station: KELP

Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett, and Wink:

Residential 0.11833; Commercial 0.51375; Public Authority 1.51545
Weather Station: KMAF

Dell City:

Residential 0.14485; Commercial 0.51375; Public Authority 3.33692
Weather Station: KELP

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~	
	November 27, 2024 (Central-Gulf)
	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE WNA**
~~**Central-Gulf Service Area**~~
~~**Page 4 of 23**~~

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 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

Supersedes Rate Schedule Dated	Meters Read On and After
~~January 15, 2024~~	
	November 27, 2024 (Central-Gulf)
	TBD
January 27, 2023 (All West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
January 30, 2024 (Rio Grande Valley)	

Texas Gas Service Company, a Division of ONE Gas, Inc.
~~**West North Service Area**~~
RATE SCHEDULE E5

FORT BLISS SERVICE RATE

APPLICABILITY

Applicable to the United States Government for all purposes at Fort Bliss, William Beaumont General Hospital, Biggs Field, Logan Heights, The First Calvary Brigade Area, the Station Hospital, Permanent Troop Housing and Supporting Facilities and AFF Board No. 4 and Guided Missile Group and Training Facilities located east of Jeb Stuart Road.

COST OF SERVICE RATE

During each monthly billing period the sum of items 1 and 2 below:

1. Cost of Service Charge:

   All Gas @ $ 0.07476 per Ccf @ 14.9 PSIA.

2. Cost of Gas Charge: In addition to the Cost of Service set forth above, Ft. Bliss billing shall include an amount equal to the Cost of Gas per billing month as determined in accordance with Rate Schedule No. 1-INC. Cost per Ccf will be determined at 14.9 PSIA and multiplied by total Ccf consumed during the billing month.

CONDITIONS

1. In case of shortage of natural gas supply, or any other emergency not due to fault of the Company, deliveries of gas hereunder may be curtailed in accordance with Company's program of curtailment applicable to its customers in the incorporated and unincorporated areas of El Paso, Texas.

2. Volume of gas shown by meter readings will be corrected to 14.9 pounds per square inch absolute. Atmospheric pressure is agreed to be 12.8 pounds.

Texas Gas Service Company, a Division of ONE Gas, Inc.

~~**West North Service Area (Select Cities)**~~

RATE SCHEDULE EDR

ECONOMIC DEVELOPMENT RATE

A. APPLICABILITY

This Economic Development Rate ("EDR") rate schedule shall apply to the following rate schedules for the incorporated areas of the Cities of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro, and Vinton, Texas: 10, 15, 16, 20, 25, 30, 40, ~~C-1,~~ CNG-1, T-1 and T-~~1~~EGen.

B. TERRITORY

The Cities of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas~~, that are within the incorporated portion of the West North Service Area~~.

C. PURPOSE

This rate schedule provides for the recovery of costs that Texas Gas Service Company, a Division of ONE Gas, Inc. incurs related to economic development in ~~a portion of the West North Service Area.~~the cities mentioned above. Successful economic development will only occur to the extent that the community and its corporate partners provide the necessary support to attract new businesses and industries to this region. New businesses and industries will increase employment, spur growth and local business expansion, create a more robust economy and improve the quality of life for the region.

D. EDR RATE

The EDR rate during each Monthly Billing Period:

All Ccf ~~@~~ metered @14.65 psi* during the monthly billing period @	$ 0.002 per Ccf

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

All applicable fees and taxes (including franchise fees) will be added to the EDR rates.

D. BILLING

1. The EDR rate shall be added to the applicable cost of service usage charge (per Ccf rate) for rate schedules: 10, 15, 16, 20, 25, 30, 40, ~~C-1,~~ CNG-1, T-1 and T-~~1~~EGen.

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

~~**Page 1 of 3**~~**2**

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~~all incorporated areas served by the Company, as listed in the Company's Rules 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.~~Service (Rate Schedule Number QSR-TGS), Section 1.1. Such service shall be provided at any point on the Company's ~~System~~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, the Cost of Service Rate shall be comprised of a customer charge per meter per month ~~listed by customer class~~ as follows:

~~Commercial $308.08 per month~~
~~plus Interim Rate Adjustments $12.88 (Footnote 1) Total Rate $320.96~~

~~Industrial $771.38 per month~~
~~plus Interim Rate Adjustments $461.83 (Footnote 2) Total Rate $1,233.21~~

~~Public Authority $178.97 per month~~
~~plus Interim Rate Adjustments $25.96 (Footnote 3) Total Rate $204.93~~

~~Compressed Natural Gas $619.55 per month~~
~~plus Interim Rate Adjustments $151.60 (Footnote 4) Total Rate $771.15~~

~~Electrical Generation $175.68 per month~~

Supersedes Rate ~~Schedule~~Schedules Dated ~~November 27, 2024~~ Meters Read On and After May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

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

Page 2 of ~~3~~2

~~plus Interim Rate Adjustments $25.96 (Footnote 5) Total Rate $201.64~~

All Transportation Customers (excluding Electric Generation) $500.00 per month

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

~~Commercial~~	~~$0.12679 per Ccf~~
~~Industrial~~	~~$0.14569 per Ccf~~
~~Public Authority~~	~~$0.13768 per Ccf~~
~~Compressed Natural Gas~~	~~$0.07817 per Ccf~~

~~Electrical Generation~~

~~For the First 5,000Ccf/month~~	~~$0.07724 per Ccf~~
~~For the Next 35,000 Ccf/month~~	~~$0.06853 per Ccf~~
~~For the Next 60,000 Ccf/month~~	~~$0.05527 per Ccf~~
~~All Over 100,000 Ccf/month~~	~~$0.04018 per Ccf~~

~~ADDITIONAL CHARGES~~

~~1)~~ All Transportation Customers (excluding Electric Generation) $0.08831 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

OTHER ADJUSTMENTS

Gas Utility Pipeline Taxes: 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)~~ Taxes: A charge will be made each month to recover the cost of any applicable ~~local~~ taxes and fees~~.~~

~~3) In~~, including franchise fees paid to 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~~cities.

TRANSPORTATION SERVICE RATE (Continued)

~~4)~~ Rate Case Expense Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS and RCE, if applicable.

Supersedes Rate ~~Schedule~~Schedules Dated
~~November 27, 2024~~

Meters Read On and After
May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

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

~~5)~~ 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.

~~6)~~ Pipeline Safety and Regulatory Program Fees: 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.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, only applicable to the incorporated areas of Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro and Vinton, Texas.

Other Charges: 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 served by the Company, 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.

SUBJECT TO

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

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.

~~Footnote 1: 2024 IRA - $12.88 (Gas Utilities Case No. 00020233)~~

~~Footnote 2: 2024 IRA - $461.83 (Gas Utilities Case No. 00020233)~~

~~Footnote 3: 2024 IRA - $25.96 (Gas Utilities Case No. 00020233)~~

~~Footnote 4: 2024 IRA - $151.60 (Gas Utilities Case No. 00020233)~~

Texas Gas Service Company, a Division of ONE Gas, Inc.

RATE SCHEDULE T-1
~~Central Gulf Service Area~~

~~Page 4 of 3~~2

~~Footnote 5: 2024 IRA - $25.96 (Gas Utilities Case No. 00020233)~~

Texas Gas Service Company, a Division of ONE Gas, Inc
SCHEDULE T-1-ENV

~~Rate Schedule~~**RATE**

~~Central Gulf Service Area~~

Page 1 of ~~3~~2

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~~ Company's distribution system, which includes all unincorporated areas served by the Company, as listed in 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.~~Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1. Such service shall be provided at any point on the Company's ~~System~~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, the Cost of Service Rate shall be comprised of a customer charge per meter per month ~~listed by customer class~~ as follows:

~~Commercial $308.08 per month~~
~~plus Interim Rate Adjustments $12.88 (Footnote 1) Total Rate $320.96~~

~~Industrial $771.38 per month~~
~~plus Interim Rate Adjustments $461.83 (Footnote 2) Total Rate $1,233.21~~

~~Public Authority $178.97 per month~~
~~plus Interim Rate Adjustments $25.96 (Footnote 3) Total Rate $204.93~~

~~Compressed Natural Gas $619.55 per month~~
~~plus Interim Rate Adjustments $151.60 (Footnote 4) Total Rate $771.15~~

Supersedes Rate ~~Schedule~~Schedules Dated
~~November 27, 2024~~ May 27, 2025 (Central-Gulf and West-North)
TBD
August 25, 2025 (Rio Grande Valley)

Meters Read On and After

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~~Electrical Generation $175.68 per month~~
~~plus Interim Rate Adjustments $25.96 (Footnote 5) Total Rate $201.64~~All Transportation Customers (excluding Electric Generation) $500.00 per month

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

~~Commercial $0.12679 per Ccf~~
~~Industrial $0.14569 per Ccf~~
~~Public Authority $0.13768 per Ccf~~
~~Compressed Natural Gas $0.07817 per Ccf~~

~~Electrical Generation~~
~~For the First 5,000Ccf/month $0.07724 per Ccf~~
~~For the Next 35,000 Ccf/month $0.06853 per Ccf~~
~~For the Next 60,000 Ccf/month $0.05527 per Ccf~~
~~All Over 100,000 Ccf/month $0.04018 per Ccf~~

~~**ADDITIONAL CHARGES**~~

~~1)~~ All Transportation Customers (excluding Electric Generation) $0.08831 per Ccf metered @ 14.65 psi*

*All customers will be billed at a Common Billing Pressure of 14.65 psi, but not all customers receive service at the pressure base of 14.65 psi. To determine the pressure base and conversion factors for your location, refer to the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 13.1.

OTHER ADJUSTMENTS

Gas Utility Pipeline Taxes: 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)~~ Taxes: 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.~~

TRANSPORTATION SERVICE RATE (Continued)

~~4)~~ Rate Case Expense Riders: The billing shall reflect adjustments in accordance with provisions of the Rate Case Expense Surcharge ~~Rider~~Riders, Rate ~~Schedule~~Schedules RCE-TGS-ENV and RCE-ENV, if applicable.

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~~5)~~ 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~~.

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

Other Charges: 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 unincorporated areas served by the Company, 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.

SUBJECT TO

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

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.

~~Footnote 1: 2024 IRA - $12.88 (Gas Utilities Case No. 00020233)~~

~~Footnote 2: 2024 IRA - $461.83 (Gas Utilities Case No. 00020233)~~

~~Footnote 3: 2024 IRA - $25.96 (Gas Utilities Case No. 00020233)~~

~~Footnote 4: 2024 IRA - $151.60 (Gas Utilities Case No. 00020233)~~

~~Footnote 5: 2024 IRA - $25.96 (Gas Utilities Case No. 00020233)~~

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ RATE SCHEDULE T-TERMS

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GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE

1.1 REQUIREMENTS FOR TRANSPORTATION SERVICE

This rate schedule shall apply to Customers who have elected Transportation Service through the Company's distribution system within the incorporated and unincorporated areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1.

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~~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~~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.

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ RATE SCHEDULE T-TERMS

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Btu: Shall mean British thermal unit(s) and shall be computed on a temperature base of 60~~°~~ degrees 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.

GENERAL TERMS AND CONDITIONS FOR TRANSPORTATION SERVICE (Continued)

Commercial Service: Service to ~~Consumers~~Customers 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.

Compressed Natural Gas (CNG) Service: Service to Customers where the Customer purchases Natural Gas to be compressed and used as a motor fuel. This rate does not include compression by the Company beyond normal meter sales pressure.

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~~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~~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 (1) calendar day and ending at 9:00 a.m. ~~(~~Central Standard Time~~)~~ the following calendar day.

Supersedes Rate Schedules Dated	Meters Read On and After
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January 30, 2024 (Rio Grande Valley)	
January 27, 2023 (West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ RATE SCHEDULE T-TERMS

~~Central Gulf Service Area~~

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Dekatherm (Dth): Shall mean ~~1~~one million (1,000,000) Btu's (1 MMBtu). This unit will be on a dry basis.

Electrical Generation Service: Service to ~~customers~~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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

Force Majeure: If either Company or Customer is rendered unable, wholly or in part, by reason of ~~force majeure~~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

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~~Central Gulf Service Area~~

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lines of pipe; freezing of wells or lines of pipe; shortage of ~~gas~~Gas supply, whether resulting from inability or failure of a supplier to deliver ~~gas~~Gas; partial or entire failure of ~~natural gas~~Natural Gas wells or ~~gas~~Gas supply; depletion of ~~gas~~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~~Gas, casing head ~~gas~~Gas, residue ~~gas~~Gas resulting from processing both casing head ~~gas~~Gas and gas-well ~~gas~~Gas, and all other hydrocarbon and non-hydrocarbon components thereof.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

Industrial Service: Service to ~~Consumers~~Customers 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 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~~Month and ending at 9:00 a.m. Central Standard Time on the first Day of the next succeeding calendar ~~month.~~ Month.

Monthly Tolerance Limit: Shall mean five percent (5~~%~~%) of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of ~~customers~~Customers for such ~~month~~Month.

Payment in Kind (PIK): Shall mean a reimbursement for lost and unaccounted for

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ RATE SCHEDULE T-TERMS

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~~gas~~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~~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.

Public Authority Service: Service to Customers that are 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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

Qualified Supplier: Shall mean an approved supplier of ~~natural gas~~Natural Gas for transportation to ~~customers~~Customers through the Company's ~~pipeline system~~Pipeline System.

Regulatory Authority: The City Council or equivalent municipal governing body of each respective city in the ~~Central Gulf Service Area~~Company's area, or the Railroad Commission of Texas, as applicable.

Service Area: The area receiving ~~gas~~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~~Gas service filed with the regulatory authorities or agencies having jurisdiction over Company or the services provided hereunder.

Texas Gas Service Company, a Division of ONE Gas, Inc. ~~Rate Schedule~~ RATE SCHEDULE T-TERMS

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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~~Natural Gas through the Company's distribution system.

Transportation Service: The transportation by the Company of ~~natural gas~~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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

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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.

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~~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~~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~~Gas, as received from designated Qualified Supplier, for the Customer, at a Company designated Point of Receipt, less Payment in Kind (PIK).

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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~~Gas caused by the failure to provide clear title to the ~~gas~~Gas;

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February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	

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

c) Customer must provide Company with a signed Transportation Form identifying its Qualified Supplier. Customer may designate no more than one (1) 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~~Gas supply is terminated by Customer's Qualified Supplier due to non-payment or other reasons, or if ~~customer~~Customer is otherwise unable to continue as a transportation ~~customer~~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~~Gas supplies, deliver ~~gas~~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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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~~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

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the Pipeline System Dths of ~~gas~~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~~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~~Gas received or delivered by Company shall be allocated in accordance with confirmed nominations at such point. Only one (1) PDA methodology shall be applied per allocation period.

d) Daily Quantity of Transportation Service Gas: Company shall receive and deliver ~~gas~~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~~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~~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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE (Continued)

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.

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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~~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.

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.

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FOR TRANSPORTATION SERVICE (Continued)

1.8 LACK OF LIABILITY

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~~Central Gulf Service Area~~

a) **Furnishing of Gas**. The Company shall not be liable for any loss or damage caused by variation in ~~gas~~Gas pressure, defects in pipes, connections and appliances, escape or leakage of ~~gas~~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~~Gas to any Consumer.

b) **After Point of Delivery.** Company shall not be liable for any damage or injury resulting from ~~gas~~Gas or its use after such ~~gas~~Gas leaves the ~~point~~Point of ~~delivery~~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~~Gas left the ~~point~~Point of ~~delivery~~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~~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.

d) **Force Majeure**. If either Company or Customer is rendered unable, wholly or in part, by reason of ~~force majeure~~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.

Supersedes Rate Schedules Dated	Meters Read On and After
~~January 15, 2024~~	
	November 27, 2024 (Central-Gulf) TBD
January 30, 2024 (Rio Grande Valley)	
January 27, 2023 (West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	
February 27, 2023 (Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park)	

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

RULES OF SERVICE

~~CENTRAL GULF~~TEXAS GAS SERVICE ~~AREA~~ALL CUSTOMERS

Incorporated and ~~Unincorporated Areas~~environs areas of: Alamo, Aledo, Alton, Andrews, Anthony, Austin, ~~Bastrop (environs only),~~Barstow, Bayou Vista, Beaumont, Bee Cave, Borger, Breckenridge, Brownsville, Bryson, Buda, Cedar Park, Clint, Combes, Crane, Cuero, Dell City, Donna, Dripping Springs, Edcouch, Edinburg, El Paso, Elsa, Galveston, Georgetown, Gonzales, Graford, Graham, Groves, Harlingen, Hidalgo, Horizon City, Hudson Oaks, Hutto, Jacksboro, Jamaica Beach, Jarrell, Kyle, La Feria, La Joya, La Villa, Laguna Vista, Lakeway, Lockhart, Los Fresnos, Luling, Lyford, Marble Falls, McAllen, McCamey, Mercedes, Millsap, Mineral Wells, Mission, Monahans, Mustang Ridge, Nederland, Nixon, Palm Valley, Palmhurst, Palmview, Pecos, Penitas, Pflugerville, Pharr, Port Arthur, Port Isabel, Port Neches, Primera, Progreso, Pyote, Rancho Viejo, Raymondville, Rio Hondo, Rollingwood, San Benito, San Elizario, San Juan, Santa Rosa, Shiner, Skellytown, Socorro, Sunset Valley, Thorntonville, Vinton, Weatherford, Weslaco, West Lake Hills, Wickett, Willow Park, Wink, and Yoakum, ~~TX~~Texas; the environs of Bastrop, Texas; and the unincorporated areas of: Bayview, Canutillo, Fabens, Jermyn, Jim Hogg County, Jonah, Laguna Heights, Monte Alto, Olmito, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, San Carlos, Starr County, and Whitt, Texas.

Effective for Meters Read On and After ~~November 27, 2024~~TBD

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

~~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~~

Supersedes and Replaces Rules of Service for Incorporated and Unincorporated Areas of the West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park (January 27, 2023), Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park (February 27, 2023), Rio Grande Valley (January 30, 2024), and Central-Gulf (November 27, 2024)

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

Supersedes and Replaces Rules of Service for Incorporated and Unincorporated Areas of the West-North Areas Except Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park (January 27, 2023), Incorporated Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park (February 27, 2023), Rio Grande Valley (January 30, 2024), and Central-Gulf (November 27, 2024)

Texas Gas Service Company, a Division of ONE Gas, Inc.
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Texas Gas Service Company, a Division of ONE Gas, Inc.
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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~~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~~ served by the ~~Company's Central Gulf Service Area~~Company comprised of the incorporated and ~~unincorporated~~environs areas of: Alamo, Aledo, Alton, Andrews, Anthony, Austin, Barstow, Bayou Vista, Beaumont, Bee Cave, Borger, Breckenridge, Brownsville, Bryson, Buda, Cedar Park, Clint, Combes, Crane, Cuero, Dell City, Donna, Dripping Springs, Edcouch, Edinburg, El Paso, Elsa, Galveston, Georgetown, Gonzales, Graford, Graham, Groves, Harlingen, Hidalgo, Horizon City, Hudson Oaks, Hutto, Jacksboro, Jamaica Beach, Jarrell, Kyle, La Feria, La Joya, La Villa, Laguna Vista, Lakeway, Lockhart, Los Fresnos, Luling, Lyford, Marble Falls, McAllen, McCamey, Mercedes, Millsap, Mineral Wells, Mission, Monahans, Mustang Ridge, Nederland, Nixon, Palm Valley, Palmhurst, Palmview, Pecos, Penitas, Pflugerville, Pharr, Port Arthur, Port Isabel, Port Neches, Primera, Progreso, Pyote, Rancho Viejo, Raymondville, Rio Hondo, Rollingwood, San Benito, San Elizario, San Juan, Santa Rosa, Shiner, Skellytown, Socorro, Sunset Valley, Thorntonville, Vinton, Weatherford, Weslaco, West Lake Hills, Wickett, Willow Park, Wink, and Yoakum, ~~and~~Texas; the environs of Bastrop, Texas; and the unincorporated areas of: Bayview, Canutillo, Fabens, Jermyn, Jim Hogg County, Jonah, Laguna Heights, Monte Alto, Olmito, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, San Carlos, Starr County, and Whitt, Texas.

Service under this Tariff is subject to the original jurisdiction of the municipalities in the ~~Central Gulf Service Area~~Company's area of service and the Railroad Commission of Texas. The Company will provide service to any person and/or business within its areas of 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~~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 (1) rate is applicable. A Customer assigned to a rate schedule shall remain on that schedule for a minimum of one (1) 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 of 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~~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.

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Applicant:	Any person, organization or group of persons or organizations making a formal request either orally or in writing for ~~gas~~Gas service from the Company.
Atmospheric Pressure:	The pressure exerted by the weight of the atmosphere, which at sea level has a mean value of roughly 14.70 pounds per square inch (psi). A table containing the average Atmospheric Pressure of each location served by the Company is shown in Section 13.
Automated Meter Reading (AMR):	The process of remotely reading a ~~gas~~Gas meter.
Average Day Usage:	The ~~gas~~Gas demand of a given Customer for ~~gas~~Gas in any one ~~month~~(1) Month divided by 30. Gas demand is considered to be equivalent to consumption during each billing ~~month~~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~~60 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.
Common Billing Pressure:	A Common Billing Pressure of 14.65 psi is used to determine an equitable measurement of volume of Natural Gas consumed for Customers who live in areas with varying Atmospheric Pressure.
Compressed Natural Gas (CNG) Service:	Service to any non-residential Customer of the Company for usage where the Customer purchases Natural Gas which will be compressed and used as a motor fuel. This service will be separately metered and does not include compression by the Company beyond normal meter sales pressure.
Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Constant Factor:	A factor that is calculated by dividing the Standard Serving Pressure by a Common Billing Pressure of 14.65 psi. This factor will be further adjusted for non-residential Customers who have requested an elevated meter pressure above the Standard Serving

	Pressure. The Constant Factor is multiplied by the change in meter readings shown on the Customer's bill to calculate a Billed Ccf volume also shown on the Customer's bill. A table containing the Constant Factor of each location served by the Company is shown in Section 13.
Consumer:	Any person or organization receiving ~~gas~~Gas service from the Company for his or her own appliances or equipment whether or not the ~~gas~~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~~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~~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 (1) calendar day and ending at 9:00 a.m. ~~(~~Central Standard Time~~)~~ the following calendar day.
Dekatherm (Dth):	Shall mean one million (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~~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~~non-residential 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~~Gas meter.

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Electronic Fund Transfer (EFT):	The process to convert a paper check or electronic bill payment request to an electronic transfer. Paper checks received by the Company or their agents are destroyed.
Electronic Radio Transponder (ERT):	A device that assists with remotely reading a ~~gas~~Gas meter.
Excess Flow Valve (EFV):	A safety device installed on a ~~natural gas~~Natural Gas service line. The EFV is designed to automatically shut off the flow of ~~natural gas~~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~~Gas in the event the line breaks at the connection of a ~~gas~~Gas appliance in a residence or in the ~~customer's~~Customer's piping system (interior or exterior) on the ~~customer's~~Customer's side of the ~~gas~~Gas meter.
Expedited Service:	Customer request for same day service or service during non-business hours for connection or reconnection of ~~gas~~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 the Company or Customer is rendered unable, wholly or in part, by reason of ~~force majeure~~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~~Gas supply, whether resulting from inability or failure of a supplier to deliver ~~gas~~Gas; partial or entire failure of ~~natural gas~~Natural Gas wells or ~~gas~~Gas supply; depletion of ~~gas~~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~~Natural, gaseous state, including gas-well ~~gas~~Gas, casing head ~~gas~~Gas, residue ~~gas~~Gas resulting from processing both casing head ~~gas~~Gas and gas-well ~~gas~~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~~Gas for operating engine-driven pumping equipment.

Master Meter: A single large volume ~~gas~~Gas measurement device by which ~~gas~~Gas is metered and sold to a single purchaser who distributes the ~~gas~~Gas to one (1) or more additional persons downstream from that meter. Master ~~meter~~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~~Month and ending at 9:00 a.m. Central Standard Time on the first Day of the next succeeding calendar ~~month~~Month.

Monthly Tolerance Limit: Shall mean five percent (5%) of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of ~~customers~~Customers for such ~~month~~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.

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Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for ~~gas~~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~~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.
Public Authority Service:	Service to Customers that are 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.
Qualified Supplier:	Shall mean an approved supplier of ~~natural gas~~Natural Gas for transportation to ~~customers~~Customers through the Company's ~~pipeline system~~Pipeline System.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the ~~Central Gulf Service Area~~Company's area of service, 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.~~
Safe Access:	This term, used throughout the Company's Rules of Service, shall mean that Company representatives shall have free access to Company-owned assets, including but not limited to meters, service lines, and all other equipment relating to Company's service and the Company shall upon request, also have access to Customer Natural Gas appliances and equipment to perform safety inspections as may be deemed necessary by the Company during the performance of routine maintenance and/or in response to emergency situations without threat or harm from the Customer, Customer representatives or animals on the property.
Special Rate Schedule:	A rate schedule designed for a specific Customer.
Standard Serving Pressure:	The Standard Serving Pressure at a Customer's meter shall be 4 ounces (0.25 psi) or 7" Water Column above the standard Atmospheric Pressure in the area served. A table containing the

	Standard Serving Pressure of each location served by the Company is shown in Section 13.
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~~Gas service filed with the ~~regulatory authorities~~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 (2) or more years.
Transportation Form:	Shall mean the Company approved selection of ~~transportation service~~Transportation Service document.
Transportation Rate Schedule:	A rate schedule designed for service to any Customer for the transportation of Customer-owned ~~natural gas~~Natural Gas through the Company's distribution ~~system~~System.
Transportation Service:	The transportation by the Company of ~~natural gas~~Natural Gas owned by someone other than the Company through the Company's distribution ~~system~~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.

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SECTION 2~~.~~ — [Reserved for ~~future rules~~Future Rules]

Texas Gas Service Company, a Division of ONE Gas, Inc.
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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.

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SECTION 4 — CONDITIONS OF SERVICE

4.1 PROVISION OF SERVICE

The Company will provide ~~gas~~Gas service to any person or organization located within the ~~Central Gulf Service Area~~Company's 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~~Natural Gas facilities and is in a location and condition satisfactory to the Company, provides clear access to Company's facilities, and enables Safe Access for the Company to provide service to Customer's property or the premises of the Consumer.

~~4.2~~4.2 USE OF NATURAL GAS EQUIPMENT AND APPLIANCES

The Customer shall provide notice to the Company of the installation of any Natural Gas appliance or equipment located on the Customer's property upon the Company's request. Customer notice shall be provided electronically or verbally when requested. Appliances and Equipment may include, but not be limited to: furnace, clothes dryer, water heater, tankless water heater, stove/oven, generator, pool heater, fireplace, fire pit, grill, commercial/industrial boilers, etc.

4.3 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~~Transportation Service, the commodity cost of ~~gas~~Gas shall be determined between the Customer and the Customer's selected supplier.

4.~~3~~4 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~~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~~Gas delivered among the various tenants on a per unit basis.

4.~~4~~5 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~~System or any major division thereof lasting more than four (4) 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~~6 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~~7 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~~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~~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~~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~~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~~Customers electronically. This information shall be provided in English and Spanish as necessary to adequately inform the ~~customers~~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~~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~~8 CUSTOMER COMPLAINTS

Upon complaint to the Company by residential or small commercial ~~customers~~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 (1) year subsequent to the final disposition of the complaint.

4.~~8~~9 COMPANY RESPONSE

Upon receipt of a complaint, either by letter, by telephone or by email from the Regulatory Authority on behalf of a ~~customer~~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~~Customer complaints to be made in writing to assist the ~~regulatory authority~~Regulatory Authority in maintaining records of the quality of service of the Company; however, telephone communications will be acceptable.

4.~~9~~10 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~~Point of ~~delivery~~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~~Gas utility service.

If the Company becomes unable to provide ~~gas~~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 Company will remedy its inability to provide ~~gas~~Gas utility service as soon as possible.

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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~~. Commencement of service by the Company and the use of ~~gas~~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 (2) forms of verifiable identification~~; one being~~: (1) a government-issued identification card bearing a photograph of Applicant; and (2) 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~~Gas utility must serve each qualified ~~applicant~~Applicant for service within its area of service ~~area~~ as rapidly as practical. As a general policy, those applications not involving line extensions, service lines or new facilities should be filled within seven (7) working days. Those applications for individual residential service requiring line extensions or service lines 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~~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~~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. However, the Company shall not be obligated to provide Expedited Service when the personnel and resources to do so are not reasonably available. 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 (20%) for handling through to the Applicant requesting service. See Section 15 relating to fees.

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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~~Gas service by another occupant if that person still resides at the premises to be served;

f) To any Applicant who refuses the Company or Company's representatives ~~access~~Safe Access to or entry for observation ~~or whose~~ of Customer-owned Natural Gas facilities or appliances and/or whose Natural Gas facilities or appliances 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~~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;

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c) Failure to pay a bill to correct previous underbilling due to misapplication of rates more than six (6) 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~~Customer has first been notified and been afforded reasonable opportunity to comply with these rules;

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

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

f) Five (5) working days after written notice from the Company for use, sale or delivery of ~~gas~~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~~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 five (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 of 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 five (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 five (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~~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 (6) 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~~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~~a.m. or after 7:00 ~~PM~~p.m. 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~~Natural Gas service in a manner that is dangerous or unreasonably interferes with service to others, the Company shall not disconnect ~~natural gas~~Natural Gas service in the following circumstances:

a) The Company shall not disconnect a delinquent residential ~~customer~~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~~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.

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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 $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~~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 areas of 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

[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.

~~customers~~Customers in the Company's areas of service~~ areas~~. The Company may provide a copy electronically.

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~~Customers of the Company and ~~customers~~Customers who are owners, operators or managers of ~~master metered~~Master Metered systems. Owners, operators or managers of ~~master metered~~Master Metered systems shall provide a copy of this rule to all their ~~customers~~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 (1) year or more, the request for service shall be treated as a new application. When service has been disconnected for less than one (1) 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 (1) 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, with Safe Access, 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.

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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 (1) 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 (2) 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 (1) 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 (2) years. No cash deposit shall be required of such Applicant under these conditions.

e) Each ~~gas~~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~~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 (1/6) 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~~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~~Company's area of ~~the Company~~service 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~~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~~Customers only, a surety bond issued by a reputable insurance company which can be drawn on for a minimum of two (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~~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~~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~~Customers inside the corporate limits of an incorporated municipality that imposes a franchise fee to Company for the ~~gas~~Gas service provided to Customer.

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SECTION 9 — BILLING AND PAYMENT OF BILLS

9.1 RENDERING OF BILLS

Bills for ~~gas~~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~~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~~ 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~~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~~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 (6) 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~~Customer with a postcard or phone call, and request that the ~~customer~~Customer read the meter and return the card or a picture of the meter dial to the utility if the meter is of a type that can be read by the ~~customer~~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~~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~~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 (2) 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 five percent (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.~~ a) TERMS AND CONDITIONS

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

~~2.~~ ii) A ~~customer's~~Customer's account should be current at the time the ~~customer~~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.~~ iii) Service is not available under this Plan for a term of less than ~~twelve (~~12~~)~~ months.

~~B.~~ b) AVERAGE PAYMENT AMOUNT

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

~~2.~~ ii) The ~~Average Payment Amount~~ average payment amount is identified as a separate item on the ~~gas~~Gas bill so the participating ~~consumer~~Consumer will know the amount to pay.

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

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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~~Gas until it passes the ~~point~~Point of ~~delivery~~Delivery. The Company's representative shall have the right to enter the Customer's premises, with Safe Access, 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.

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

b) The Customer shall take all reasonable precautions when excavating, digging or constructing around or near Company-owned Natural Gas facilities to include calling 811 to identify the location of buried Natural Gas lines prior to digging or constructing in the vicinity of Natural Gas facilities.

c) 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, including but not limited to the failure to call 811 to identify the location of Gas lines before digging, 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.

10.3 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~~Gas after it passes the ~~point~~Point of ~~delivery~~Delivery. Any facilities downstream of the meter not installed by the ~~Customer~~Company 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.

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~~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~~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~~Gas furnished by the Company ~~and~~, to include any conversions of existing equipment and appliances required to conduct and utilize the ~~gas~~Gas furnished by the Company from the outlet of the meter set, to the point(s) of utilization, and ~~those~~any portions of the service line and meter set not furnished by the Company, as described in Section 10.5.

b) The Applicant shall be responsible for 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~~. No action of the Company, in accordance with this Tariff, shall release the Applicant of the responsibility for the Customer-owned facilities, equipment or appliances 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~~local rules, and shall be properly designed for the pressures and volumes to be handled. Where there are ~~none~~no applicable local, state or federal requirements, the most current International Fuel Gas Code shall apply.

10.7 RELOCATION OF COMPANY FACILITIES

a) A charge of not more than the 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.

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

c) If the Company shall change the Point of Delivery or change the location of its equipment on private property due to encroachment by Customer-owned property, the Customer 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~~Natural Gas 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 then own and be responsible for all service piping from the main line up to the Company's meter~~, and~~. The Customer will then own and be responsible for all piping from the meter to and within the building.

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

~~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.~~

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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~~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~~c) Determination of whether a proposed extension is cost justified shall be made based on the following economic model: the Maximum Allowable Investment (MAI) shall be equal to the expected number of new premises times the annual base revenue per new premise based on current Tariff rates times ten; or MAI = Expected New Premises x Annual Base Revenue x 10. The calculation of the MAI shall reflect the impact of related economic factors including, but not limited to, future residential growth, future commercial growth and operational efficiencies.

d) If the cost of a proposed extension is lower than the MAI, the Company may at its sole discretion provide the Applicant a payment to offset some or all of the cost of Customer or developer infrastructure including but not limited to the cost of installing Natural Gas piping from the meter to the Natural Gas appliance as well as required venting for each Natural Gas appliance. This payment shall be based on the actual cost of Natural Gas piping and venting and shall not cause the total cost of the proposed extension to exceed the MAI. Any such payments will be treated as an investment in intangible plant and amortized over a ten-year period.

e) The Company may pay to Applicant reasonable costs related to acquiring necessary right-of-way and reasonable costs related to the management of facility installation activities.

11.2 RESIDENTIAL MULTI-UNIT LINE EXTENSION AND CONSTRUCTION CHARGES

a) The Company shall install the necessary facilities to provide service to Applicants for residential multi-unit projects pursuant to the provisions in Section 11.1 above.

b) The Company will provide Applicants for residential multi-unit projects a payment to offset some or all of the cost of Customer or developer infrastructure including but not limited to the cost of installing Natural Gas piping from the meter to the Natural Gas appliance as well as required venting for each Natural Gas appliance. This payment shall be based on the actual cost of Natural Gas piping and venting and shall not exceed the MAI as calculated in Section 11.1(c) above. Any such payments will be treated as an investment in intangible plant and amortized over a ten-year period.

c) Multi-unit structures are defined as having four (4) or more individual units under one (1) roof.

d) To be eligible for this payment, each unit must, at a minimum, contain either a Natural Gas water heater or Natural Gas furnace, plus one (1) other Natural Gas appliance for a total of two (2) installed Natural Gas appliances.

11.3 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~~Customer and the cost thereof. This cost shall include all

amounts to be spent for ~~system~~System improvements necessary to deliver the required ~~gas~~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~~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~~4 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~~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~~Master Meter or individual meters served by a Company-owned ~~system~~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~~Gas service upon completion of the Company's facilities.

11.~~4~~5 ADVANCES

The mutually agreed upon terms will determine the amount and term of any 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~~6 CONSTRUCTION OF FACILITIES

As soon as practical after the advance has been paid or it has been determined that no advance will be required, and the permits for construction have been obtained, 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~~7 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~~each subsequent anniversary of the execution ~~dates~~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.

11.~~7~~8 REFUND LIMITATIONS

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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~~term, any remaining amount of the advance shall be retained by the Company as a contribution in aid of construction.

11.~~8~~9 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 (6) months following expiration of the ~~five year period~~term of the extension agreement shall be retained by the Company and considered a contribution in aid of construction.

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SECTION 12 — METERS

12.1 METER REQUIREMENTS

a) All ~~gas~~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~~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~~Gas delivered to its ~~customers~~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~~Gas used during the period. Such estimates shall be based on either~~—~~:

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

b) That Customer's normal use of ~~gas~~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 (2) 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~~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 (2) 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, with Safe Access, 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~~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~~Safe Access to the meter at all reasonable times for reading thereof and at all reasonable times for reading, maintenance, testing, disconnection 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 five (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 or her.

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 two percent (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 (6) 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 (3) 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~~Customer at the same location, when available, and on consumption under similar conditions at the same location or of other similarly situated ~~customers~~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 six (6) months for 0-500 Mcf/d; every three (3) months for volumes 500-~~2000~~2,000 Mcf/d; and every month for volumes ~~2000~~2,000 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~~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~~Point of ~~delivery~~Delivery of ~~gas~~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~~Point of ~~delivery~~Delivery shall be at the property line. The title of all ~~gas~~Gas sold by the Company to the Consumer shall pass from the Company at the ~~point~~Point of ~~delivery~~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 (1) meter location is permitted for the same Customer, the

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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~~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~~Master Meter into the piping systems of others to be distributed to more than one (1) Consumer, except when the ~~gas~~Gas served is resold to those Consumers on either a commodity or separate cost of service basis; provided, however, that those Customers purchasing ~~gas~~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~~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~~Natural Gas to a third party for resale to the public as fuel for ~~natural gas~~Natural Gas powered vehicles (NGV's).

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

SECTION 13 — GAS MEASUREMENT

13.1 PRESSURE

The standard serving and measurement pressure at Customer meters shall be 4 ounces (0.25 ~~psig~~psi) or 7" Water Column above the standard ~~atmospheric pressure~~ Atmospheric Pressure in the area served.

To achieve a common pressure base throughout the state for Customer billing, the Company will convert the Customer's Standard Serving Pressure to a Common Billing Pressure by multiplying by a Constant Factor, shown below. The ~~atmospheric pressure and standard~~Constant Factor is determined by dividing the Customer's Standard Serving Pressure by 14.65. For Customers with the Standard Serving Pressure of 4 ounces at their meter, the Constant Factor shown below will be on their monthly bill as a component of calculating the billed volumes. For Customers with a serving pressure more than 4 ounces at their meter, the Constant Factor will be adjusted to accommodate the increased pressure at the meter. The Atmospheric Pressure and Standard Serving Pressure, determined to be the average in the cities and environs of the ~~Central Gulf Service Area~~Company's area of service, are listed below~~.~~:

Cities and their Environs	Atmospheric Pressure ~~PSIA~~PSI	Standard Serving Pressure ~~PSIA~~PSI	Constant Factor
Alamo	14.40	14.65	1.0000
Aledo	14.40	14.65	1.0000
Alton	14.40	14.65	1.0000
Andrews	13.10	13.35	0.9113
Anthony	12.80	13.05	0.8908
Austin	14.40	14.65	1.0000
Barstow	13.50	13.75	0.9386
Bastrop	14.40	14.65	1.0000
Bayou Vista	14.70	14.95	1.0205
Bayview	14.40	14.65	1.0000
Beaumont	14.70	14.95	1.0205
Bee Cave	14.40	14.65	1.0000
Borger	13.10	13.35	0.9113
~~Buda~~Breckenridge	14.40	14.~~65~~90	1.0171
Brownsville	14.40	14.65	1.0000
Bryson	14.40	14.65	1.0000
Buda	14.40	14.65	1.0000
Canutillo	12.80	13.05	0.8908
Cedar Park	14.40	14.65	1.0000
Clint	12.80	13.05	0.8908
Combes	14.40	14.65	1.0000
Crane	13.50	13.75	0.9386
Cuero	14.48	14.73	1.0055
Dell City	12.80	13.05	0.8908
Donna	14.40	14.65	1.0000
Dripping Springs	14.40	14.65	1.0000

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

Edcouch	14.40	14.65	1.0000
Edinburg	14.40	14.65	1.0000
El Paso	12.80	13.05	0.8908
Elsa	14.40	14.65	1.0000
Fabens	12.80	13.05	0.8908
Galveston	14.70	14.95	1.0205
Georgetown	14.40	14.65	1.0000
Gonzales	14.48	14.73	1.0055
Graford	14.40	14.65	1.0000
Graham	14.40	14.90	1.0171
Groves	14.70	14.95	1.0205
~~Hutto~~Harlingen	14.40	14.65	1.0000
Hidalgo	14.40	14.65	1.0000
Horizon City	12.80	13.05	0.8908
Hudson Oaks	14.40	14.65	1.0000
Hutto	14.40	14.65	1.0000
Jacksboro	14.40	14.65	1.0000
Jamaica Beach	14.70	14.95	1.0205
Jarrell	14.40	14.65	1.0000
Jermyn	14.40	14.65	1.0000
Jim Hogg County	14.40	14.65	1.0000
Jonah	14.40	14.65	1.0000
Kyle	14.40	14.65	1.0000
La Feria	14.40	14.65	1.0000
La Joya	14.40	14.65	1.0000
La Villa	14.40	14.65	1.0000
Laguna Heights	14.40	14.65	1.0000
Laguna Vista	14.40	14.65	1.0000
Lakeway	14.40	14.65	1.0000
Lockhart	14.48	14.73	1.0055
Los Fresnos	14.40	14.65	1.0000
Luling	14.48	14.73	1.0055
Lyford	14.40	14.65	1.0000
Marble Falls	14.40	14.65	1.0000
McAllen	14.40	14.65	1.0000
McCamey	13.50	13.75	0.9386
Mercedes	14.40	14.65	1.0000
Millsap	14.40	14.65	1.0000
Mineral Wells	14.40	14.65	1.0000
Mission	14.40	14.65	1.0000
Monahans	13.50	13.75	0.9386
Monte Alto	14.40	14.65	1.0000

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

Mustang Ridge	14.40	14.65	1.0000
Nederland	14.70	14.95	1.0205
Nixon	14.48	14.73	1.0055
Olmito	14.40	14.65	1.0000
Palm Valley	14.40	14.65	1.0000
Palmhurst	14.40	14.65	1.0000
Palmview	14.40	14.65	1.0000
Palo Pinto	14.40	14.65	1.0000
Pecos	13.50	13.75	0.9386
Penitas	14.40	14.65	1.0000
Perrin	14.40	14.65	1.0000
Pflugerville	14.40	14.65	1.0000
Pharr	14.40	14.65	1.0000
Port Arthur	14.70	14.95	1.0205
Port Isabel	14.40	14.65	1.0000
Port Neches	14.70	14.95	1.0205
Possum Kingdom	14.40	14.65	1.0000
Primera	14.40	14.65	1.0000
Progreso	14.40	14.65	1.0000
Punkin Center	14.40	14.65	1.0000
Pyote	13.50	13.75	0.9386
Rancho Viejo	14.40	14.65	1.0000
Raymondville	14.40	14.65	1.0000
Rio Hondo	14.40	14.65	1.0000
Rollingwood	14.40	14.65	1.0000
San Benito	14.40	14.65	1.0000
San Carlos	14.40	14.65	1.0000
San Elizario	12.80	13.05	0.8908
San Juan	14.40	14.65	1.0000
Santa Rosa	14.40	14.65	1.0000
Shiner	14.48	14.73	1.0055
Skellytown	13.02	13.27	0.9058
Socorro	12.80	13.05	0.8908
Starr County	14.40	14.65	1.0000
Sunset Valley	14.40	14.65	1.0000
~~Yoakum~~Thorntonville	13.50~~14.48~~	13.75~~14.73~~	0.9386
Vinton	12.80	13.05	0.8908
Weatherford	14.40	14.65	1.0000
Weslaco	14.40	14.65	1.0000
West Lake Hills	14.40	14.65	1.0000
Whitt	14.40	14.65	1.0000
Wickett	13.50	13.75	0.9386

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Willow Park	14.40	14.65	1.0000
Wink	13.50	13.75	0.9386
Yoakum	14.48	14.73	1.0055

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~~Standard Serving Pressure under a load condition of approximately ~~10~~ten percent (10%) 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 (100) cubic feet (Ccf). A cubic foot shall be defined as the amount of ~~gas~~Gas which occupies a volume of one (1) cubic foot at the ~~standard serving pressure~~Standard Serving Pressure and at a temperature of 60 degrees Fahrenheit.

Whenever the Company delivers ~~gas~~Gas at any pressure other than the ~~standard serving pressure~~Standard Serving Pressure, volumes shall be corrected to the ~~standard serving pressure~~Common Billing 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.~~Common Billing 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~~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~~Gas had been delivered at the ~~standard serving pressure~~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~~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

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

Whenever ~~gas~~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~~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~~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~~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~~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~~Gas from Boyle's Law shall be made in accordance with Report No. 3.

b) Temperature of ~~gas~~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~~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~~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~~Gas for use in billing shall be defined as the gross thermal value of one (1) cubic foot of ~~gas~~Gas at a pressure of 14.73 ~~psia~~psi 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~~psi 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~~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~~Gas volumes, pressure, temperature, BTU content or specific gravity downstream of the ~~point~~Point of ~~delivery~~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 the Company's billing purposes.

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

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~~psi 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~~Gas are not significantly altered.

14.2 CHARACTER OF GAS

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

14.3 ODORIZATION

All ~~gas~~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.

Texas Gas Service Company, a Division of ONE Gas, Inc.

Rules of Service – ~~Central Gulf Service Area~~ALL CUSTOMERS

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~~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~~Gas air adjustments on a standard domestic and commercial ~~gas~~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~~Gas turned on.	$~~38~~40.00
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~~20.00
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.	

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

		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~~a.m. or ~~P.M~~p.m. scheduling.	$~~18~~20.00
		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~~75.00
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~~1,500 cubic feet per hour Over ~~1500~~1,500 cubic feet per hour ---------- Orifice Meters All sizes	 $~~150~~165.00 $~~225~~230.00 ---------- $200.00
f)	Payment Re-processing Fee	A fee will be charged to the Customer for the recovery of costs associated to the reprocessing of any payment, including paper check, electronic transfer payment and debit/credit card payment that has been rejected or returned by the bank for any reason.	$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~~20.00
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~~40.00 $~~50~~55.00 $~~70~~75.00
i)	Special Read Fee	A special read fee shall be charged for ~~customer~~ 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~~ Customer-requested meter exchanges when a meter is working properly or done for the ~~Customers~~Customer's convenience.	$~~180~~200.00

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

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). May be charged in tandem with Unauthorized Consumption Fee in situations that include both Tampering and Unauthorized Consumption.	$~~180~~200.00
l)	Unauthorized Consumption Fee	Charges for the replacement of an illegally broken meter seal or locking device, and/or a bypass of the meter, to the Customer who could be reasonably expected to benefit from ~~gas~~Gas service received through said meter. May be charged in tandem with Meter Tampering Fee in situations that include both Tampering and Unauthorized Consumption.	$~~30~~32.00 plus expenses
m)	No Access Fee	A fee charged to a Customer who schedules an appointment but fails to appear.	$~~18~~20.00
n)	Meter Removal Fee	A fee will be charged to the Customer to remove the meter due to tampering, accessibility issues, and other reasons deemed necessary by the Company in accordance with this Tariff.	$~~25~~28.00
o)	Account Research Fee	An hourly fee will be charged for Customer account information requiring research of accounting/billing information.	$~~20~~25.00
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~~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~~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	A deposit will be required from any new or current residential Customer to mitigate credit exposure. Current Customers may be assessed deposits due to delinquent bill payment behavior.	Minimum $~~75~~125.00
c)	Non-Residential Customer Deposit	A deposit will be required from any new or current non-residential Customer to mitigate credit exposure. Current Customers may be assessed deposits due to delinquent bill payment behavior.	Minimum $250.00

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

SECTION 16 — TAPPING FEES

16.1 TAPPING FEES

The Company may, at its option, extend lines to serve a group of new Customers outside or inside the incorporated by the use of Contribution In Aid of Construction (CIAC). Unless not economical or reasonable, the Company shall allow payment of the CIAC amount in the form of a monthly Tapping Fee charged to the existing and subsequent Customers in the area to be served. The fee will continue to be charged to all Customers connecting to the Extension of Facilities each month until the Company recovers the amount of CIAC required to serve the area. At least fifty percent (50%) of the existing homes in the area must be under contract for service for this type of Extension of Facilities to be available to the area.

The monthly per Customer Tapping Fee will be equal to the Monthly Amortization of the CIAC divided by the number of Customers participating in the program.

The Tapping Fee will usually be set within the first six (6) months of billing the first Customer receiving Gas from this extension. In some cases, this period could be extended.

In order to calculate the monthly Amortization of the CIAC, the following steps are to be followed:

1. Calculate the Required Rate Base

   Required Rate Base = Cost of Mains, services and yard lines

2. Calculate the Revenue Requirement

   Revenue Requirement = (Required Rate Base x return on capital) + related Federal Income Taxes + Depreciation

   Note: Depreciation = Required Rate Base x currently authorized rate by Component

3. Calculate the Annual Revenues to be received from Customers

   Annual Revenue = Number of Customers x the average annual revenue per Customer
   Note: The Number of Customers includes Customers connected to the System and Customers contracted to connect to the System within the first six (6) months of billing the first Customers receiving Gas from the System.

4. Calculate the Justified Rate Base

   The Justified Rate Base is the Rate Base that is backed into by using the revenue requirement model described in Step 2 above. The model backs into the Justified Rate Base by calculating the return, Federal Income Taxes and Depreciation for a given investment level, such that the sum of the return, Federal Income Taxes and Depreciation equals the Annual Revenues calculated in Step 3 above.

5. Calculate the Contribution In Aid of Construction (CIAC)

   CIAC = Required Rate Base – Justified Rate Base

6. Calculate the CIAC monthly payment

CIAC monthly payment is determined by using an amortization table. The variables include number of payments, interest rate and the outstanding CIAC.

7. Calculate the Monthly Tapping Fee

Monthly Tapping Fee = CIAC monthly payment divided by the number of Customers used in Step 3 above.

8. If the Monthly Tapping fee is not economical or reasonable, a one-time lump sum CIAC amount may be required. This CIAC amount would then reduce the amount in Step 5 above, and the Monthly Tapping Fee would then be re-calculated less the one-time fee.

CIAC will change overtime based upon additional capital investments (principally to tie in new Customers) and for reductions based upon the tapping fee payments. The interest rate changes annually and is based upon Chase Bank (or its successors prime rate plus two percent).

For each project undertaken, the Company will file with the respective Regulatory Authority an initial Tapping Fee Rider showing the amount and calculation of the Tapping Fee. For each project undertaken, the Company will file with the Regulatory Authority an annual reconciliation report, detailing the application of the Tapping Fee to principal and interest and the outstanding CIAC balance.

Texas Gas Service Company, a Division of ONE Gas, Inc.

~~**West North Service Area**~~

RATE SCHEDULE TF-IS

TAPPING FEE RATES

A. APPLICABILITY

The Tapping Fee rates, as set forth in Section (C) below and pursuant to the Rules of Service, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the incorporated areas of Burbridge Acres, Cotton Valley Estates, and Jones Subdivision Colonias.

B. TERRITORY

Burbridge Acres Colonia in the City of Clint, TX.
Cotton Valley Estates Colonia in the City of Socorro, TX.
Jones Subdivision in the City of Socorro, TX.

C. CURRENT RATES

The Tapping Fee rates for the colonias listed below will continue to be charged to all customers connecting to the extension of facilities each month until the Company recovers the amount of Contribution In Aid of Construction (CIAC) required to serve the area. During each monthly billing period:

A tapping fee charge per meter per month of $ 7.22 applicable to the Burbridge Acres Colonia in the City of Clint, TX.

A tapping fee charge per meter per month of $ 8.41 applicable to the Cotton Valley Estates Colonia in the City of Socorro, TX.

A tapping fee charge per meter per month of $ 7.82 applicable to the Jones Subdivision in the City of Socorro, TX.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE TF-OS**

~~**West North Service Area**~~ **Page 1 of ~~2~~1**

TAPPING FEE RATES

A. APPLICABILITY

The Tapping Fee rates, as set forth in Section (C) below and pursuant to the Rules of Service, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the unincorporated areas of Agua Dulce, Burbridge Acres, Panorama Village, and Westway Colonias.

B. TERRITORY

Agua Dulce Colonia in the environs of El Paso, TX.
Burbridge Acres Colonia in the environs of El Paso, TX.
Panorama Village Colonia in the environs of El Paso, TX.
Westway Colonia in the environs of the El Paso, TX.

C. CURRENT RATES

The Tapping Fee rates for the colonias listed below will continue to be charged to all customers connecting to the extension of facilities each month until the Company recovers the amount of Contribution In Aid of Construction (CIAC) required to serve the area. During each monthly billing period:

A tapping fee charge per meter per month of $ 8.82 applicable to the Agua Dulce Colonia in the environs of El Paso, TX.

A tapping fee charge per meter per month of $ 7.22 applicable to the Burbridge Acres Colonia in the environs of El Paso, TX.

A tapping fee charge per meter per month of $ 4.85 applicable to the Panorama Village Colonia in the environs of El Paso, TX.

A tapping fee charge per meter per month of $ 26.33 applicable to the Westway Colonia in the environs of El Paso, TX.

D. ANNUAL RECONCILIATION REPORT

Per the Company's ~~Rule~~Rules of Service ~~for the West North Service Area~~, Section 16.1 Tapping Fees, the Company shall file with the Railroad Commission of Texas ("Commission") an annual reconciliation report detailing the application of the tapping fee for each colonia to principal and interest and the outstanding CIAC balance.

Texas Gas Service Company, a Division of ONE Gas, Inc. **RATE SCHEDULE TF-OS**

~~**West North Service Area**~~ **Page 2 of ~~2~~1**

~~TAPPING FEE RATES (Continued)~~

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

Fee or Deposit	TGS Current Fee CGSA	RGV	WNSA	Proposed Fee
Connect	$38.00	$38.00	$35.00	$40.00
Reconnect Fee	$38.00	$38.00	$35.00	$40.00
Read-In (Connect Fee - Read Only)	$18.00	$18.00	$15.00	$20.00
Special Handling	$18.00	$18.00	$15.00	$20.00
Expedited Service/Overtime/After Hours	$70.00	$70.00	$65.00	$75.00
Regular Labor Rate	$50.00	$50.00	$48.00	$55.00
No Access Fee (Door Tag)	$18.00	$18.00	$15.00	$20.00
Meter Test Up to 1500 CFH	$150.00	$150.00	$150.00	$165.00
Meter Test Over 1500 CFH	$225.00	$225.00	$200.00	$230.00
Orifice Meters	$200.00	$200.00	$200.00	$200.00
Payment Re-processing Fee (Returned Check Fee)	$25.00	$25.00	$25.00	$25.00
Collection Fee (All Classes)	$18.00	$18.00	$15.00	$20.00
Special Read	$20.00	$20.00	$18.00	$20.00
Meter Exchange (Customer Request)	$180.00	$180.00	$150.00	$200.00
Unauthorized Consumption (Plus Expenses)	$30.00	$30.00	$30.00	$32.00
Meter Removal Fee	$25.00	$25.00	$25.00	$28.00
Account Research per hour Fee	$20.00	$20.00	$20.00	$25.00
Excess Flow Valve Installation Fee	$400.00	$400.00	$400.00	$400.00
Minimum Deposit Residential	$75.00	$75.00	$75.00	$125.00
Minimum Non Residential Deposit	$250.00	$250.00	$250.00	$250.00
Meter Tampering (Residential)	$180.00	$180.00	$150.00	$200.00

PUBLIC NOTICE
2026 TGS Pipeline Integrity Testing Rider

Texas Gas Service Company, a Division of ONE Gas, Inc., (the "Company" or "TGS") hereby gives notice of rates to be charged from April 20XX through March 20XX under the Pipeline Integrity Testing ("PIT") Rider applicable to all incorporated and environs areas served by the Company, as listed in the Company's Rules of Service (Rate Schedule Number QSR-TGS), Section 1.1. The PIT Rider permits the Company to recover the cost of pipeline safety testing that the Company is required to perform by law.

The effect of the PIT Rider on the various rate schedules is set forth in the table below:

Rate Schedule	PIT Rate per Ccf	Average Monthly Bill Impact	Number of Customers
Residential			
Commercial			
Industrial			
Public Authority			
Compressed Natural Gas			
Electric Generation Transportation			
Transportation			

Persons with questions or who want more information about this filing may contact Texas Gas Service at 1-800-700-2443. A copy of the filing will be available on the Company's website at https://www.texasgasservice.com/rateinformation/home.

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF ANTHONY Q. BROWN

BEFORE ME, the undersigned authority, on this day personally appeared Anthony Q. Brown who having been placed under oath by me did depose as follows:

1. "My name is Anthony Q. Brown. 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.

Anthony Q. Brown

SUBSCRIBED AND SWORN TO BEFORE ME by the said Anthony Q. Brown on this 5th day of June 2025.

Christine Bell

Notary Public in and for the State of Texas

My commission expires: 2/23/2028

CHRISTINE MARIE BELL
Notary ID #130547096
My Commission Expires
February 23, 2028

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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LIST OF EXHIBITS

EXHIBIT SLM-1 TGS Partner Agencies
EXHIBIT SLM-2 Docket 17471 Share the Warmth Terms

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 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 Company's requests related to the following issues in this rate case:

1. Consolidation of all of existing service areas — West North Service Area ("WNSA"), Central-Gulf Service Area ("CGSA"), and Rio Grande Valley Service Area ("RGVSA") — in order to implement statewide rates and rate schedules;

2. Expansion of customer assistance program, approval of a customer assistance residential service rate pilot program and the recovery of associated costs;

3. Recovery of credit card processing fees;

4. Regulatory asset treatment of cloud-based computing costs; and

5. Revisions to the line extension policy in the Rules of Service.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following schedules: G-25, Credit Card Processing Fees, and G-26, Customer Assistance Programs.

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 Docket Nos. OS-21-00007061, OS-22-00009896 ("Docket No. 9896"), OS-23-00014399 ("Docket No. 14399"), and OS-24-00017471 ("Docket No. 17471").

II. CONSOLIDATION

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING CONSOLIDATION OF EXISTING SERVICE AREAS IN THIS STATEMENT OF INTENT?

A. TGS proposes to consolidate all three of its existing service areas, the WNSA, CGSA, and the RGVSA, to reflect a single statewide territory with consistent rates and tariffs applicable to all customers in Texas. As explained by Company witnesses Jeffrey Husen and Alejandro Limón, the proposed consolidation aligns with operational realities already in place under the Company's functional operating model.

Q. HAS THE COMMISSION APPROVED PRIOR CONSOLIDATION REQUESTS FOR TGS?

A. Yes. TGS's consolidation requests have been consistently approved by the Commission since 2016, allowing TGS to reduce the number of regulatory service areas from ten to three. Specifically:

- in GUD No. 10488, the Commission approved a settlement agreement establishing the Gulf Coast Service Area, to consolidate the Galveston and South Jefferson County Service Areas;

- in GUD No. 10506, the Commission issued a Final Order approving a new West Texas Service Area, which was formerly three separate areas: El Paso, Dell City and Permian;
- in GUD No. 10526, the Commission approved a unanimous settlement agreement in which the then-existing Central Texas and South Texas Service Areas were combined to establish the Central Texas Service Area;
- in GUD No. 10928, the Commission issued a Final Order that approved consolidation of the Central Texas Service Area and Gulf Coast Service Area to establish the Company's CGSA; and
- in Docket No. 9896, the Commission issued a Final Order approving consolidation of the West Texas Service Area, North Texas Service Area and Borger/Skellytown Service Area to establish the WNSA.

Q. DO PRIOR COMMISSION DECISIONS SUPPORT SERVICE AREA CONSOLIDATION IN THIS CASE?

A. Yes. Since 2004, consolidation of service areas has consistently been supported and approved by the Commission and affirmed by the court. I am not aware of a case in which the Commission has rejected service area consolidation. Commission practice and policy overwhelmingly support service area consolidation as do the facts and evidence in this case. The table below shows the Commission's long-standing support for consolidation and the setting of system-wide rates:[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, the North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896 consol., Final Order at Finding of Fact ("FoF") Nos. 32-38 (Jan. 18, 2023); *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 the Gulf Coast Service Area*, GUD No. 10928 consol., Final Order at FoF Nos. 30-35 (Aug. 4, 2020); *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 Nos. 45-49 (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 at FoF No. 40 (Nov. 15, 2016); 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 Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order at FoF No. 39 (May 3, 2016); *Statement of Intent filed by Atmos Energy Corp., to Change Gas Utility Rates Within the Unincorporated Areas Served by the Atmos Energy Corp., West Texas Division*, GUD No. 10174 consol., Examiners' Letter No. 29 at 7-8 (Aug. 3, 2012) and Final Order at FoF

GUD or Docket No.	Utility	Year of Decision
9896	TGS	2023
10928	TGS	2020
10506	TGS	2016
10526	TGS	2016
10488	TGS	2016
10174	Atmos Energy	2012
10170	Atmos Energy	2012
10038	CenterPoint Energy	2011
9902	CenterPoint Energy	2010
9869	Atmos Energy	2010
9791	CenterPoint Energy	2008

Nos. 23-27 (Oct. 2, 2012); *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., Examiners Letter No. 32 at 7 (Aug. 3, 2012) and Final Order at FoF No. 33 (Dec. 4, 2012); *Statement of Intent Filed by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Texas Gas to Increase Rates on a Division Wide Basis in the South Texas Division*, GUD No. 10038 consol., Examiners' Letter No. 15 at 2 (Feb. 23, 2011); *Statement of Intent Filed by CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas to Increase Gas Utility Rates Within the Cities of Galena Park, Jacinto City, Southside Place, West University Place, and all of the Unincorporated Areas Served by the Houston Division*, GUD No. 9902, Interim Order at FoF Nos. 2-5, Conclusion of Law ("CoL") No. 4 (Oct. 22, 2009) and Final Order at FoF No. 15 (Feb. 23, 2010); *Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos Energy Corp., a Mid-Tex Division by the City of Dallas; Statement of Intent to Increase Gas Utility Rates in the Unincorporated Areas Served by the Mid-Tex Division*, GUD No. 9869, Interim Order at FoF Nos. 5-7 & CoL No. 7 (Jul. 14, 2009); *Statement of Intent Filed by CenterPoint Energy Entex to Increase the Rates in the Unincorporated Areas of the Texas Coast Division and All Consolidated Dockets*, GUD No. 9791, Order on Rehearing at FoF Nos. 30, 57, 70 (Dec. 16, 2008); *Statement of Intent Filed by Atmos Energy Corporation to Increase Utility Rates Within the Unincorporated Areas Served by the Atmos Energy Corp., Mid-Tex Division and Petition for De Novo Review of the Denial of the Statement of Intent Filed by Atmos in Various Municipalities*, GUD No. 9762 consol., Interim Order at CoL No. 8 (Feb. 12, 2008) and Final Order at FoF No. 25 (Jun. 24, 2008); *Petition for De Novo Review of the Reduction of the Gas Utility Rates of Atmos Energy Corp., Mid-Tex Division, by The Cities of Blue Ridge, Caddo Mills et al., Atmos Energy Corporation Statement of Intent to Change Rates in the Atmos Energy Corp., Mid-Tex Division Gas Utility System, and Petition for Review from the Actions of Municipalities Denying Rate Request*, GUD No. 9670 consol., Interim Order at FoF Nos. 22-24, CoL No. 9 (Aug. 15, 2006) and Final Order at FoF No. 29 (Mar. 29, 2007); *Statement of Intent Filed by West Texas Gas, Inc., to Increase Special Rates in the Unincorporated Towns and Rural Areas, Environs, and Appeals from the Decisions of the Cities of Balmorhea, Claude, Darrouzett, Eden, Farwell, Follett, Groom, Higgins, Junction, Menard, Miami, Mobeetie, Shamrock, Stratford, Texhoma, Wheeler, Paint Rock, Cactus, Canadian, Kermit, Natalia, Somerset, Sonora, and Texline*, GUD No. 9488 consol., Final Order at FoF Nos. 10, 19 and CoL No. 3 (Nov. 23, 2004); and *Statement of Intent Filed by TXU Gas Company to Change Rates in the Company's Statewide Gas Utility System*, GUD No. 9400, Final Order at CoL No. 24 (May 25, 2004).

GUD or Docket No.	Utility	Year of Decision
9762	Atmos Energy	2008
9670	Atmos Energy	2007
9488	West Texas Gas	2004
9400	Atmos Energy	2004

As shown in the table above, consolidation was most recently approved by the Commission for TGS in 2023, in Docket No. 9896 when TGS obtained approval to combine the West, North and Borger/Skellytown service areas to form the WNSA. The Commission reached that conclusion following full litigation of the consolidation issues in Docket No. 9896.

In GUD No. 10928, although the majority of issues in that case were settled, the parties litigated consolidation, and the Administrative Law Judge ("ALJ") recommended approval, which the Commission granted in 2020. In addition, in 2016, the Commission approved consolidation in GUD No. 10506, which was a litigated case. In 2016, separate service areas were consolidated to create the Gulf Coast Service Area in GUD No. 10488 and the Central Texas Service Area in GUD No. 10526. Both of those cases were resolved through settlement agreements the Commission approved. In addition to consolidation requests, there have been instances in which a utility sought approval of system-wide rates, which would allow it to charge the same rates to all customers within a single service area or geographic location. That is effectively what TGS is seeking in this filing—approval to consolidate separate existing service areas and to implement uniform rates throughout the state of Texas.

Q. HOW HAS THE COMMISSION PREVIOUSLY ANALYZED THE FACTS IN A GIVEN CONSOLIDATION CASE WHILE ALSO TAKING PRIOR DECISIONS INTO ACCOUNT?

A. In GUD No. 10928, the Examiners explained in the Proposal for Decision ("PFD") that while the facts of that case were distinct from prior cases, "the legal treatment on utility service area consolidation in Texas contained in the GUD No. 10506 PFD" applied in GUD No. 10928 as well.[2] In the contested case in Docket No. 9896, the Examiners similarly explained that while the decision "turns on the unique evidence presented in this case . . . the Examiners' ultimate recommendation is informed, in part, by the Commission's consistent treatment in approving consolidation requests made in prior dockets."[3]

From my reading, this means that the Commission will review the facts in a given case while also relying on a similar analysis of the various arguments for and against consolidation in a way that is consistent with its prior consolidation decisions. That is exactly what the Examiners in GUD No. 10928 and Docket No. 9896 did in 2020 and 2023, respectively.

[2] GUD No. 10928 consol., PFD at 14 (Jul. 6, 2020) (citing GUD No. 10506 consol., First Amended PFD at 8-14 (Sept. 16, 2020)).

[3] Docket No. OS-22-00009896 consol., Amended PFD at 12 (Jan. 11, 2023); *see also*, GUD No. 10928 consol., Final Order at FoF Nos. 30-35 and CoL No. 10; and GUD No. 10506 consol., Final Order at FoF No. 45-49.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED ADMINISTRATIVE EFFICIENCIES RESULTING FROM CONSOLIDATION?

A. Yes. In GUD Nos. 10506 and 10928 and Docket No. 9896, the ALJs relied on evidence showing consolidation will likely reduce the number of cost-of-service studies and rate-filing packages TGS must prepare each time it seeks to change rates within the consolidated service areas. The ALJs concluded that with consolidation, rate changes would be implemented uniformly and consistently, which is more economical, efficient, and cost-effective for TGS and its customers.[4]

Consistent with the ALJs' reasoning, the proposed statewide consolidation will reduce the number of cost-of-service analyses, rate cases and Interim Rate Adjustment ("IRA" or "GRIP") filings for the Company from three to one, which is more economical and efficient for the Company, customers and its regulators. Prior to the consolidations beginning in 2016, the Company had to separately prepare rate filings for each of its ten service areas which is a time- and resource-intensive effort and maintain over 400 individual tariffs. By reducing its rate filings through consolidation, rate case expenses should also be reduced because there will be fewer rate cases. In addition, cities within the separate service areas could pool their resources in order to reduce each municipality's individual expense to review each future filing. The proposed statewide consolidation will reduce the number of tariffs administered by both the Company and the Company's regulators from 98

[4] Docket No. OS-22-00009896 consol., Final Order at FoF Nos. 32-35; GUD No. 10928 consol., Final Order at FoF Nos. 30-33; and GUD No. 10506 consol., Final Order at FoF No. 45-47.

tariffs for the three existing service areas combined compared to 38 tariffs, on a statewide basis.

Q. WHAT ARE THE CURRENT AND PROPOSED RESIDENTIAL RATES IN THIS CASE?

A. As illustrated in the table below, the levels of existing rates in the currently designated WNSA, CGSA, and RGVSA vary widely from one another. The table also shows that the proposed statewide rates smooth out disparities in rates among customers because customers who receive the same gas service will be charged in a more equitable way for that service.

Line No.	Description	Residential Rates Current Small	Current Large	Recommended Small	Recommended Large
	(a)	(b)	(c)	(d)	(e)
	Incorporated and Environs Rates				
1	**CGSA**				
2	Customer Charge	$21.36	$33.36	$29.50	$39.50
3	Usage Rates	$0.87646	$0.46737	$0.67553	$0.31189
4	**WNSA**				
5	Customer Charge	$21.85	$38.35	$29.50	$39.50
6	Usage Rates	$0.46668	$0.01668	$0.67553	$0.31189
7	**RGVSA**				
8	Customer Charge	$23.64	$38.64	$29.50	$39.50
9	Usage Rates	$2.02007	$0.63545	$0.67553	$0.31189

Q. WHAT ARE THE BILL IMPACTS FOR THE PROPOSED RESIDENTIAL RATES IN THIS CASE?

A. As illustrated in the table below, the bill impacts demonstrate that, depending on the levels of existing rates in the WNSA, CGSA, or RGVSA, there are different rate impacts under consolidation.

Line No.	Description	Current	Recommended	Change Dollars	Change %
	(a)	(b)	(c)	(d)	(e)
	Residential - Small				
1	**Incorporated and Environs**				
2	CGSA	$44.88	$48.82	$3.94	8.78%
3	WNSA	$38.44	$48.82	$10.38	27.00%
4	RGVSA	$62.53	$48.82	$(13.71)	(21.93)%
	Residential - Large				
5	**Incorporated and Environs**				
6	CGSA	$77.29	$74.30	$(2.99)	(3.87)%
7	WNSA	$59.66	$74.30	$14.64	24.54%
8	RGVSA	$78.89	$74.30	$(4.59)	(5.82)%

This data shows that consolidation will lead to more consistent or equal cost impacts on customers because there will be a larger, single group of customers in the state instead of three separate customer bases, in three separate service areas supporting three separate costs of service.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED SYSTEM-WIDE RATE IMPACTS RESULTING FROM CONSOLIDATION?

A. Yes. In prior consolidation requests, as is the case with the proposed statewide consolidation, the proposed consolidated rates have differing impacts on different customer groups. The ALJs in both GUD Nos. 10506 and 10928 noted in the

Proposals for Decision that the proposed consolidation would result in system-wide rates for all customers in the proposed combined service areas, which would avoid unreasonable rate differences between localities or between classes of service.[5] Similarly, the Final Orders in both GUD No. 10928 and Docket No. 9896 contain Findings of Fact that "system-wide rates . . . avoid unreasonable rate differences between customers and localities. . . . "[6]

In the Amended Proposal for Decision in Docket 9896, the ALJ observed that the "significant increase" in one existing service area is "tempered by a corresponding decrease" in other existing services areas. The ALJ concluded that "the overall effect is to smooth out disparities in rates among customers in the different service areas."[7]

The ALJs in GUD Nos. 10506 and 10928, also explained in both cases that:

- TGS's proposed service area consolidation is not discriminatory or prejudicial;
- There is no credible evidence that TGS will charge unreasonably different rates between localities or classes of service in the consolidation service area; and
- Even if some customers will end up paying higher rates than they would have without consolidation, the "public interest" may be broader than the specific interests of one locality or its customers and may include more than quantifiable rate impacts.[8]

[5] GUD No. 10506 consol., First Amended PFD at 12; GUD No. 10928 consol., PFD at 14-16.
[6] GUD No. 10928 consol., Final Order at FoF No. 34; Docket No. OS-22-00009896 consol., Final Order at FoF No. 36.
[7] Docket No. OS-22-00009896 consol., Amended PFD at 12-13.
[8] GUD No. 10928 consol., PFD at 14-15; GUD No. 10506 consol., First Amended PFD at 12-13.

Q. HOW HAS THE UTILITY'S PERSPECTIVE BEEN CONSIDERED RELATED TO CONSOLIDATION REQUESTS?

A. In addition to considering the impacts to customers and efficiencies for the Company's regulators, the Commission has also recognized the importance of considering the utility's point of view. In GUD No. 10506, the ALJ explained the issue as follows:

> [T]he Commission must also balance the interests of TGS. The Legislature makes plain that the purpose of GURA is "to establish a comprehensive and adequate regulatory system for gas utilities to assure rates, operations, and services that are just and reasonable to the customers *and to the utilities*." [citation omitted] Though regulated, gas utilities are not guaranteed a profit. Rather, they are afforded the *opportunity* to earn a reasonable return on their invested capital used and useful in providing service to the public in excess of their reasonable and necessary operating expenses. [citation omitted] It is illogical, then, to require gas utilities to strive for efficiency in their operations to earn a reasonable return, while at the same time denying them opportunities to economize and streamline their operations by consolidating service areas—where doing so is appropriate and in the public interest.[9]

The ALJs in GUD No. 10928 and Docket No. 9896, also included this analysis in the Proposals for Decision supporting consolidation in those cases.[10] This discussion shows the ways in which the perspective of the utility should be considered and can support consolidation like the one TGS requests in this rate case.

[9] GUD No. 10506 consol., First Amended PFD at 13 (emphasis in original).
[10] GUD No. 10928 consol., PFD at 16; Docket No. OS-22-00009896 consol., Amended PFD at 14.

Q. DOES SERVING PRESSURE IMPACT THE COMPANY'S CONSOLIDATION REQUEST?

A. Yes. Customers served by the Company in different geographic areas receive natural gas service at differing serving pressures. If a single statewide rate is to be implemented, customers' usage must be adjusted to reflect a common billing pressure.

Q. WHAT IS SERVING PRESSURE?

A. Serving pressure is the sum of atmospheric pressure plus the meter pressure, measured in pounds per square inch ("psi"). The standard meter pressure is four ounces or 0.25 pounds. Consequently, standard serving pressure in any location is the sum of that location's atmospheric pressure plus 0.25 psi.

Q. WHY DOES SERVING PRESSURE DIFFER FROM ONE LOCATION TO ANOTHER ?

A. Serving pressure differs from one location to another because atmospheric pressure differs from one location to another. Atmospheric pressure is a function of altitude. The highest atmospheric pressure is 14.7 psi at sea level. As altitude increases from sea level, atmospheric pressure goes down. For example, atmospheric pressure in Denver, Colorado, the "mile high city," is 12.4 psi.

Q. WHAT ARE THE ATMOSPHERIC PRESSURES AND STANDARD SERVING PRESSURES IN AREAS SERVED BY TGS?

A. Section 13.1 of the Company's Rules of Service lists the atmospheric pressure and standard serving pressure of every location served by TGS. Standard serving

pressure in areas served by TGS ranges from 13.05 psi in El Paso, Texas, to 14.95 psi in Galveston, Texas.

Q. WHAT IS THE IMPACT OF SERVING PRESSURE ON NATURAL GAS USAGE IN DIFFERENT LOCATIONS?

A. The Company's meters measure its customers' natural gas usage in hundred cubic feet ("Ccf"). Serving pressure affects the number of molecules of gas included in one Ccf of gas. Under higher serving pressures, more molecules of gas are included in one Ccf, and a customer will use fewer Ccf to heat their home, heat their water or cook their food. Under lower serving pressures, fewer molecules of gas are included in one Ccf, and a customer will use more Ccf to heat their home, heat their water or cook their food.

Q. IS IT POSSIBLE TO MEASURE THE RELATIVE IMPACT OF SERVING PRESSURE ON NATURAL GAS USAGE IN DIFFERENT LOCATIONS?

A. Yes. It is possible to calculate the Ccf that would be required to perform a particular heating task under different serving pressures simply by multiplying the Ccf by a ratio of the two serving pressures. For example, if a customer in El Paso, with a serving pressure of 13.05 psi, used 1 Ccf of gas to cook a meal, that same exact meal cooked on that same exact stove in Galveston, with a serving pressure of 14.95 psi, would require only 0.873 Ccf of gas. The calculation is 1 Ccf times 13.05 psi divided by 14.95 psi.

Q. WHAT IS THE IMPACT OF SERVING PRESSURE ON BASE RATES?

A. In a rate case, the Company's approved base rates are calculated using normalized volumes. While not typically specified, those volumes are expressed at a particular

pressure. It is important that the approved rates be charged to customer usage stated at the same pressure that the rate design was based upon in order that the Company not over- or under-collect its approved cost of service. Historically, TGS's base rates have been calculated using volumes stated at local serving pressure. Those approved base rates have been charged to customers based on customer usage measured at the customer's meter at the local serving pressure.

Q. HOW DO SERVING PRESSURE DIFFERENCES AFFECT THE CALCULATION OF STATEWIDE RATES?

A. As noted in the El Paso and Galveston examples above, customers at sea level will use fewer Ccf of gas than customers at higher altitudes (and lower serving pressures) to accomplish the same heating tasks. Consequently, if TGS were to charge the same rate per Ccf to all customers statewide, customers in Galveston would be advantaged, and customers in El Paso would be disadvantaged. To fairly charge the same rate to all customers, all customers' usage must be restated to a common billing pressure, and approved base rates must be designed based on usage at the same common billing pressure. As discussed above, usage at one pressure can be converted to usage at another pressure simply by using a ratio of the two pressures.

Q. HOW HAS TGS TREATED SERVING PRESSURE IN THIS RATE CASE?

A. In this rate case, TGS has converted all usage to a common billing pressure of 14.65 psi so that approved rates will be designed based on Ccf stated at 14.65 psi.

Q. HOW WILL TGS CHARGE THE APPROVED RATES AT THE CONCLUSION OF THIS RATE CASE ?

A. As explained previously, it is important that rates be charged for usage stated at the same pressure used to design the rates, in order that the Company not over- or under-collect its cost of service. Consequently, at the conclusion of this case, TGS will apply a conversion factor, or "constant factor," to each customer's metered usage to restate that customer's usage from local serving pressure to a common billing pressure of 14.65 psi when calculating the customer's monthly bill. Section 13.1 of the Rules of Service describes this process and includes a list of the constant factors necessary to restate usage to 14.65 psi for each area served by the Company. The Company's usage of a common billing pressure of 14.65 psi to both design and charged rates ensures that customers throughout the state will be billed fairly relative to one another.

III. CUSTOMER ASSISTANCE

Q. WHAT NEW OR EXPANDED CUSTOMER ASSISTANCE PROGRAMS DOES TGS PROPOSE?

A. The Company proposes an expanded Share the Warmth program and a Customer Assistance residential rate schedule pilot program for qualifying customers. The costs associated with each proposed program are reflected in Schedule G-26.

Q. WHAT IS THE SHARE THE WARMTH PROGRAM?

A. Share the Warmth is a program that allows TGS customers to voluntarily contribute their own money to a fund and to provide financial assistance for fellow customers who need help paying their natural gas bills. TGS contracts with entities and agencies in different parts of Texas to administer the fund. Customers may contact

the offices of the partner agency and apply for assistance. Attached to my testimony as Exhibit SLM-1, is a chart showing TGS's partner agencies in Texas.

Q. PLEASE EXPLAIN THE HISTORY OF THE SHARE THE WARMTH PROGRAM.

A. TGS, and its predecessor, Southern Union Gas, have offered Share the Warmth since at least the mid-1990s. When ONEOK purchased the Texas assets of Southern Union Gas in 2003, the program was renamed "Share the Warmth" from "Project Care." TGS has provided these customer-donated funds to local agencies to administer the funds for the duration of the program.

Q. HOW DOES TGS PROMOTE SHARE THE WARMTH TO EXISTING CUSTOMERS TO ENCOURAGE VOLUNTARY CONTRIBUTIONS TO THE FUND?

A. TGS promotes Share the Warmth in bill inserts, verbally when customers call the call centers, through information on the TGS website, in emails for customers who have provided an email address to the Company, through TGS social media and through new technologies, including users of the "TGS App" on their smart devices.

Q. SINCE 2020, AT WHAT LEVELS HAVE CUSTOMERS VOLUNTARILY CONTRIBUTED TO SHARE THE WARMTH ANNUALLY?

A. Contributions from customers have grown to nearly $100,000 annually in years 2020 through 2024, following enhanced efforts by TGS to promote the program to customers. The actual amounts contributed by customers are shown in the table below.

Customer Contributions to Share the Warmth from TGS Customers 2020-2024

2020	2021	2022	2023	2024
$94,172	$93,623	$93,617	$90,349	$92,493

Q. WHEN DID TGS BEGIN CONTRIBUTING COMPANY DOLLARS TO SHARE THE WARMTH?

A. TGS agreed to match voluntary customer contributions up to $100,000 from the then-existing Central Texas Service Area customers as part of the settlement agreement in a Central Texas Service Area rate case, which was signed on October 11, 2016.[11] In 2020, TGS agreed to contribute up to $120,000 per year as part of the settlement agreement in a subsequent CGSA rate case.[12] In 2024, TGS agreed to contribute up to $200,000 per year as part of the settlement agreement in the last CGSA rate case.[13] Under the agreement, each year, a working group including individuals from TGS, the City of Austin and the participating charities, meet to determine the appropriate level of funding up to $200,000 for that year. Attached as Exhibit SLM-2, is a copy of the terms that were agreed to as part of that settlement, which was approved by the Commission on November 19, 2024. In each case, TGS's agreement to make contributions was made in consideration of other items that were being negotiated as part of that settlement agreement.

[11] GUD No. 10526 consol., Final Order at Attachment 1. In addition, then-existing CTSA Cities approved the settlement agreement through ordinances adopted in October, November or December 2016.
[12] GUD No. 10928 consol., Final Order at Attachment 5.
[13] *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*, Docket No. OS-24-00017471 consol., Final Order at Attachment 3 (Nov. 19, 2024).

Q. SINCE 2017, AT WHAT LEVELS DID TGS CONTRIBUTE TO SHARE THE WARMTH ANNUALLY FOR THE CGSA?

A. TGS complied with the 2016 agreement to match customer contributions in the Central Texas Service Area by making disbursements to assistance agencies in December 2017, 2018 and 2019. The amount of the contributions ranged from $34,000 to $45,000, annually. Pursuant to the 2020 agreement, TGS contributed $120,000 in 2020. More recently, based on the annual recommendations of the working group, TGS contributed $90,000 in 2021, $100,000 in 2022, $120,000 in 2023, and $200,000 in 2024.

In addition to the funds voluntarily provided by TGS customers, and the TGS contributions detailed above, partner agencies also receive Combined Energy Assistance Program (CEAP) funds from the Texas Department of Housing and Community Affairs. Likewise, private agencies, churches, and non-profits, including the ONE Gas Foundation also provide monies for utility assistance.

Q. WHAT DOES TGS PROPOSE FOR THE SHARE THE WARMTH PROGRAM?

A. The Company recognizes that an important public policy interest is served by ensuring the funding of a program to provide home heating assistance to individuals. Qualified customers should have a resource to help pay their utility bills, and TGS supports continued efforts to ensure resources are available in amounts necessary to meet the ongoing need. TGS believes it is important to maintain the Share the Warmth program to do just that. However, funding beyond that previously provided by the utility, would now be required at a significantly

higher level than the past contributions, and such funding should be treated as a reasonable and necessary expense of the utility and eligible for recovery through the cost of service.

Based on the Company's positive experience in the CGSA, TGS proposes a new program to cover the entire state with an available amount of $2 million per year to replace the existing $200,000 CGSA contribution. The new $2 million program funding would be distributed to partner agencies statewide and included in the Company's cost of service. In addition, TGS will continue to promote Share the Warmth with our customers via avenues such as bill inserts, the TGS website, TGS social media and more. TGS will also continue to make the ONE Gas Foundation board aware of customer assistance giving opportunities.

Q. WHY DO YOU BELIEVE ANY REQUIRED PAYMENTS TO SHARE THE WARMTH SHOULD BE RECOVERED FROM CUSTOMERS?

A. The statutory requirements of the Gas Utility Regulatory Act require the Commission to set rates that enable the Company to recover its reasonable and necessary expenses and provide the Company a reasonable opportunity to earn a reasonable return on its used and useful investment—no more, no less. The only funds available to the Company to make a required payment to Share the Warmth come from these rates; and these rates, by law, are sufficient only to cover the Company's expenses, plus a reasonable opportunity to earn a reasonable return on investment. It follows that a required payment not included in the Company's cost of service necessarily would come out of the allotted return on investment. As a

result, a portion of the return on investment would be taken back from the Company to fund the required payment.

In contrast, the Company's prior matching contributions to Share the Warmth were made pursuant to settlement agreements with the intervening parties in prior rate cases, and based upon consideration of many items that were negotiated as part of the settlement agreements.

Q. DOES COMMISSION RULE § 7.5414 PROHIBITING THE INCLUSION OF CHARITABLE CONTRIBUTIONS IN THE COST OF SERVICE, PREVENT THE COMMISSION FROM RECOGNIZING A CONTRIBUTION TO SHARE THE WARMTH IN TGS'S COST OF SERVICE?

A. No. Rule § 7.5414 clearly prohibits the Company from including charitable contributions in its cost of service, which the Company has elected to make to recipients selected by the Company, in amounts determined by the Company. If the Company were to make a required payment to Share the Warmth, the payment would no longer be a contribution, but a reasonable and necessary business expense, not subject to this rule.

Q. ARE THERE ANY ADDITIONAL COSTS ASSOCIATED WITH THE COMPANY'S PROPOSED EXPANDED SHARE THE WARMTH PROGRAM?

A. Yes. In addition to the $2 million annual payment to Share the Warmth, the Company would require contribution management software at a cost of $120,000 annually, to administer the contracts and payments to the partner agencies and to

track the distribution of funds in order to provide transparent and accountable reporting on the program. In addition, the Company would require an employee to oversee the program, maintain the relationships with the partner agencies and to provide regular reporting and analysis. Finally, the Company proposes to spend up to $60,000 per year on outreach and education to make sure that customers are aware of the assistance available to them and how to access it.

Q. PLEASE DESCRIBE THE PROPOSED CUSTOMER ASSISTANCE RESIDENTIAL SERVICE RATE PILOT PROGRAM.

A. The Company proposes a pilot program for up to 30,000 active qualifying residential customers to receive service at a reduced customer charge and volumetric rate, as outlined on Rate Schedule 16. Rate Schedule 16 reflects a customer charge and volumetric rate that are approximately 25% lower than the proposed Rate Schedule 10, for small residential customers. A customer served under this rate schedule would be responsible for the full cost of any associated rate schedules or riders such as the Cost of Gas Clause, PIT Rider or Rate Case Expense Rider.

Q. HOW WOULD A CUSTOMER QUALIFY FOR SERVICE UNDER RATE SCHEDULE 16?

A. The Company proposes to contract with a third party to build and administer a website at which the residential customer can apply for the customer assistance rate and provide required documentation to assist in reviewing the customer for qualification. The third-party contractor would provide TGS with a monthly update

of customers qualifying for the reduced rate, and they would oversee the process for customers on the program to requalify for subsequent years.

Q. ARE THERE ANY ADDITIONAL COSTS ASSOCIATED WITH THE COMPANY'S PROPOSED CUSTOMER ASSISTANCE RESIDENTIAL SERVICE RATE PILOT PROGRAM?

A. Yes. The cost for the third-party contractor described above to administer the website, application and qualification process for customers who wish to participate in the program will be $343,000 annually, at a level of 30,000 participating customers. Further, the Company would require an employee to oversee the program, work with the third-party vendor and to provide regular reporting and analysis. Finally, the Company proposes to spend up to $60,000 per year on outreach and education to make sure that customers are aware of the program and how to apply.

Q. DOES THE COMPANY'S PROPOSED COST OF SERVICE IN THIS PROCEEDING INCLUDE THE COST OF THE TWO PROPOSED CUSTOMER ASSISTANCE PROGRAMS?

A. Yes. Schedule G-26 includes the proposed $2 million required Share the Warmth funding; the $120,000 annual cost of the donation management platform; the $343,000 annual cost of the third party vendor to administer the website, application and qualification process for the proposed customer assistance rate schedule; $60,000 in outreach expenses; and $104,000 for salary, payroll taxes and benefits for one employee to oversee the programs, collaborate with the partner agencies and the third-party qualification vendor, update and maintain contracts

with the partner agencies, and to monitor and report on the distribution of funds. If both proposed programs are approved, the proposed $60,000 outreach funds and the cost of one employee would cover both proposed programs.

IV. CREDIT CARD PROCESSING FEES

Q. WHAT ARE CREDIT CARD PROCESSING FEES?

A. Credit card processing fees are the fees charged by credit card companies when a customer pays with a credit card.[14] Historically, the customer was alerted that they would be charged an additional "convenience" fee by the payment processor if they chose to pay by credit card. This is still the practice at TGS. TGS customers who pay their bills by credit card must pay an additional $1.49 fee to the third-party contractor that provides credit card payment processing services for TGS. As the use of electronic forms of payment has ramped up in recent years, utilities are gradually adopting the model employed by most retailers in which the retailer pays the card processing fees as a regular business expense and recovers the cost through their pricing.

Q. WHAT IS THE COMPANY'S REQUEST REGARDING CREDIT CARD PROCESSING FEES?

A. TGS proposes to begin paying the credit card processing fees assessed when its customers pay their utility bills by credit card and to include them in the cost of service. Schedule G-25 contains a proforma adjustment for credit card processing fees expense.

[14] Processing fees apply equally to debit cards as well as credit cards. References to credit cards throughout this section of my testimony should be understood to also include debit cards.

Q. ARE THERE BENEFITS OF TGS PAYING CREDIT CARD PROCESSING FEES?

A. Yes. This approach enhances customer satisfaction by providing the payment experience customers have come to expect from all retailers and service providers. It simplifies the payment process making it smoother and more seamless for the customers. The Company will more easily be able to control the process from end to end and be able to offer customers convenience, security and stability. Additionally, assuming responsibility for these fees provides TGS an opportunity to negotiate lower rates with processors, as they often find it easier to manage fees at the Company level.

Q. HOW DID TGS CALCULATE THE PROFORMA ADJUSTMENT FOR CREDIT CARD FEES ON SCHEDULE G-25?

A. The adjustment on Schedule G-25 was calculated by multiplying the current credit card processing fee of $1.49 per transaction, by the total number of customer credit card payments for the twelve months ended December 31, 2024. The actual number of credit card payments per year will likely increase after implementation of this new practice, and as mentioned above, TGS may negotiate a lower fee structure in the future.

Q. HOW DOES THE COMPANY PROPOSE TO ACCOUNT FOR THE DIFFERENCES IN ACTUAL EXPERIENCE COMPARED TO THE PROFORMA CALCULATION?

A. TGS proposes to establish a tracking mechanism to record annual credit card processing fees for each year following implementation of the new practice, and to

defer costs greater than or less than the amount included in the cost of service. TGS proposes to true up the costs in the Company's next general rate case.

V. CLOUD COMPUTING

Q. WHAT IS CLOUD COMPUTING?

A. Cloud computing is a third-party subscription that provides software and hardware resources that are accessed over the Internet. ONE Gas does not take possession of the software or hardware because it is owned, hosted, and maintained by a third-party provider. ONE Gas pays an annual fee for the use of the software, the hosting services and necessary maintenance. Cloud computing software and hardware enhancements are generally included in the subscription, resulting in faster innovation and flexible demand-based resources. Examples of ONE Gas' cloud computing subscriptions include customer relationship management, customer service surveys, data analytics, leak survey data collection, emergency callout systems, business continuity services, collaboration service, and ticket management solutions. These programs are essential for TGS's ability to provide safe and reliable service to customers.

Q. WHAT ARE THE BENEFITS OF CLOUD COMPUTING?

A. Some of the benefits of cloud computing are:

1. switching from on-premise software to cloud-based software provides more frequent enhancements, and ONE Gas inherits these enhancements without having to implement upgrades, which reduces costs;

2. for the majority of applications, the need to maintain hardware within a data center is reduced or eliminated, thereby reducing costs;

3. simplifying recovery in the event of a major problem with ONE Gas' IT environment;

4. improved scalability when applications need more resources without having to buy additional hardware; and

5. improved accessibility, which allows employees access to information on a variety of devices.

Q. WHAT IS TGS'S REQUEST WITH REGARD TO CLOUD COMPUTING COSTS?

A. The Company is requesting approval to include all cloud computing costs for contracts worth more than $50,000 and having terms greater than one year, as capital investment recoverable through annual IRA or GRIP filings consistent with the treatment approved by the Commission in a recent CenterPoint rate case, Docket No. OS-23-00015513 ("Docket No. 15513") and a recent Atmos Energy Corp. rate case, Docket No. OS-24-00018879 ("Docket No. 18879").[15]

Q. ARE ANY CLOUD COMPUTING COSTS INCLUDED IN NET PLANT CURRENTLY?

A. Yes, consistent with prior Commission approval in GUD No. 10928 and Docket Nos. 9896 and 14399,[16] the Company included cloud computing *implementation costs* as Corporate capital investment in Federal Energy Regulatory Commission ("FERC") Account 391.99, as shown on Workpaper C.c., which is discussed in the direct testimony of Company witness Eric Sanford. That balance is amortized over

[15] *Statement of Intent of CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas to Change Rates in the Unincorporated Areas and Municipalities That Have Ceded Original Jurisdiction Within the Houston, Texas Coast, Beaumont/East Texas, and South Texas Divisions*, Docket No. OS-23-00015513 consol., Final Order at FoF No. 50 (Jun. 25, 2024); *Statement of Intent Filed by Atmos Energy Corp. to Change Gas Utility Rates Within the Unincorporated Areas Served by its West Texas Division*, Docket No. OS-24-00018879 consol., Final Order at FoF No. 60 (May 13, 2025).

[16] GUD No. 10928 consol., Final Order at FoF No. 70; Docket No. OS-22-00009896 consol., Final Order at FoF No. 51; *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. 64 (Jan. 18, 2024).

13 years as shown on Workpaper G-15.c.1. In contrast, the annual cloud computing *license or subscription costs* are recorded as a prepayment in FERC Account 165, and expensed over the life of the service agreement, and are found in Workpaper B-2.b.1., which is also discussed in Mr. Sanford's testimony.

Q. IS THERE A BENEFIT ASSOCIATED WITH RECORDING ALL CLOUD COMPUTING COSTS AS CAPITAL INVESTMENT?

A. Yes. Under the Company's proposal, annual cloud computing license or subscription costs will receive consistent treatment with cloud computing implementation costs and will be amortized over a longer period, reducing the impact to customer rates.

Q. ARE CAPITALIZED CLOUD COMPUTING COSTS APPROPRIATE TO INCLUDE IN THIS RATE CASE AND FUTURE FILINGS?

A. Yes. As the Commission's prior decisions show, these costs are reasonable and necessary amounts to include in rate base in this rate case and in future GRIP filings and rate cases because the nature of these investments has not changed, and, for regulatory purposes, the costs continue to be capital investment necessary to provide service to customers. Similar to on-premise software, ONE Gas continues to invest capital to implement software solutions. Cloud computing costs support Information Technology efforts, which provide critical services employees use in their efforts to provide service safely and reliably to customers, including those served in Texas by TGS. The National Association of Regulated Utility

Commissioners issued a November 2016 resolution[17] that recognizes the benefits of cloud computing and urges commissions to utilize treatment for cloud computing costs that is similar to that of the software that cloud computing is replacing.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED TGS'S REQUEST TO RECOVER CERTAIN CLOUD COMPUTING COSTS AS CAPITAL INVESTMENT IN RATE CASES AND SUBSEQUENT GRIP FILINGS?

A. Yes. TGS included cloud computing implementation costs in GUD No. 10928 and Docket Nos. 9896 and 14399, and they were approved for recovery in each of those cases, as was the treatment of those costs in future IRA filings.[18] In this filing, TGS requests the same treatment for cloud computing annual license and subscription costs as previously approved for cloud computing implementation costs. The Company's requested treatment of cloud computing annual license and subscription costs was approved by the Commission in a recent CenterPoint rate case, Docket No. 15513, and a recent Atmos Energy rate case, Docket No. 18879.

Q. ARE THERE ANY ACCOUNTING STANDARDS REGARDING CLOUD COMPUTING THAT IMPACT RECOVERY IN RATES?

A. Yes. Accounting Standards Update 2018-15[19] (ASU) published by Financial Accounting Standards Board (FASB) in 2018, requires that after December 15, 2019, cloud computing implementation costs be capitalized and recorded as "Other Assets," Account 186. To maintain consistency in regulatory treatment, TGS is

[17] Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements, *Nat'l Ass'n of Regul. Util. Comm'rs* (adopted Nov. 16, 2016), https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476.

[18] GUD No. 10928 consol., Final Order at FoF No. 70; Docket No. OS-22-00009896 consol., Final Order at FoF No. 18; Docket No. OS-23-00014399 consol., Final Order at FoF No. 46.

[19] Financial Accounting Series - Accounting Standards Update, No. 2018-15 at 22 (Aug. 2018) https://asc.fasb.org/imageRoot/22/118236022.pdf.

requesting authorization for regulatory purposes to continue to include cloud computing implementation investment in FERC Account 391.99, in its regulatory filings. The standard further requires these assets to be amortized over the term of the hosting agreement with the cloud computing service, which is typically three to five years.

Q. WHAT IS TGS REQUESTING IN THIS CASE?

A. TGS is requesting authorization for regulatory purposes to continue to amortize cloud computing implementation costs, and begin to amortize cloud computing annual license and subscription costs, over the same 13-year life as on-premise software to maintain consistency in regulatory treatment and to recover cloud computing costs for contracts worth more than $50,000 and having terms greater than one year, as capital investment recoverable through annual IRA filings.

VI. LINE EXTENSION POLICY

Q. WHAT REVISIONS DOES THE COMPANY PROPOSE TO ITS LINE EXTENSION POLICY IN THE RULES OF SERVICE?

A. TGS proposes revisions to the Rules of Service to:

- document and clarify the Company's existing practices with regard to line extensions;
- incorporate guidance from a recent Commission decision in Docket No. 18879, which also aligns with the Company's existing practices; and
- include two additions that would establish a new Company practice to expand the categories of facilities that the Company may include in invested capital.

Specifically, the Company proposes to include in § 11.1c of the Rules of Service, the formula by which the Company determines if a line extension is cost

justified. This proposed revision does not change longstanding Company practice. Rather, it details and clarifies the existing practice.

In addition, the Company proposes to add language in § 11.1e clarifying its existing practice regarding the recoverability of certain costs associated with right of way and facility installation management, using language consistent with the Final Order in Docket No. 18879.

Finally, the Company proposes to add language in § 11.1d and § 11.2, specifying certain instances when the Company may include in invested capital, some or all of the cost of customer piping and venting.

Q. WHAT IS A LINE EXTENSION POLICY?

A. The Company's line extension policy, which is addressed in § 11 of the Company's Rules of Service, sets forth the conditions under which the Company will extend its mains in order to serve to new customers. Under the policy, when a main line is extended to a new customer, the Company calculates the cost of the line extension. The expenditure for such extensions must be cost justified. If the cost justification test is not met, the Company will collect a payment called a Contribution In Aid of Construction ("CIAC") from the entity (or person) who is requesting the line extension to make the extension cost justified.

Q. WHAT IS THE COMPANY'S GOAL IN DETERMINING IF A LINE EXTENSION IS COST JUSTIFIED?

A. The Company's goal is to ensure that each project produces revenue sufficient to cover the additional cost of service resulting from the capital expenditures necessary to extend or build a new part of the Company's system. In other words,

the Company seeks to ensure that existing customers' rates are not unduly affected due to investment for new customer additions.

Q. HOW DOES THE COMPANY DETERMINE IF A LINE EXTENSION IS COST JUSTIFIED?

A. The Company achieves its goal of protecting existing customers from rate increases driven by new investment by estimating the amount of annual new revenue that will be generated by a line extension and then comparing that revenue to the capital investment required by the project. The maximum allowed investment is equal to ten years of associated revenue. To the extent that a project is more costly than ten years of revenue, CIAC is collected in the amount of the shortfall. The Company refers to this as "ten-year revenue maximum allowed investment."

Q. WHY IS IT APPROPRIATE TO SET THE MAXIMUM ALLOWED INVESTMENT AT TEN YEARS?

A. As previously discussed, the goal is to ensure that the revenue generated by a project, covers the increase to the cost of service caused by the capital investment in that project. The increase to the cost of service caused by an investment is generally equal to the return on the investment, plus taxes and depreciation. The Company's weighted-average cost of capital, grossed up for income taxes, plus the average depreciation rate, plus the average ad valorem tax rate - totals to approximately 10%. Thus, in order for a project to recover its additional cost of service, the annual revenue generated by a project should be equal to (or greater than) approximately 10% of the capital investment (10 years divided by 100%

equals 10% per year). Stated another way, the capital investment should be equal to (or less than) ten years of revenue.

Q. WHY IS IT IMPORTANT TO COLLECT THE APPROPRIATE AMOUNT OF CIAC?

A. The Company should collect enough CIAC to ensure that the revenue associated with each new line extension covers the increase to the cost of service associated with that line extension. If the Company were to collect less CIAC than that, existing customers would be forced to subsidize new development and would be unfairly burdened. If the Company were to collect more CIAC than that, new development would subsidize existing customers, which would inappropriately shift costs from existing customers to new customers and discourage new development.

Q. DO EXISTING CUSTOMERS BENEFIT FROM NEW DEVELOPMENT?

A. Yes. As long as the capital investment required for new development is supported by the associated revenue, then new development benefits both new customers and existing customers. New development benefits new customers by providing a reliable and cost-effective energy alternative. New development also benefits existing customers by providing a larger customer base across which to spread fixed costs and the ongoing costs of system maintenance and replacements. TGS ensures that the capital investment required for new development is supported by the associated revenue through the use of CIAC, an approach that maintains the proper balance among all stakeholders.

Q. DOES THE COMPANY COLLECT CIAC ON EVERY LINE EXTENSION PROJECT?

A. No, the majority of line extension projects undertaken by the Company cost less than the maximum allowable investment. That is to say, the new revenue associated with the majority of line extensions exceeds the increase to the cost of service caused by the line extension. In circumstances where the cost of a project exceeds the new revenue associated with the line extension, and the developer is unwilling to pay the required CIAC, the Company does not take on that project.

Q. DOES TGS WAIVE COLLECTION OF CIAC IN ORDER TO COMPETE FOR NEW CUSTOMERS?

A. No, the Company does not.

Q. DOES TGS EVER PAY INCENTIVES TO DEVELOPERS IN ORDER TO COMPETE FOR NEW CUSTOMERS?

A. No, the Company does not.

Q. WHAT COSTS, IN ADDITION TO THE INSTALLATION OF FACILITIES, DOES THE COMPANY INCUR RELATED TO NEW DEVELOPMENTS?

A. The Company may, in certain circumstances, incur reasonable costs related to acquiring necessary rights-of-way, and reasonable costs related to the management of facility installation activities. These current Company practices are identical to those specifically addressed and authorized in the Final Order in Docket No. 18879.

Q. WHAT ARE COSTS RELATED TO THE MANAGEMENT OF FACILITY INSTALLATION ACTIVITIES?

A. Costs related to the management of facility installation activities may occur when a developer hires a Company-approved contractor and oversees the installation of the new natural gas infrastructure by that contractor. Some developers prefer this approach because the new infrastructure may be installed more quickly than if the developer were to wait for Company crews to install the infrastructure. In these instances, TGS engineers design the project and calculate the cost for Company crews to complete the project. TGS inspectors approve the completed installation of the new natural gas infrastructure. The developer is reimbursed for the cost of the project at the same cost that the Company would have incurred if the Company had performed the installation. That cost includes an overhead provision to cover the developer's management of natural gas facility installation activities.

Q. HAS THE COMMISSION RECENTLY PROVIDED ANY GUIDANCE REGARDING LINE EXTENSIONS?

A. Yes. On May 13, 2025, the Commission issued a Final Order in Docket No. 18879, which clarifies that it is reasonable for a utility to include in invested capital reasonable developer infrastructure costs including: any reasonable amounts paid to a developer for the installation of actual infrastructure related to providing natural gas service; reasonable costs related to acquiring necessary rights-of-way; and, reasonable costs related to the management of facility installation activities.

Q. DOES THE COMPANY'S REQUEST ON THIS ISSUE ALIGN WITH THE COMMISSION'S GUIDANCE?

A. Yes. The Company proposes the addition of § 11.1d, § 11.1e and § 11.2 to its Rules of Service to reflect this Commission decision and the Company's understanding of these terms.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED ADDITION IN § 11.1E.

A. In § 11.1e, the Company adds language to clarify its existing practice of including in invested capital reasonable costs related to acquiring necessary rights-of-way and reasonable costs related to the management of facility installation activities, as set forth by the Commission in the final order in Docket No. 18879.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED REVISION TO § 11.1D.

A. In § 11.1d, TGS proposes a new practice to specifically include the installation of customer owned natural gas piping and venting as "reasonable developer infrastructure costs" that may be paid by the Company under its line extension policy, provided the total costs paid by the Company for the project remain within the maximum allowable investment as calculated in § 11.1c.

Customer piping and venting is "actual infrastructure related to providing natural gas service." However, unlike mains and services, TGS does not take ownership of customer piping and venting. While the Company does not currently reimburse developers for the costs of customer piping and venting, TGS proposes, on a going-forward basis, to include in invested capital reasonable and necessary

reimbursed costs for the installation of customer piping and venting as 'Intangible Plant' to be amortized over a period of ten years.

Q. IS IT BENEFICIAL FOR TGS TO BE PERMITTED TO REIMBURSE DEVELOPERS FOR THE COST OF CUSTOMER PIPING AND VENTING IN CERTAIN CIRCUMSTANCES?

A. Yes. Occasionally, a developer will elect not to have TGS install natural gas mains and services in a new development because the cost to the developer of installing related customer piping and venting is cost prohibitive for the developer. In this circumstance, it would be beneficial to potential new customers (and to existing customers) for TGS to reimburse the developer for some or all of the cost of customer piping and venting, because it would encourage the addition of new customers in situations where the cost of customer piping and venting is an obstacle to the developer installing natural gas facilities. Provided the total expenditure for installation of mains and services as well as customer piping and venting does not exceed the maximum allowable investment under § 11.1c, existing customers' rates would not be unduly impacted by the new installation. Existing customers would benefit because future cost increases related to fixed costs and system maintenance and replacements would be spread over a larger customer base.

Q. WHAT DOES THE COMPANY PROPOSE IN § 11.2 OF THE RULES OF SERVICE?

A. In § 11.2, the TGS adds a provision identical to that in § 11.1d, but relating to reimbursement for customer piping and venting in new or existing residential multi-unit projects. This section includes definitions specific to multi-unit projects.

Q. IS THERE A UNIQUE OPPORTUNITY PROVIDED BY RESIDENTIAL MULTI-UNIT PROJECTS?

A. Yes. Multi-unit projects provide the opportunity to add customers often in already-developed areas where the Company has existing mains and services. Consequently, the cost to the Company of adding these customers may be quite low. However, the cost is often prohibitive to the owner of the multi-unit project, because the cost to install customer piping and venting for many densely situated apartments is a good deal greater than the cost to install customer piping and venting in single-family-home neighborhoods. If the Company is permitted to reimburse the residential multi-unit project owner for some (or all) of the cost of customer piping and venting, new customers can be added to the system at a relatively low cost per customer. As previously stated, the addition of new customers to the system benefits existing customers because fixed costs and system replacements are spread over a larger customer base.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Texas Gas Service Partner Agencies

TGS Area	Partner Agency
Customers in Travis County	Travis County Health and Human Services
Central Gulf Customers outside of Travis County	Catholic Charities of Central Texas
Rio Grande Valley Customers	Cameron Willacy Counties Community Projects Hildalgo County Community Services
Customers in El Paso County	Project Bravo
West North Customers outside of El Paso County	Catholic Charities of Central Texas

Detailed Share the Warmth Terms

Texas Gas Service ("TGS") will make a contribution in the CGSA to Share the Warmth of $200,000 annually until the next general rate case in the CGSA. TGS will also endeavor to increase awareness of the Share the Warmth Program among its CGSA customers to promote increased customer contributions. TGS will produce at least one bill insert per year to customers, increase mentions on social media, increase visibility on the TGS website, increase training of its customer service representatives at its call centers, and make improvements in delivering messages to customers who receive bills via electronic (paperless) means.

TGS will issue a joint news release with the program administrators each fall, bringing awareness to the Share the Warmth Program and inviting support.

The purpose of TGS's contribution is not to replace other sources of customer support, but to provide resources in addition to existing resources.

On November 1, 2024, TGS will make a contribution of $120,000 under the prior Share the Warmth agreement. Upon Railroad Commission issuance of a Final Order in OS-24-00017471, TGS will make an additional contribution of $80,000 on or about December 1, 2024. Prior to that date, a committee will meet and review the amount of funds expended on natural gas utility assistance by Travis County and the Catholic Charities of Central Texas (the Program Administrators) in the preceding calendar year. This Committee will include a representative from the Travis County Health and Human Service Department, City of Austin Telecommunications and Regulatory Affairs department, TGS and a representative from Catholic Charities of Central Texas.

This committee will also convene in the fall of 2025 to review the current contracts and guidelines between TGS and Travis County and TGS and Catholic Charities. The committee will review eligibility requirements, maximum contribution amounts, number of times a year a customer is eligible for assistance and make recommendations for changes in the Share the Warmth Program so that Share the Warmth will complement and support existing programs to the best of their ability.

On November 1, 2025, TGS will make another $200,000 contribution to the Programs for the CGSA if all funds for Share the Warmth, CEAP (Consolidated Energy Assistance Program) and for the Program Administrators have been expended. If all funds have not been expended, then TGS's contribution will be reduced to an amount that will meet the expected need. This amount will be determined by the Committee.

This process will continue each year until the next general rate case in the CGSA.

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 5th day of June 2025.

Notary Public in and for the State of Texas

My commission expires: 2/23/2028

CHRISTINE MARIE BELL
Notary ID #130547096
My Commission Expires
February 23, 2028

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

ERIC S. SANFORD

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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DIRECT TESTIMONY OF ERIC S. SANFORD

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Eric S. Sanford. 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 Manager of Corporate Rates and Regulatory Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration in Accounting from Northeastern State University. I began my employment with ONEOK, Inc., ("ONEOK") in 2001, as a Staff Specialist II within the Information Technology Department. In 2004, I was promoted to Business System Analyst II. In 2006, I served as a Manager of Billing Control in the ONEOK Accounting Department. In 2010, I served as the Manager of Property Accounting and retained that position with ONE Gas after its separation from ONEOK. In 2017, I served as the Manager of Billing Control. In 2020, I served as the Corporate Accounting Manager until February of 2024, when I accepted my current position as Manager of Corporate Rates and Regulatory Analysis. Prior to joining ONEOK, I worked as a Billing Specialist at WorldCom, Inc.

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS MANAGER 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 before the Oklahoma Corporation Commission ("OCC") in PUD 2025-000011, and the Kansas Corporation Commission ("KCC") in 24-KGSG-610-RTS.

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 supports the reasonableness of certain rate base adjustments, including Corporate and TGS Division capital investments, materials and supplies, prepayments and depreciation and amortization expense. Additionally, I explain and support TGS's operating expense adjustments for depreciation and amortization.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THE RATE CASE?

A. My testimony relates to Company witness Anthony Q. Brown's direct testimony as he supports the Direct TGS rate base adjustments, whereas I support TGS Division and allocated Corporate rate base adjustments. Company witnesses Jeffrey J. Husen and Alejandro Limón also support the Company's request for capital investment cost recovery.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring the following schedules:

RATE BASE:	
Schedule B Rate Base	Co-Sponsor with Anthony Q. Brown
Schedule B-1 M&S	Co-Sponsor with Anthony Q. Brown
Schedule B-2 Prepayments	Co-Sponsor with Anthony Q. Brown
Schedule C Plant	Co-Sponsor with Anthony Q. Brown
Schedule C-1 CCNC	Co-Sponsor with Anthony Q. Brown
Schedule D Reserves	Co-Sponsor with Anthony Q. Brown
OPERATING INCOME:	
Schedule G-15 Depreciation & Amortization	Co-Sponsor with Anthony Q. Brown

The schedules I address in my testimony are for the Company's proposed statewide consolidation, which consolidates the existing Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA"), and West North Service Area ("WNSA").[1]

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

[1] I have also prepared and support stand-alone schedules for the CGSA, RGVSA and WNSA.

II. 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. Mr. Brown further discusses in his direct testimony Direct rate base and its three components. Additionally, the allocations applied to these rate base adjustments follow the Corporate allocation methodology, which is discussed further in Company witness Keara J. Downum's direct testimony.

Q. WHY IS IT NECESSARY TO INCLUDE CORPORATE AND TGS DIVISION INVESTMENTS IN RATE BASE?

A. Corporate and TGS Division investment assets are necessary for TGS's provision of utility service but are not reflected in the TGS costs; thus, an adjustment is necessary to include these investments in rate base to determine the revenue requirement. The adjustments for these allocations reflect the same approach TGS has taken in prior statements of intent filings, and which the Railroad Commission of Texas ("Commission") has approved in TGS's last fully litigated rate case (Docket No. OS-22-00009896 ("Docket No. 9896")) and also in TGS's settled cases (*see*, Docket Nos. OS-23-00014399 ("Docket No. 14399") and OS-24-00017471 ("Docket No. 17471")).[2]

[2] *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 ("FoF") No. 40 (Jan. 18, 2023); *see also*, *Statement of Intent of Texas Gas Service Company, a Division of*

Q. WHICH RATE BASE ITEMS DO YOU ADDRESS?

A. I address the rate base items for capital costs that are for TGS Division or allocated from ONE Gas. These rate base items include materials and supplies, prepayments, Net PIS, Construction Completed Not Classified ("CCNC") and Accumulated Reserves for Depreciation and Amortization. I also address Schedule B which contains a summary of all rate base items.

Q. PLEASE DISCUSS THE RATE BASE ADJUSTMENTS ASSOCIATED WITH MATERIALS AND SUPPLIES.

A. The Materials and Supplies Inventory balance is a component of rate base and consists of the average monthly balances of TGS Direct Materials and Supplies Inventory and Stores Load, as well as ONE Gas Measurement Assets ("OMA"). The OMA inventory balance of Materials and Supplies represents meters, automatic meter readers, electronic receiver transmitters and regulators, held at a centralized meter shop. The monthly OMA Inventory balances and a 13-month average are provided on Schedule B-1. Mr. Brown addresses the TGS Direct and stores loads portions of materials and supplies in his direct testimony.

Q. HOW WERE THE OMA INVENTORY AMOUNTS OF MATERIALS AND SUPPLIES CALCULATED?

A. The OMA inventory balance of the Materials and Supplies balance was calculated by taking the average balance over 13 months, which allows TGS to normalize

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); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order (Nov. 19, 2024).

fluctuations during the test year. The average 13-month balance was adjusted to reflect annualization of the cost allocation percentages for the first quarter of 2025. These assets are allocated to TGS Direct based on the Texas customer count.[3] The allocation methodology follows the Corporate allocation methodology, which is discussed further in Ms. Downum's direct testimony.

Q. IS IT REASONABLE TO INCLUDE THE OMA INVENTORY PORTION OF MATERIALS AND SUPPLIES AS PART OF THE CALCULATION OF THE COST OF SERVICE IN THIS CASE?

A. Yes. The OMA inventory balance of Materials and Supplies are expenditures necessary for the provision of utility service by TGS 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. This is the same approach TGS has taken in prior statements of intent, which the Commission has previously approved.[4]

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 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

[3] Traditionally, these assets are further allocated to CGSA, RGVSA, and WNSA based on the service area customer count.

[4] *See,* Docket No. OS-22-00009896 consol., Final Order; Docket No. OS-23-00014399 consol., Final Order; and Docket No. OS-24-00017471 consol., Final Order.

miscellaneous prepaid items. ONE Gas and TGS Division prepayments are provided on Schedule B-2, and in 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.

Q. DO THE INVESTMENTS IN PREPAYMENTS DESCRIBED ABOVE INCLUDE ANY AFFILIATE COSTS?

A. Yes. As discussed in the direct testimony of Company witness Jaime D. Shelton, ONE Gas formed a wholly-owned captive insurance subsidiary, Utility Insurance Company ("UIC"), in 2017 to provide insurance to ONE Gas and its Divisions. Some UIC premiums are included in Corporate and TGS Division costs. A complete list containing UIC premiums included in rate base is attached to Ms. Downum's direct testimony as Exhibit KJD-1. Also, Mr. Brown explains in his 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 2025.

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 TGS costs; thus, prepayments are appropriately included in rate base. This is the same approach TGS has taken in prior statements of intent filings which the Commission has previously approved.[5]

Q. NEXT, PLEASE EXPLAIN THE TGS DIVISION AND ONE GAS ALLOCATED CAPITAL INVESTMENT SHOWN ON SCHEDULES C, C-1, AND D.

A. The TGS Division net PIS (gross plant, less accumulated reserves) is $8,309,343. ONE Gas' allocated net PIS is $46,133,460. 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 CASES AND REFLECTED ON SCHEDULES C AND C-1.

A. Corporate and TGS Division capital expenditures made since the last rate cases and reflected on Schedules C and C-1 primarily consist of investments in a new Customer Information Center ("CIC") that TGS uses to meet customer needs, and

[5] *See also, 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, Final Order (Dec. 14, 2010); *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); and Docket No. OS-22-00009896 consol., Final Order.

includes 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 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 for the reporting of non-emergency pipeline safety concerns, managing of suggested process improvements, and the acknowledging of 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 could 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 and for other very similar projects, were approved for recovery by the Commission in Docket Nos. 9896, 14399 and 17471.

Q. WERE THE CAPITAL EXPENDITURES FOR THE TGS DIVISION AND CORPORATE PROJECTS PRUDENT, REASONABLE AND NECESSARY?

A. Yes, they were. Corporate capital and TGS Division investment are necessary for the provision of service in Texas. 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. If a

technology system becomes unavailable, operations may be impaired. Additionally, ONE Gas and TGS maintain office and training spaces needed for employees to adequately and safely provide reliable gas service to customers. Likewise, it is necessary for the Company to provide reliable technology systems, infrastructure and office/training facilities to employees who provide either indirect support or direct service to customers through leak detection, emergency response, customer billing, dispatching and scheduling of service calls. Similarly, the Company is obligated to protect sensitive customer information, continually enhance cybersecurity to avoid threats, take steps to improve website functionality, and to reasonably maintain office and training facilities. The direct testimony of Mr. Limón also 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 certain Corporate and TGS Division costs for activities such as: (1) plant additions, transfers or retirements mistakenly coded to TGS; (2) costs for meals greater than $25 per person, exclusive of taxes and tip amounts, and adjustments to hotel stays greater than $175 per night, exclusive of taxes;[6] (3) duplicative Vertex sales tax; and (4) expenses related to Company owned aviation. These adjustments are reflected in Workpapers C.b, C.c, C-1.b, C-1.c, D.b, and D.c.

[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 Central Texas Service Area and the Gulf Coast Service Area,* GUD No. 10928 consol., Final Order at FoF No. 71-72 (Aug. 4, 2020).

III. OPERATING EXPENSE ADJUSTMENTS

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 Company witness Ronald E. 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 Nos. 14399 and 17471.[7] Corporate depreciation rates and amortization periods are consistent throughout ONE Gas and its Divisions. The KCC[8] and OCC[9] 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.

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[7] *See,* Docket No. OS-22-00009896 consol., Final Order at FoF No. 87; s*ee also*, Docket No. OS-23-00014399 consol., Final Order at FoF No. 38; and Docket No. OS-24-00017471 consol., Final Order at FoF No. 44.

[8] *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).

[9] *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).

Dr. White conducted a 2025 depreciation study to determine the depreciation rates for TGS Division plant. 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 CORPORATE DEPRECIATION RATES AND AMORTIZATION PERIODS PREVIOUSLY APPROVED BY THE COMMISSION TO CALCULATE THE DEPRECIATION AND AMORTIZATION EXPENSE?

A. These Corporate depreciation rates were subject to a comprehensive review in seven different Texas rate cases and are already being utilized by TGS statewide. If the regulatory authority were to now establish parameters for Corporate assets that are different from those utilized in other 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, which would be a complicated and costly process.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF ERIC S. SANFORD

BEFORE ME, the undersigned authority, on this day personally appeared Eric S. Sanford who having been placed under oath by me did depose as follows:

1. "My name is Eric S. Sanford. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Manager of Rates and Regulatory Compliance 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.

Eric S. Sanford

SUBSCRIBED AND SWORN TO BEFORE ME by the said Eric S. Sanford on this 4 day of June 2025.

M. BETH WILLIAMS NOTARY # 13002055 EXP. 03/01/29 PUBLIC STATE OF OKLAHOMA

M Beth Williams
Notary Public in and for the State of Oklahoma

My commission expires: 3/1/2029

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

KEARA J. DOWNUM

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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LIST OF EXHIBITS

EXHIBIT KJD-1	Schedule of Utility Insurance Company Premiums
EXHIBIT KJD-2	Corporate Allocation Manual

DIRECT TESTIMONY OF KEARA J. DOWNUM

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Keara J. Downum. 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 a Rates Analyst II.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am a licensed Certified Public Accountant and earned a Master of Science Degree in Accounting in July 2022 and a Bachelor of Science Degree in Accounting in December 2020 from Oklahoma State University. From February 2018 to June 2020, I worked as a contract employee in the ONE Gas Rates and Regulatory department. From June 2020 through December 2020, I completed an internship with ONE Gas' Corporate Accounting and Rates and Regulatory departments. From January 2021 through November 2022, I served as a Tax Intern at Grant Thornton LLP and a contract tax preparer at Edwards Tax and Accounting. In November 2022, I began serving as a Rates Analyst II at ONE Gas.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony before the Oklahoma Corporation Commission ("OCC") in PUD2023-000012 and the Kansas Corporation Commission ("KCC") in 24-KGSG-610-RTS.

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 Texas Gas Service Company ("TGS" or the "Company");

2. Explains and supports ONE Gas' cost allocation methodology, including causal allocations and the ONE Gas Distrigas ("Distrigas") formula;

3. 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;

4. Explains and supports adjustments associated with payroll, overtime and payroll related taxes and benefits; and

5. 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 Anthony Q. Brown's direct testimony as he supports the Direct TGS expense adjustments, whereas I support TGS Division and allocated Corporate expense adjustments. My testimony also relates to Company witness Megan Z. Gough's direct testimony that addresses employee compensation and benefits, and Company witness Jaime D. Shelton's direct testimony that discusses ONE Gas' affiliate company, Utility Insurance Company ("UIC").

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring the following schedules:

OPERATING INCOME:	
Schedule G Summary of Operating Revenue & Expense Adj	Co-Sponsor with Anthony Q. Brown and Zane M. Drummond
Schedule G-4 Base Payroll Adjustment	Sponsoring
Schedule G-5 Overtime Payroll Adjustment	Sponsoring
Schedule G-6 Benefits & Payroll Tax Adjustment	Sponsoring
Schedule G-8 Incentive Compensation	Sponsoring
Schedule G-9 Miscellaneous Adjustments	Co-Sponsor with Anthony Q. Brown
Schedule G-10 Rents	Co-Sponsor with Anthony Q. Brown
Schedule G-13 Injuries and Damages	Sponsoring
Schedule G-14 Advertising Expense	Co-Sponsor with Anthony Q. Brown
Schedule G-21 Distrigas Allocation Percentage	Sponsoring
Schedule G-22 Causal Allocation Percentage	Sponsoring

The schedules I address in my testimony are for the Company's proposed statewide consolidation, which consolidates the existing Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA"), and West North Service Area ("WNSA").[1]

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

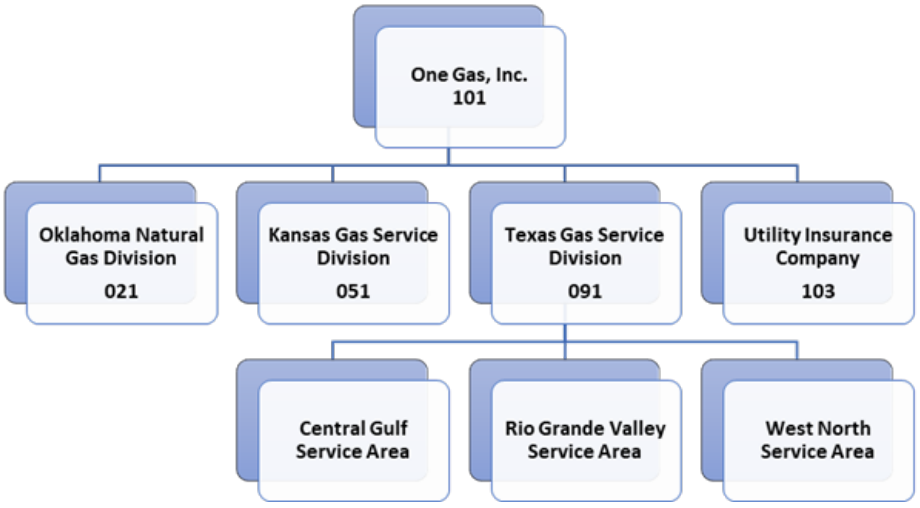
II. ORGANIZATIONAL STRUCTURE OVERVIEW

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, UIC, a wholly-owned captive insurance

[1] I have also prepared and support stand-alone schedules for the WNSA, CGSA, and RGVSA.

subsidiary. Ms. Shelton discusses UIC in more detail in her direct testimony. TGS is currently divided into three service areas — the CGSA, RGVSA, and WNSA. This filing requests approval to consolidate these three service areas into a single TGS statewide jurisdiction.



Q. DOES THE UTILITY SERVICE PROVIDED BY TGS INCLUDE CENTRALIZED SERVICES?

A. Yes, both ONE Gas and TGS Division provide certain necessary, centralized services for TGS. 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. The activities performed through these cost centers are subject to cost assignment using the methodology set forth below.

Q. ARE COSTS ASSOCIATED WITH PROVIDING SHARED SERVICES TO TGS 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 TGS by TGS Division and ONE Gas employees, and the costs associated with those services are 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?

A. Yes. A portion of UIC premiums for ONE Gas and TGS is included as allocated costs in the amount of $8,141,773. A complete list containing the UIC premiums included in rate base and operations and maintenance ("O&M") expense is attached to my testimony as Exhibit KJD-1. Ms. Shelton provides direct testimony describing UIC and its services, and Mr. Brown discusses the Company's compliance with the associated affiliate standard.

III. COST ALLOCATION METHODOLOGY

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, cost responsibility for these services must be reasonably allocated among the various ONE Gas business entities and TGS. 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, so those costs are directly assigned to that specific business entity. Conversely, indirect costs are costs that cannot be attributed to a specific business entity 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 TGS. 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; 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 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.

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 KJD-2.

- 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.

Q. WOULD THE SAME TYPES OF CENTRALIZED SUPPORT SERVICES AS THOSE PROVIDED BY TGS DIVISION AND ONE GAS BE REQUIRED IF TGS WAS A STAND-ALONE BUSINESS?

A. Yes, these services would need to be provided even if TGS was a stand-alone business. TGS 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. 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.

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.[2] 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.

[2] *Distrigas of Massachusetts Corp.*, 41 FERC ¶ 61,205 (1987).

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.[3] These modifications further refine the Distrigas Method to fairly and reasonably allocate the costs to the ONE Gas business entities, including TGS.

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"); Rio Grande Valley Service Area in Docket No. OS-23-00014399 ("Docket No. 14399"); and most recently the Central-Gulf Service Area in Docket No. OS-24-00017471 ("Docket No. 17471").[4]

[3] 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.

[4] *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, a Division of ONE Gas, Inc., to Increase 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*

Additionally, the OCC[5] 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, Inc.'s allocation methodology in a settled 2005 KGS rate case and ONE Gas' allocation methodology in the 2016, 2018 and 2023 KGS rate cases.

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 the Railroad Commission of Texas ("Commission"), the FERC,[6] the OCC and accepted by the KCC.

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 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 (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-22-00009696 consol., Final Order (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 (Jan. 30, 2024); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order (Nov. 19, 2024).

[5] *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).

[6] *Distrigas,* 41 FERC ¶ 61,205.

IV. 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 $103,174,740. Workpaper G.a.2.a provides a summary showing the TGS 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.

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 2021 through December 2024 (four years). Next, injuries and damages expense for the 12 months ended December 2024 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 Docket Nos. 14399 and 17471, which were resolved through settlement agreements.

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 2025 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.

V. 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 Direct TGS and TGS Division employees as well as Corporate employees whose costs are allocated during the test year. Adjusted base salaries were calculated by annualizing test year payroll at December 31, 2024. 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 2024 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

TGS. 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 Nos. 9896, 14399 and 17471, 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 Direct TGS and TGS Division employees as well as Corporate employees whose costs are allocated. 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 TGS. 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 Nos. 9896, 14399 and 17471, 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 Direct TGS and TGS Division as well as Corporate employees whose costs are allocated. 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 TGS. 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 Nos. 9896, 14399 and 17471, 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 $1,393.11, and included on Workpaper G-6. This amount is for Direct TGS employees. The amount was calculated based on December 2024 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.

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 Direct TGS payroll as reasonable and necessary and supported by the evidence.[7] 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:

[7] GUD No. 10506 consol., Final Order at Finding of Fact ("FoF") Nos. 86-87; and Docket No. OS-22-00009896 consol., Final Order at FoF No. 71.

Description	Amount
Pension	$611,062
OPEB	$75,361
Total	$686,423

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 TGS.

VI. 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).[8] 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

[8] https://www.sec.gov/divisions/corpfin/ecfr/17cfr229.402a.pdf.

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 Company also followed this approach in Docket Nos. 14399 and 17471, which were 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 TGS is $611,717. The Company removed the $611,717 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 TGS is $2,180,779 of which $1,178,236 was attributable to financial metrics for NEOs. Removing that amount results in TGS requesting recovery of $1,002,543. 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.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

	A	B	C
1	**UIC Premiums Included in Rate Base and Expenses**		
2			
3	**Rate Base**	**Expenses**	**Total**
4	3,057,832	5,083,941	**8,141,773**

CORPORATE UIC PREMIUMS ALLOCATED TO CGSA

TEST YEAR ENDING DECEMBER 31, 2024

LINE NO.	POLICY TYPE	DECEMBER 2023[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	$ 9,440	$ 8,496	$ 7,552	$ 6,608	$ 5,664	$ 4,720	$ 3,776	$ 2,832	$ 1,888	$ 944	$ -	$ 15,598	$ 14,180		
2	UIC Excess Liability	1,213,760	1,092,384	971,008	849,632	728,256	606,880	485,504	364,128	242,752	121,376	-	1,312,245	1,192,950		
3	UIC Property	38,000	28,500	19,000	9,500	-	118,173	107,430	96,687	85,944	75,201	64,458	53,715	42,972		
4	UIC Workers Compensation	49,100	44,190	39,280	34,370	29,460	24,550	19,640	14,730	9,820	4,910	-	61,666	56,060		
5	UIC Cyber	82,294	-	966,141	878,310	790,479	702,648	614,817	526,986	439,155	351,324	263,493	175,662	87,831		
6	**CORPORATE UIC PREMIUMS**	**$ 1,392,594**	**$ 1,173,570**	**$ 2,002,981**	**$ 1,778,420**	**$ 1,553,859**	**$ 1,456,971**	**$ 1,231,167**	**$ 1,005,363**	**$ 779,559**	**$ 553,755**	**$ 327,951**	**$ 1,618,886**	**$ 1,393,993**		**$ 1,251,467**
7	**Allocated to TGS - Distrigas Allocation**														**30.25%**	**378,569**

Footnotes:

[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.b.1 Prepays - Corporate (CONFIDENTIAL)". In the Prepayment Detail tab, filter on "UTILITY INSURANCE COMPANY" in the " Description" column to identify the UIC premiums contained in "WKP B-2.b.1 Prepays - Corporate (CONFIDENTIAL)".

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	**TGS DIVISION UIC PREMIUMS ALLOCATED TO CGSA**																
2	**TEST YEAR ENDING DECEMBER 31, 2024**																
3																	
4																	
5	**LINE NO.**	**POLICY TYPE**	**DECEMBER 2023[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	$ 9,380	$ 8,442	$ 7,504	$ 6,566	$ 5,628	$ 4,690	$ 3,752	$ 2,814	$ 1,876	$ 938	$ -	$ 91,531	$ 83,210		
7	2	UIC Excess Liability	4,310,520	3,879,468	3,448,416	3,017,364	2,586,312	2,155,260	1,724,208	1,293,156	862,104	431,052	-	2,986,357	2,714,870		
8	3	UIC Property	234,304	175,728	117,152	58,576	-	768,086	698,260	628,434	558,608	488,782	418,956	349,130	279,304		
9	4	UIC Workers Compensation	53,400	48,060	42,720	37,380	32,040	26,700	21,360	16,020	10,680	5,340	-	65,989	59,990		
10	5	**TGS DIVISION UIC PREMIUMS**	**$ 4,607,604**	**$ 4,111,698**	**$ 3,615,792**	**$ 3,119,886**	**$ 2,623,980**	**$ 2,954,736**	**$ 2,447,580**	**$ 1,940,424**	**$ 1,433,268**	**$ 926,112**	**$ 418,956**	**$ 3,493,007**	**$ 3,137,374**		**$ 2,679,263**
11																	
12		**Footnotes:**															
13		[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.a.1 Prepays - TGS Div (CONFIDENTIAL)". In the Prepayment Detail Schedule tab, see Line No. 13 to identify the UIC premium total contained in "WKP B-2.a.1 Prepays - TGS Div (CONFIDENTIAL)".															

	A	B	C	D
1	**CORPORATE UIC PREMIUM EXPENSE ALLOCATED TO CGSA**			
2	**TEST YEAR EXPENSE JAN - DEC 31, 2024**			
3				
4				
5	**LINE NO.**	**POLICY TYPE**		**UIC Expense 2024**
6	1	UIC Auto Liability		17,022
7	2	UIC Excess Liability		1,431,546
8	3	UIC Property		128,915
9	4	UIC Workers Compensation		67,276
10	5	UIC Cyber		1,053,967
11	6	**CORPORATE UIC PREMIUMS**		**$ 2,698,725**
12	7	**Allocated to TGS - Distrigas Allocation**	**30.25%**	**$ 816,364**

	A	B	C	D
1	**TGS UIC PREMIUM EXPENSE ALLOCATED TO CGSA**			
2	**TEST YEAR EXPENSE JAN - DEC 31, 2024**			
3				
4				
5	**LINE NO.**	**POLICY TYPE**		**UIC Expense 2024**
6	1	UIC Auto Liability		99,850
7	2	UIC Excess Liability		3,257,831
8	3	UIC Property		837,906
9	4	UIC Workers Compensation		71,990
10	5	**TGS UIC PREMIUMS**		**$ 4,267,577**

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.

Corporate Services (includes Environmental Health & Safety)

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 KEARA J. DOWNUM

BEFORE ME, the undersigned authority, on this day personally appeared Keara J. Downum who having been placed under oath by me did depose as follows:

1. "My name is Keara J. Downum. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Rates Analyst II of Rates and Regulatory Compliance 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.

Keara J. Downum

SUBSCRIBED AND SWORN TO BEFORE ME by the said Keara J. Downum on this 4th day of June 2025.

M. BETH WILLIAMS NOTARY # 13002055 EXP. 03/01/29 PUBLIC STATE OF OKLAHOMA

M Beth Williams
Notary Public in and for the State of Oklahoma

My commission expires: 3/1/2029

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

MEGAN Z. GOUGH

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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LIST OF EXHIBITS

EXHIBIT MZG-1	Willis Towers Watson 2025 General Rate Case Total Compensation Study for TGS (CONFIDENTIAL)
EXHIBIT MZG-2	Willis Towers Watson 2024 Long-Term Incentives Policies and Practices Survey Report U.S. (Excerpt) - LTI Prevalence (CONFIDENTIAL)
EXHIBIT MZG-3	ONE Gas, Inc. 2024 Annual Employee Short-Term Incentive Plan (CONFIDENTIAL)
EXHIBIT MZG-4	ONE Gas, Inc. 2024 Annual Officer Short-Term Incentive Plan (CONFIDENTIAL)
EXHIBIT MZG-5	ONE Gas, Inc. 2024 Amended and Restated Equity Compensation Plan (CONFIDENTIAL)
EXHIBIT MZG-6	ONE Gas Inc. 2023 Ben Val Study (CONFIDENTIAL)

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 Director 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 and was recently promoted to Director of Compensation in January of 2025. 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. Yes, I filed testimony before the Commission in Docket No. OS-24-00017471 ("Docket No. 17471"). Similarly, I have also filed 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, Docket No. OS-22-00009896 ("Docket No. 9896"). Company witness Keara J. Downum also addresses aspects of these issues in her direct testimony.

II. COMPENSATION COMPONENTS

Q. WHAT ARE THE COMPENSATION COMPONENTS?

A. Compensation is comprised of several components, including base pay and incentive programs commonly known as Short-Term Incentives ("STI") and Long-Term Incentives ("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.

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 Willis Towers Watson ("WTW") 2025 General Rate Case Total Compensation Study for TGS ("Compensation Study") provided in Confidential Exhibit MZG-1 on page 3 states, "When compared to available published survey data, Texas Gas' compensation levels are at the low end of the competitive range (+/- 10%) based on the company's stated compensation philosophy for base salary, target total cash compensation, and target total direct compensation." WTW's assessment included the review of small and large utility peers as well as the general industry.

III. SHORT-TERM INCENTIVE PLAN

Q. PLEASE EXPLAIN ONE GAS' STI PLAN.

A. The STI Plan provides employees the opportunity to earn 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 each peer group 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 2024 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, ONE Gas structures the STI program to include a company modifier ranging from 0% to 150%, and an individual performance modifier ranging from 0% to 133%, so that the award opportunity is competitive with the

median of the market. In fact, 50% of small utility peer companies and 57% of large utility peer companies studied offer a maximum incentive payout at the 200% level. No annual incentives are earned if the company's performance is below threshold.

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. The individual modifier for 2024 ranged between 0% and 133%. 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 2024 Test Year, the Field Technician - C&M in the example below, had $52,000 in base wages and a 4% incentive target. The Gas Tech Senior - Customer Service Field had $54,000 in base wages and a 4% incentive target. ONE Gas performance resulted in a company modifier of 120.80%. 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**
$52,000	x	4%	x	100%	x	120.80%	=	**$2,513**
Gas Tech Senior - Customer Service Field								
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$54,000	x	4%	x	85%	x	120.80%	=	**$2,218**

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 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.

IV. 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. In February 2024, 129 non-officers received an LTI grant. Additionally, the LTI payout that vested in February 2024, included 93 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, approves all executive LTI grants and receives information on all non-executive LTI grants.

In 2024, 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 WTW 2024 Long-Term Incentives Policies and Practices Survey Report U.S. provided in Confidential Exhibit MZG-2, at pages 5-6, 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 not 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 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. This performance metric is measured by the Company's 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. Relative TSR is a common measure of long-term performance associated with utility performance plans such as the ONE Gas Performance Stock Units.

TSR is the total return on a company's stock over the performance period with dividends reinvested into company stock as they are accrued. The number of Performance Stock Units awarded at the time of vesting is based on our TSR positioning, as a percentage basis at the end of the three-year performance period. If the actual TSR percentile rank falls between the stated percentile ranks set forth in the chart below, the payout percentage is interpolated between the percentile rank above and below the actual percentile rank. No Performance Stock Units are earned if our TSR ranking at the end of the performance period is below the 25th percentile. This measurement is commonly referred to as "relative TSR."

Percentile Rank	Payout (as a % of Target)
90th percentile and above	200%
75th percentile	150%
50th percentile	100%
25th percentile	50%
Below the 25th percentile	—%

Q. WHAT IS THE PURPOSE OF OFFERING LTI?

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 and engage 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 68.5% of energy companies using that metric according to the WTW 2024 Long-Term Incentives Policies and Practices Survey Report U.S. excerpt - LTI Prevalence as provided in the attached 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 LTI 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 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.

V. ONE GAS COMPENSATION PHILOSOPHY

Q. PLEASE EXPLAIN ONE GAS' EMPLOYEE COMPENSATION PROGRAM.

A. ONE Gas' employee compensation program is designed to attract, engage 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 can be in the form of STI and LTI. 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 the competitive market in which we compete for talent. 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, engage, and retain qualified workers

to operate safely and efficiently in our communities. Our compensation plans are intended to incentivize 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 with market compensation studies, the Commission determined that TGS's

[1] Named Executive Officers are those employees whose compensation is required to be disclosed under 17 C.F.R. Section 229.402(a).

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 HAD IN PRIOR DOCKETS?

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. Downum.

Q. IS ONE GAS' COMPENSATION APPROACH CONSISTENT WITH GURA § 104.060?

A. Yes. Although I am not a lawyer, I have read the statute and it is my opinion that ONE Gas' compensation approach is consistent with GURA § 104.060. ONE Gas participates in national and industry-specific independent compensation studies to determine market competitive pay ranges and incentive pay targets for each position. We use data from independent third-party human resources compensation consulting firms to benchmark our pay practices to the energy services utilities and

[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 Finding of Fact ("FoF") Nos. 65-69 (Jan. 18, 2023).

general industries. 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.

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 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 therefore should be presumed reasonable by regulators under GURA § 104.060. My understanding of the statute is consistent with the Commission's decisions in Docket No. 9896, Docket No. OS-23-000014399, and Docket No. 17471.

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:

- 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 approach 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' 2025 Proxy Statement on page 55.[3] As it does for all positions, ONE Gas strives to pay experienced executives within a competitive range of the median level of total compensation for peer companies.

[3] Schedule 14(a) 2025 Proxy Statement available at https://d18rn0p25nwr6d.cloudfront.net/CIK-0001587732/7b7e76ab-dedd-4da0-a97d-12118b5583f7.pdf.

The Compensation Study provided as Confidential Exhibit MZG-1 on page 4 shows the reasonableness of executive compensation compared to peer companies.

Q. DOES MARKET 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 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 2024 Long-Term Incentives Policies and Practices Survey Report U.S. excerpt - LTI Prevalence found that 67.5% of the 117 energy companies responding granted restricted LTI and 96.6% 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 important to offer competitive compensation packages 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 each 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 and utilities industries and is how WTW and the Company were able to determine that TGS's individual pay components of both salaries and incentives are at the low end of the competitive market range of compensation.

If ONE Gas were to eliminate incentives and increase base pay, it would be difficult for the Commission, as well as our compensation team, to determine the appropriate market value for each element of pay. For example, if we shifted incentive compensation to base pay, all else being equal, the overall compensation level may appear to be aligned to the market data for base pay, however would not

[4] *See*, Confidential Exhibit MZG-1 at 7, 9.

take into account the total direct compensation value. Shifting away from our incentive compensation program would make it more difficult for the Company, the Commission and (current and/or future) employees to compare the Company's compensation offering against our peers.

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. Meaning, we do not assume variable pay, or pay at risk, is a part of fixed pay so as to ensure both company and individual performance justify this form of compensation to an employee. This encourages our employees to be invested in the safety and financial health of our company.

The Company's ability to attract, engage 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 compensation. Providing employees the opportunity to earn incentive compensation in addition to base pay is an integral component of ONE Gas' compensation package as well as ensures this form of compensation is aligned to the best interest of our stakeholders and relies on company and individual performance.

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. 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.

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 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.

VI. 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 and engage 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 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. ONE Gas also 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 costs. ONE Gas has regular governance meetings with current healthcare vendors and has a navigation vendor which

provides support to employees by helping them to 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 and retain employees that will support our business of providing natural gas to our customers safely and reliably. Part of that attraction, engagement 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 that 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 and retain qualified employees, which benefits customers and communities by ensuring the delivery of safe, reliable and efficient service.

VII. 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
or Protective Order issued in this proceeding.

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 Director of Compensation 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.

Megan Z Gough

Megan Z. Gough

SUBSCRIBED AND SWORN TO BEFORE ME by the said Megan Z. Gough on this 4th day of June 2025.

KIRA LUEVANO
NOTARY
#20000536
EXP. 01/14/2028
PUBLIC
STATE OF OKLAHOMA

Notary Public in and for the State of Oklahoma

My commission expires: 01/14/2028

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

CYNDI L. KING

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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EXHIBIT CLK-1 Prepaid Pension Asset

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 25 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-23-000014399 ("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 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, 2024, of $24.1 million and an allocated portion of the corporate prepaid asset of $20.6 million. TGS's portion of the total asset is $44.7 million. These amounts are shown on Exhibit CLK-1.

Q. WHAT AMOUNT IS THE COMPANY ASKING TO BE INCLUDED IN RATE BASE?

A. The amount is $44.7 million, as shown in Exhibit CLK-1.

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 North Service Area in Docket No. OS-22-00009896, in the Rio Grande Valley Service Area Docket No. 14399

and in the Central-Gulf Service Area Docket No. OS-24-00017471.[1] 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.[2] 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.

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 the prior cases identified above.

III. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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[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., Final Order (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 (Jan. 30, 2024); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order (Nov. 19, 2024).

[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 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).

TEXAS GAS SERVICE COMPANY

TWELVE MONTHS ENDED DECEMBER 31, 2024

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	TGS Expense Reduction
	(a)	(b)	(c)	(d) = b * c	(e)	(f) = d + e	(g)	(h) = f * g	(i)	(j)
10	2018	$ 63,872.699	24.72%	$ 15,789.331	$ 36,753.287	$ 52,542.618	7.25%	3,809.340	30,408.906	3,809.340
11	2019	$ 76,979.308	25.40%	$ 19,552.744	$ 33,163.628	$ 52,716.372	7.20%	3,795.579	34,204.485	3,795.579
12	2020	$ 72,824.572	25.63%	$ 18,664.938	$ 28,937.707	$ 47,602.645	7.20%	3,427.390	37,631.875	3,427.390
13	2021	$ 68,548.217	26.81%	$ 18,374.761	$ 24,965.926	$ 43,340.687	7.15%	3,098.859	40,730.734	3,098.859
16	2022	$ 67,843.246	28.07%	$ 19,043.599	$ 23,527.498	$ 42,571.097	6.40%	2,724.550	43,455.284	2,724.550
17	2023	$ 69,404.601	28.57%	$ 19,831.532	$ 24,096.037	$ 43,927.569	6.75%	2,965.111	46,420.395	2,965.111
18	2024	$ 69,597.335	29.63%	$ 20,621.690	$ 24,106.934	$ 44,728.624	6.70%	2,996.818	49,417.213	2,996.818

		TGS Total	Allocation to service area	TGS
Prepaid Pension Asset		$ 44,728.624	100.0000%	$ 44,728.624

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

SUBSCRIBED AND SWORN TO BEFORE ME by the said Cyndi L. King on this 5th day of June 2025.

JOANNE C. DAVIS NOTARY # 05009895 EXP. 10/25/25 PUBLIC STATE OF OKLAHOMA

Notary Public in and for the State of Oklahoma

My commission expires: October 25, 2025

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JAIME D. SHELTON

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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EXHIBIT JDS-6	ONE Gas, Inc. Analysis of Insurance Costs (CONFIDENTIAL)

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. Yes, I filed testimony before the Railroad Commission of Texas ("Commission") in Docket No. OS-24-00017471.

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 Anthony Q. Brown, who also addresses the affiliate cost recovery standard, and the direct testimony of Company witness Keara J. Downum, who sponsors the schedule (*see*, Exhibit KJD-1) 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 COMMISSION?

A Yes, they have been accepted as appropriate costs in Docket Nos. OS-22-00009896, OS-23-00014399 and OS-24-00017471.[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, the North Texas Service Area, and the Borger Skellytown Service Area*, Docket No. OS-22-00009896 consol., Final Order at Finding of Fact ("FoF") Nos. 75-78 (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 Nos. 42-43 (Jan. 30, 2024); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order at FoF Nos. 50-52 (Nov. 19, 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. Downum.

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 owns and manages UIC, it is able to help control increases in deductibles and premiums when claims occur and does not have to take claims from other clients into consideration like the general insurance market does.

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 $10.1 million since UIC was created for liability coverage and $1.7 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, 2024, UIC has paid out one claim on its liability policy for TGS and medical stop loss claims related to the benefit plan as a whole. In this case, UIC, UIC's reinsurer and ONE Gas shareholders bore the entire cost of the claim 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. Downum 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 $10.1 million in liability insurance and $1.7 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
or Protective Order issued in this proceeding.

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, 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.

Jaime D. Shelton

Jaime D. Shelton

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jaime D. Shelton on this 9th day of June 2025.

JOANNE C. DAVIS NOTARY PUBLIC # 05009895 EXP. 10/25/25 STATE OF OKLAHOMA

Joanne C Davis

Notary Public in and for the State of Oklahoma

My commission expires: October 25, 2025

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

KENNETH W. EAKENS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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LIST OF EXHIBITS

EXHIBIT KWE-1	Rev. Proc. 2023-15
EXHIBIT KWE-2	Notice to Regulators - IRS Form 3115
EXHIBIT KWE-3	EDIT Balance and Annual Amortization

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 ONE Gas 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 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") and Docket No. OS-24-00017471 ("Docket No. 17471") before the Railroad Commission of Texas ("Commission"). Similarly, I have also filed testimony before the Kansas Corporation Commission in 24-KGSG-610-RTS; and before the Oklahoma Corporation Commission in Cause No. PUD2025-000011.

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 guidance regarding the Internal Revenue Service ("IRS") Natural Gas Safe Harbor ("NGSH") Method commonly referred to within the industry as part of the "Repair Regulations" impacts the Company. This method, outlined in Revenue Procedure 2023-15 ("Rev. Proc. 2023-15"), published by the IRS on April 14, 2023, allows for the deduction of certain repair and maintenance costs for tax purposes, even when those same costs are capitalized for book purposes. I also address the treatment of Accumulated Deferred Income Taxes ("ADIT") and Excess Deferred Income Taxes ("EDIT") resulting from ONE Gas' adoption of Rev. Proc. 2023-15.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE DIRECT TESTIMONY OF OTHER COMPANY WITNESSES?

A. Company witness Janet M. Simpson addresses the calculation of ADIT in her direct testimony.

II. NATURAL GAS SAFE HARBOR METHOD FOR TAX REPAIRS DEDUCTION

Q. WHAT IS REVENUE PROCEDURE 2023-15?

A. On April 14, 2023, the IRS published Rev. Proc. 2023-15 (Exhibit KWE-1). Rev. Proc. 2023-15 provides long-awaited guidance on the safe harbor method of tax treatment for expenditures related to maintain, repair, replace, or improve natural gas distribution and transmission property. Rev. Proc. 2023-15 created the NGSH and defined its parameters.

Q. WHAT IS A SAFE HARBOR?

A. The safe harbor permits utilities to deduct qualified gas system repair costs in full instead of capitalizing and depreciating them over 20+ years. Without the NGSH, the IRS could audit and challenge whether deductions meet the facts-and-circumstances test under the tangible property regulations, which is a time-consuming and uncertain process. With the NGSH:

- The IRS agrees not to challenge a utility's deduction as long as it follows the safe harbor rules.
- The utility has clear guidelines on what qualifies.
- The utility avoids penalties and exposure for improper capitalization under §263(a).

Q. PLEASE PROVIDE A BROAD OVERVIEW OF NGSH.

A. Rev. Proc. 2023-15 reflects IRS guidance simplifying how natural gas utilities handle repair and maintenance costs for tax purposes. It allows the company to deduct many of these expenses on its tax return, even though they are still capitalized and depreciated in the company's financial (book) accounting.

Q. WHAT BENEFITS DOES THIS PROVIDE CUSTOMERS AND THE COMPANY?

A. The difference between tax and book treatment reduces the Company's taxable income and ultimately benefits customers by lowering utility rates. In addition to the financial benefits, the guidance also reduces the complex administrative burden of tracking expenditures which are treated as capital on the financial books and as repair expenses on the tax return. The NGSH also lowers the risk of IRS disputes or audits over whether costs were correctly classified as deductible or capitalized.

Q. WHAT IS THE SCOPE AND PURPOSE OF THIS NEW PROCEDURE?

A. Rev. Proc. 2023-15 aims to reduce uncertainty and disputes between taxpayers and the IRS regarding the tax treatment of certain expenditures. Specifically, the revenue procedure clarifies whether certain costs to maintain, repair, replace and improve parts of the distribution and transmission system are capital expenditures or expenses allowable as deductions for tax purposes. Stated differently, the revenue procedure clarifies whether those expenditures must be treated as capital investments (IRC §263(a)) or routine business expenses for tax purposes (IRC §162(a)).

Q. PLEASE SUMMARIZE THE KEY COMPONENTS OF THE REVENUE PROCEDURE.

A. The Revenue Procedure is extensive, but the key components are as follows:

- Defines units of property;
- Provides simplified rules for determining whether the costs of replacing or repairing components must be capitalized or can be treated as ordinary business expenses;
- Stipulates that costs resulting in a betterment, restoration, or adaptation of property must be capitalized; and
- Establishes safe harbor methods specific to natural gas transmission and distribution property.

Q. PLEASE SUMMARIZE THE KEY CHANGES.

A. The key changes under the NGSH Method are summarized below:

- Linear vs. non-linear rules;
  - Linear property (e.g., pipes, fittings, valves) follows a bright-line test; if more than 10% of a transmission property unit is replaced, costs must be capitalized;
  - Non-linear property (e.g., compressors, regulators, meters) has an optional safe harbor, while replacing major components requires capitalization;
- Expenditures that are automatically capitalized ("per se capital expenditures");
  - Per se capital expenditures—an expense that is automatically classified as a capital cost under the tax rules, no analysis needed, no exceptions—include costs incurred for adding new customers, increasing capacity, repairing damaged property, or adapting property for a new use; and
  - Distribution service lines must be capitalized if they relate to distribution main replacements exceeding four miles.

III. ONE GAS ADOPTION OF NGSH METHOD

Q. HAS ONE GAS ADOPTED THE NGSH ACCOUNTING METHOD FOR REPAIRS?

A. Yes. ONE Gas filed a change of accounting method for tax purposes with its 2023 Corporate Income Tax return to adopt the NGSH Method. Adopting the NGSH is a change in accounting method that qualifies for automatic IRS consent. You do not need to request permission or file a private letter ruling ("PLR") as long as your change qualifies and you follow the correct procedures, the IRS must accept the change. This change resulted in a one-time Section 481(a) adjustment of $44.8 million, generating $9.4 million in ADIT as a reduction to the rate base. A notice of this filing (IRS Form 3115) was submitted to each regulatory authority in Texas by November 15, 2024, which I have attached as Exhibit KWE-2.

Q. DOES THE CHANGE IN ACCOUNTING PROVIDE A BENEFIT TO CUSTOMERS?

A. Yes. The benefit to customers is realized over time. The accounting method change resulted in a $44.8 million tax deduction under Section 481(a), which generated a Deferred Tax Liability ("DTL") and a corresponding Net Operating Loss ("NOL") that created a Deferred Tax Asset ("DTA"). These two items largely net against each other on the Company's balance sheet, meaning there is no net reduction to rate base until the NOL is utilized to offset future taxable income.

As the NOL is applied in future tax years—subject to the 80% taxable income limitation—the DTA will decrease, allowing the remaining DTL to appear as a net source of cost-free capital, which reduces rate base. Because NOLs are typically utilized more quickly than deferred liabilities reverse, the rate base benefit

will begin to phase in sooner than if the Section 481(a) DTL stood alone. I will discuss this further later in my testimony.

Q. HOW WILL THE COMPANY'S FUTURE REPAIRS DEDUCTIONS BE AFFECTED?

A. The Company's future repairs deductions will increase due to the change in accounting provided that future capital expenditures continue to align with repair activities rather than new growth investments. While the change in accounting allows for greater deductions compared to prior treatment, the actual impact will depend on the mix of repair and replacement projects. These deductions, when realized, create additional cost-free capital and contribute to a larger balance in ADIT, which serves as a reduction to rate base.

Q. HOW WILL THIS DEFERRED TAX ASSET BE TREATED?

A. The DTA will be used to reduce taxable income in future filings subject to the IRS limitation of 80% of taxable income. It will also be included in rate base consistent with repairs deductions in accumulated deferred income tax that are a reduction to rate base. Ms. Simpson describes the calculation of these and other ADIT amounts in her direct testimony.

Q. WHAT IS THE EFFECT ON THE COMPANY'S NOL BALANCE?

A. The NOL will be removed from the Company's books and no longer be reflected in rate base more quickly than the additional ADIT. Absent changes in tax law or other significant circumstances, ADIT amortizes over the depreciable life of the asset, while NOLs are typically utilized more quickly. As a result, the NOL balance

declines faster, leaving a larger rate base reduction over time, which benefits customers.

Q. DID THE SECTION 481(A) ADJUSTMENT AND CHANGE IN ACCOUNTING RESULT IN CHANGES TO EDIT?

A. Yes, although the total amount of EDIT to be returned to customers has not changed since the 2017 Tax Cuts and Jobs Act, the adjustment did move dollars from Protected to Unprotected under IRS regulations. As a result of the Section 481(a) adjustment, property that previously had protected excess deferred income taxes (EDIT) related to method/life differences has been reclassified to unprotected excess. The amount of EDIT that was reclassified from protected to unprotected EDIT is $7.4 million.

Q. WHAT REQUEST IS TGS MAKING CONCERNING THE AMORTIZATION OF THIS ADDITIONAL APPROXIMATELY $7.4 MILLION OF UNPROTECTED EDIT?

A. The Company is requesting that this unprotected EDIT, that was previously protected, be consistently returned using Average Rate Assumption Method ("ARAM") for three reasons:

1. The customer EDIT amortization will remain consistent over time.
2. These repair deductions relate directly to assets that are expensed over the depreciable lives of the assets; therefore, it makes sense for the EDIT related to these assets be amortized based on the ARAM which approximates the remaining depreciable life of the Company's assets.
3. This treatment would be consistent with prior requests related to EDIT moving from protected to unprotected.

Q. PRIOR TO THE ACCOUNTING CHANGE, WAS THIS $7.4 MILLION TO BE RETURNED THROUGH EDIT CREDITS USING ARAM?

A. Yes, it was.

Q. PLEASE FURTHER EXPLAIN THE ARAM.

A. The ARAM is a method used by regulated utilities to account for the reduction of EDIT resulting from changes in tax rates. ARAM is used to amortize the EDIT reserve over the remaining life of the property that generated the deferred taxes, i.e. average depreciation rates.

Q. YOU MENTIONED A PREVIOUS SIMILAR REQUEST CONCERNING EDIT THAT HAS MOVED DOLLARS TO BE RETURNED TO CUSTOMERS FROM PROTECTED TO UNPROTECTED EDIT. PLEASE DISCUSS.

A. TGS requested that the cost of removal portion of EDIT that had previously been treated as protected and was moved to unprotected be amortized using ARAM as it related to assets being expensed over their depreciable lives. Docket No. 14399 and Docket No. 17471 before the Commission approved ARAM treatment for the unprotected cost of removal portion of the EDIT amortization.[1]

[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 Rio Grande Valley Service Area*, Docket No. OS-23-00014399 consol., Direct Testimony of Kenneth W. Eakens and Final Order at Finding of Fact ("FoF") No. 61-63 (Jan. 30, 2024); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Direct Testimony of Kenneth W. Eakens and Final Order at FoF No. 40 (Nov. 19, 2024).

Q. AGAIN, IS THIS REQUESTED TREATMENT OF THE SECTION 481(A) ADJUSTMENT CONSISTENT WITH THE REQUESTED AND APPROVED TREATMENT FOR COST OF REMOVAL THAT WAS PREVIOUSLY APPROVED BY TGS IN DOCKET NO. 14399 AND DOCKET NO. 17471 BEFORE THE COMMISSION?

A. Yes, it is.

IV. EDIT BALANCE AND ANNUAL AMORTIZATION

Q. WHAT IS THE EDIT BALANCE FOR TGS?

A. As detailed in Exhibit KWE-3, the balance of EDIT for TGS at December 31, 2024, is $27.9 million.

Q. HOW IS THE EDIT BALANCE AT DECEMBER 31, 2024, CALCULATED?

A. The initial EDIT balance, shown on page 1 of Exhibit KWE-3, of TGS 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 Tax Cuts and Jobs Act. The December 31, 2024, EDIT balance for TGS is calculated by taking the initial EDIT balance and subtracting the annual amortization for the years 2018, 2019, 2020, 2021, 2022, 2023 and 2024, also shown on page 1 of Exhibit KWE-3, resulting in a December 31, 2024, balance of $27.9 million.

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 TGS is $2.3 million.

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 TGS. TGS used the ARAM methodology for the calculation of the "protected" portions of EDIT. TGS used the same ARAM amortization percentage for the "unprotected" NGSH EDIT balance resulting from PLR Rev. Proc. 2023-14, as previously discussed. TGS used the previously agreed amortization period for "unprotected" EDIT, excluding Cost of Removal and NGSH.

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 Commission Docket No. OS-22-00009896, TGS's Rio Grande Valley Service Area in Docket No. 14399 and most recently in the Company's Central-Gulf Service Area in Docket No. 17471.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Part III

Administrative, Procedural, and Miscellaneous

26 CFR 1.263(a)-3: Amounts paid to improve tangible property.
(Also Part I, §§ 162, 165, 167, 168, 263(a), 263A, and 446; 1.165-7(a)(2), 1.167(a)-11, 1.168(i)-1, 1.446-1.)

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SECTION 1. PURPOSE

This revenue procedure provides a safe harbor method of accounting that taxpayers may use to determine whether certain expenditures to maintain, repair, replace, or improve natural gas transmission and distribution property must be capitalized as improvements under § 263(a) of the Internal Revenue Code (Code) or as the costs of property produced by the taxpayer for use in its trade or business under § 263A, or are allowable as deductions under § 162.[1] This revenue procedure also provides procedures for taxpayers to obtain automatic consent to change their method of accounting to the safe harbor method of accounting permitted by this revenue procedure.

SECTION 2. BACKGROUND

.01 Taxpayers that transmit and distribute natural gas pay or incur significant expenditures to maintain, repair, replace, and improve natural gas transmission and distribution property. Generally, whether these expenditures are allowable as deductions under § 162 for repairs or maintenance or must be capitalized under § 263(a) as improvements to property depends on whether these expenditures result in

[1] Unless otherwise specified, all "section" or "§" references are to sections of the Code or the Income Tax Regulations (26 CFR part 1).

a betterment or restoration of the property or adapt it to a new or different use. See §§ 1.162-4 and 1.263(a)-3(d). Whether these expenditures are capitalized under § 263A depends, generally, on whether these expenditures are properly allocable to property produced by the taxpayer. See § 1.263A-1(a)(3). Applying capitalization principles to natural gas transmission and distribution property can be particularly difficult, largely because the property consists of a network of interconnected assets. As a consequence, there often exists uncertainty as to whether certain costs to maintain, repair, replace, and improve parts or components of such interconnected property are capital expenditures or expenses allowable as deductions.

.02 To reduce uncertainty and associated disputes between taxpayers and the IRS regarding whether expenditures to maintain, repair, replace, or improve natural gas transmission and distribution property must be capitalized or are allowable as deductions, this revenue procedure provides a "natural gas transmission and distribution property safe harbor method of accounting" or "NGSH Method" (as defined under section 4.01 of this revenue procedure) for determining whether certain costs of maintaining, repairing, replacing, and improving natural gas transmission and distribution property are required to be capitalized under § 263(a) or § 263A, or may be treated as ordinary and necessary business expenses for which a deduction is allowable under § 162(a).

.03 To apply the NGSH Method, a taxpayer must first classify its natural gas transmission and distribution property as either linear property (for example, pipes, fittings, and valves) or non-linear property (for example, compressors, regulators, and meters). If a taxpayer chooses to use the NGSH Method for its linear property, the

taxpayer (1) must use the "safe harbor method for linear property" (as defined under section 4.02 of this revenue procedure) for all of the taxpayer's linear transmission and distribution property and (2) may choose to apply the "safe harbor method for non-linear property" (as defined under section 4.03 of this revenue procedure) for all of the taxpayer's non-linear transmission and distribution property. However, if a taxpayer chooses to use the NGSH Method for its non-linear property, the taxpayer must use (1) the safe harbor method for non-linear property for all of the taxpayer's non-linear transmission and distribution property and (2) the safe harbor method for linear property for all of the taxpayer's linear transmission and distribution property.

.04 The safe harbor method for linear property provides different rules for linear transmission property (generally, linear property that transmits natural gas from production facilities to local distribution systems) and for linear distribution property (generally, linear property that distributes natural gas to local customers). For linear transmission property, the safe harbor method for linear property defines the appropriate units of transmission property and provides a simplified rule for determining whether the costs of replacing a portion of that unit of linear transmission property must be capitalized under §§ 263(a) and 263A. See section 5.02 of this revenue procedure. For linear distribution property, the safe harbor method does not define units of property but divides distribution property into "distribution mains" and "distribution service lines" and provides simplified rules for determining whether the costs of replacing distribution mains and the costs of repairing, maintaining, replacing, or improving distribution service lines must be capitalized under §§ 263(a) and 263A. See sections 5.03 and 5.07 of this revenue procedure. A taxpayer using the safe harbor method for linear

property is required to use it for both its linear transmission property and its linear distribution property.

.05 The safe harbor method for non-linear property defines units of property and major components of non-linear transmission and distribution property and provides that a taxpayer must capitalize the costs of replacing a unit of non-linear property or a major component of a unit of non-linear property under §§ 263(a) and 263A. See section 5.04 of this revenue procedure and Appendix A of this revenue procedure (Appendix A). In addition, if a taxpayer replaces a unit of non-linear property or a major component of a unit of non-linear property, the taxpayer must also capitalize the costs of any repairs, maintenance, or replacements that directly benefit or are incurred by reason of the replacement of the unit of non-linear property or major component of the unit of non-linear property. Except as otherwise provided in section 6.04 of this revenue procedure, if a taxpayer chooses to use the safe harbor method for non-linear property, the taxpayer must use this safe harbor method for all its non-linear transmission and distribution property.

.06 This revenue procedure also provides “per se capitalization rules” that apply to both linear and non-linear property. These per se capitalization rules identify certain costs that a taxpayer must treat as capital expenditures if the taxpayer utilizes the NGSH Method. See section 5.05 of this revenue procedure. For example, in general, a taxpayer using the NGSH Method is required to capitalize the costs of additions and replacements that materially increase capacity to one or more customers. See sections 5.05(1)(b) and (2) of this revenue procedure. Also, under the per se capitalization rules, a taxpayer using the NGSH Method must capitalize the costs of: (1) replacing all or part

of property if the taxpayer deducts a loss for the replaced property (other than a casualty loss) or takes the adjusted basis of the replaced property into account in realizing gain or loss resulting from a sale or exchange of the replaced property; and (2) repairing and replacing all or part of property for which the taxpayer is required to take a basis adjustment as a result of a casualty loss or relating to a casualty event. These rules are referred to collectively as the "disposition/loss per se capitalization rules." See section 5.05(1)(g) and (h) of this revenue procedure.

.07 Replacements of natural gas transmission and distribution property often involve dispositions of properties that are replaced. These dispositions generally require taxpayers to recognize gain or loss, or take a basis adjustment, thus triggering the disposition/loss per se capitalization rules under the NGSH Method. Accordingly, the NGSH Method would not be useful without providing a mechanism to mitigate the effects of these dispositions and the resulting application of the disposition/loss per se capitalization rules to a taxpayer utilizing this safe harbor method. Thus, a taxpayer using the NGSH Method must include costs capitalized under the NGSH Method in general asset accounts as described under § 168(i)(4) and § 1.168(i)-1(l). See section 5.08 of this revenue procedure. The use of general asset accounts limits (1) the circumstances under which a taxpayer is required to recognize a loss on the disposition of property, and (2) the circumstances under which a taxpayer is required to take a casualty loss or a basis adjustment as a result of a casualty event. Therefore, the inclusion of transmission and distribution property in general asset accounts allows a taxpayer to avoid triggering the disposition/loss per se capitalization rules. The use of general asset accounts also allows a taxpayer to continue to depreciate this property

after its disposition.

In addition, to facilitate the transition to the use of general asset accounts, this revenue procedure requires a taxpayer using the NGSH Method to make a late general asset account election under §§ 168(i)(4) and § 1.168(i)-1(l) for natural gas transmission and distribution property that the taxpayer previously placed in service and owns at the beginning of its year of change. See section 5.08(2) of this revenue procedure. Moreover, to incentivize taxpayers to use the NGSH method and to encourage taxpayers to change to the NGSH method for their first taxable year ending after May 1, 2023, this revenue procedure provides a special transition rule. Under this rule, if a taxpayer changes to the NGSH Method for its first taxable year ending after [date of publication of this revenue procedure in the IRB], the taxpayer does not have to apply certain per se capitalization rules to amounts paid or incurred to replace or repair linear property or non-linear property, as applicable, in taxable years ending on or before May 1, 2023. See section 5.08(3)(a) of this revenue procedure.

.08 The safe harbor method for linear property and the safe harbor method for non-linear property are methods of accounting under § 446. Section 446(e) and § 1.446-1(e) require taxpayers to secure the consent of the Commissioner of Internal Revenue (Commissioner) before changing a method of accounting for Federal income tax purposes. Section 1.446-1(e)(3)(ii) authorizes the Commissioner to prescribe administrative procedures setting forth the limitations, terms, and conditions necessary to permit a taxpayer to obtain consent to change a method of accounting. Section 6.05 of this revenue procedure provides the procedures by which a taxpayer may obtain automatic consent for a change in method of accounting to use the safe harbor method

for linear property and the safe harbor method for non-linear property.

SECTION 3. SCOPE

.01 In general. Only a taxpayer that meets both of the requirements of section 3.01(1) and (2) of this revenue procedure may choose to apply the NGSH Method.

(1) The taxpayer has a depreciable interest in natural gas transmission or distribution property described in section 4 of this revenue procedure.

(2) The taxpayer pays or incurs costs (other than costs described in section 3.03 of this revenue procedure) to maintain, repair, replace, or improve the particular property referenced in section 3.01(1) of this revenue procedure.

.02 Application to entities. The determination of whether a taxpayer satisfies the requirements of both section 3.01(1) and (2) of this revenue procedure is made separately with respect to each member of a consolidated group and with respect to each partnership, S corporation, or trust (other than a grantor trust).

.03 Exclusions. The NGSH Method does not apply to the following:

(1) The costs of property for the transmission, distribution, control, or storage of natural gas at a marine liquefied natural gas terminal capable of shipping or receiving liquid natural gas for import or export;

(2) The costs of enclosures or buildings suitable for occupation;

(3) The costs of non-linear property that is not specifically identified in Appendix A (for example, tools, fixtures, furniture, computer equipment, and other miscellaneous equipment);

(4) The costs of smart pipeline inspection gauges as defined in section 4.27 of this revenue procedure; and

(5) The costs of cleaning pipeline inspection gauges as defined in section 4.28 of this revenue procedure.

SECTION 4. DEFINITIONS

The following definitions apply solely for purposes of this revenue procedure (including its appendices):

.01 Natural gas transmission and distribution property safe harbor method of accounting. "Natural gas transmission and distribution property safe harbor method of accounting" or "NGSH Method" means the safe harbor method for linear property, the safe harbor method for non-linear property, and the other applicable rules set out in this revenue procedure, collectively, regardless of whether the taxpayer chooses to use both methods, or uses only the safe harbor method for linear property.

.02 Safe harbor method for linear property. "Safe harbor method for linear property" means the method of accounting described in sections 5.02, 5.03, and 5.07 of this revenue procedure in conjunction with the other applicable rules set forth in this revenue procedure.

.03 Safe harbor method for non-linear property. "Safe harbor method for non-linear property" means the method of accounting described in section 5.04 of this revenue procedure in conjunction with the other applicable rules set forth in this revenue procedure.

.04 Natural gas transmission property. "Natural gas transmission property" means real and personal property that is used to transport, control, and store natural gas at any point between (1) a gas processing plant or custody transfer point and (2) a city gate station or other delivery point, generally connecting to a natural gas distribution system.

Gas production wells, gathering lines, and processing plants are not included in this definition.

.05 Natural gas distribution property. "Natural gas distribution property" means real and personal property that is used to transport, control, and store natural gas at any point between (1) a city gate station or other custody transfer point generally connecting to a transmission system, and (2) the customer gas meter or other delivery point to the customer. For this purpose, "natural gas distribution property" includes both (1) the city gate station or other custody transfer point and (2) the customer gas meter or other delivery point to the customer.

.06 Linear property. "Linear property" means all natural gas transmission and distribution property except non-linear property. Examples of linear property include pipes, valves, tunnels, casing, and fittings.

.07 Non-linear property. "Non-linear property" means all natural gas transmission and distribution property that is compressor station property, gas storage facility property, measuring and regulating station property, or meters or regulators, wherever located. Examples of non-linear property include compressors, tanks, liquefaction equipment, and structures.

.08 Work order. "Work order" means a written document that identifies and defines the scope of a specific project. A work order may include repairs, maintenance, replacements, and/or improvements to natural gas transmission or distribution property.

.09 Blanket work order. "Blanket work order" means a written document that authorizes a project or projects over a specific period of time, generally not exceeding one year. A blanket work order may include repairs, maintenance, replacements,

and/or improvements to natural gas transmission or distribution property.

.10 Replacement. "Replacement" means the installation of property so that existing property can be removed from service, whether or not the existing property is physically removed. Generally, a replacement made pursuant to a work order is a single replacement for purposes of this revenue procedure, regardless of whether (1) the work is performed at the same or different times, and (2) in the case of linear property, the property that is replaced is contiguous or noncontiguous. Multiple replacements made under separate work orders or made pursuant to a blanket work order may be aggregated for purposes of applying the NGSH Method. See section 5.06 of this revenue procedure for the rules for aggregating costs related to linear and non-linear transmission and distribution property.

.11 City gate station. "City gate station" means a measuring and regulating station at which a distribution system receives natural gas, generally from a transmission system.

.12 Hydraulic subsystem. "Hydraulic subsystem" means all linear transmission property used to direct the flow of natural gas that is maintained within the same operating pressure range in the shortest section between any two of the following points:

(1) a gas processing plant;

(2) a compressor station at a storage facility;

(3) a compressor station not described in section 4.12(2) of this revenue procedure (including between two compressor stations described in this section 4.12(3));

(4) a regulator (including between two regulators);

(5) the point where the taxpayer's distribution system begins; or

(6) a custody transfer point where the gas is delivered to or from another party. For example, a regulator located between another regulator and a compressor station divides that section of linear transmission property into two separate hydraulic subsystems, even if both subsystems are maintained within the same operating pressure range.

.13 Compressor station property. "Compressor station property" means property that supplies the energy to move natural gas at increased pressure at storage facilities or in transmission lines, including but not limited to compressors, instrumentation and controls, meters, regulators, measuring equipment, odorizing equipment, gas detection equipment, electric supply equipment, equipment to maintain pipeline quality gas, mounting pads, buildings, and fencing or walls.

.14 Gas storage facility property. "Gas storage facility property" means property at an above ground or underground gas storage facility, including a compressed or liquefied natural gas storage facility, and an underground storage facility in a salt formation or a depleted well or well field. Gas storage facility property does not include property at a liquefied natural gas marine terminal capable of shipping or receiving liquefied natural gas for import or export.

.15 Measuring and regulating station property. "Measuring and regulating station property" means property at a location that measures or regulates natural gas, including but not limited to meters, regulators, and gauges.

.16 Measuring equipment. "Measuring equipment" means equipment used to measure the pressure or temperature of the gas. As used in this revenue procedure, the term does not include a meter that measures gas flow, as defined in section 4.23 of

this revenue procedure.

.17 Instrumentation and controls. "Instrumentation and controls" mean the analog and digital devices that measure, monitor, or control the equipment at storage facilities, compressor stations, and measuring and regulating stations (including city gate stations). Instrumentation and controls include SCADA (supervisory control and data acquisition) equipment and measuring and regulating equipment. As used in this revenue procedure, however, instrumentation and controls do not include assets that are treated as separate units of property (for example, meters or regulators).

.18 Distribution main. "Distribution main" means a distribution line that serves as a common source of supply for more than one distribution service line. "Distribution mains" means more than one section of distribution main in a natural gas distribution system.

.19 Distribution service line. "Distribution service line" means a line that carries natural gas from the distribution main to the customer gas meter.

.20 Distribution service line costs. "Distribution service line costs" means direct and indirect costs paid or incurred to repair, maintain, replace, or improve distribution service lines.

.21 Lateral line. "Lateral line" means a line in a natural gas distribution or transmission system that branches away from the central and primary part of the system.

.22 Compressor. "Compressor" means a mechanical device for increasing the pressure of gas.

.23 Meter. "Meter" means an instrument for measuring and indicating or recording

the flow of gas that has passed through it.

.24 Regulator. "Regulator" means a device that reduces the pressure in a gas line and maintains the pressure within a constant band.

.25 Well. "Well" means a cased bore hole used for gas input or output for an underground storage reservoir, including a storage well.

.26 Equipment to maintain pipeline quality gas. "Equipment to maintain pipeline quality gas," also known as "purification equipment," means equipment used to ensure that the gas moving through a line is maintained within certain parameter. This term includes, but is not limited to, the equipment used to remove liquids and impurities from the gas, and the equipment used to heat or cool the gas to make it suitable for movement through the line.

.27 Smart pipeline inspection gauges. "Smart pipeline inspection gauges," also known as "smart pigs," are devices that are equipped with sensors that gauge the thickness of pipes they are traveling through and detect cracks, fissures, erosion and other problems that may affect the integrity of the pipeline. Smart pipeline inspection gauges are not included within the definition of natural gas transmission or distribution property for purposes of this revenue procedure.

.28 Cleaning pipeline inspection gauges. "Cleaning pipeline inspection gauges," also known as "cleaning pigs," are devices that have brushes, scrapers, or similar tools and are used for cleaning pipelines by removing sedimentation and build-up that can impede the flow of gas. Cleaning pipeline inspection gauges are not included within the definition of natural gas transmission or distribution property for purposes of this revenue procedure.

.29 Odorizing equipment. "Odorizing equipment" means equipment that injects an odorant or other additive into the gas so that leaks can be detected by the sense of smell.

.30 Gas detection equipment. "Gas detection equipment" means equipment that indicates the existence of natural gas in a specific area.

.31 Electric supply equipment. "Electric supply equipment" means equipment that supplies electricity to equipment at a compressor station or gas storage facility, including but not limited to generators, batteries and chargers, and transformers.

.32 Liquefaction equipment. "Liquefaction equipment" means equipment that is used in connection with the liquefaction of natural gas, including but not limited to cold boxes, heat exchangers, condensers, and vaporizing units.

.33 Cathodic protection. "Cathodic protection" means a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

SECTION 5. NATURAL GAS TRANSMISSION AND DISTRIBUTION PROPERTY SAFE HARBOR METHOD OF ACCOUNTING

.01 In general.

(1) A taxpayer using the NGSH Method must apply the safe harbor method for linear property provided in sections 5.02 and 5.03 of this revenue procedure to the direct and indirect costs of replacing all its linear transmission and distribution main property, including any unit of property rules described therein. A taxpayer using the NGSH Method must also apply the safe harbor method for distribution service line costs as provided in section 5.07 of this revenue procedure. Moreover, a taxpayer using the NGSH Method may, but is not required to, apply the safe harbor method for non-linear

property provided in section 5.04 of this revenue procedure to the direct and indirect costs of repairing, maintaining, replacing, and improving all its non-linear transmission and distribution property, including the application of the units of property and major components described in Appendix A. In addition, except as provided in section 5.08(3)(a) of this revenue procedure, a taxpayer using the NGSH Method must apply the per se capitalization rules provided in section 5.05 of this revenue procedure and the aggregation rules provided in section 5.06 of this revenue procedure to property subject to the NGSH Method. Finally, a taxpayer using the NGSH Method must include certain costs of natural gas transmission and distribution property in general asset accounts as provided in section 5.08 of this revenue procedure.

(2) Solely for purposes of this revenue procedure, the IRS will respect a reasonable and consistently applied designation of property by the taxpayer as either transmission or distribution property for Federal or State regulatory purposes, whichever is applicable. If the taxpayer is unregulated, the IRS will respect a reasonable and consistently applied designation that the taxpayer uses for its books and records.

(3) A taxpayer may not rely on the unit of property definitions provided in this revenue procedure for any other purpose of the Code or regulations, including for determining the unit of property under other sections of the Code or determining the asset for depreciation purposes (including placed in service, retirements, dispositions, or classification under § 168(e) or Rev. Proc. 87-56, 1987-2 C.B. 674) for the same or similar type of assets.

(4) Amounts required to be capitalized under the NGSH Method are capital expenditures and must be taken into account through a charge to capital account or

basis. Amounts that are paid or incurred for MACRS property and that are capitalized under this NGSH Method are accounted for in the manner described in section 5.08 of this revenue procedure.

.02 Safe harbor method for linear property—application to transmission property.

(1) Unit of property for linear transmission property. For purposes of this revenue procedure, the unit of property for linear natural gas transmission property is the linear property within each hydraulic subsystem as defined in section 4.12 of this revenue procedure. If a transmission segment is composed of two or more parallel lines, each line between each compressor station or other connection point is a separate unit of property. A lateral line on a transmission line is not a separate unit of property unless there is a compressor station or regulator at the junction point between the lateral line and the main transmission line. If a lateral line can be treated as part of a unit of property with more than one main transmission line, the taxpayer should designate the main line with which the lateral line is associated and follow that designation consistently.

(2) Simplified rule for replacements of linear transmission property. Whether a taxpayer using the safe harbor method for linear property must capitalize the cost of a replacement of linear transmission property is determined by the length of the line replaced. If more than 10 percent of the length of the unit of linear transmission property is replaced, the cost of the replacement must be capitalized under §§ 263(a) and 263A. If 10 percent or less of the length of the unit of linear transmission property is replaced, the cost of the replacement is not required to be capitalized under § 263(a) or § 263A. The cost of the replacement includes the direct and indirect costs of

replacing the pipe and any associated linear property, including, but not limited to, connectors, cathodic protection, valves, casing, tunnels, instrumentation and controls, and structural supports for such property.

(3) Blanket work orders.

(a) Allocation. To the extent a taxpayer cannot specifically identify whether amounts charged to a blanket work order are for a replacement of linear transmission property greater than 10 percent of the unit of linear transmission property, the taxpayer may use any reasonable method to allocate costs charged to the blanket work order if the reasonable method is consistently applied by the taxpayer.

(b) De minimis charges. A taxpayer that adheres to a policy that limits per-event charges under a blanket work order to replacements of property costing $50,000 or less is not required to capitalize the costs of replacing linear transmission property charged to the blanket work order. Replacements of property qualifying under this de minimis rule are not taken into account in determining whether more than 10 percent of the length of the unit of linear transmission property is replaced under section 5.02(2) of this revenue procedure or in applying the aggregation requirement in section 5.06 of this revenue procedure.

.03 Safe harbor method for linear property—application to distribution property.

(1) In general. For purposes of determining whether the costs of replacing linear distribution property must be capitalized under the NGSH Method, the unit of linear distribution property is not defined. Instead, the taxpayer must initially determine whether the costs are for the replacement of distribution mains as defined in section 4.18 of this revenue procedure or are distribution service line costs as defined in section

4.20 of this revenue procedure. To determine whether the costs of replacing distribution mains must be capitalized, the taxpayer must apply the simplified rule provided in section 5.03(2) of this revenue procedure. To determine whether distribution service line costs must be capitalized, the taxpayer must apply the simplified rules provided in section 5.07 of this revenue procedure.

(2) Simplified rule for replacements of distribution mains. Whether a taxpayer using the safe harbor method for linear property must capitalize the cost of replacing distribution mains is determined by the length of the distribution mains replaced. If more than four miles of distribution mains are replaced, the cost of the replacement must be capitalized under §§ 263(a) and 263A. If four miles or less of distribution mains are replaced, the cost of the replacement is not required to be capitalized under § 263(a) or § 263A. The cost of the replacement includes the direct and indirect costs of replacing the distribution mains and any associated linear property, including, but not limited to, connectors, cathodic protection, valves, casing, tunnels, instrumentation and controls, and structural supports for such linear property.

(3) Blanket work orders.

(a) Allocation. To the extent a taxpayer cannot specifically identify whether amounts charged to a blanket work order are for the replacement of distribution mains greater than four miles, the taxpayer may use any reasonable method to allocate costs charged to the blanket work order if the reasonable method is consistently applied by the taxpayer.

(b) De minimis charges. A taxpayer that adheres to a policy that limits per-event charges under a blanket work order to replacements of property costing $50,000 or less

is not required to capitalize the costs of distribution mains replacements charged to the blanket work order. Replacements of property qualifying under the de minimis rule in this section 5.03(3)(b) are not taken into account in determining replacement length under section 5.03(2) of this revenue procedure or in applying the aggregation requirement in section 5.06 of this revenue procedure.

.04 Safe harbor method for non-linear property – application to transmission and distribution property.

(1) Applicability. A taxpayer may use the safe harbor method for non-linear property only if the taxpayer uses the safe harbor method for linear property. However, a taxpayer is not required to apply the safe harbor method for non-linear property if it uses the safe harbor method for linear property. If a taxpayer does not use the safe harbor method for non-linear property, then the taxpayer must apply §§ 162, 263(a), 263A, and the regulations thereunder to determine the appropriate units of property for its non-linear property and to determine whether amounts paid or incurred to repair, maintain, replace, or improve these units of property must be capitalized.

(2) Units of property under the safe harbor method for non-linear property. For purposes of applying the safe harbor method for non-linear property, the units of property and corresponding major components of non-linear property are identified in Appendix A. A taxpayer that uses a unit of property definition provided in Appendix A must also use the major component definitions provided in Appendix A for that unit of property. Similarly, a taxpayer that uses a major component definition provided in Appendix A must also use the unit of property definition provided in Appendix A associated with that major component.

(3) Simplified rule for replacements of non-linear property. The safe harbor method for non-linear property applies to the direct and indirect costs paid or incurred to repair, maintain, replace, or improve the taxpayer's non-linear transmission and distribution property. If the taxpayer replaces a unit of non-linear property or a major component of a unit of non-linear property as identified in Appendix A, then the taxpayer must capitalize the amounts paid to replace the unit of non-linear property or major component of the unit of non-linear property under §§ 263(a) and 263A. In addition, if a taxpayer replaces a unit of non-linear property or a major component of a unit of non-linear property, the taxpayer must also capitalize the costs of any repairs, maintenance, or replacements that directly benefit or are incurred by reason of the replacement of the unit of non-linear property or major component of the unit of non-linear property. If the taxpayer pays or incurs amounts to repair, maintain, replace, or improve non-linear transmission or distribution property, but does not replace either a unit of non-linear property or a major component of a unit of non-linear property as part of these activities, then the taxpayer is not required to capitalize the amounts paid or incurred for such activities under § 263(a) or § 263A. However, if a taxpayer pays or incurs amounts to repair, maintain, replace, or improve its non-linear transmission or distribution property, and these costs relate to per se capital expenditures described under section 5.05 of this revenue procedure, then the amounts paid or incurred must be capitalized under section 5.05 of this revenue procedure.

.05 Per se capital expenditures.

(1) In general. Except as provided in section 5.08(3)(a) of this revenue procedure, a taxpayer using the NGSH Method must capitalize the direct and indirect costs

described in section 5.05(1)(a) through (j) of this revenue procedure to the extent these costs are paid or incurred with respect to linear property or non-linear property subject to the NGSH Method, notwithstanding any other provision of this revenue procedure. Per se capital expenditures include:

(a) The costs of property necessary to add one or more new customers;

(b) The costs of materially increasing capacity of the property to one or more existing or potential customers (see section 5.05(2) of this revenue procedure for the application of this rule to linear property);

(c) The costs of adding a unit of non-linear property or adding a major component of a unit of non-linear property other than as a replacement, as defined in section 4.10 of this revenue procedure, for an existing major component;

(d) The costs of property that extends a transmission or distribution system (see section 5.05(3) of this revenue procedure for the application of this rule to the costs of additional linear property required to relocate or replace an existing line);

(e) The costs of property that adds cathodic protection, protective wrapping, or protective coating to linear property;

(f) The costs of adding instrumentation and control equipment, including remote actuation or monitoring equipment, to property that did not previously have similar equipment; for these purposes, new instrumentation and control equipment is not similar if it provides additional functionality;

(g) The costs of replacing all or part of property if the taxpayer deducts a loss for the replaced property (other than a casualty loss), or takes the adjusted basis of the replaced property into account in realizing gain or loss resulting from a sale or exchange

of the replaced property;

(h) The costs of repairing or replacing all or part of property as a result of damage for which the taxpayer is required to take a basis adjustment as a result of a casualty loss under § 165, or relating to a casualty event described in § 165;

(i) The costs of easements or other rights in real property; and

(j) The costs of adapting property to a new or different use.

(2) Materially increasing capacity of linear property.

(a) Determining materiality. For purposes of applying section 5.05(1)(b) of this revenue procedure to linear transmission property or linear distribution property, an expenditure for linear property materially increases capacity to one or more existing or potential customers if the work performed increases capacity by more than five percent to one or more existing or potential customers. In the case of transmission property, an increase in capacity is determined based on the increase in the capacity of the hydraulic subsystem, measured in terms of millions of cubic feet per day. In the case of distribution property, an increase in capacity is determined based on the increase in the throughput of gas to one or more existing or potential customers served or to be served by the added or replaced property, measured in terms of thousands of cubic feet per hour. For purposes of section 5.05(1)(b) of this revenue procedure, an increase in capacity does not include amounts paid to return linear property to its original capacity prior to any wear, tear, or other damage necessitating such expenditure.

(b) Taxpayer's purpose. A taxpayer is not required to capitalize costs that materially increase capacity to linear property under section 5.05(2)(a) of this revenue procedure if the taxpayer can establish with reasonable certainty, through its books and

records, that the principal purpose of an addition or replacement of linear property was for safety reasons, to standardize its system, or to comply with regulatory requirements, unrelated to increasing capacity. However, these costs may be subject to capitalization under sections 5.02, 5.03, or 5.07 of this revenue procedure or other per se capitalization rules under this section 5.05.

(3) Property that extends a system. For purposes of applying section 5.05(1)(d) of this revenue procedure, the cost of property that extends a transmission or distribution system does not include the cost of additional linear property required to relocate or replace an existing line that will continue to run between the same two endpoints. However, if more than 10 percent of the length of the original unit of property is replaced, in the case of a replacement of linear transmission property, the costs of the replacement must be capitalized under section 5.02(2) of this revenue procedure. If more than four miles of distribution mains is replaced, in the case of a replacement of distribution mains, the cost of the replacement must be capitalized under section 5.03(2) of this revenue procedure.

(4) Special rule for identified distribution service line costs associated with distribution mains. If the taxpayer can identify with reasonable accuracy distribution service line costs associated with distribution main costs that are treated as per se capital expenditures under this section 5.05, then the identified distribution service line costs are also treated as per se capital expenditures under this section 5.05. For rules regarding identified and unidentified distribution service line costs, see section 5.07 of this revenue procedure.

(5) Coordination with other rules. Replacements of property for which the

replacement costs are per se capital expenditures under this section 5.05 are not taken into account in determining whether more than 10 percent of the length of the unit of linear transmission property is replaced for purposes of applying section 5.02 of this revenue procedure, or in determining whether more than four miles of distribution mains are replaced for purposes of section 5.03 of this revenue procedure.

(6) Examples. The following examples illustrate the application of this section 5.05. In each example, it is assumed that (a) the taxpayer is a corporation and files its Federal income tax return on an accrual method and a calendar year basis, (b) the taxpayer uses the safe harbor method for linear property and the safe harbor method for non-linear property for all its natural gas transmission and distribution property, and (c) the taxpayer does not make an election under § 1.168(i)-1(e)(3)(ii) (disposition of all assets remaining in a general asset account) or § 1.168(i)-1(e)(3)(iii) (disposition of an asset in a qualifying disposition). In addition, for the following examples, it is assumed that none of the aggregation requirements of section 5.06 of this revenue procedure apply.

(a) Example 1. (i) Z is a local natural gas distribution company that supplies gas to an industrial customer via a three-inch diameter distribution service line. Due to planned expansion of its facility, the customer will require more gas than can be supplied via the existing line. Z's records include correspondence with the customer indicating that Z agreed to install a second three-inch distribution service line and a second meter to meet the customer's need for additional gas at its facility. As a result of Z's installation of a second three-inch distribution service line, throughput of gas to the customer is increased by 100 percent.

(ii) The cost of installing the second distribution service line is a per se capital expenditure under section 5.05(1)(b) of this revenue procedure because it increases Z's capacity to its customer by more than five percent and Z's records reflect that the distribution service line is added for the principal purpose of increasing capacity to Z's customer. The cost of installing a second meter must be capitalized under the per se capitalization rule in section 5.05(1)(c) of this revenue procedure because the new meter is an addition of a unit of non-linear property defined in section 2.04 of Appendix A.

(b) Example 2. Y is a natural gas transmission company that owns and operates a natural gas transmission pipeline that is 300 miles in length. Section A of this pipeline runs for 80 miles between two compressor stations, and is a hydraulic subsystem that is a unit of property. The pipe in Section A is 12 inches in diameter, except for a seven-mile segment that is 10 inches in diameter. Y incurs costs to replace the seven-mile 10-inch segment with 12-inch pipe in order to increase the capacity of Section A. As a result of the replacement, the capacity of Section A to Y's customers, as measured in terms of millions of cubic feet of gas per day, increased by more than five percent. In addition, Y's records do not specifically indicate a principal purpose for replacing the seven-mile segment. Accordingly, the cost of replacing the existing 10-inch transmission line with the larger 12-inch transmission line must be capitalized as a per se capital expenditure under section 5.05(1)(b) of this revenue procedure.

(c) Example 3. X is a natural gas transmission company that owns and operates a natural gas transmission pipeline that is 300 miles in length. Section B of this transmission pipeline runs for 80 miles between two compressor stations and is a

hydraulic subsystem that is a unit of property. The pipe in Section B is 10 inches in diameter. X replaces seven miles of Section B with 12-inch pipe. As a result of the replacement, the capacity of Section B to X's customers, as measured in terms of millions of cubic feet of gas per day, increased by two percent. Because the replacement did not result in an increase in Section B's capacity by more than five percent, the cost of replacing the seven miles of pipe is not a per se capital expenditure under section 5.05(1)(b) of this revenue procedure and, because less than 10 percent of Section B (7 miles out of 80 miles = 8.8 percent) is replaced, the cost is not required to be capitalized under section 5.02(2) of this revenue procedure.

(d) Example 4. (i) W is a local natural gas distribution company that supplies gas to a group of existing customers via an older three-inch diameter distribution main and individual distribution service lines. Pursuant to regulatory requirements, W performs regular safety risk assessments that take into account the age and composition of the pipeline at various locations. Based on this safety assessment, W determines it is necessary to replace three miles of distribution mains. The distribution main is replaced with four-inch diameter pipe, which is one of the standard sizes currently used by W for all distribution main replacements. W's books and records indicate that the principal purpose of the replacement was the result of the safety risk assessment. W can identify with reasonable accuracy the distribution service line costs that are associated with the distribution mains replacement.

(ii) Pursuant to section 5.05(2)(b) of this revenue procedure, the cost to replace the distribution main is not a per se capital expenditure under section 5.05(1)(b) of this revenue procedure because the taxpayer's books and records indicate that the principal

purpose of the distribution main replacement was to reduce safety risk. Additionally, because the length of the distribution main replacement is less than four miles, the cost of the distribution main replacement is not required to be capitalized under section 5.03(2) of this revenue procedure. Similarly, because W can identify the costs of replacing the distribution service lines with the distribution main replacement, the cost of replacing the associated distribution service lines is not a per se capital expenditure under section 5.05(1)(b) of this revenue procedure and is not required to be capitalized under section 5.07(2)(b)(ii) of this revenue procedure.

(e) Example 5. (i) V is a local natural gas distribution company that supplies natural gas to a group of existing customers at the edge of its service area via three miles of three-inch diameter distribution main, and individual distribution service lines. V's records reflect that certain customers were experiencing gas delivery issues. Consequently, V replaces the entire three-mile segment with four-inch diameter pipe, as well as the associated service lines. V's books and records do not indicate any principal purpose of replacing the three-mile segment of distribution main other than to address its customer's gas delivery issues. V's replacement of the three-mile segment of distribution main increased the throughput of gas to its existing customers by seven percent.

(ii) Because the replacement of the distribution main results in an increase in the throughput of gas to the customers served by the distribution main of more than five percent, the cost to replace the three miles of distribution mains is a per se capital expenditure under section 5.05(1)(b) of this revenue procedure. Additionally, because the cost of the distribution main replacement is a per se capital expenditure, the cost of

replacing the associated distribution service lines is a per se capital expenditure under sections 5.05(4) and 5.07(2)(a) of this revenue procedure.

(f) Example 6. (i) U is a local natural gas distribution company that owns and operates 160 miles of distribution mains. U's distribution mains currently include one-, two-, three-, and four-inch diameter pipe. The diameters and materials vary depending on the year of installation. U is currently standardizing its distribution mains by using pipe in two-inch and four-inch diameters. Any distribution main pipe that is replaced is replaced with one of these two standard sizes. U replaces 875 feet of three-inch diameter pipe with four-inch diameter pipe, which had the effect of increasing its throughput to one or more existing or potential customers by more than five percent. U's books and records indicate that its use of the larger diameter pipe was necessary to standardize its system with currently available sizes of pipe.

(ii) Because U's books and records indicate that the replacement is made to standardize its system, pursuant to section 5.05(2)(b) of this revenue procedure, the cost of the replacement is not a per se capital expenditure under section 5.05(1)(b) of this revenue procedure. Finally, because less than four miles of the distribution main pipe is replaced, the cost of the replacement is not required to be capitalized under section 5.03(2) of this revenue procedure.

(g) Example 7. (i) T is a local natural gas distribution company that owns and operates 160 miles of natural gas distribution mains. T's distribution mains include iron pipe and polyethylene pipe. T is currently using polyethylene pipe when it needs to replace pipe in its distribution mains because it considers polyethylene pipe to be better pipe for several reasons. T replaces three miles of four-inch diameter iron pipe in its

distribution mains with four-inch diameter polyethylene pipe. There is no change in the throughput of gas to customers served by the distribution main as a result of this replacement.

(ii) The cost of the replacement is not a per se capital expenditure under section 5.05(1)(b) of this revenue procedure because the replacement does not materially increase capacity to one or more existing or potential customers. Additionally, because the distribution main replacement is for four miles or less, the cost of the replacement is not required to be capitalized under section 5.03(2) of this revenue procedure.

(h) Example 8. S, a local natural gas distribution company, is required to relocate a distribution main to accommodate construction of a road. In order to reroute its distribution main around the construction site, S replaces one mile of pipe and also adds 1,000 feet of pipe to the distribution system. Notwithstanding the addition of pipe to the distribution system, the cost of the relocation is not a per se capital expenditure under section 5.05(1)(d) of this revenue procedure because the pipeline continues to run between the same two endpoints. Additionally, the cost of the relocation is not required to be capitalized under section 5.03(2) of this revenue procedure because the replacement of distribution main pipe is four miles or less.

.06 Aggregation requirements.

(1) General rule. For purposes of determining whether the applicable thresholds for capitalization of property provided in sections 5.02, 5.03, and 5.04 of this revenue procedure are met, a taxpayer must aggregate multiple replacements if all of the following requirements are met:

(a) The replacements are within –

(i) the same unit of property, for non-linear property and linear transmission property, or

(ii) the same five-digit United States Postal Service ZIP Code delivery area, for linear distribution property;

(b) The replacements are described in one authorizing document, as defined in section 5.06(2) of this revenue procedure; and

(c) The authorizing document –

(i) identifies the property with respect to which the replacements will occur or the locations where property will be replaced;

(ii) identifies the amount of pipe to be replaced, or total cost of the replacements; and

(iii) provides that the replacements are expected to be completed within five years after the date of the authorizing document. If the authorizing document does not provide a time period over which replacements will be completed, this requirement will be considered to be met unless it is determined upon original authorization that it will take more than five years to complete the replacements.

(2) Authorizing document.

(a) For purposes of this section 5.05 of this revenue procedure, the term "authorizing document" means the following:

(i) a regulatory commission decision that requires replacements as part of an identified program aimed at a specific purpose;

(ii) a written project authorization aimed at a specific purpose;

(iii) a work order as defined under section 4.08 of this revenue procedure; or

(iv) a blanket work order as defined under section 4.09 of this revenue procedure and which is aimed at a specific purpose.

(b) A regulatory commission decision does not include a decision, whether or not designated as an "order," that authorizes expenditures for replacements but does not require replacements to be made.

(3) General and specific authorizing documents. If replacements are described by a general authorizing document as well as one or more specific authorizing documents (for example, a regulatory commission decision and a written project authorization implementing the regulatory commission decision), aggregation is based on the most general authorizing document that meets the requirements of section 5.06(1)(c) of this revenue procedure. For example, if a general authorizing document provides that replacements are not expected to be completed within five years of this authorizing document, then aggregation of the replacements pursuant to this authorizing document is not required. However, if a subsequent more specific authorizing document implementing that same program or project provides that certain replacements are expected to be completed within five years of this subsequent authorizing document, then aggregation of the replacements described in the subsequent authorizing document is required, provided that the other requirements described in section 5.06(1) of this revenue procedure are met.

(4) Aggregation of replacements across multiple years. Multiple replacements that meet the requirements described in section 5.06(1) of this revenue procedure are aggregated without regard to whether they are performed in one year or multiple years.

(5) Modifications. Modifications to an authorizing document, or to the work done pursuant to an authorizing document, that occur within the taxable year are taken into account in determining whether to aggregate replacements, and whether to capitalize the expenditures, in that taxable year, but do not affect the aggregation of replacements pursuant to that authorizing document in a prior taxable year.

(6) Anti-abuse rule. If a taxpayer acts (a) to divide closely related transmission or distribution property replacement projects into multiple written project authorizations, work orders, or blanket work orders or (b) to mischaracterize the intended or expected scope of a project, in order to avoid the application of the aggregation rules under this section 5.06, rather than for non-tax business reasons, appropriate adjustments will be made by the Commissioner to carry out the purposes of this revenue procedure.

(7) Examples. The following examples illustrate the application of this section 5.06. In each example, it is assumed that (a) the taxpayer is a corporation and files its Federal income tax return on an accrual method and a calendar year basis, (b) the taxpayer uses the safe harbor method for linear property and the safe harbor method for non-linear property for all its natural gas transmission and distribution property, and (c) the taxpayer does not make an election under § 1.168(i)-1(e)(3)(ii) (disposition of all assets remaining in a general asset account) or § 1.168(i)-1(e)(3)(iii) (disposition of an asset in a qualifying disposition).

(a) Example 1. (i) R is a natural gas distribution company in State A. The Public Utility Commission (Regulator) of State A sets the rates and approves tariffs for R. Regulator issues Rate Order 12345 as a result of certain rate proceedings. Rate Order 12345 allows for the incremental recovery of up to an additional $30 million annually in

revenue through rates and tariffs. Rate Order 12345 states that these dollars are for the recovery of incremental operating expense, maintenance expense, and return on investment related to the replacement of distribution mains in its natural gas distribution system; however, no specific replacements are required, and Rate Order 12345 does not provide a time period over which replacements will be completed. R makes annual filings documenting such costs, which match revenue billed to incremental expense and include R's allowed return on investment. The specific distribution main replacements are determined by R based on known conditions and risk analysis.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.03 of this revenue procedure, aggregation of pipeline replacements is not required under this section 5.06 because Rate Order 12345 (A) does not identify a program aimed at a specific purpose for the replacements; (B) does not require specific replacements to be made; (C) does not identify the property with respect to which the replacements will occur or the locations for the replacements; (D) does not identify the amount of pipe or the total cost of the replacements; and (E) does not specify that the replacements are within the same Zip Code. All these criteria must be satisfied for the aggregation requirement of this section 5.06 to apply to replacements performed under Rate Order 12345.

(b) Example 2. Q is a local natural gas distribution company. Based on estimated general maintenance and upgrade costs and anticipated revenues through its rates and tariffs, Q budgets $100 million during Year 1 for replacements within its distribution system. For purposes of determining whether the distribution main replacement costs are capitalized under section 5.03 of this revenue procedure, an

aggregation of pipeline replacements is not required under this section 5.06 because Q's budget document is not a written project authorization aimed at a specific purpose.

(c) Example 3. P is a local natural gas distribution company. P issues a blanket work order for replacements of less than 2,000 feet of distribution mains. The blanket work order is used predominantly for the repair of leaks, but does not establish a project aimed at a specific purpose. P performs several replacements under the blanket work order to repair leaks. For purposes of determining whether the replacement costs are capitalized under section 5.03 of this revenue procedure, an aggregation of distribution main replacements under the blanket work order is not required under this section 5.06 because the blanket work order is not an authorizing document under section 5.06(2) of this revenue procedure.

(d) Example 4. (i) O is a natural gas distribution company in State B. Following an explosion near a population center in State B that may be attributable to Type L pipe deteriorating faster than anticipated, Regulator issues an order in Year 1 requiring all Type L pipe used in the transmission or distribution of natural gas or other combustible material in State B to be replaced within five years to eliminate a safety risk to State B citizens. The order also specifies procedures for applying for a special tariff to support replacements of Type L pipe. In response to this order, O's management instructs its engineering department to initiate a project to identify all Type L pipe in its distribution system in State B. O issues a written project authorization that will involve a review of its purchases of Type L pipe, physical identification of the pipe, and inspection of sections of pipeline. As the locations of Type L pipe are identified, O prepares work orders to replace the Type L pipe. In one ZIP Code delivery area, O identifies six

sections of Type L distribution mains, totaling eight miles, and each of these sections are replaced under six separate work orders, as they are identified. Each work order identifies the location and the amount of the distribution mains to be replaced. Each work order is for a replacement of less than four miles of distribution mains.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.03 of this revenue procedure, the replacements are not aggregated under this section 5.06 under the Regulator's order because, although the order is an authorizing document within the meaning of section 5.06(2) of this revenue procedure, the order does not identify the amount or costs of the distribution mains to be replaced, as required by section 5.06(1)(c)(ii) of this revenue procedure. Similarly, the replacements are not aggregated under the written project authorization issued by O because the authorization does not identify the amount or the costs of the distribution mains to be replaced. See section 5.06(1)(c)(ii) of this revenue procedure. Rather, each of the six work orders qualify as separate authorizing documents under section 5.06(2) of this revenue procedure and provides the information required in section 5.06(1)(c). Because neither the Regulator's order nor the written project authorization meets the requirements for aggregation under this section 5.06, and each work order constitutes a separate authorizing document for the replacement of less than four miles of distribution mains, the costs of the replacements are not required to be capitalized under section 5.03 of this revenue procedure.

(e) Example 5. (i) The facts are the same as in Example 4, except that in response to the Regulator's order, in Year 1, O's management issues a written project authorization for the replacement of all Type L pipe in County Z in State B, identifying

the quantity and location of all Type L pipe in County Z, and authorizing $2 million for this purpose. County Z falls within two ZIP Code delivery areas, Area F and Area G. The project authorization does not provide a time period in which the replacements will be completed but there is no reason to expect that the project will take longer than five years.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.03 of this revenue procedure, the replacements are aggregated under this section 5.06 pursuant to O's written project authorization, which authorizes the replacement of distribution mains for a specific purpose and identifies the location of the replacements and the amount of distribution mains to be replaced. Accordingly, for each of the ZIP Code delivery areas affected by the written project authorization, replacements within that ZIP Code delivery area that are covered by the written project authorization are aggregated, even though the replacements may be noncontiguous, may occur over more than a single year, and may involve several work orders. The aggregate replacements in Area F total seven miles, and the aggregate replacements in Area G total three miles. Accordingly, under section 5.03 of this revenue procedure, the replacement costs of distribution mains in Area F are capitalized and the replacement costs of distribution mains in Area G are not required to be capitalized.

(f) Example 6. (i) The facts are the same as in Example 4 except O knows that it also has Type L pipe in its distribution systems in State Y. In response to Regulator's order, O issues a written project authorization authorizing its crews in State Y to replace all Type L pipe that is more than 10 years old as Type L pipe is encountered in the normal course of operations. It is reasonable to expect that the replacements under this

project authorization would not be completed within five years. During Year 2, O exceeds its capital maintenance budget in State Y by $1 million. A review of the work orders charged to the project authorization during Year 2 indicates that O spent $2 million on replacing 12 miles of functional Type L distribution mains. One work order authorized the replacement of six miles of distribution mains at different locations within ZIP Code delivery Area H at a cost of $ 1.2 million. The remaining three work orders each authorized the replacement of two miles of distribution mains at different locations within ZIP Code delivery Area J.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.03 of this revenue procedure, the replacements of Type L distribution mains in State Y in Year 2 are not aggregated under this section 5.06 under O's written project authorization, because the written project authorization does not specify the amount of mains or the total cost of replacements, or the period over which the replacements are to occur and it is reasonable to expect that the replacements will not be completed within five years. However, the replacement of six miles of distribution mains pursuant to the work order charged in Year 2 authorizing the replacement of six miles of distribution mains at specified locations within ZIP Code delivery Area H is aggregated under this section 5.06 because this work order meets the requirements of section 5.06(1) of this revenue procedure and constitutes an authorizing document. See section 5.06(3) of this revenue procedure. Although the other three work orders are for replacements of distribution mains within the same ZIP Code delivery area, these work orders are not aggregated because they constitute separate authorizing documents. Because each of these three work orders is for the replacement of less

than four miles of distribution mains, the costs of these distribution main replacements are not required to be capitalized under section 5.03 of this revenue procedure.

(g) Example 7. (i) M is a natural gas distribution company. M budgets $10 million for the replacement of distribution mains that run through subdivisions A and B, which are in ZIP code delivery area H. The budget directs the work to be done through a written project authorization, which is issued in Year 1. The work under the written project authorization is reasonably expected to be completed in late Year 2 or early Year 3. The priority of replacements will be determined based on risk assessments, but the written project authorization calls for the eventual replacement of five miles of distribution mains in ZIP code delivery area H.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.03 of this revenue procedure, aggregation is not required by the general budget because the budget does not qualify as an authorizing document under section 5.06(2) of this revenue procedure. However, the replacements done pursuant to the written project authorization are aggregated under this section 5.06 because the document is aimed at a specific purpose, authorizes the replacement of a known amount of distribution mains in a certain location and, although it does not specify the time period over which replacements will be completed, there is no reason to expect that completing the replacements will take longer than five years. Because the aggregate replacements of distribution mains within ZIP Code area H total more than four miles, the costs to replace the five miles of distribution mains are capitalized under section 5.03 of this revenue procedure.

(h) Example 8. (i) L is a natural gas transmission company that operates a

natural gas transmission line in State C. In Year 1, L conducts an internal inspection of a 100-mile section of the transmission line, a hydraulic subsystem that is a separate unit of property under section 5.02(1) of this revenue procedure. An analysis of the survey indicates that 11 miles (11 percent) of the pipe in this section should be removed and replaced due to deterioration. In a written project authorization issued in January of Year 1, L's management authorized $22 million to replace the 11 miles of pipe and directed that the work commence as soon as practicable. The project is expected to be completed in Year 1. Based on a study of actual deterioration in removed pipe versus the deterioration shown by the inspection device, L's engineers determine in November of Year 1 that the replacement of only nine miles (9 percent) is warranted. The replacement of the nine miles, which was performed under two separate work orders, is completed in December of Year 1.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.02 of this revenue procedure, the replacements are required to be aggregated under this section 5.06 pursuant to the January, Year 1, authorization, which meets the requirements of section 5.06(1) and (2) of this revenue procedure. Under section 5.06(5) of this revenue procedure, the aggregation determination is based on the status of the written project authorization and the work done, or to be done, at the end of each taxable year. As of the end of Year 1, it was known that only nine miles of the transmission line were replaced. Because the aggregated replacements total less than 10 percent of the unit of linear transmission property, the cost of the replacements is not required to be capitalized under section 5.02 of this revenue procedure.

(i) Example 9. (i) The facts are the same as in Example 8, except that the January Year 1 project authorization required the replacement of only nine miles (9 percent) of L's 100-mile hydraulic subsystem. In November of Year 1, L's engineers then determined that a total of 11 miles (11 percent) had to be replaced, and the replacement of 11 miles was completed in December of Year 1.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.02 of this revenue procedure, the replacement work is aggregated pursuant to the January Year 1 project authorization, which meets the requirements of section 5.06(1) and (2) of this revenue procedure. Under section 5.06(5) of this revenue procedure, the aggregation determination is based on the status of the written project authorization and the work done, or to be done, at the end of each taxable year. It was known as of the end of Year 1 that more than 10 percent of the unit of property was replaced, as aggregated under this section 5.06 pursuant to the January Year 1 project authorization. Accordingly, the cost of the replacements in Year 1 must be capitalized under section 5.02 of this revenue procedure.

(j) Example 10. (i) The facts are the same as in Example 8, except that when the January Year 1 written project authorization is issued, L's management expects that the work will not be completed until Year 3. The work commences in Year 1 and continues in Years 2 and 3. In Year 3, based on a study of actual deterioration in removed pipe versus that shown by the inspection device, L's engineers determine that the replacement of only nine miles (9 percent) of the 100-mile section is warranted, rather than the 11 miles (11 percent) originally anticipated. In December of Year 3, L's engineers issue the final work order, authorizing the replacement of two additional miles

of pipe, and the work is completed. In aggregate, only nine total miles of pipe are replaced under the written project authorization.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.02 of this revenue procedure, the replacement work expected to be performed in Year 1, Year 2, and Year 3 is aggregated pursuant to the January Year 1 project authorization, which meets the requirements of sections 5.06(1) and (2) of this revenue procedure. Because the replacement of more than 10 percent of the unit of property was authorized in January of Year 1, the costs of the replacements that are incurred in Year 1 and Year 2 are capitalized. Under section 5.06(5) of this revenue procedure, the aggregation determination is based on the status of the written project authorization and the work done, or to be done, as of the close of each taxable year, and modifications do not affect the aggregation of replacements in prior taxable years. Therefore, the fact that only a total of nine miles (nine percent of the 100-mile unit of property) was eventually replaced does not affect the tax treatment of the replacement costs incurred in Year 1 and Year 2. However, the costs incurred in Year 3 are not required to be capitalized because, at the end of Year 3, L knows that only nine percent of the unit of property was replaced under the Year 1 project authorization.

(k) Example 11. (i) The facts are the same as in Example 10, except that pursuant to L's initial survey, the January Year 1 written project authorization requires the replacement of only nine miles of pipe (nine percent of the 100-mile unit of property). Eight miles are replaced in Years 1 and 2. In Year 3, L's engineers determine that five additional miles of pipe should be replaced for a total of 13 miles and request that management modify the project and authorize additional funds to complete

the 13-mile replacement. The project authorization is modified accordingly, and replacement of the remaining five miles is completed by December of Year 3.

(ii) For purposes of determining whether the replacement costs are capitalized under section 5.02 of this revenue procedure, the costs of the replacements expected to be performed in Years 1 through 3 were aggregated under this section 5.06 pursuant to the Year 1 project authorization, which meets the requirements of sections 5.06(1) and (2). Under section 5.06(5) of this revenue procedure, the aggregation determination was based on the status of the written project authorization and the work done, or to be done, as of the close of each taxable year, and modifications would not affect the aggregation of replacements in prior taxable years. Accordingly, the costs incurred in Years 1 and 2 are not required to be capitalized because, as of the end of each of those taxable years, the total replacements required by the project authorization were not expected to exceed 10 percent of the unit of property. Pursuant to section 5.06(5) of this revenue procedure, however, the cost of the five miles replaced in Year 3 is required to be capitalized, because, as of the end of Year 3, it was known that a total of 13 miles (13 percent of the unit of property) were replaced pursuant to the Year 1 project authorization.

.07 Safe harbor method for linear property – rules for distribution service line costs.

(1) In general. A taxpayer using the safe harbor method for linear property must determine the amount of distribution service line costs that must be capitalized using the rules described in sections 5.07(2) and 5.07(3) of this revenue procedure. The rules in section 5.07(2) of this revenue procedure determine the treatment of distribution service line costs that a taxpayer can identify with reasonable accuracy as paid or incurred for a

project described in section 5.07(2) of this revenue procedure. The rules in section 5.07(3) of this revenue procedure determine the treatment of distribution service line costs that the taxpayer is unable to identify with reasonable accuracy as paid or incurred for a project described in section 5.07(2) of this revenue procedure.

(2) Rules for identified distribution service line costs. To the extent that a taxpayer can identify, with reasonable accuracy, distribution service line costs, the following treatment applies to the identified costs:

(a) Identified costs that are per se capital expenditures. Identified distribution service line costs that are per se capital expenditures described under section 5.05 of this revenue procedure, including distribution service line costs associated with distribution main costs that are per se capital expenditures described under section 5.05 of this revenue procedure, are required to be capitalized.

(b) Identified costs other than per se capital expenditures.

(i) Identified distribution service line costs, other than per se capital expenditures described in section 5.07(2)(a) of this revenue procedure, associated with distribution main replacements that are required to be capitalized under section 5.03(2) of this revenue procedure (that is, associated with distribution main replacements that are more than four miles), are required to be capitalized;

(ii) Identified distribution service line costs, other than per se capital expenditures described in section 5.07(2)(a) of this revenue procedure, associated with distribution main replacements that are not required to be capitalized under section 5.03(2) of this revenue procedure (that is, associated with distribution main replacements that are four miles or less), are not required to be capitalized; and

(iii) Identified distribution service line costs, other than per se capital expenditures described in section 5.07(2)(a) of this revenue procedure, not associated with distribution main replacements (for example, the replacement of a customer's service line only) are not required to be capitalized.

(3) Simplified rules for unidentified distribution service line costs. To the extent a taxpayer cannot identify distribution service line costs with reasonable accuracy as provided under section 5.07(2) of this revenue procedure, the simplified rules in this section 5.07(3) apply to determine the amount of such costs to be capitalized under §§ 263(a) and 263A. Step 1 determines the total amount of unidentified distribution service line costs. Steps 2 through 4 determine the capitalization ratio that applies to such costs. In Step 5, the taxpayer multiplies the total amount of unidentified distribution line costs determined in Step 1 by the capitalization ratio to determine the amount of its unidentified distribution service line costs that are required to be capitalized.

(a) Step 1. Determine total unidentified distribution service line costs. To determine the total unidentified distribution service line costs, the taxpayer's total distribution service line costs for the taxable year are reduced by the identified distribution service line costs described in section 5.07(2) of this revenue procedure.

(b) Step 2. Determine total distribution main replacement costs not associated with identified distribution service line costs (denominator of capitalization ratio). To determine the total distribution main replacement costs not associated with identified distribution service line costs for purposes of the denominator in the capitalization ratio, the taxpayer's total distribution main replacement costs, including distribution main

replacement costs qualifying under the de minimis rule for blanket orders under section 5.03(3)(b) of this revenue procedure, paid or incurred in the taxable year are decreased by the following:

(i) Distribution main replacement costs that are required to be capitalized as per se capital expenditures under section 5.05 of this revenue procedure;

(ii) Distribution main replacement costs associated with identified distribution service line costs required to be capitalized under section 5.07(2)(b)(i) of this revenue procedure; and

(iii) Distribution main replacement costs associated with identified distribution service line costs not required to be capitalized under section 5.07(2)(b)(ii) of this revenue procedure.

(c) Step 3. Determine capitalized distribution main replacement costs not associated with identified distribution service line costs (numerator of capitalization ratio). To determine the capitalized distribution main replacement costs not associated with identified distribution service line costs for purposes of the numerator in the capitalization ratio, the taxpayer's total costs of distribution main replacements that are required to be capitalized under section 5.03(2) of this revenue procedure are decreased by any amount of distribution main replacement costs associated with identified distribution service line costs required to be capitalized under section 5.07(2)(b)(i) of this revenue procedure (the amount determined in section 5.07(3)(b)(ii) of this revenue procedure).

(d) Step 4. Determine capitalization ratio. To determine the capitalization ratio, divide the taxpayer's capitalized distribution main replacement costs not associated with

identified distribution service line costs that were capitalized, as determined under Step 3, by the taxpayer's total distribution main replacement costs not associated with distribution service line costs, as determined under Step 2.

(e) Step 5. Determine the portion of unidentified distribution service line costs that must be capitalized. To determine the portion of unidentified distribution service line costs that must be capitalized, multiply the taxpayer's capitalization ratio, as determined under Step 4, by the taxpayer's total unidentified distribution service line costs determined under Step 1.

(f) Formula. The following formula reflects the rule provided in this section 5.07(3):

$$\text{Total unidentified distribution service line costs (Step 1)} \times \underbrace{\left[\frac{\text{Capitalized distribution main replacement costs not associated with identified distribution service line costs (Step 3)}}{\text{Total distribution main replacement costs not associated with identified distribution service line costs (Step 2)}}\right]}_{\text{Capitalization ratio (Step 4)}} = \text{Capitalized unidentified distribution service line costs (Step 5)}$$

(4) Example.

(a) Facts. K is a corporation that operates a natural gas distribution system in State D. K files its Federal income tax return on an accrual method and a calendar year basis and uses the NGSH Method. K uses work orders and blanket work orders to authorize replacement and repair work on its distribution system. K's work orders detail the scope of each individual project and capture direct and indirect costs for labor,

construction, and materials. K's work orders for the replacement of distribution mains identify the distribution service lines that are replaced in conjunction with these distribution main replacements.

In Year 1, K incurs costs of $9 million with respect to replacements of linear distribution property. Of this amount, K incurs $8 million for replacements of distribution mains (including $1 million in distribution main replacement costs qualifying under the de minimis rule for blanket work orders), and K incurs $1 million for distribution service lines costs. Of the $1 million K incurs for work on distribution service lines, K incurs $150,000 for distribution service line costs that are per se capital expenditures, including distribution service line costs associated with distribution mains, the costs of which are per se capital expenditures. K incurs $60,000 for distribution service line costs that are capitalized under the NGSH Method because they are associated with distribution main replacements of more than four miles, and K incurs $140,000 for distribution service line costs that are not required to be capitalized under the NGSH Method because they are associated with distribution main replacements of four miles or less. K also incurs $100,000 for distribution service line costs, other than per se capital expenditures, not associated with distribution main replacements. Of the $8 million K incurs for replacement of distribution mains, K incurs $2 million for per se capital expenditures related to distribution mains, $1.5 million for distribution main replacements exceeding four miles, and $3.5 million for distribution main replacements of four miles or less. K can associate $600,000 of the $1.5 million K incurs for distribution main replacements exceeding four miles with identified distribution service line costs that are capitalized under section 5.07(2)(b)(i) of this revenue procedure. K

can also associate $2.5 million of the $3.5 million K incurs for distribution main replacements of four miles or less with identified distribution service line costs that are not required to be capitalized under section 5.07(2)(b)(ii) of this revenue procedure.

(b) Step 1. To determine its total unidentified distribution service line costs, K begins with the $1 million it incurs for its work on distribution service lines for Year 1 and subtracts its identified distribution service line costs for Year 1. These identified distribution service lines costs are the sum of (i) $150,000, K's distribution service line costs that are per se capital expenditures under section 5.07(2)(a) of this revenue procedure, (ii) $60,000, K's distribution service line costs that are capitalized under section 5.07(2)(b)(i) of this revenue procedure because they are associated with distribution main replacements of more than four miles, (iii) $140,000, K's distribution service line costs that are not capitalized under section 5.07(2)(b)(ii) of this revenue procedure because they are associated with distribution main replacements of four miles or less, and (iv) $100,000, K's distribution service line costs that are identified under section 5.07(2)(b)(iii) of this revenue procedure as not associated with any distribution main replacements. Thus, K's total identified distribution service line costs equals $450,000 ($150,000 + $60,000 + $140,000 + $100,000). K subtracts the total identified distribution service line costs of $450,000 from the total distribution service line costs it incurs for the taxable year of $1 million. The net result of $550,000 ($1 million – $450,000) is the total unidentified distribution service line costs.

(c) Step 2. K then determines the total distribution main replacement costs not associated with identified distribution service line costs by taking the total costs incurred in Year 1 with respect to distribution main replacement property of $8 million (which

includes the $1,000,000 for expenditures of less than $50,000 on blanket work orders qualifying under the de minimis rule) and decreasing these costs by (i) $2 million, the distribution main replacement costs that are per se capital expenditures under section 5.05 of this revenue procedure; (ii) $600,000, the distribution main replacements costs associated with identified distribution service line costs that are capitalized under section 5.07(2)(b)(i) of this revenue procedure; and (iii) $2.5 million, the distribution main replacements costs associated with identified distribution service line costs that are not required to be capitalized under section 5.07(2)(b)(ii) of this revenue procedure. The net result of $2.9 million ($8 million – ($2 million + $600,000 + $2.5 million)) comprises the total distribution main replacement costs not associated with identified distribution service line costs.

(d) Step 3. Next, K determines the total costs of distribution main replacements that are capitalized under section 5.03(2) of this revenue procedure to be $1.5 million because such costs are for distribution main replacements over four miles. Then, K reduces this amount by $600,000, the distribution main replacement costs associated with identified distribution service line costs that are capitalized under section 5.07(2)(b)(i) of this revenue procedure. The difference, $900,000, represents the total capitalized costs of distribution main replacements that were not associated with identified service line costs.

(e) Step 4. K then determines the capitalization ratio to be applied to its total unidentified distribution service line costs by dividing the total capitalized cost of distribution main replacements that are not associated with identified distribution service line costs of $900,000 by the total costs of distribution main replacements that are not

associated with distribution service line costs of $2.9 million. The quotient of 0.31 ($900,000 / $2.9 million) is the capitalization ratio.

(f) Step 5. Finally, K determines the unidentified distribution service line costs that must be capitalized by multiplying the capitalization ratio of 0.31 by the total unidentified service line costs of $550,000. The product of $170,500 (0.31 x $550,000) is the unidentified distribution service line costs that must be capitalized.

.08 General asset accounts and transition rules.

(1) Requirement to use general asset accounts. A taxpayer using the NGSH Method must make a general asset account election under § 168(i)(4) and § 1.168(i)-1(l) to include in general asset accounts certain natural gas transmission and distribution property that is MACRS property, as defined in § 1.168(b)-1(a)(2). The following property must be included in general asset accounts:

(a) Certain property placed in service in or after year of change. Natural gas transmission and distribution property that is capitalized under the NGSH Method, that is MACRS property, and that is placed in service by the taxpayer in or after the taxable year for which the taxpayer adopts or changes to the NGSH Method. See § 1.168(i)-1(l) for time and manner of making a general asset account election for such property; and

(b) Certain property placed in service before year of change. Natural gas transmission and distribution property described in section 5.08(2)(a) of this revenue procedure. See section 5.08(2) of this revenue procedure for the application of general asset accounts to this property.

(2) Late general asset election required for certain property placed in service before year of change.

(a) In general. A taxpayer that changes to the NGSH Method must change its method of accounting to the NGSH Method on either a cut-off basis, as permitted under section 6.04 of this revenue procedure, or with a § 481(a) adjustment as described in sections 6.01, 6.02, and 6.03 of this revenue procedure. A taxpayer that changes to the NGSH Method of accounting with a cut-off or § 481(a) adjustment must also make a late general asset account election under § 168(i)(4) and § 1.168(i)-1(l) to include certain transmission and distribution property in general asset accounts. Specifically, for property for which the taxpayer did not make a general asset account election (as defined in section 5.08(2)(d) of this revenue procedure), the taxpayer must make a late general asset account election to include in general asset accounts certain MACRS property placed in service by the taxpayer in taxable years prior to the year of change and owned by the taxpayer at the beginning of the year of change, as follows:

(i) Change made in taxpayer's first, second, or third taxable years with a § 481(a) adjustment. If a taxpayer changes to the NGSH Method for the taxpayer's first, second, or third taxable year ending after May 1, 2023, with a § 481(a) adjustment, the taxpayer must make a late general asset account election for linear and non-linear property, as applicable, that is described in section 5.08(2)(a) of this revenue procedure and that is capitalized under the NGSH Method as a result of this method change. See section 5.08(3)(a) of this revenue procedure for a special rule providing exceptions to certain per se capital expenditure rules applicable to a taxpayer that changes to the NGSH Method for its first taxable year ending after May 1, 2023 with a § 481(a) adjustment.

(ii) Change made in taxpayer's first, second, or third taxable years on a cut-off

basis. If a taxpayer changes to the NGSH Method for the taxpayer's first, second, or third taxable year ending after May 1, 2023 on a cut-off basis under section 6.04 of this revenue procedure, the taxpayer must make a late general asset account election for linear and non-linear property, as applicable, that is described in section 5.08(2)(a) of this revenue procedure and that was capitalized by the taxpayer under its prior method of accounting in taxable years prior to the year of change.

(iii) Change made in fourth or subsequent taxable years. If a taxpayer changes to the NGSH Method for the taxpayer's fourth taxable year ending after May 1, 2023, or for any subsequent taxable year, the taxpayer must make a late general asset account election for linear and non-linear property, as applicable, that is described in section 5.08(2)(a) of this revenue procedure, that is capitalized, or that should have been capitalized under §§ 263(a) and 263A and the corresponding regulations in taxable years prior to the year of change. See section 5.08(3)(b) of this revenue procedure for special rules applying to a taxpayer that changes in its fourth or subsequent taxable year.

(iv) Year of change. For purposes of section 5.08 of this revenue procedure, "year of change" refers to the taxable year for which the taxpayer changes to the safe harbor method for linear property, the taxable year for which the taxpayer changes to both the safe harbor method for linear property and the safe harbor method for non-linear property, or the taxable year for which the taxpayer changes to the safe harbor method for non-linear property if the taxpayer had previously changed to and continues to apply the safe harbor method for linear property.

(b) Time and manner of making late general asset account election. A taxpayer

that changes to the safe harbor method for linear property must make the late general asset account election for property described in section 5.08(2)(a) of this revenue procedure on its original Federal income tax return or information return, as applicable, for the first taxable year that the taxpayer changes to the safe harbor method for linear property. A taxpayer that changes to the safe harbor method for non-linear property must make the late general asset account election for property described in section 5.08(2)(b) of this revenue procedure on its original Federal income tax return or information return for the first taxable year that the taxpayer changes to the safe harbor method for non-linear property. The IRS will treat the making of a late general asset account election under this section 5.08(2) as a change in method of accounting under § 446(e). The manner of making this change in method of accounting is described in section 6.05 of this revenue procedure.

(c) Effect of late general asset account election. By making a late general asset account election described in this section 5.08(2) of this revenue procedure, the taxpayer consents to, and agrees to apply, all the provisions of § 1.168(i)-1 to the natural gas transmission and distribution property included in any general asset account. See § 1.168(i)-1. Accordingly, if the taxpayer's present methods of accounting are not in accord with § 1.168(i)-1, the taxpayer must change to the methods of accounting permitted under § 1.168(i)-1 no later than the first taxable year that the taxpayer uses the natural gas transmission and distribution property safe harbor method of accounting.

(d) Property for which the taxpayer did not make a general asset account election. For any property described in section 5.08(2)(a) of this revenue procedure, the

term “property for which the taxpayer did not make a general asset account election” refers to any property for which the taxpayer:

(i) Did not make a general asset account election for property in accordance with § 1.168(i)-1(l), or its predecessor § 1.168(i)-1(k);

(ii) Did not make a late general asset account election under section 6.32(1)(a)(i) of Rev. Proc. 2015-14, 2015-5 I.R.B. 450, or section 6.32(1)(a)(i) of the APPENDIX to Rev. Proc. 2011-14, 2011-4 I.R.B. 330, as modified and clarified by Rev. Proc. 2014-17, 2014-12 I.R.B. 661; or

(iii) Revoked a general asset account election pursuant to section 6.11(1)(a) of Rev. Proc. 2016-29, 2016-21 I.R.B. 880, section 6.34(1)(a) of Rev. Proc. 2015-14, or section 6.34(1)(a) of the APPENDIX to Rev. Proc. 2011-14.

(3) Special rules for certain years of change.

(a) Changes made in the taxpayer’s first taxable year with a § 481(a) adjustment—certain per se capital expenditure rules not applied in prior years. If a taxpayer changes to the safe harbor method for linear property or for both linear property and non-linear property, as applicable, for the taxpayer’s first taxable year ending after May 1, 2023 with a § 481(a) adjustment, the per se capital expenditure rules of section 5.05(1)(g) and (h) of this revenue procedure do not apply to amounts paid or incurred to replace or repair linear property or both linear property and non-linear property, as applicable, in taxable years ending on or before May 1, 2023.

(b) Changes made in taxpayer’s fourth or subsequent taxable years.

(i) Taxpayer required to make change on a cut-off basis. A taxpayer that changes to the safe harbor method for linear property for the taxpayer’s fourth taxable

year ending after May 1, 2023, or for any subsequent taxable year, must make the change on a cut-off basis, and is not eligible to use the NGSH Method rules provided in sections 5.02, 5.03, 5.05, 5.06, and 5.07 of this revenue procedure for any linear property expenditures paid or incurred prior to the year of change. A taxpayer that changes to the safe harbor method for non-linear property for the taxpayer's fourth taxable year ending after May 1, 2023, or for any subsequent taxable year, must make this change on a cut-off basis, and is not eligible to use the NGSH Method rules provided in sections 5.04, 5.05, and 5.06 of this revenue procedure for any non-linear property expenditures paid or incurred prior to the year of change.

(ii) Concurrent change. If a taxpayer changes to the safe harbor method for linear property or the safe harbor method for non-linear property for the taxpayer's fourth taxable year ending after May 1, 2023, or for any subsequent taxable year, and did not properly capitalize under §§ 263(a) and 263A any linear property expenditures or non-linear property expenditures, as applicable, paid or incurred prior to the year of change, the taxpayer also must change its method of accounting to properly capitalize such expenditures under §§ 263(a) and 263A for the same year of change. The taxpayer must change to a method of accounting described under sections 11.08, 12.01, 12.02, 12.08, and/or 12.12 of Rev. Proc. 2022-14, 2022-7 I.R.B. 1, as applicable, and such method change must be made on the same Form 3115, *Application for Change in Accounting Method*, on which the taxpayer changes to the safe harbor method for linear property and the safe harbor method for non-linear property, as applicable.

(4) Examples. The following examples illustrate the application of this section

5.08. In each example, it is assumed that the taxpayer (i) is a C corporation that files its Federal income tax returns on an accrual method and a calendar taxable year basis, (ii) is within the scope of this revenue procedure, (iii) placed in service natural gas transmission property or distribution property that is described in section 4 of this revenue procedure and is MACRS property, (iv) did not make a general asset account election for any natural gas transmission property or distribution property placed in service by the taxpayer in any taxable year before the first taxable year that the taxpayer uses the NGSH Method, (v) is changing its methods of accounting for both linear and non-linear property under the NGSH Method for the same taxable year, and (vi) is not changing to the NGSH Method on a cut-off basis under section 6.04 of this revenue procedure. It is also assumed, unless otherwise stated, that the costs of linear and non-linear property replacements before Year 1 were not capitalized under § 263(a), that these costs would not have been required to be capitalized under sections 5.02, 5.03, 5.04, 5.06, and 5.07 of this revenue procedure, and that these costs would not have been treated as per se capital expenditures under sections 5.05(1)(a)-(f), (i), or (j) of this revenue procedure. Further, it is assumed that § 1.168(i)-1(e)(3) (special rules for certain dispositions of assets in general asset accounts) does not apply for the first taxable year that the taxpayer uses the NGSH Method and for any subsequent taxable year. Moreover, for purposes of these examples, “Year 1” refers to the taxpayer’s first taxable year ending after May 1, 2023, “Year 2” refers to the taxpayer’s second taxable year ending after May 1, 2023, and “Year 4” refers to the taxpayer’s fourth taxable year ending after May 1, 2023. The following examples do not address the treatment of depreciation or the requirement or computation of the § 481(a)

adjustment, if applicable, for purposes of changing the taxpayer's methods of accounting under section 6 of this revenue procedure.

(a) Example 1. (i) J is a natural gas transmission company. Before Year 1, J owned and placed in service natural gas transmission property at a cost of $100 million before any dispositions or additions. Before Year 1, J replaced parts of such property that had an original cost of $10 million and incurred $12 million for the cost of such replacements. On its Federal income tax returns before Year 1, J recognized losses upon the dispositions of that $10 million of property and deducted $12 million for the cost of the replacements under § 162(a). J files a Form 3115 with its Federal income tax return for Year 1 to change its methods of accounting for linear and non-linear property to use the NGSH Method.

(ii) Pursuant to the special rule in section 5.08(3)(a) of this revenue procedure, the per se capital expenditure rules in section 5.05(1)(g) and (h) of this revenue procedure do not apply to the replacement cost of $12 million that J deducted under § 162(a) before J's Year 1. Accordingly, this $12 million cost of the replacements is not a per se capital expenditure under the NGSH Method.

(iii) At the beginning of Year 1, J owns natural gas transmission property at a cost of $90 million ($100 million - $10 million). Because Year 1 is J's first taxable year ending after May 1, 2023, J must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $90 million of natural gas transmission property that J owns at the beginning of Year 1.

(b) Example 2. (i) The facts are the same as the facts in Example 1, except that, during Year 1, J replaced a part of the natural gas transmission property that had an

original cost of $2 million and incurred $3.5 million for the cost of such replacements.

(ii) As a result of the late general asset account election in Example 1, the $2 million of the natural gas transmission property that J replaced during Year 1 is in a general asset account. Pursuant to § 1.168(i)-1(e)(2), J does not recognize a loss upon the disposition of that $2 million of property and continues to depreciate that property on its Federal income tax return for Year 1 and subsequent taxable years.

(iii) Because J did not recognize a loss upon the disposition of that $2 million of property, the cost of $3.5 million for replacing a part of the natural gas transmission property during Year 1 is not a per se capital expenditure under section 5.05(1)(g) or (h) of this revenue procedure. Accordingly, for its Federal income tax return for Year 1, J must apply the NGSH Method to all amounts incurred in Year 1 that are subject to the NGSH Method, including the $ 3.5 million in replacement costs. Also, J must make general asset account elections to include in general asset accounts all costs capitalized under the NGSH Method in Year 1.

(c) Example 3. (i) I is a local natural gas distribution company. Before Year 1, I owned and placed in service gas distribution property at a cost of $120 million before any dispositions or additions. Before Year 1, I replaced parts of such property that had an original cost of $10 million and incurred $12 million for the cost of such replacements. On its Federal income tax returns before Year 1, I recognized losses upon the dispositions of that $10 million of property and deducted $12 million for the cost of the replacements under § 162(a). During Year 1, I replaced a part of the natural gas distribution property that had an original cost of $2 million and incurred $3 million for the cost of such replacements. On its Federal income tax return for Year 1, I

recognized a loss upon the disposition of the $2 million of replaced property, and deducted $3 million for the cost of the replacements under § 162(a). I files a Form 3115 with its Federal income tax return for Year 2 to change its methods of accounting for its linear and non-linear property to use the NGSH Method.

(ii) Because I filed its method change in Year 2, the special rule for certain per se capital expenditures under section 5.08(3)(a) of this revenue procedure does not apply to taxable years ending before the taxpayer's first taxable year for which the taxpayer changes. Accordingly, the per se capital expenditure rules in section 5.05(1)(g) and (h) of this revenue procedure apply to the replacement cost of $12 million that I deducted under § 162(a) on its Federal income tax returns before Year 1, and to the replacement cost of $3 million that I deducted under § 162(a) on its Federal income tax return for Year 1. Therefore, the total cost of $15 million for these replacements is a per se capital expenditure, and must be capitalized, under the NGSH Method.

(iii) At the beginning of Year 2, I owns natural gas distribution property at a cost of $123 million ($120 million-$10 million+$12 million-$2 million+$3 million). Because Year 2 is I's second taxable year ending after May 1, 2023, under section 5.08(2)(a)(i) of this revenue procedure, I must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $123 million of natural gas distribution property that I owns at the beginning of Year 2. In addition, for its Federal income tax return for Year 2, I must apply the NGSH Method to all amounts paid or incurred in Year 2 that are subject to the NGSH Method, and I must make general asset account elections to include in general asset accounts all costs capitalized under the NGSH Method in Year 2.

(d) Example 4. (i) H is a local natural gas distribution company. Before Year 4, H owned and placed in service natural gas distribution property at a cost of $150 million before any dispositions or additions. Before Year 4, H replaced parts of such property that had an original cost of $30 million and incurred $45 million for the cost of such replacements. On its Federal income tax returns before Year 4, H recognized losses upon the dispositions of that $30 million of property and capitalized $45 million for the cost of the replacements under § 263(a). H files a Form 3115 with its Federal income tax return for Year 4 to change its methods of accounting for its linear and non-linear property to use the NGSH Method.

(ii) At the beginning of Year 4, H owns natural gas distribution property at a cost of $165 million ($150 million - $30 million + $45 million). Because Year 4 is H's fourth taxable year ending after May 1, 2023, under section 5.08(2)(a)(iii) of this revenue procedure, H must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $165 million of natural gas distribution property that H owns at the beginning of Year 4. Pursuant to section 5.08(3)(b)(i) of this revenue procedure, H is not eligible to use any of the NGSH Method rules provided in sections 5.02, 5.03, 5.04, 5.05, 5.06, and 5.07 of this revenue procedure for any natural gas transmission and distribution property expenditures paid or incurred prior to Year 4. However, for its Federal income tax return for Year 4, H must apply the NGSH Method to all amounts paid or incurred in Year 4 that are subject to the NGSH Method, and H must make general asset account elections to include in general asset accounts all costs capitalized under the NGSH Method in Year 4.

.09 Class life asset depreciation range system (CLADR) percentage repair allowance

exclusion. A taxpayer that changes its treatment of natural gas transmission and distribution property expenditures to use the NGSH Method may not elect the class life asset depreciation range system repair allowance under § 1.167(a)-11(d)(2) in any taxable year that the taxpayer uses the NGSH Method. In addition, for any taxable year in which the § 1.167(a)-11(d)(2) repair allowance election was made, the NGSH Method may not be applied to change the taxpayer's treatment of property to which the taxpayer elected to apply the repair allowance under § 1.167(a)-11(d)(2).

.10 Applicability of § 263A. Amounts paid or incurred to which the taxpayer applies the NGSH Method are not capitalized separately under § 263A(a)(1)(B) and (b)(1) as direct or indirect costs of producing gas transmission and distribution property. However, a taxpayer that produces natural gas or acquires natural gas for resale in its trade or business must capitalize under § 263A direct and allocable indirect costs of producing or acquiring such property or any other property subject to § 263A. See §§ 1.263A-2 and 1.263A-3.

.11 Statistical sampling. In applying the NGSH Method, statistical sampling may be used by following the guidance provided in Rev. Proc. 2011-42, 2011-37 I.R.B. 318.

SECTION 6. CHANGE IN METHOD OF ACCOUNTING

.01 In general. A change to the safe harbor method for linear property and/or a change to the safe harbor method for non-linear property under this revenue procedure is a change in method of accounting to which the provisions of §§ 446 and 481, and the corresponding regulations, apply. However, section 6.04 of this revenue procedure allows certain taxpayers to choose to change to these methods of accounting on a cut-off basis. A taxpayer that wants to change to the methods of accounting described in

this revenue procedure must, if eligible, use the automatic change procedures in Rev. Proc. 2015-13, 2015-5 I.R.B. 419, as clarified and modified by Rev. Proc. 2015-33, 2015-24 I.R.B. 1067, and as modified by Rev. Proc. 2021-34, 2021-35 I.R.B. 337, by Rev. Proc. 2021-26, 2021-22 I.R.B. 1163, by Rev. Proc. 2017-59, 2017-48 I.R.B. 543, and by section 17.02(b) and (c) of Rev. Proc. 2016-1, 2016-1 I.R.B. 1.

.02 Statistical sampling. A taxpayer changing to the NGSH Method may use statistical sampling in determining the § 481(a) adjustment amount attributable to any single taxable year by following the guidance provided in Rev. Proc. 2011-42.

.03 Extrapolation. A taxpayer changing to the NGSH Method may use the extrapolation methodology provided in Appendix B of this revenue procedure (Appendix B) in determining the § 481(a) adjustment amount, if the taxpayer is within the scope of section 1.02 of Appendix B. Extrapolation methodologies not permitted in Appendix B are not permitted under the NGSH Method.

.04 Optional cut-off basis for first 3 taxable years.

(1) Availability of change on a cut-off basis. A taxpayer that changes to the safe harbor method for linear property for the taxpayer's first, second, or third taxable year ending after May 1, 2023, may choose to change to this method of accounting on a cut-off basis. See section 2.07 of Rev. Proc. 2015-13. A taxpayer that chooses to change to the safe harbor method for linear property on a cut-off basis under this section 6.04, and also changes to the safe harbor method for non-linear property for the taxpayer's first, second, or third taxable year ending after May 1, 2023, also must change to the safe harbor method for non-linear property on a cut-off basis, regardless of the year of this change. A taxpayer that changes to the safe harbor method for linear property for

the taxpayer's first, second, or third taxable year ending after May 1, 2013, and does not make this change on a cut-off basis is not permitted to change to the safe harbor method for non-linear property on a cut-off basis.

(2) Effect of change on a cut-off basis. A taxpayer that chooses to change to the NGSH Method on a cut-off basis is not eligible to use the NGSH Method rules under sections 5.02, 5.03, 5.04, 5.05, 5.06, and 5.07 of this revenue procedure for any linear property costs and non-linear property costs paid or incurred prior to the year of change, but must make the late general asset account election for the property described in section 5.08(2)(a)(ii) of this revenue procedure. A § 481(a) adjustment is neither required nor permitted for the change to the NGSH Method on a cut-off basis. Further, a taxpayer that chooses to make this change on a cut-off basis under this section 6.04 does not receive audit protection under section 8.01 of Rev. Proc. 2015-13 in connection with this change. See section 8.02(2) of Rev. Proc 2015-13.

.05 Automatic change. Rev. Proc. 2022-14 is modified to add new section 3.12, to read as follows:

3.12 Natural gas transmission and distribution property method of accounting under Rev. Proc. 2023-15.

(1) Description of change.

(a) Applicability. This change applies to a taxpayer that is within the scope of Rev. Proc. 2023-15 and wants to change its treatment of natural gas transmission and distribution property costs to use the natural gas transmission and distribution property safe harbor method of accounting (NGSH Method) described in Rev. Proc. 2023-15. Specifically, this change applies to a taxpayer that wants to change to "the safe harbor

method for linear property" or "the safe harbor method for non-linear property" and other applicable rules in accordance with Rev. Proc. 2023-15, including the making of a late general asset account election as required under section 5.08(2) of Rev. Proc. 2023-15. This change also applies to a taxpayer that previously changed to the safe harbor method for linear property and wants to change to the safe harbor method for non-linear property for a subsequent taxable year.

(b) Inapplicability. This change does not apply to the making of a late general asset account election other than in accordance with section 5.08(2) of Rev. Proc. 2023-15.

(2) Certain eligibility rules temporarily inapplicable.

(a) In general. The eligibility rules in section 5.01(1)(d) and (f) of Rev. Proc. 2015-13 do not apply to a taxpayer that changes to the NGSH Method provided in Rev. Proc. 2023-15 for its first, second, or third taxable year ending after May 1, 2023.

(b) Concurrent automatic change.

(i) If a taxpayer makes both a change under this section 3.12 and a change under section 6.12(3)(b) and/or section 6.15 of this revenue procedure for linear property and/or non-linear property for its first, second, or third taxable year ending after May 1, 2023, on a single Form 3115 for the same asset for the same year of change in accordance with section 3.12(6)(b) of this revenue procedure, the eligibility rules in section 5.01(1)(d) and (f) of Rev. Proc. 2015-13 do not apply to the taxpayer for these changes.

(ii) If a taxpayer makes both a change under this section 3.12 and a change under section 11.08, 12.01, 12.02, 12.08, and/or 12.12 of this revenue procedure, as

applicable, for its linear property or non-linear property costs in its first, second, or third taxable year ending after May 1, 2023, on a single Form 3115 for the same year of change in accordance with section 3.12(6) of this revenue procedure, the eligibility rules in section 5.01(1)(d) and (f) of Rev. Proc. 2015-13 do not apply to the taxpayer for these changes.

(3) Manner of making change.

(a) Late general asset account election.

(i) The late general asset account election change described in section 5.08(2) of Rev. Proc. 2023-15 is made using a modified cut-off method under which the unadjusted depreciable basis and the depreciation reserve of the asset as of the beginning of the year of change are accounted for using the proposed method of accounting. The late general asset account election change requires each general asset account to include a beginning balance for both the unadjusted depreciable basis and the depreciation reserve. The beginning balance for the unadjusted depreciable basis of each general asset account is equal to the sum of the unadjusted depreciable bases as of the beginning of the year of change for all assets included in that general asset account. The beginning balance of the depreciation reserve of each general asset account is equal to the sum of the greater of the depreciation allowed or allowable as of the beginning of the year of change for all assets included in that general asset account.

(ii) For the late general asset account election change described in section 5.08(2) of Rev. Proc. 2023-15, the taxpayer must attach to its Form 3115 a statement providing that the taxpayer agrees to the following additional terms and conditions:

(A) The taxpayer consents to, and agrees to apply, all the provisions of § 1.168(i)-1 to the assets that are subject to the election specified in section 5.08(2) of Rev. Proc. 2023-15; and

(B) Except as provided in § 1.168(i)-1(c)(1)(ii)(A), (e)(3), (g), or (h), the election made by the taxpayer under section 5.08(2) of Rev. Proc. 2023-15 is irrevocable and will be binding on the taxpayer for computing taxable income for the year of change and for all subsequent taxable years with respect to the assets that are subject to this election.

(b) Cut-off basis for certain changes. Except for changes to make a late general asset account election described in section 3.12(3)(a) of this revenue procedure, a change to the NGSH Method described in Rev. Proc. 2023-15 is made on a cut-off basis and applies only to natural gas transmission and distribution property costs paid or incurred beginning in or after the year of change if–

(i) Sections 5.08(2)(a)(ii) and 6.04 of Rev. Proc. 2023-15 apply (the taxpayer changes to the NGSH Method described in Rev. Proc. 2023-15 for the first, second, or third taxable year ending after May 1, 2023, on a cut-off basis); or

(ii) Section 5.08(2)(a)(iii) of Rev. Proc. 2023-15 applies (the taxpayer changes to the NGSH Method described in Rev. Proc. 2023-15 for the fourth taxable year ending after May 1, 2023, or for any subsequent taxable year).

(4) Section 481(a) adjustment.

(a) In general. Except as provided in section 3.12(3)(b) of this revenue procedure, a taxpayer changing its methods of accounting under this section 3.12 must take the entire net § 481(a) adjustment into account, whether positive or negative, in

computing taxable income for the year of change in the manner provided in section 7.03 of Rev. Proc. 2015-13. The entire net § 481(a) adjustment includes all aspects of the NGSH Method described in Rev. Proc. 2023-15, including a change to the methods of accounting permitted under § 1.168(i)-1 pursuant to section 5.08(2) of Rev. Proc. 2023-15. However, a § 481(a) adjustment is neither required nor permitted for the late general asset account election described in section 5.08(2) of Rev. Proc. 2023-15. Further, a § 481(a) adjustment is neither required nor permitted if the taxpayer chooses to change to the NGSH Method on a cut-off basis under section 6.04 of Rev. Proc. 2023-15 or if the taxpayer changes to this method during the time described in section 5.08(2)(a)(iii) of Rev. Proc. 2023-15.

(b) Repair allowance property. A taxpayer changing its method of accounting under this section 3.12 must not include in the § 481(a) adjustment any amount attributable to property for which the taxpayer elected to apply the repair allowance under § 1.167(a)-11(d)(2) for any taxable year in which the repair allowance election was made.

(c) Statistical sampling. A taxpayer changing to the NGSH Method under this section 3.12 may use statistical sampling in determining the § 481(a) adjustment amount attributable to any single taxable year by following the guidance provided in Rev. Proc. 2011-42, 2011-37 I.R.B. 318.

(d) Extrapolation. A taxpayer changing to the NGSH Method under this section 3.12 may use the extrapolation methodology provided in Appendix B to Rev. Proc. 2023-15 (Appendix B) in determining the § 481(a) adjustment amount if the taxpayer is within the scope of section 1.02 of Appendix B. Extrapolation methodologies not

permitted in Appendix B are not permitted under the NGSH Method.

(5) No audit protection for certain taxpayers. If a taxpayer chooses to change to the NGSH Method described in Rev. Proc. 2023-15 on a cut-off basis as permitted under section 6.04 of Rev. Proc. 2023-15 or is required to change on a cut-off basis under section 5.08(3)(b)(i) of Rev. Proc. 2023-15, the taxpayer does not receive audit protection under section 8.01 of Rev. Proc. 2015-13 in connection with this change.

(6) Concurrent automatic changes.

(a) A taxpayer making changes under this section 3.12 for more than one asset for the same year of change must file a single Form 3115 for all such assets. The single Form 3115 must provide a single net § 481(a) adjustment for all such changes.

(b) A taxpayer making changes under this section 3.12 and changes under section 6.12(3)(b) and/or section 6.15 of this revenue procedure for linear property or non-linear property costs for the same year of change must file a single Form 3115 for all changes and must enter the designated automatic accounting method change numbers for all changes on the appropriate line on the Form 3115. See section 6.03(1)(b) of Rev. Proc. 2015-13 for information on making concurrent changes.

(c) A taxpayer making changes under this section 3.12 and also making a coordinating change to its linear property or non-linear property costs under section 11.08, 12.01, 12.02, 12.08, and/or 12.12 of this revenue procedure, as applicable, must file a single Form 3115 for the same year of change for all these changes, provided that the taxpayer is not prohibited from filing an automatic change under the eligibility rules under section 5 of Rev. Proc. 2015-13. For changes required to be filed on a single Form 3115 under this section, the taxpayer must enter the designated automatic

accounting method change numbers for all changes on the appropriate line on the Form 3115. See section 6.03(1)(b) of Rev. Proc. 2015-13 for information on making concurrent changes.

(d) A taxpayer that changes to a method of accounting under this section 3.12 for taxable years ending after the third taxable year ending after May 1, 2023 and is also required to change its method of accounting to properly capitalize its linear property or non-linear property costs under § 263(a) and/or § 263A under section 5.08(3)(b)(ii) of Rev. Proc. 2023-15, must file a single Form 3115 for the same year of change for all these changes, provided that the taxpayer is not prohibited from filing an automatic change under the eligibility rules set out in section 5 of Rev. Proc. 2015-13, 2015-5 I.R.B. 419. For changes required to be filed on a single Form 3115 under this paragraph, the taxpayer must enter the designated automatic accounting method change numbers for all changes on the appropriate line on the Form 3115. See section 6.03(1)(b) of Rev. Proc. 2015-13 for information on making concurrent changes.

(7) Examples. The following examples illustrate this section 3.12. In each example, it is assumed that the taxpayer (a) is a C corporation, on an accrual method of accounting and using a calendar taxable year, (b) is within the scope of Rev. Proc. 2023-15, (c) placed in service natural gas transmission property or distribution property that is described in section 4 of Rev. Proc. 2023-15 and is MACRS property, (d) did not make a general asset account election for any natural gas transmission property or distribution property placed in service by the taxpayer in any taxable year before the first taxable year that the taxpayer uses the NGSH Method, (e) is changing its methods of accounting for both linear property and non-linear property under the NGSH Method for

the same taxable year, and (f) is not changing to the NGSH Method on a cut-off basis under section 6.04 of Rev. Proc. 2023-15. Unless otherwise stated, it also is assumed that (a) the cost of the replacements before Year 1 were not capitalized under § 263(a), (b) the cost of the replacements before Year 1 would not have been capitalized if the taxpayer used the NGSH Method provided under sections 5.02, 5.03, 5.04, 5.06, and 5.07 of Rev. Proc. 2023-15 for such prior taxable years, and (c) the taxpayer's natural gas transmission and distribution property expenditures are not per se capital expenditures under section 5.05(1)(a)-(f), (i), or (j) of Rev. Proc. 2023-15. Further, it is assumed that § 1.168(i)-1(e)(3) (special rules for certain dispositions of assets in general asset accounts) does not apply for the first taxable year that the taxpayer uses the NGSH Method. Moreover, for purposes of these examples, "Year 1" refers to the taxpayer's first taxable year ending after May 1, 2023, "Year 2" refers to the taxpayer's second taxable year ending after May 1, 2023, and "Year 4" refers to the taxpayer's fourth taxable year ending after May 1, 2023.

(a) Example 1. (i) X is a local natural gas distribution company. Before Year 1, X owned and placed in service natural gas distribution property at a cost of $120 million before any dispositions or additions. Before Year 1, X replaced parts of such property that had an original cost of $10 million and incurred $12 million for the cost of such replacements. On its Federal income tax returns before Year 1, X recognized losses upon the dispositions of that $10 million of property, capitalized $12 million for the cost of the replacements of that property under § 263(a), and deducted depreciation of $800,000 on such $12 million. X files a Form 3115 with its Federal income tax return for Year 1 to change its methods of accounting to use the NGSH Method described in Rev.

Proc. 2023-15.

(ii) Because Year 1 is X's first taxable year ending after May 1, 2023, section 5.08(2)(a)(i) and (3)(a) of Rev. Proc. 2023-15 apply. Pursuant to section 5.08(3)(a) of Rev. Proc. 2023-15, the per se capital expenditure rules in section 5.05(1)(g) and (h) of Rev. Proc. 2023-15 do not apply to the replacement cost of $12 million that X capitalized under § 263(a) on its Federal income tax returns before Year 1. Accordingly, this $12 million cost of the replacements is not treated as a per se capital expenditure under the NGSH Method. Therefore, at the beginning of Year 1, X is treated under Rev. Proc. 2023-15 as owning natural gas distribution property at a cost of $110 million ($120 million - $10 million). Under section 5.08(2)(a)(i) of Rev. Proc. 2023-15, X must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $110 million of natural gas distribution property that X owns at the beginning of Year 1. These general asset accounts also must include the total depreciation allowed or allowable before the beginning of Year 1 for such property as the beginning balances of the depreciation reserves. The late general asset account election change is made on a modified cut-off method and, therefore, a § 481(a) adjustment is neither required nor permitted for the late general asset account election change.

(iii) On its Form 3115 to change to the NGSH Method provided under Rev. Proc. 2023-15, the net negative § 481(a) adjustment for this change is $11,200,000 (deduction of $12 million for the cost of the replacements before Year 1 less depreciation of $800,000 for such replacement assets before Year 1) and is deducted in computing X's taxable income for Year 1.

(b) Example 2. (i) The facts are the same as in Example 1, except that X files a Form 3115 with its Federal income tax return for Year 2 to change its method of accounting to use the NGSH Method described in Rev. Proc. 2023-15, and, before Year 2, X deducted depreciation of $1,000,000 on the replacement cost of $12 million.

(ii) Because X filed its method change in Year 2, the special rule under section 5.08(3)(a) of Rev. Proc. 2023-15 does not apply to the replacement cost of $12 million that X capitalized under § 263(a) on its Federal income tax returns before Year 1. Accordingly, section 5.05(1)(g) and (h) of Rev. Proc. 2023-15 apply to the replacement cost of $12 million that X capitalized on its Federal income tax returns before Year 2. The total cost of $12 million for this replacement is a per se capital expenditure, and must be capitalized, under the NGSH Method.

(iii) At the beginning of Year 2, X is treated under the NGSH Method as owning natural gas distribution property at a cost of $122 million ($120 million - $10 million + $12 million). Under section 5.08(2)(a)(i) of Rev. Proc. 2023-15, X must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $122 million of natural gas distribution property that X owns at the beginning of Year 2. These general asset accounts also must include the total depreciation allowed or allowable before the beginning of Year 2 for such property as the beginning balances of the depreciation reserves. The late general asset account election change is made on a modified cut-off method and, therefore, a § 481(a) adjustment is neither required nor permitted for the late general asset account election.

(iv) On its Form 3115 to change to the NGSH Method under Rev. Proc. 2023-15, the net § 481(a) adjustment for this change is zero. Under its present method of

accounting and under the NGSH Method (proposed method of accounting), X properly capitalized the $12 million for the cost of the replacements before Year 1 and claimed depreciation for such replacement assets before Year 2.

(c) Example 3. (i) Y is a local natural gas distribution company. Before Year 1, Y owned and placed in service natural gas distribution property at a cost of $120 million before any dispositions or additions. Before Year 1, Y replaced parts of such property that had an original cost of $10 million, and incurred $12 million for the cost of such replacements. On its Federal income tax returns before Year 1, Y recognized losses upon the dispositions of that $10 million of property, and deducted $12 million for the cost of the replacements of such property under § 162(a). During Year 1, Y replaced a part of the natural gas distribution property that had an original cost of $2 million and incurred $3 million for the cost of such replacements. If Y had capitalized the $15 million for the cost of the replacements, the total depreciation allowed or allowable for these assets would have been $1 million before Year 2. On its Federal income tax return for Year 1, Y recognized a loss upon the disposition of that $2 million of property, and deducted $3 million for the cost of the replacements under § 162(a). Y files a Form 3115 with its Federal income tax return for Year 2 to change its method of accounting to use the NGSH Method described in Rev. Proc. 2023-15.

(ii) Because Y filed its method change for Year 2, section 5.08(2)(a)(i) of Rev. Proc. 2023-15 applies to this change. However, the special rule under section 5.08(3)(a) Rev. Proc. 2023-15 would apply only if Y had filed its method change for Year 1. Accordingly, section 5.05(1)(g) and (h) of Rev. Proc. 2023-15 apply to the replacement cost of $12 million that Y deducted under § 162(a) on its Federal income

tax returns before Year 1, and to the replacement cost of $3 million that Y deducted under § 162(a) on its Federal income tax return for Year 1. Therefore, the total cost of $15 million for these replacements is a per se capital expenditure, and must be capitalized, under the NGSH Method.

(iii) At the beginning of Year 2, Y is treated under Rev. Proc. 2023-15 as owning natural gas distribution property at a cost of $123 million ($120 million - $10 million + $12 million - $2 million + $3 million). Under section 5.08(2)(a)(i) of Rev. Proc. 2023-15, Y must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $123 million of natural gas distribution property that Y owns at the beginning of Year 2. These general asset accounts also must include the total depreciation allowed or allowable before the beginning of Year 2 for such property as the beginning balances of the depreciation reserves. The late general asset account election change is made on a modified cut-off method and, therefore, a § 481(a) adjustment is neither required nor permitted for the late general asset account election.

(iv) On its Form 3115 to change to the NGSH Method of Rev. Proc. 2023-15, the net positive § 481(a) adjustment for this change is $14 million ($15 million for the cost of the replacements before Year 2 less depreciation allowed or allowable of $1 million for such replacement assets before Year 2) and is taken into account in computing Y's income in the manner provided in section 3.12(4)(a) of this revenue procedure.

(d) Example 4. (i) Z is a local natural gas distribution company. Before Year 4, Z owned and placed in service natural gas distribution property at a cost of $150 million before any dispositions or additions. Before Year 4, Z replaced parts of such property

that had an original cost of $30 million and incurred $45 million for the cost of such replacements. On its Federal income tax returns before Year 4, Z recognized losses upon the dispositions of that $30 million of property, capitalized $45 million for the cost of the replacements under § 263(a), and deducted depreciation of $15 million on such $45 million. Z files a Form 3115 with its Federal income tax return for Year 4 to change its method of accounting to use the NGSH Method described in Rev. Proc. 2023-15. Assume Z is eligible to file Form 3115 for Year 4 under the automatic change procedures in Rev. Proc. 2015-13.

(ii) At the beginning of Year 4, Z owns natural gas distribution property at a cost of $165 million ($150 million - $30 million + $45 million). Because Year 4 is Z's fourth taxable year ending after May 1, 2023, sections 5.08(2)(a)(iii) and 5.08(3)(b) of Rev. Proc. 2023-15 apply. Accordingly, under section 5.08(2)(a)(iii) of Rev. Proc. 2023-15, Z must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $165 million of natural gas distribution property that Z owns at the beginning of Year 1. These general asset accounts also must include the total depreciation allowed or allowable before the beginning of Year 4 for such property as the beginning balances of the depreciation reserves. The late general asset account election change is made using a modified cut-off method and, therefore, a § 481(a) adjustment is neither permitted nor required for the late general asset account election.

(iii) Because sections 5.08(2)(a)(iii) and 5.08(3)(b) of Rev. Proc. 2023-15 apply, Z's change to the NGSH Method described in Rev. Proc. 2023-15, applies only to natural gas transmission and distribution property expenditures paid or incurred by Z beginning in Year 4 and is made on a cut-off basis. Therefore, a § 481(a) adjustment is

neither required nor permitted for the change to the NGSH Method described in Rev. Proc. 2023-15.

(e) Example 5. (i) The facts are the same as in Example 4 except that, on its Federal income tax returns before Year 4, Z improperly deducted $45 million for the cost of the replacements under § 162(a). Such $45 million of replacement costs should have been capitalized under § 263(a). If Z had capitalized the $45 million for the cost of the replacements, the total depreciation allowed or allowable for such assets would have been $15 million before Year 4.

(ii) Because Year 4 is Z's fourth taxable year ending after May 1, 2023, sections 5.08(2)(a)(iii) and 5.08(3)(b) of Rev. Proc. 2023-15 apply. Pursuant to section 5.08(3)(b) of Rev. Proc. 2023-15, Z must also change its method of accounting to capitalize under § 263(a) the $45 million for the cost of the replacements incurred before Year 4. The net positive § 481(a) adjustment for this coordinating change is $30 million ($45 million for the cost of the replacements before Year 4 less depreciation allowed or allowable of $15 million for such replacement assets before Year 4). Z takes this net positive § 481(a) adjustment of $30 million into account in computing Z's taxable income in the manner provided in section 3.12(4)(a) of this revenue procedure.

(iii) Z owns natural gas distribution property at a cost of $165 million ($150 million - $30 million + $45 million) at the beginning of Year 4. Accordingly, Z must make a late general asset account election on its Form 3115 to include in general asset accounts all of the $165 million of natural gas distribution property that Z owns at the beginning of Year 4. These general asset accounts also must include the total depreciation allowed or allowable before the beginning of Year 4 for such property as

the beginning balances of the depreciation reserves. The late general asset account election change is made using a modified cut-off method and, therefore, a § 481(a) adjustment is neither permitted nor required for the late general asset account election.

(iv) Because sections 5.08(2)(a)(iii) and 5.08(3)(b) of Rev. Proc. 2023-15 apply, Z's change to the NGSH Method provided under sections 5.02, 5.03, 5.04, 5.06, and 5.07 of Rev. Proc. 2023-15, applies only to natural gas transmission and distribution property expenditures paid or incurred by Z beginning in Year 4 and is made on a cut-off basis. Therefore, a § 481(a) adjustment is neither required nor permitted for the change to the NGSH Method described in Rev. Proc. 2023-15.

(v) Pursuant to section 3.12(6)(c) and section 5.08(3)(b) of Rev. Proc. 2023-15 the change to capitalize the replacement costs of $45 million, the late general asset account election change, and the change to use the NGSH Method provided under Rev. Proc. 2023-15 must be included on the same Form 3115 filed by Z for Year 4.

(8) Designated automatic accounting method change number. The designated automatic accounting method change number for a change to the methods of accounting under this section 3.12 is "269."

(9) Contact information. For further information regarding a change under this section, contact Hyowon Lee or Merrill Feldstein at (202) 317-5100 (not a toll-free call).

SECTION 7. EFFECT ON OTHER DOCUMENTS

.01 Section 3.12 of Rev. Proc. 2022-14 is modified to include the accounting method changes in this revenue procedure.

.02 Rev. Proc. 2011-42 is amplified.

SECTION 8. EFFECTIVE DATE

This revenue procedure is effective for taxable years ending after May 1, 2023.

SECTION 9. PAPERWORK REDUCTION ACT

The collection of information contained in this revenue procedure has been submitted to the Office of Management and Budget for review under OMB control number 1545-0123 in accordance with the Paperwork Reduction Act (44 U.S.C. 3507(d)). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number. The collection of information in this revenue procedure is in section 6. This information is necessary and will be used to determine whether the taxpayer properly changed to a permitted method of accounting. The collections of information are required for the taxpayer to obtain consent to change its method of accounting.

SECTION 10. DRAFTING INFORMATION

The principal authors of this revenue procedure are Natasha Mulleneaux and Merrill Feldstein of the Office of Associate Chief Counsel (Income Tax and Accounting). For further information regarding this revenue procedure, contact Hyowon Lee or Merrill Feldstein at 202-317-5100 (not a toll-free call).

APPENDIX A—UNIT OF PROPERTY AND MAJOR COMPONENT DEFINITIONS FOR NON-LINEAR PROPERTY

SECTION 1. INTRODUCTION

.01 In general. This Appendix A lists the units of property and major components for non-linear natural gas transmission and distribution property to which the taxpayer applies the non-linear safe harbor method. See section 5.04 of this revenue procedure. The units of property and major components are listed for compressor stations, gas storage facilities, and measuring and regulating stations, including city gate stations. Not all the identified units of property are necessarily present at a given location; for example, an above-ground compressed natural gas storage facility will not have liquefaction equipment or a well. Each meter and regulator is a separate unit of property, wherever located. If a unit of property has major components, all the major components are identified. The treatment of the costs of non-linear property that are not specifically identified in this Appendix A (for example, tools, fixtures, furniture, computer equipment, and other miscellaneous equipment) are excluded from this revenue procedure and are determined under §§ 263(a), 263A, and other applicable authority.

.02 Instrumentation and controls. In general, instrumentation and controls are a major component of the unit of property they monitor or control. However, all the on-site instrumentation and controls for each compressor station, gas storage facility, or measuring and regulating station that are not associated with a particular unit of property are a single unit of non-linear property. As used in this revenue procedure, the term “instrumentation and controls” does not include assets that are treated as separate units of property (for example, meters and regulators).

.03 Scope. This Appendix A does not apply to determine the units of property of non-linear property or the major components of these units of property if the taxpayer does not use the safe harbor method for non-linear property.

SECTION 2. UNITS OF NON-LINEAR PROPERTY

.01 Compressor station property. At a compressor station, the units of non-linear property are the following:

(1) Each compressor, including prime mover.

(2) Each meter.

(3) Each regulator.

(4) Each tank.

(5) Each flaring or incinerating system, including stack.

(6) All the lines at the station, including header, pipe, coatings, fittings, valves, and cathodic protection.

(7) All the gas detection equipment at the station.

(8) All the equipment to maintain pipeline gas quality at the station, including the following major components:

(a) Each scrubber.

(b) Each filter separator.

(c) Each separator.

(d) Each dehydrator (also referred to as a dryer).

(e) Each chromatograph.

(f) Each continuous gas sampler.

(g) Each water vapor monitor.

(h) Each sulfur removal apparatus.

(i) Each cooler.

(j) Each heater.

(9) All the electric supply equipment at the station, including the following major components:

(a) Each generator, including motor.

(b) Each set of batteries and charger.

(c) Each transformer.

(d) Each power supply (for example, a variable frequency drive).

(e) All other electric supply devices, including switchgear.

(10) All the odorizing equipment at the station, including the following major components:

(a) All the equipment to inject an odorant or other additive into the gas stream.

(b) Each tank for storing odorant or other additive.

(11) All the onsite instrumentation and control equipment at the station that is not a major component of a specific unit of non-linear property.

(12) Each structure, including pad, walls, and roof, housing compressors and related equipment.

(13) Each additional structure, including pad, walls, and roof.

(14) All fencing, walls, enclosures, and miscellaneous structures or land improvements that are not capitalized to the land surrounding a compressor station and any miscellaneous pads.

(15) Each parcel of land and each easement or other right to land.

.02 Gas storage facility property. At a gas storage facility, the units of property are the following:

(1) Each tank.

(2) Each well, including the following major components:

(a) The wellhead.

(b) The casing.

(3) Each compressor, including prime mover.

(4) Each meter.

(5) Each regulator.

(6) Each flaring or incinerating system, including stack.

(7) All the lines at the facility, including header, pipe, coatings, fittings, valves, and cathodic protection.

(8) All the equipment to maintain pipeline quality gas at the facility, including the following major components:

(a) Each scrubber.

(b) Each filter separator.

(c) Each separator.

(d) Each dehydrator (also referred to as a dryer).

(e) Each chromatograph.

(f) Each continuous gas sampler.

(g) Each water vapor monitor.

(h) Each sulfur removal apparatus.

(i) Each cooler.

(j) Each heater.

(9) All the odorizing equipment at the facility, including the following major components:

(a) All the equipment to inject an odorant or other additive into the gas stream.

(b) Each tank for storing odorant or other additive.

(10) All the liquefaction equipment at the facility, including the following major components:

(a) Each cold box.

(b) Each heat exchanger.

(c) Each condenser.

(d) Each vaporizing unit (also referred to as a vaporizer).

(11) All the onsite instrumentation and control equipment at the facility that is not a major component of a specific unit of non-linear property.

(12) Each structure, including pad, walls, and roof, housing compressors and related equipment.

(13) Each additional structure, including pad, walls, and roof.

(14) All the fencing, walls, enclosures, and/or miscellaneous structures surrounding the facility and any miscellaneous pads.

(15) Each parcel of land and each easement or other right to land.

.03 Measuring and regulating station property. At a measuring and regulating station, including a city gate station, the units of non-linear property are the following:

(1) Each meter.

(2) Each regulator.

(3) All the lines at the station, including header, pipe, coatings, fittings, valves, and cathodic protection.

(4) All the equipment to maintain pipeline quality gas at the station, including the following major components:

(a) Each scrubber.

(b) Each filter separator.

(c) Each separator.

(d) Each dehydrator (also referred to as a dryer).

(e) Each chromatograph.

(f) Each continuous gas sampler.

(g) Each water vapor monitor.

(h) Each sulfur removal apparatus.

(i) Each heater.

(5) All the odorizing equipment at the station, including the following major components:

(a) All the equipment to inject an odorant or other additive into the gas stream.

(b) Each tank for storing odorant or other additive.

(6) All the onsite instrumentation and control equipment at the facility that is not a major component of a specific unit of non-linear property.

(7) Each structure, including pad, walls, and roof.

(8) All the fencing, walls, enclosures, and miscellaneous structures surrounding the station and any miscellaneous pads.

(9) Each parcel of land and each easement or other right to land.

.04 Meters and regulators. Each meter and each regulator not described in section 2.01 through 2.03 of this Appendix A, including a meter or regulator located at a customer's premises, is a separate unit of non-linear property.

APPENDIX B—EXTRAPOLATION GUIDANCE

SECTION 1. INTRODUCTION

.01 In general. This Appendix B provides an extrapolation methodology that an eligible taxpayer may use in connection with a change to apply the NGSH Method. The extrapolation methodology described in this Appendix B provides the exclusive extrapolation methodology that is permitted under the NGSH Method for determining the amount of a § 481(a) adjustment.

.02 Scope. This Appendix B does not apply to a change to apply the NGSH Method if the taxpayer does not have a minimum of three representative years within the testing period as described in section 2.02(1) of this Appendix B.

SECTION 2. EXTRAPOLATION METHODOLOGY

.01 Application. A taxpayer making a change to apply the NGSH Method may use the extrapolation procedures provided in this Appendix B to determine the § 481(a) adjustment resulting from the change in method of accounting for the safe harbor method for linear property and the safe harbor method for non-linear property, if applicable. A taxpayer may choose to use this extrapolation procedure for its change to the safe harbor method for linear property, for its change to the safe harbor for non-linear property, or for both changes. The extrapolation procedures are performed separately for the safe harbor method for linear property and the safe harbor method for non-linear property to determine the respective § 481(a) adjustment. Generally, the taxpayer first applies the method to a testing period of recent, representative years and derives an average repair deduction under the method of accounting as a percentage of total capital additions for financial accounting purposes. This percentage, adjusted by a

reduction percentage that varies based on time, is then applied to the adjusted capital additions for financial accounting purposes for prior years for which extrapolation is used to derive a deemed § 481(a) adjustment amount for each year. These extrapolated § 481(a) adjustment amounts are then combined with the actual adjustment amounts for years in which the § 481(a) adjustment is calculated in the normal manner to arrive at the total § 481(a) adjustment attributable to the change in method of accounting.

.02 Calculation methodology. In order to determine the amount of the § 481(a) adjustment for a prior year to which extrapolation is applied, the following calculation methodology must be used:

(1) Testing period. First, a testing period is determined as follows:

(a) In general. The taxpayer must use as the testing period a minimum of three consecutive taxable years (testing years), except as described in section 2.02(1)(b)(ii) of this Appendix B. Generally, the final year of the testing period is the taxable year preceding the year of change. Alternatively, a taxpayer may choose the year of change as the final year of the testing period.

(b) Representative years required. The testing years must be representative of all years included in the § 481(a) adjustment.

(i) In determining whether a year is representative, a taxpayer must take into account restructuring transactions, including acquisitions and dispositions as well as any other events that resulted in significant capital changes.

(ii) If one of the taxable years in the testing period described in section 2.02(1)(a) of this Appendix B is not representative, the taxpayer must exclude data from

the non-representative year from the testing period and use data from the fourth most recent taxable year to establish a testing period (with such fourth most recent taxable year being a testing year). If the fourth most recent taxable year is not representative either, the taxpayer may not use an extrapolation methodology for determining the amount of a § 481(a) adjustment attributable to its change to the NGSH Method under this revenue procedure.

(c) Additional years. Under the extrapolation calculation methodology, if the taxpayer has sufficient data to calculate the repair deduction percentage for more than three years, the taxpayer may include those years in the testing period. The additional testing years must be consecutive years that immediately precede the original three-year testing period, except that a year that is not representative, as described in section 2.02(1)(b) of this Appendix B, must be excluded. A taxpayer may not use, as an additional testing year, a year that is separated from the rest of the testing period by more than one non-representative year.

(2) Repair deduction percentage. Second, a repair deduction percentage for each year for which extrapolation is used (extrapolation year) is computed as follows, using data from the testing period.

(a) Repair deductions during the testing period under the proposed method. For each testing year, the amount of repair expenses that would be allowable as deductions under the NGSH Method, before taking into account book-tax basis adjustments, is determined.

(b) Tentative repair deduction percentage. The sum of the repair expenses allowable as deductions for all testing years in the testing period, as determined under

section 2.02(2)(a) of this Appendix B, is then divided by the sum of all capital additions during the testing period. For this purpose, a taxpayer must use capital additions for financial statement purposes (book capital additions). The resulting ratio represents the average percentage of capitalized additions that are properly treated as repair expenses allowable as deductions under the NGSH Method (tentative repair deduction percentage), before taking into account book-tax basis adjustments.

(c) Repair deduction percentage for an extrapolation year. The tentative repair deduction percentage is then multiplied by a reduction percentage for each extrapolation year. For each extrapolation year, the reduction percentage is determined by using the formula (1 - (0.10*(X/Y))), where X equals the number of years the extrapolation year precedes the final year of the testing period and Y equals the total number of taxable years in the testing period. The reduction percentage for an extrapolation year multiplied by the tentative repair deduction percentage equals the repair deduction percentage for the extrapolation year.

(3) Extrapolation year tentative repair deduction amount. Third, a tentative repair deduction amount under the proposed method is calculated for each extrapolation year.

(a) The repair deduction amount for an extrapolation year is calculated by multiplying the repair deduction percentage for the extrapolation year (determined in section 2.02(2) of this Appendix B) by the book capital additions for the extrapolation year.

(b) In determining the repair deduction amount for an extrapolation year, a taxpayer must account for any book-tax basis adjustments for property placed in service in the extrapolation year. Book-tax basis adjustments for property placed in service in

the extrapolation year may be accounted for by multiplying the tentative repair deduction amount for an extrapolation year by the taxpayer's book-to-tax adjustment percentage for the extrapolation year. Tax adjustments that must be accounted for include, but are not limited to, the following types of adjustments:

(i) adjustments resulting from a change in accounting method permitted under Rev. Proc. 2000-7, 2000-1 C.B. 712, involving the treatment of the costs incurred in removing retired assets;

(ii) adjustments resulting from a change in the treatment of capitalized amounts determined under § 263A, including reductions for additional mixed service costs allocated to inventory and adjustments to account for changes to interest capitalization amounts;

(iii) adjustments arising from casualty loss deductions recognized under § 165; and

(iv) adjustments resulting from research and experimental expenditures deducted under § 174.

(4) Repair allowance adjustment and repair deduction amount. Fourth, for each extrapolation year in which the repair allowance election under § 1.167(a)-11(d)(2) (ADR repair allowance) was made, the tentative repair deduction amount must be reduced by the cost of repairs to natural gas transmission property or natural gas distribution property attributable to ADR repair allowance property. To determine the reduction where a prior ADR repair allowance election was made for the natural gas transmission property or natural gas distribution property, taxpayers must use a method comparable to the method actually used to allocate qualified repair expenditures to

repair allowance property for that year. For example, if in applying § 1.167(a)-11(d)(2) for the 1997 taxable year a taxpayer determined that 73 percent of its 1997 qualified repair expenditures for natural gas transmission and natural gas distribution property were attributable to repair allowance property, then that same percentage (73 percent) must be applied to determine the reduction to the repair deduction amount otherwise calculated under section 2.02(3) of this Appendix B. The amount determined after reducing the tentative repair deduction amount by the cost of repairs attributable to CLADR repair allowance property is the repair deduction amount for the extrapolation year.

(5) Tentative extrapolation year § 481(a) adjustment amount. Fifth, the tentative § 481(a) adjustment amount for each extrapolation year is determined. The tentative § 481(a) adjustment for each extrapolation year is calculated by subtracting the repair deduction amount for that year, as determined under sections 2.02(1) through 2.02(4) of this Appendix B, from the amount of repair expenses the taxpayer deducted for that year under its prior method of accounting, including § 481(a) adjustments resulting from any prior change in method of accounting. The difference, whether positive or negative, is the tentative § 481(a) adjustment amount for the extrapolation year.

(6) Extrapolation year § 481(a) adjustment amount. Sixth, the tentative § 481(a) adjustment amount for each extrapolation year must be adjusted to account for any differences in depreciation, credits, or any other cumulative differences in deductions between the extrapolation year and the year of change resulting from the taxpayer's proposed method of accounting. For instance, if under the proposed method a taxpayer's repair deduction for an extrapolation year would be tentatively increased by

$1,000, such that the unadjusted basis of the property placed in service would be correspondingly decreased by $1,000, the $1,000 tentative repair deduction increase for the extrapolation year must be reduced by the portion of the $1,000 in unadjusted basis that the taxpayer had recovered prior to the year of change.

(7) Total § 481(a) adjustment. Finally, the total § 481(a) adjustment attributable to the change to the taxpayer's proposed method of accounting is determined. The total § 481(a) adjustment for the year of change is calculated by combining the § 481(a) adjustment amounts for all extrapolation years, as described in this section 2.02 of this Appendix B, with the adjustment amounts, after taking into account book-tax basis adjustments, for years determined under § 481(a) in the normal manner.

.03 Example. In 2023, W, a calendar year taxpayer, changes its method of accounting to the NGSH Method. W uses the extrapolation methodology provided in section 2 of this Appendix B to determine the amount of its § 481(a) adjustment attributable to taxable years 2003 through 2019.

Following the general rule in section 2.02(1) of this Appendix B, W uses as its testing period 2020, 2021, and 2022, the three consecutive taxable years ending with 2022, the year preceding the year of change. Assume that each of 2020, 2021, and 2022 are representative of all years included in W's § 481(a) adjustment.

W's book capital additions for 2020, 2021, and 2022 are $3,000, $3,000, and $4,000, respectively, for a total of $10,000. Of these amounts, the portions that are properly treated as repair expenses allowable as deductions resulting from the application of W's proposed method of accounting for 2020, 2021, and 2022, before taking into account book-tax basis adjustments, are $300, $400, and $300, respectively, for a total of

$1,000.

For its 2014 extrapolation year, W's book capital additions were $3,333. W's book-to-tax adjustment percentage for 2014 is 90 percent. In 2013, W elected to apply the ADR repair allowance under § 1.167(a)-11(d)(2), which applied to 25 percent of W's natural gas transmission and natural gas distribution property. Under W's prior method of accounting (prior to application of the NGSH Method), W deducted $150 in repair expenses in 2014.

W determines its § 481(a) adjustment for 2014 as follows:

Step 1. W determines that it will use taxable years 2020, 2021, and 2022 as the testing years in its testing period.

Step 2. W calculates its repair deduction percentage for each extrapolation year. First, a tentative repair deduction percentage is calculated using data from the testing period (taxable years 2020, 2021, and 2022). Book capital additions that are properly treated as repair expenses allowable as deductions resulting from the application of the proposed method of accounting, before taking into account book-tax basis adjustments, for 2020, 2021, and 2022, the testing years that comprise the testing period, equal $1,000 ($300 + $400 + $300). Total book capital additions for the testing period are $10,000 ($3,000 + $3,000 + $4,000). W's tentative repair deduction percentage is 10 percent ($1,000 / $10,000).

Next, W calculates the reduction percentage for each extrapolation year using the formula (1 - (0.10 * (X/Y))), where X equals the number of years the extrapolation year precedes 2022, the final year of the testing period, and Y equals 3, the number of years in the testing period (2020-2022). The reduction percentage for each extrapolation year

is calculated as follows:

Extrapolation Year	Reduction Percentage Calculation (Step A)	Reduction Percentage Calculation (Step B)
2019	0.10 * (3/3) = 0.10	1 – 0.10 = 0.90 = 90.0%
2018	0.10 * (4/3) = 0.133	1 – 0.133 = 0.867 = 86.7%
2017	0.10 * (5/3) = 0.167	1 – 0.167 = 0.833 = 83.3%
2016	0.10 * (6/3) = 0.20	1 – 0.20 = 0.80 = 80.0%
2015	0.10 * (7/3) = 0.233	1 – 0.233 = 0.767 = 76.7%
2014	0.10 * (8/3) = 0.267	1 – 0.267 = 0.733 = 73.3%
2013	0.10 * (9/3) = 0.30	1 – 0.30 = 0.70 = 70.0%
2012	0.10 * (10/3) = 0.333	1 – 0.333 = 0.667 = 66.7%
2011	0.10 * (11/3) = 0.367	1 – 0.367 = 0.633 = 63.3%
2010	0.10 * (12/3) = 0.40	1 – 0.40 = 0.60 = 60.0%
2009	0.10 * (13/3) = 0.433	1 – 0.433 = 0.567 = 56.7%
2008	0.10 * (14/3) = 0.467	1 – 0.467 = 0.533 = 53.3%
2007	0.10 * (15/3) = 0.50	1 – .50 = 0.50 = 50.0%
2006	0.10 * (16/3) = 0.533	1 – 0.533 = 0.467 = 46.7%
2005	0.10 * (17/3) = 0.567	1 – 0.567 = 0.433 = 43.3%
2004	0.10 * (18/3) = 0.60	1 – 0.60 = 0.40 = 40.0%
2003	0.10 * (19/3) = 0.633	1 – 0.633 = 0.367 = 36.7%

Finally, W multiplies the tentative repair deduction percentage for each extrapolation year by the reduction percentage for each extrapolation year to calculate the repair deduction percentage for each extrapolation year. Accordingly, for 2014, W's repair deduction percentage is 7.33 percent (10 percent X 73.33 percent = 7.33 percent).

Step 3. Next, W calculates a tentative repair deduction amount for each extrapolation year. For its 2014 extrapolation year, W multiplies its book capital additions for 2014 ($3,333) by its repair deduction percentage (7.33 percent), resulting in an initial tentative repair deduction amount of $244. Next, W accounts for any book-tax basis adjustments for property placed in service in 2014 by multiplying the initial tentative repair deduction amount ($244) for 2014 by W's book-to-tax adjustment percentage for 2014 (90 percent), resulting in a tentative repair deduction amount of $220.

Step 4. W must reduce its tentative repair deduction amount for 2014 to exclude repairs attributable to natural gas transmission property and natural gas distribution property for which W elected to apply the ADR repair allowance. In 2014, W determined that 25 percent of its 2014 qualified repair expenditures for natural gas transmission and natural gas distribution property were attributable to repair allowance property. Therefore, W reduces the repair deduction amount for 2014 ($220) by 25 percent ($55), yielding a repair deduction amount for 2014 of $165.

Step 5. W determines its tentative § 481(a) adjustment amount for 2014. W subtracts the adjusted gross repair deduction amount for 2014 ($165) from the amount of repair expenses W deducted for 2014 under its prior method of accounting (as adjusted for purposes of computing any prior § 481(a) adjustment) ($150). Therefore,

W's § 481(a) adjustment amount for 2014 is negative $15.

Step 6. To determine its § 481(a) adjustment amount for 2014, W must account for its decreased depreciation deductions resulting from the additional $15 of repair expenditures allowable as deductions under the proposed method of accounting. Assuming that the additional $15 of repair expenditures allowable as deductions for 2014 results in a $4.50 of reduction in cumulative depreciation expense through January 1, 2023, the beginning of the year of change, that is attributable to the assets placed in service in 2014, W's § 481(a) adjustment amount for the increased repair deductions that would have been permitted in 2014 under the proposed method of accounting is negative $10.50 (-$15.00 + $4.50).

Step 7. To determine its total § 481(a) adjustment, W combines the adjustments attributable to its extrapolation years 2003 through 2019, computed using the extrapolation method in this Appendix B (as described above for 2014), with the § 481(a) adjustments attributable to 2020 through 2022, determined using the actual data from those years and taking into account book-tax basis adjustments. W must take the entire § 481(a) adjustment (whether positive or negative) into account in 2023, W's year of change.

Texas Gas Service
A Division of ONE Gas

1301 S. Mopac Expressway
Suite 400
Austin, TX 78746
stacey.mcTaggart@onegas.com

November 7, 2024

Railroad Commission of Texas
Attn: Kari French, Asst. Exec. Director
1701 N. Congress
P.O. Box 12967
Austin, Texas 78711-2967

and,

Municipal Regulators
Attn: City Managers and/or City Clerks

Ms. French and Municipal Representatives:

Texas Gas Service Company, a division of ONE Gas, Inc. ("TGS" or "the Company") is providing this letter for informational purposes only, to inform you, as our regulator, of the adoption of a new tax method made by the Company. TGS will analyze the potential impact on rates and will reflect any changes in TGS's next general rate case filed in your jurisdiction.

In 2023, the United States Internal Revenue Service ("IRS") provided guidance in Revenue Procedure 2023-15 regarding a new accounting method, Natural Gas Safe Harbor Method ("NGSH" Method), utilities are to consider when determining whether certain natural gas transmission and distribution property expenditures can be deducted or must be capitalized for federal tax purposes. The Company has elected to adopt the NGSH Method of accounting and notified the IRS of this election on October 15, 2024, with the filing of IRS Form 3115, *Application for Change in Accounting Method*. As required by the IRS, TGS is providing a copy of the Form 3115 as filed by ONE Gas, Inc., on a corporate basis (as opposed to a division basis) to each regulator within thirty days of the Company's 2023 federal income tax return filing.

Further, the Company consents to a normalization method of accounting (as defined in IRC Sec 168(i)(9)), which will be used for its public utility property subject to the application. At the beginning of the year of change, the Company will adjust its deferred tax reserve account (or similar account), to reflect the deferred federal income tax liability from the Section 481(a) adjustment applicable to the public utility property as reported on IRS Form 3115.

TGS will reflect any impacts of this election on rates in its next general rate case filed in your jurisdiction. If you have any questions, please feel free to contact me via email at stacey.mctaggart@onegas.com to schedule a time to discuss.

November 7, 2024
Notice of IRS Form 3115 Filing

Respectfully,



Stacey L. McTaggart
Director of Rates and Regulatory

Enclosures

November 7, 2024
Notice of IRS Form 3115 Filing

Certificate of Service

On this the 7th day of November, 2024, I certify that the foregoing notice and the attached copy of ONE Gas' IRS Form 3115, filed on October 15, 2024, has been mailed via overnight mail to the regulators of Texas Gas Service Company as listed below.

Judy Jenkins Hitchye

Railroad Commission of Texas, Gas Services Division

Cities of Central Gulf-Service Area	Cities of West North Service Area	Cities of Rio Grande Service Area
City of Bastrop	City of Andrews	City of Alamo
City of Bayou Vista	City of Aledo	City of Alton
City of Beaumont	Town of Anthony	City of Brownsville
City of Bee Cave	City of Barstow, c/o Ward Co.	Town of Combes
City of Buda	City of Breckenridge	City of Donna
City of Cedar Park	City of Borger	City of Edcouch
City of Dripping Springs	City of Bryson	City of Edinburg
City of Galveston	Town of Clint	City of Elsa
City of Georgetown	City of Crane	City of Harlingen
City of Groves	City of Dell City	City of Hidalgo
City of Hutto	City of El Paso	City of La Feria
City of Jamaica Beach	City of Graford	City of La Joya
City of Kyle	City of Graham	City of La Villa
City of Lakeway	Horizon City	City of Laguna Vista
City of Marble Falls	City of Hudson Oaks	City of Los Fresnos
City of Mustang Ridge	City of Jacksboro	City of Lyford
City of Nederland	City of McCamey	City of McAllen
City of Pflugerville	City of Millsap	City of Mercedes
City of Rollingwood	City of Mineral Wells	City of Mission
City of Sunset Valley	City of Monahans	City of Palm Valley
City of West Lake Hills	Town of Thorntonville	City of Palmhurst
City of Austin	City of Pecos	City of Palmview
City of Cuero	City of Pyote	City of Penitas
City of Gonzales	City of San Elizario	City of Pharr
City of Lockhart	Skellytown	City of Port Isabel
City of Luling	City of Socorro	City of Primera

November 7, 2024
Notice of IRS Form 3115 Filing

City of Nixon
City of Port Arthur
City of Port Neches
City of Shiner
City of Yoakum
Village of Vinton
City of Weatherford
City of Wickett
City of Willow Park
City of Wink
City of Progreso
Town of Rancho Viejo
City of Raymondville
City of Rio Hondo
City of San Benito
City of San Juan
City of Santa Rosa
City of Weslaco

Form **3115**
(Rev. December 2022)
Department of the Treasury
Internal Revenue Service

Application for Change in Accounting Method

Go to *www.irs.gov/Form3115* for instructions and the latest information.

OMB No. 1545-2070

Attachment Sequence No. **315**

Name of filer (name of parent corporation if a consolidated group) (see instructions)
ONE Gas, Inc.

Identification number (see instructions) [redacted]

Principal business activity code number (see instructions)
221210

Number, street, and room or suite no. If a P.O. box, see the instructions.
15 E. 5th Street

Tax year of change begins (MM/DD/YYYY) 01/01/2023

Tax year of change ends (MM/DD/YYYY) 12/31/2023

City or town, state, and ZIP code
Tulsa, OK 74103

Name of contact person (see instructions)
Brian F. Brumfield

Name of applicant(s) (if different than filer) and identification number(s) (see instructions)
See Attachment

Contact person's telephone number
(918) 947-7383

Does the filer want to receive a copy of the change in method of accounting letter ruling or other correspondence related to this Form 3115 by fax or encrypted email attachment? If "Yes," see instructions . . . . . ☑ Yes ☐ No

If the applicant is a member of a consolidated group, check this box . . . . . ☑

If **Form 2848**, Power of Attorney and Declaration of Representative, is attached (see instructions for when Form 2848 is required), check this box . . . . . ☐

Check the box to indicate the type of applicant.

- ☐ Individual
- ☑ Corporation
- ☐ Controlled foreign corporation (Sec. 957)
- ☐ 10/50 corporation (Sec. 904(d)(2)(E))
- ☐ Qualified personal service corporation (Sec. 448(d)(2))
- ☐ Exempt organization. Enter Code section:
- ☐ Cooperative (Sec. 1381)
- ☐ Partnership
- ☐ S corporation
- ☐ Insurance co. (Sec. 816(a))
- ☐ Insurance co. (Sec. 831)
- ☐ Other (specify):

Check the appropriate box to indicate the type of accounting method change being requested. See instructions.

- ☐ Depreciation or Amortization
- ☐ Financial Products and/or Financial Activities of Financial Institutions
- ☐ Other (specify): Routine Repairs (2023-15) Safe Harbor for Gas T&D

Caution: To be eligible for approval of the requested change in method of accounting, the taxpayer must provide all information that is relevant to the taxpayer or to the taxpayer's requested change in method of accounting. This includes (**1**) all relevant information requested on this Form 3115 (including its instructions), and (**2**) any other relevant information, even if not specifically requested on Form 3115.

The taxpayer must attach all applicable statements requested throughout this form.

Part I Information for Automatic Change Request

		Yes	No
1	Enter the applicable designated automatic accounting method change number ("DCN") for the requested automatic change. Enter only one DCN, except as provided for in guidance published by the IRS. If the requested change has no DCN, check "Other," and provide both a description of the change and a citation of the IRS guidance providing the automatic change. See instructions.		
a	(1) DCN: 269 (2) DCN: _____ (3) DCN: _____ (4) DCN: _____ (5) DCN: _____ (6) DCN: _____ (7) DCN: _____ (8) DCN: _____ (9) DCN: _____ (10) DCN: _____ (11) DCN: _____ (12) DCN: _____		
b	Other ☐ Description: _____		
2	Do any of the eligibility rules restrict the applicant from filing the requested change using the automatic change procedures (see instructions)? If "Yes," attach an explanation		✓
3	Has the filer provided all the information and statements required (**a**) on this form and (**b**) by the List of Automatic Changes under which the applicant is requesting a change? See instructions	✓	
	Note: Complete Part II and Part IV of this form, and, Schedules A through E, if applicable.		

Part II Information for All Requests

		Yes	No
4	During the tax year of change, did or will the applicant (**a**) cease to engage in the trade or business to which the requested change relates, or (**b**) terminate its existence? See instructions		✓
5	Is the applicant requesting to change to the principal method in the tax year of change under Regulations section 1.381(c)(4)-1(d)(1) or 1.381(c)(5)-1(d)(1)?		✓
	If "No," go to line 6a.		
	If "Yes," the applicant cannot file a Form 3115 for this change. See instructions.		

Sign Here

Under penalties of perjury, I declare that I have examined this application, including accompanying schedules and statements, and to the best of my knowledge and belief, the application contains all the relevant facts relating to the application, and it is true, correct, and complete. Declaration of preparer (other than applicant) is based on all information of which preparer has any knowledge.

Signature of filer (and spouse if joint return)	Date	Name and title (print or type)
[signature]		Brian F. Brumfield, Vice President and CAO

Preparer (other than filer/applicant)

Print/Type preparer's name	Preparer's signature	Date
Firm's name		

Part II Information for All Requests (*continued*)

		Yes	No
6a	Does the applicant (or any present or former consolidated group in which the applicant was a member during the applicable tax year(s)) have any federal income tax return(s) under examination (see instructions)? If "No," go to line 7a.		✓
b	Is the method of accounting the applicant is requesting to change an issue under consideration (with respect to either the applicant or any present or former consolidated group in which the applicant was a member during the applicable tax year(s))? See instructions	N/A	
c	Enter the name and telephone number of the examining agent and the tax year(s) under examination. Name N/A Telephone number N/A Tax year(s) N/A		
d	Has a copy of this Form 3115 been provided to the examining agent identified on line 6c?	N/A	
7a	Does audit protection apply to the applicant's requested change in method of accounting? See instructions If "No," attach an explanation.	✓	
b	If "Yes," check the applicable box and attach the required statement. ☑ Not under exam ☐ 3-month window ☐ 120 day: Date examination ended ☐ Method not before director ☐ Negative adjustment ☐ CAP: Date member joined group ☐ Audit protection at end of exam ☐ Other		
8a	Does the applicant (or any present or former consolidated group in which the applicant was a member during the applicable tax year(s)) have any federal income tax return(s) before Appeals and/or a federal court? If "No," go to line 9.		✓
b	Is the method of accounting the applicant is requesting to change an issue under consideration by Appeals and/or a federal court (for either the applicant or any present or former consolidated group in which the applicant was a member for the tax year(s) the applicant was a member)? See instructions If "Yes," attach an explanation.	N/A	
c	If "Yes," enter the name of the (check the box) ☐ Appeals officer and/or ☐ counsel for the government, telephone number, and the tax year(s) before Appeals and/or a federal court. Name Telephone number Tax year(s)		
d	Has a copy of this Form 3115 been provided to the Appeals officer and/or counsel for the government identified on line 8c?	N/A	
9	If the applicant answered "Yes" to line 6a and/or 8a with respect to any present or former consolidated group, attach a statement that provides each parent corporation's (**a**) name, (**b**) identification number, (**c**) address, and (**d**) tax year(s) during which the applicant was a member that is under examination, before an Appeals office, and/or before a federal court.		
10	If for federal income tax purposes, the applicant is either an entity (including a limited liability company) treated as a partnership or an S corporation, is it requesting a change from a method of accounting that is an issue under consideration in an examination, before Appeals, or before a federal court, with respect to a federal income tax return of a partner, member, or shareholder of that entity?	N/A	
11a	Has the applicant, its predecessor, or a related party requested or made (under either an automatic or non-automatic change procedure) a change in method of accounting within any of the 5 tax years ending with the tax year of change? If "No," go to line 12.		✓
b	If "Yes," for each trade or business, attach a description of each requested change in method of accounting (including the tax year of change) and state whether the applicant received consent.		
c	If any application was withdrawn, not perfected, or denied, or if a Consent Agreement granting a change was not signed and returned to the IRS, or the change was not made or not made in the requested year of change, attach an explanation.		
12	Does the applicant, its predecessor, or a related party currently have pending any request (including any concurrently filed request) for a private letter ruling, change in method of accounting, or technical advice? If "Yes," for each request attach a statement providing (**a**) the name(s) of the taxpayer, (**b**) identification number(s), (**c**) the type of request (private letter ruling, change in method of accounting, or technical advice), and (**d**) the specific issue(s) in the request(s).		✓
13	Is the applicant requesting to change its **overall** method of accounting? If "Yes," complete Schedule A on page 4 of the form.		✓

Part II Information for All Requests *(continued)*

		Yes	No
14	If the applicant is either **(i) not** changing its overall method of accounting, or **(ii)** changing its overall method of accounting **and** changing to a special method of accounting for one or more items, attach a detailed and complete description for each of the following (see instructions):		
a	The item(s) being changed.		
b	The applicant's present method for the item(s) being changed.		
c	The applicant's proposed method for the item(s) being changed.		
d	The applicant's present overall method of accounting (cash, accrual, or hybrid).		
15a	Attach a detailed and complete description of the applicant's trade(s) or business(es). See section 446(d).		
b	If the applicant has more than one trade or business, as defined in Regulations section 1.446-1(d), describe (i) whether each trade or business is accounted for separately; **(ii)** the goods and services provided by each trade or business and any other types of activities engaged in that generate gross income; **(iii)** the overall method of accounting for each trade or business; and **(iv)** which trade or business is requesting to change its accounting method as part of this application or a separate application. **Note:** If you are requesting an automatic method change, see the instructions to see if you are required to complete lines 16a–16c.		
16a	Attach a full explanation of the legal basis supporting the proposed method for the item being changed. Include a detailed and complete description of the facts that explains how the law specifically applies to the applicant's situation and that demonstrates that the applicant is authorized to use the proposed method.		
b	Include all authority (statutes, regulations, published rulings, court cases, etc.) supporting the proposed method.		
c	Include either a discussion of the contrary authorities or a statement that no contrary authority exists.		
17	Will the proposed method of accounting be used for the applicant's books and records and financial statements? For insurance companies, see the instructions . . . . . If "No," attach an explanation.		✓
18	Does the applicant request a conference with the IRS National Office if the IRS National Office proposes an adverse response?	✓	
19a	If the applicant is changing to either the overall cash method, an overall accrual method, or is changing its method of accounting for any property subject to section 263A, any long-term contract subject to section 460 (see 19b), or inventories subject to section 471 or 474, enter the applicant's gross receipts for the 3 tax years preceding the tax year of change.		

1st preceding year ended: mo. yr.	2nd preceding year ended: mo. yr.	3rd preceding year ended: mo. yr.
$ N/A	$ N/A	$ N/A

b	If the applicant is changing its method of accounting for any long-term contract subject to section 460, in addition to completing 19a, enter the applicant's gross receipts for the 4th tax year preceding the tax year of change: 4th preceding year ended: mo. _____ yr. ____ $ _____		

Part III Information for Non-Automatic Change Request

		Yes	No
20	Is the applicant's requested change described in any revenue procedure, revenue ruling, notice, regulation, or other published guidance as an automatic change request? . . . . . If "Yes," attach an explanation describing why the applicant is submitting its request under the non-automatic change procedures.	N/A	
21	Attach a copy of all documents related to the proposed change (see instructions).		
22	Attach a statement of the applicant's reasons for the proposed change.		
23	If the applicant is a member of a consolidated group for the year of change, do all other members of the consolidated group use the proposed method of accounting for the item being changed? . . . . . If "No," attach an explanation.	N/A	
24a	Enter the amount of **user fee** attached to this application (see instructions) . . . . . $ _____		
b	If the applicant qualifies for a reduced user fee, attach the required information or certification (see instructions).		

Part IV Section 481(a) Adjustment

		Yes	No
25	Does published guidance require the applicant (or permit the applicant and the applicant is electing) to implement the requested change in method of accounting on a cut-off basis? If "Yes," attach an explanation and do not complete lines 26, 27, 28, and 29 below.		✓
26	Enter the section 481(a) adjustment. Indicate whether the adjustment is an increase (+) or a decrease (-) in income. $ See Attachment Attach a summary of the computation and an explanation of the methodology used to determine the section 481(a) adjustment. If it is based on more than one component, show the computation for each component. If the applicant waived any deductions with respect to the method of accounting pursuant to Regulations section 1.59A-3(c)(6)(i), include a summary of the waived deductions. If more than one applicant is applying for the method change on the application, attach a list of the (a) name, (b) identification number, and (c) the amount of the section 481(a) adjustment attributable to each applicant.		
27	Is the applicant required to take into account in the year of change any remaining portion of a section 481(a) adjustment from a prior change (see instructions)? If "Yes," enter the amount. $		✓
28	Is the applicant making an election to take the entire amount of the adjustment into account in the tax year of change? If "Yes," check the box for the applicable elective provision used to make the election (see instructions). ☐ $50,000 de minimis election ☐ Eligible acquisition transaction election	N/A	
29	Is any part of the section 481(a) adjustment attributable to transactions between members of an affiliated group, a consolidated group, a controlled group, or other related parties? If "Yes," attach an explanation.		✓

Schedule A—Change in Overall Method of Accounting (If Schedule A applies, Part I below must be completed.)

Part I Change in Overall Method (see instructions)

1 Check the appropriate boxes below to indicate the applicant's present and proposed methods of accounting.

Present method:	☐ Cash	☐ Accrual	☐ Hybrid (attach description)
Proposed method:	☐ Cash	☐ Accrual	☐ Hybrid (attach description)

2 Enter the following amounts as of the close of the tax year preceding the year of change. If none, state "None." Also, attach a statement providing a breakdown of the amounts entered on lines 2a through 2g.

		Amount
a	Income accrued but not received (such as accounts receivable)	$
b	Income received or reported before it was earned (such as advanced payments). Attach a description of the income and the legal basis for the proposed method	
c	Expenses accrued but not paid (such as accounts payable)	
d	Prepaid expenses previously deducted	
e	Supplies on hand previously deducted and/or not previously reported	
f	Inventory on hand previously deducted and/or not previously reported. Complete Schedule D, Part II	
g	Other amounts (specify). Attach a description of the item and the legal basis for its inclusion in the calculation of the section 481(a) adjustment.	
h	**Net section 481(a) adjustment** (Combine lines 2a–2g.) Indicate whether the adjustment is an increase (+) or decrease (-) in income. Also enter the net amount of this section 481(a) adjustment amount on Part IV, line 26	$

3 Is the applicant also requesting the recurring item exception under section 461(h)(3)? ☐ Yes ☐ No

4 Attach copies of the profit and loss statement (Schedule F (Form 1040) for farmers) and the balance sheet, if applicable, as of the close of the tax year preceding the year of change. Also attach a statement specifying the accounting method used when preparing the balance sheet. If books of account are not kept, attach a copy of the business schedules submitted with the federal income tax return or other return (such as tax-exempt organization returns) for that period. If the amounts in Part I, lines 2a through 2g, do not agree with the amounts shown on the balance sheet, attach a statement explaining the differences.

5 Is the applicant making a change to the overall cash method or to a method in which a taxpayer uses an accrual method for purchases and sales of inventory and uses the cash method for computing all other items of income and expense (see instructions)? ☐ Yes ☐ No

Part II Change to the Cash Method for Non-Automatic Change Request (see instructions)

Applicants requesting a change to the cash method must attach the following information:

1 A description of inventory items (items whose production, purchase, or sale is an income-producing factor) and materials and supplies used in carrying out the business.

2 An explanation as to whether the applicant is required to use an accrual method under any section of the Code or regulations.

Schedule B—Changes Related to the Deferral Method for Advance Payments, Cost Offset Methods, and/or the Applicable Financial Statement Income Inclusion Rule (see instructions)

1 If the applicant is requesting to change to the deferral method for advance payments under Regulations section 1.451-8(c) or (d), as described in the instructions, attach the information specified in the instructions.

2 If the applicant is requesting to change to or within a cost offset method under Regulations section 1.451-3(c) and/or Regulations section 1.451-8(e), as described in the instructions, attach the information specified in the instructions.

3 If the applicant is requesting to change to or within a method to conform to the applicable financial statement (AFS) income inclusion rule under section 451(b) and Regulations section 1.451-3, as described in the instructions, attach a detailed description of the proposed method including the information specified in the instructions.

Schedule C—Changes Within the LIFO Inventory Method (see instructions)

Part I General LIFO Information

Complete this section if the requested change involves changes within the LIFO inventory method. Also, attach a copy of all **Forms 970**, Application To Use LIFO Inventory Method, filed to adopt or expand the use of the LIFO method.

1 Attach a description of the applicant's present and proposed LIFO methods and submethods for each of the following items:

a Valuing inventory (for example, unit method or dollar-value method).

b Pooling (for example, by line or type or class of goods, natural business unit, multiple pools, raw material content, simplified dollar-value method, inventory price index computation (IPIC) pools, vehicle-pool method, etc.).

c Pricing dollar-value pools (for example, double-extension, index, link-chain, link-chain index, IPIC method, etc.).

d Determining the current-year cost of goods in the ending inventory (such as, most recent acquisitions, earliest acquisitions during the current year, average cost of current-year acquisitions, rolling-average cost, or other permitted method).

2 If any present method or submethod used by the applicant is not the same as indicated on Form(s) 970 filed to adopt or expand the use of the method, attach an explanation.

3 If the proposed change is not requested for all the LIFO inventory, attach a statement specifying the inventory to which the change is and is not applicable.

4 If the proposed change is not requested for all of the LIFO pools, attach a statement specifying the LIFO pool(s) to which the change is applicable.

5 Attach a statement addressing whether the applicant values any of its LIFO inventory on a method other than cost. For example, if the applicant values some of its LIFO inventory at retail and the remainder at cost, identify which inventory items are valued under each method.

6 If changing to the IPIC method, attach a completed Form 970.

Part II Change in Pooling Inventories

1 If the applicant is proposing to change its pooling method or the number of pools, attach a description of the contents of, and state the base year for, each dollar-value pool the applicant presently uses and proposes to use.

2 If the applicant is proposing to use natural business unit (NBU) pools or requesting to change the number of NBU pools, attach the following information (to the extent not already provided) in sufficient detail to show that each proposed NBU was determined under Regulations sections 1.472-8(b)(1) and (2):

a A description of the types of products produced by the applicant. If possible, attach a brochure.

b A description of the types of processes and raw materials used to produce the products in each proposed pool.

c If all of the products to be included in the proposed NBU pool(s) are not produced at one facility, state the reasons for the separate facilities, the location of each facility, and a description of the products each facility produces.

d A description of the natural business divisions adopted by the taxpayer. State whether separate cost centers are maintained and if separate profit and loss statements are prepared.

e A statement addressing whether the applicant has inventories of items purchased and held for resale that are not further processed by the applicant, including whether such items, if any, will be included in any proposed NBU pool.

f A statement addressing whether all items including raw materials, goods-in-process, and finished goods entering into the entire inventory investment for each proposed NBU pool are presently valued under the LIFO method. Describe any items that are not presently valued under the LIFO method that are to be included in each proposed pool.

g A statement addressing whether, within the proposed NBU pool(s), there are items both sold to unrelated parties and transferred to a different unit of the applicant to be used as a component part of another product prior to final processing.

3 If the applicant is engaged in manufacturing and is proposing to use the multiple pooling method or raw material content pools, attach information to show that each proposed pool will consist of a group of items that are substantially similar. See Regulations section 1.472-8(b)(3).

4 If the applicant is engaged in the wholesaling or retailing of goods and is requesting to change the number of pools used, attach information to show that each of the proposed pools is based on customary business classifications of the applicant's trade or business. See Regulations section 1.472-8(c).

Schedule D—Change in the Treatment of Long-Term Contracts Under Section 460, Inventories, or Other Section 263A Assets (see instructions)

Part I Change in Reporting Income From Long-Term Contracts (Also complete Part III on pages 7 and 8.)

1 To the extent not already provided, attach a description of the applicant's present and proposed methods for reporting income and expenses from long-term contracts. Also, attach a representative actual contract (without any deletions) for the requested change. If the applicant is a construction contractor, attach a detailed description of its construction activities.

2a Are the applicant's contracts long-term contracts as defined in section 460(f)(1) (see instructions)? . . ☐ Yes ☐ No

b If "Yes," do all the contracts qualify for the exception under section 460(e) (see instructions)? . . . . ☐ Yes ☐ No
If line 2b is "No," attach an explanation.

c Is the applicant requesting to use the percentage-of-completion method using cost-to-cost under Regulations section 1.460-4(b)? . . . . . ☐ Yes ☐ No

d If line 2c is "Yes," in computing the completion factor of a contract, will the applicant use the simplified cost-to-cost method described in Regulations section 1.460-5(c)? . . . . . ☐ Yes ☐ No

e If line 2c is "No," is the applicant requesting to use the exempt-contract percentage-of-completion method under Regulations section 1.460-4(c)(2)? . . . . . ☐ Yes ☐ No
If line 2e is "Yes," attach an explanation of what method the applicant will use to determine a contract's completion factor.
If line 2e is "No," attach an explanation of what method the applicant is using and the authority for its use.

3a Does the applicant have long-term manufacturing contracts as defined in section 460(f)(2)? . . . . . ☐ Yes ☐ No

b If "Yes," attach a description of the applicant's manufacturing activities, including any required installation of manufactured goods.

4a Does the applicant enter into cost-plus long-term contracts? . . . . . ☐ Yes ☐ No

b Does the applicant enter into federal long-term contracts? . . . . . ☐ Yes ☐ No

Part II Change in Valuing Inventories Including Cost Allocation Changes (Also complete Part III on pages 7 and 8.)

1 Attach a description of the inventory goods being changed.

2 Attach a description of the inventory goods (if any) NOT being changed.

3a Is the applicant subject to section 263A? If "No," go to line 4a . . . . . ☐ Yes ☐ No

b Is the applicant's present inventory valuation method in compliance with section 263A (see instructions)? If "No," attach a detailed explanation . . . . . ☐ Yes ☐ No

4a Check the appropriate boxes in the chart.

	Inventory Method Being Changed		Inventory Method Not Being Changed
	Present method	Proposed method	Present method
Identification methods:			
Specific identification			
FIFO			
LIFO			
Other (attach explanation)			
Valuation methods:			
Cost			
Cost or market, whichever is lower			
Retail cost			
Retail, lower of cost or market			
Other (attach explanation)			
b Enter the value at the end of the tax year preceding the year of change.	$	$	

5 If the applicant is changing from the LIFO inventory method to a non-LIFO method, attach the following information (see instructions).

a Copies of Form(s) 970 filed to adopt or expand the use of the method.

b **Only for applicants requesting a non-automatic change.** A statement describing whether the applicant is changing to the method required by Regulations section 1.472-6(a) or (b), or whether the applicant is proposing a different method.

c **Only for applicants requesting an automatic change.** The statement required by section 23.01(5) of Rev. Proc. 2022-14 (or its successor).

6 Is the applicant presently using the AFS cost offset method as described in Regulations section 1.451-3(c) and/or the advance payment cost offset method described in Regulations section 1.451-8(e), or is the applicant changing to such methods for the same year of change as the requested change in inventory method? If "Yes," see the instructions for rules regarding concurrent changes . . . . . ☐ Yes ☐ No

Part III **Method of Cost Allocation** (Complete this part if the requested change involves either property subject to section 263A or long-term contracts as described in section 460.) See instructions.

Section A—Allocation and Capitalization Methods

Attach a description (including sample computations) of the present and proposed method(s) the applicant uses to capitalize direct and indirect costs properly allocable to real or tangible personal property produced and property acquired for resale, or to allocate direct and indirect costs required to be allocated to long-term contracts. Include a description of the method(s) used for allocating indirect costs to intermediate cost objectives such as departments or activities prior to the allocation of such costs to long-term contracts, real or tangible personal property produced, and property acquired for resale. The description must include the following:

1 The method of allocating direct and indirect costs (for example, specific identification, burden rate, standard cost, or other reasonable allocation method).

2 The method of allocating mixed service costs (for example, direct reallocation, step-allocation, simplified service cost using the labor-based allocation ratio, simplified service cost using the production cost allocation ratio, or other reasonable allocation method).

3 Except for long-term contract accounting methods, the method of capitalizing additional section 263A costs (for example, simplified production with or without the historic absorption ratio election, modified simplified production with or without the historic absorption ratio election, simplified resale with or without the historic absorption ratio election including permissible variations, the U.S. ratio, or other reasonable allocation method).

Section B—Direct and Indirect Costs Required To Be Allocated

Check the appropriate boxes showing the costs that are or will be fully included, to the extent required, in the cost of real or tangible personal property produced or property acquired for resale under section 263A or allocated to long-term contracts under section 460. Mark "N/A" in a box if those costs are not incurred by the applicant. If a box is not checked, it is assumed that those costs are not fully included to the extent required. Attach an explanation for boxes that are not checked.

		Present method	Proposed method
1	Direct material		
2	Direct labor		
3	Indirect labor		
4	Officers' compensation (not including selling activities)		
5	Pension and other related costs		
6	Employee benefits		
7	Indirect materials and supplies		
8	Purchasing costs		
9	Handling, processing, assembly, and repackaging costs		
10	Offsite storage and warehousing costs		
11	Depreciation, amortization, and cost recovery allowance for equipment and facilities placed in service and not temporarily idle		
12	Depletion		
13	Rent		
14	Taxes other than state, local, and foreign income taxes		
15	Insurance		
16	Utilities		
17	Maintenance and repairs that relate to a production, resale, or long-term contract activity		
18	Engineering and design costs (not including section 174 research and experimental expenses)		
19	Rework labor, scrap, and spoilage		
20	Tools and equipment		
21	Quality control and inspection		
22	Bidding expenses incurred in the solicitation of contracts awarded to the applicant		
23	Licensing and franchise costs		
24	Capitalizable service costs (including mixed service costs)		
25	Administrative costs (not including any costs of selling or any return on capital)		
26	Research and experimental expenses attributable to long-term contracts		
27	Interest		
28	Other costs (Attach a list of these costs.)		

Part III Method of Cost Allocation (*continued*) See instructions.

Section C—Other Costs Not Required To Be Allocated (Complete Section C only if the applicant is requesting to change its method for these costs.)

		Present method	Proposed method
1	Marketing, selling, advertising, and distribution expenses		
2	Research and experimental expenses not included in Section B, line 26		
3	Bidding expenses not included in Section B, line 22		
4	General and administrative costs not included in Section B		
5	Income taxes		
6	Cost of strikes		
7	Warranty and product liability costs		
8	Section 179 costs		
9	On-site storage		
10	Depreciation, amortization, and cost recovery allowance not included in Section B, line 11		
11	Other costs (Attach a list of these costs.)		

Schedule E—Change in Depreciation or Amortization (see instructions)

Applicants requesting approval to change their method of accounting for depreciation or amortization complete this section. Applicants ***must*** provide this information for each item or class of property for which a change is requested.

Note: See the ***Summary of the List of Automatic Accounting Method Changes*** in the instructions for information regarding automatic changes under sections 56, 167, 168, or 197, or former sections 168, 1400I, or 1400L. **Do not** file Form 3115 with respect to certain late elections and election revocations. See instructions.

1 Is depreciation for the property determined under Regulations section 1.167(a)-11 (CLADR)? ☐ **Yes** ☐ **No**
If "Yes," the only changes permitted are under Regulations section 1.167(a)-11(c)(1)(iii).

2 Is any of the depreciation or amortization required to be capitalized under any Code section, such as section 263A? ☐ **Yes** ☐ **No**
If "Yes," enter the applicable section _____

3 Has a depreciation, amortization, expense, or disposition election been made for the property, such as the election under sections 168(f)(1), 168(i)(4), 179, 179C, or Regulations section 1.168(i)-8(d)? ☐ **Yes** ☐ **No**
If "Yes," state the election made _____

4a Attach a statement describing the property subject to the change. Include the property's description, type, placed-in-service year, and use in the applicant's trade or business or income-producing activity. Also include the type and amount of any federal tax credit claimed or grant received, along with any necessary adjustments to basis required under the Internal Revenue Code, with respect to the property.

b If the property is residential rental property, did the applicant live in the property before renting it? ☐ **Yes** ☐ **No**

c Is the property public utility property? ☐ **Yes** ☐ **No**

5 To the extent not already provided in the applicant's description of its present method, attach a statement explaining how the property is treated under the applicant's present method (for example, depreciable property, inventory property, supplies under Regulations section 1.162-3, nondepreciable section 263(a) property, property deductible as a current expense, etc.).

6 If the property is not currently treated as depreciable or amortizable property, attach a statement of the facts supporting the proposed change to depreciate or amortize the property.

7 If the property is currently treated and/or will be treated as depreciable or amortizable property, provide the following information for both the present (if applicable) and proposed methods:

a The Code section under which the property is or will be depreciated or amortized (for example, section 168(g)).

b The applicable asset class from Rev. Proc. 87-56, 1987-2 C.B. 674, for each asset depreciated under section 168 (MACRS) or under former section 1400L; the applicable asset class from Rev. Proc. 83-35, 1983-1 C.B. 745, for each asset depreciated under former section 168 (ACRS); an explanation why no asset class is identified for each asset for which an asset class has not been identified by the applicant.

c The facts to support the asset class for the proposed method.

d The depreciation or amortization method of the property, including the applicable Code section (for example, 200% declining balance method under section 168(b)(1)).

e The useful life, recovery period, or amortization period of the property.

f The applicable convention of the property.

g Whether the additional first-year special depreciation allowance (for example, as provided by section 168(k), 168(l), 168(m), or former section 168(n), 1400L(b), or 1400N(d)) was or will be claimed for the property. If not, also provide an explanation as to why no special depreciation allowance was or will be claimed.

h Whether the property was or will be in a single asset account, a multiple asset account, or a general asset account.

Statements Attached to and Made Part of
Form 3115
Application for Change in Accounting Method
Automatic Change #269
December 31, 2023

ONE Gas, Inc.
[redacted]

Page 1, Name of Applicant(s)

This Application is being filed by ONE Gas, Inc. [redacted] (hereinafter "Applicant" or "Taxpayer").

Statement Required by Section 6.02(5) of Rev. Proc. 2015-13
The Taxpayer represents that the above referenced applicant is the only member of the consolidated group that has this item that is the matter of this method change request.

Request for Faxed Documents

In accordance with the procedures set forth in section 9.04(3) of Rev. Proc. 2024-1, the Taxpayer requests that a copy of any document related to this request (e.g., a request for additional information) be provided to the Taxpayer and the Taxpayer's authorized representatives via fax at the number(s) below.

Taxpayer's Fax Number: Brian F. Brumfield (918-606-8551)

Part II, Question 11b – Previous Requests

There are no other pending requests before the IRS. Changes/Requests for Change within the past five years are as follows:

Entity Making Change	Description of Change	Type of Change	Status of Change	Year or Change
ONE Gas, Inc [redacted]	Change under Rev. Proc. 2000-50 in method of accounting for the costs of computer software.	Automatic	Deemed Consent	12/31/2021

Part II, Question 11c – Applications Withdrawn

None.

Part II, Question 14a – Item Being Changed

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The Taxpayer is filing change 269 to change its treatment of natural gas transmission and distribution property to adopt the transmission and distribution property safe harbor method of accounting provided in Rev. Proc. 2023-15. Specifically, the Taxpayer wants to change to "the safe harbor method for linear property" and "the safe harbor method for non-linear property" in accordance with Rev. Proc. 2023-15. In conjunction with this change, the Taxpayer will make a late general asset account election as required under section 5.08(2) of Rev. Proc. 2023-15. The Taxpayer has a depreciable interest in natural gas transmission and distribution property and incurs costs (other than excluded costs) to maintain, repair, replace or improve such property.

Part II, Question 14b – Present Method

The Taxpayer is a natural gas utility regulated by the Kansas Corporation Commission ("KCC"), Oklahoma Corporation Commission ("OCC") and the Public Utility Commission of Texas ("RCC"). The Taxpayer presently utilizes units of property("UOPs") as determined and used in its books of account for regulatory reporting purposes and does not define the UOP in a manner that is consistent with the safe harbor.

The Taxpayer has not claimed a federal income tax credit with respect to any of the costs or assets subject to this accounting method change.

Part II, Question 14c – Proposed Method

Under the Taxpayer's proposed method of accounting, the Taxpayer will follow the natural gas safe harbor method of accounting for its linear transmission, linear distribution and non-linear property as described below.

With respect to its linear transmission property, the Taxpayer will utilize the safe harbor method for linear property described in Section 5.02 of Rev. Proc. 2023-15 to determine its repairs and maintenance deductions, including

- Determining its UOPs for such property in accordance with Section 5.02(1) of the revenue procedure;
- Applying the simplified rule for replacements of such property in accordance with Section 5.02(2) of the revenue procedure;

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- Following the treatment outlined for blanket work orders in Section 5.02(3) of the revenue procedure; and
- Applying the aggregation requirements of Section 5.06 of the revenue procedure.

With respect to its linear distribution property, the Taxpayer will utilize the safe harbor method for linear property described in Section 5.03 of Rev. Proc. 2023-15 to determine its repairs and maintenance deductions, including

- Applying the simplified rule for replacements of distribution mains in accordance with Section 5.03(2) of the revenue procedure;
- Following the treatment outlined for blanket work orders in Section 5.03(3) of the revenue procedure;
- Applying the aggregation requirements of Section 5.06 of the revenue procedure;
- Following the rules for identified distribution service line costs provided in Section 5.07(2) of the revenue procedure and the simplified rules for unidentified distribution service line costs provided in Section 5.07(3) of the revenue procedure.

With respect to its non-linear transmission and distribution property, the Taxpayer will utilize the safe harbor method for non-linear property described in Section 5.04 of Rev. Proc. 2023-15 to determine its repairs and maintenance deductions, including

- Using the UOPs and major components provided in Appendix A of the revenue procedure in making its repairs and maintenance determinations;
- Applying the simplified rule for replacements of such property in accordance with Section 5.04(3) of the revenue procedure;
- Applying the aggregation requirements of Section 5.06 of the revenue procedure; and

In applying the natural gas safe harbor method to both its linear and its non-linear transmission and distribution property, the Taxpayer will capitalize all costs designated as "per se capital expenditures" in Section 5.05(1) of Rev. Proc. 2015-13.

In addition, the Taxpayer will make late general asset account (GAA) elections under IRC Section 168(i)(4) and Treas. Reg. Sec. 1.168(i)-1(l) to include in GAAs its natural gas transmission and distribution property placed in service prior to the tax year of change and owned by the Taxpayer at the beginning of the tax year of change.

The Taxpayer's proposed change in method of accounting for federal income tax purposes is not related to the adoption of the International Financial Reporting Standards (IFRS) for financial statement purposes.

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Special rules for blanket work orders.

(1) Blanket work order de minimis rule. A taxpayer that adheres to a policy that limits per-event charges under a blanket work order procedure to replacements of property costing $50,000 or less is not required to capitalize the costs of linear property replacements charged to the blanket work order. Replacements of property qualifying under this de minimis rule are not taken into account in determining whether more than 10 percent of the length of the unit of linear transmission property is replaced under section 5.02(2) of Rev. Proc. 2023-15 or in applying the aggregation requirement in section 5.06 of Rev. Proc. 2023-15.

Part II, Question 14d – Present Overall Method of Accounting

The Taxpayer's overall method of accounting is the accrual method.

Part II, Question 15 – Description of Trade or Business

The applicant, for purposes of this Form 3115, is a publicly traded company, ONE Gas, Inc. The applicant is a 100% regulated utility company engaged in the transmission, distribution and sale of natural gas. It provides natural gas to over 2.3 million residential, commercial and industrial customers in the states of Kansas, Oklahoma and Texas. The Applicant's business activity code is 221210. The Applicant does not have more than one trade or business as defined in Regulations Section 1.446-1(d).

Part II, Question 17 – Proposed Method Will Not be Used for Book

The proposed method of accounting will not be used for the Taxpayer's books and records and financial statement purposes because the method is not an acceptable method under the FERC accounting rules and the method does not likely follow the same rules as the generally accepted accounting principles ("GAAP"). The proposed method will be used in the Applicant's tax books and records.

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Part II, Question 18 – Conference of Right

If it is tentatively determined that the Taxpayer has changed its method of accounting without complying with all the applicable provisions of Rev. Proc. 2015-13, as modified, clarified and amplified (for example, the Taxpayer changed to a method of accounting that varies from the applicable accounting method described in Rev. Proc. 2015-13, as modified, clarified and amplified, or the Taxpayer is outside the scope of Rev. Proc. 2015-13, as modified, clarified and amplified), the Taxpayer requests a conference of right. To arrange the time and place of such a conference, please contact the Taxpayer's representative:

Brian F. Brumfield (918) 947-7383
ONE Gas, Inc.
15 E. 5th Street.
Tulsa, OK 74103

Part IV, Question 26 – Net Section 481(a) Adjustment

Net Section 481(a) Adjustment (Decrease in Computing Taxable Income)	($239,267,385)

Applicant	EIN	481(a) Adjustment
ONE Gas, Inc.	[redacted]	($239,267,385)
Total		($239,267,385)

Taxpayer incurred expenses for repairs and maintenance that were previously capitalized and depreciated over 20 years, depending on the asset repaired, but deducted under Sec. 162 based on the Taxpayer's present method of accounting which utilizes units of property generally consistent with the 300-399 Plant Chart of Accounts for regulatory reporting purposes under the FERC Electric Uniform System of Accounts mandated for Public Utilities. Under the proposed method, the amounts would have been expensed during the tax year as incurred based on units of property as defined by Rev. Proc. 2023-15. The net §481(a) adjustment is a net decrease in taxable income of $239,267, 385. This adjustment is the difference between the current method and the proposed method, and it is the remaining basis in the capitalized repairs and maintenance costs affected by the method change. Thus, the net §481(a) adjustment will be (1) the difference

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between the repair expenditures claimed under the proposed and current methods plus (2) the difference between the depreciation expense on repair expenditures required to be capitalized under the proposed and current methods. This net §481(a) adjustment will be recognized in full in the year of change pursuant to Section 3.12(4) of Rev. Proc. 2023-43.

The Taxpayer represents that it intends to comply with Section 263A and will treat the repairs or depreciation on the components as indirect costs, if properly allocable, in accordance with Treas. Reg. § 1.263A-1(e)(3)(ii). The effect of Section 263A, if any, is reflected in the Taxpayer's Section 481(a) adjustment.

Computation of net §481(a) adjustment – Rev. Proc. 2023-15

Taxpayer followed the procedures contained in Section 2 of Appendix B of Rev. Proc. 2023-15 to calculate the net §481(a) adjustment.

Step 1:
Taxpayer used data from a minimum of three of the most recent taxable years as required under Section 2.02(1) to calculate the gross repairs deduction. 2023 is the year of change and the taxpayer used actual data from a testing period of taxable years 2020-2022. These are consecutive years as required under Section 2.02(1)(a) of Appendix B and are representative years as required and defined under Section 2.02(1)(b) of Appendix B. For each of the taxable years in the testing period, taxable years 2020-2022, the deductible repair expenses were calculated under the safe harbor method using the actual data from those years.

Steps 2-3:
The repairs deduction percentage for each year in the extrapolation period 2010-2019 is calculated in accordance with Section 2.02(2) of Appendix B. The extrapolation year tentative repair deduction amount is calculated under Section 2.02(3) of Appendix B.

Step 4:
N/A. Taxpayer did not elect to apply the § 1.167(a)-11(d)(2) repair allowance.

Step 5:
The repair amounts calculated using Steps1-3 were reduced by the sum of the repair expenses the taxpayer had taken under its method of accounting prior to application of the safe harbor. This

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resulted in an adjusted gross repair deduction in the amount of $470,147,165 as shown in Table 1 below.

Step 6:
Taxpayer accounted for its decreased depreciation deductions resulting from the additional repair expenditures allowable under the proposed method of accounting and calculated the amount of decreased depreciation deductions (as a result of taking a repairs deduction) as required under Section 2.02(6) of Appendix B. The repairs deduction was assigned to the various 'tax classes' (combination of tax asset class with the same tax depreciation method, life and convention) by year by applying the ratio of corresponding book additions to total book additions and multiplying it by the repairs deduction amount for the year. The difference in depreciation under the proposed method versus the depreciation under the current method was then calculated. The decreased depreciation deductions totaled $230,879,780 as shown in Table 1 below.

Step 7:
Taxpayer's total 481(a) adjustment is determined by combining the results of Steps 5 and 6. The total 481(a) adjustment of $239,267,865 is shown in Table 1 below:

Table 1		**Total**
Deductible Repair Expenses [2.02(2)(a)]	$	(470,147,165)
Tax Adjustments before Depreciation [2.02(2)]	$	230,879,780
Net §481(a) adjustment	$	(239,267,385)

Statement required by Section 3.12(3)(a)(ii) of Rev. Proc. 2024-23:

Pursuant to the requirements of section 5.08(2) of Rev. Proc. 2023-15 and section 3.12(3)(a) of Rev. Proc. 2024-23, the Taxpayer hereby agrees to the following additional terms and conditions:

(1) The taxpayer consents to, and agrees to apply, all the provisions of Treas. Reg. § 1.168(i)-1 to the assets that are subject to the election specified in section 5.08(2) of Rev. Proc. 2023-15; and

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(2) Except as provided in section 1.168(i)-1(c)(1)(ii)(A), (e)(3), (g), or (h), the election made by the taxpayer under section 5.08(2) of Rev. Proc. 2023-15 is irrevocable and will be binding on the taxpayer for computing taxable income for the year of change and for all subsequent taxable years with respect to the assets that are subject to this election.

Statement required by Section 3.12(3)(c) of Rev. Proc. 2024-23:

Pursuant to section 3.12(3)(c) of Rev. Proc. 2024-23, whereby the assets subject to this change in method of accounting are public utility property within the meaning of section 168(i)(10), the Taxpayer agrees to the following additional terms and conditions:

1) A normalization method of accounting (within the meaning of section 168(i)(9)) will be used for the public utility property subject to the Form 3115;

2) As of the beginning of the year of change, the taxpayer will adjust its deferred tax reserve account or similar account in the taxpayer's regulatory books of account by the amount of the deferral of federal income tax liability associated with the section 481(a) adjustment applicable to the public utility property subject to the Form 3115; and

3) Within 30 calendar days of filing the federal income tax return for the year of change, the taxpayer will provide a copy of the completed Form 3115 to any regulatory body having jurisdiction over the public utility property subject to the Form 3115.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024
ARAM Estimate for amounts attributed to the Combined Texas Jurisdictions

Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Non-protected (ARAM)	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount
Texas Direct Plant Assets Depreciation	($76,721,922)	($76,721,922)			($76,721,922)	
Texas Direct Plant Repairs	($23,780,320)			(23,780,320)	(23,780,320)	
Texas Cost of Removal Asset	$9,523,032		9,523,032		9,523,032	
Texas Tax Repairs 481(a)	($7,400,723)		(7,400,723)		(7,400,723)	
Texas Other Nonprotected plant	($1,794,371)			(1,794,371)	(1,794,371)	
Texas Other Rate Base Items	($6,730,641)			(6,730,641)	(6,730,641)	
TGS Division Plant Assets Depreciation	($571,323)	(571,323)			(571,323)	
ONE Gas Plant Assets Depreciation	($3,364,068)	(3,364,068)				(3,364,068)
Texas NOL (See NOL tab, Note 6)	$55,327,343	55,327,343		-	55,327,343	
ADIT - Accumulated Deferred Income Taxes	($55,512,994)	($25,329,970)	$2,122,309	($32,305,333)	($52,148,926)	($3,364,068)
	-	-	-	-	-	-

Texas

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization	GrossUp*	Total Refund
Year 1 - 2018 Actuals	6,183,517	388,159	(1,471,939)	1,384,287	5,099,737	1,099,242	6,198,979
Year 2 - 2019 Actuals	6,177,969	359,364	(1,545,154)	1,401,715	4,992,179	1,048,957	6,041,136
Year 3 - 2020 Actuals	6,727,402	418,187	(2,278,000)	2,200,619	4,867,589	900,979	5,768,569
Year 4 - 2021 Actuals	6,357,000	557,188	(764,838)	640,789	6,149,350	1,163,384	7,312,735
Year 5 - 2022 Actuals	2,209,911	383,504	(622,382)	534,404	1,971,033	131,516	2,102,549
Year 6 - 2023 Est	3,011,143	282,582	(1,005,033)	922,719	2,288,691	154,107	2,442,799
Year 7 - 2024 Est	2,920,615	354,236	(1,002,813)	883,903	2,272,038	145,974	2,418,011
Year 8 - 2025 Est	3,021,174	347,172	(1,047,218)	921,715	2,321,127	154,987	2,476,114
Year 9 - 2026 Est	2,976,098	307,139	(1,016,587)	900,216	2,266,651	145,382	2,412,033
Year 10 - 2027 Est	2,868,222	136,581	(988,526)	878,500	2,016,277	105,740	2,122,017
Year 11 - 2028 Est	1,337,102	18,502	(912,116)	800,367	443,488	84,028	527,517
Year 12 - 2029 Est	1,377,783	3,028	(998,862)	860,537	381,949	85,157	467,106

*NOTE: Gross-up not included for WNSA

45,167,937	3,555,643	(13,653,469)	12,329,772	35,070,110	9,322,434	
45,167,937	$ 3,555,643	(13,653,469)		35,070,110	5,219,453	
12,006,667	$ 945,171	(3,629,403)				
57,174,604	$ 4,500,814	(17,282,873)				

$ 57,174,604	$ 4,500,814	$ (17,282,873)

$ -

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	2028 Amortization	2029 Amortization	Total	
Texas Direct Plant Assets Depreciation	$636,166	$587,766	$699,349	$805,364	$977,427	$1,558,597	$1,564,533	$1,492,501	$1,447,033	$1,404,230	$1,298,985	$1,410,930	$13,882,880	-
Texas Direct Plant Repairs	$4,145,650	$4,145,650	$4,145,650	$4,139,799	$1,034,894	$1,034,894	$1,034,894	$1,034,894	$1,034,894	$1,034,894	$0	$0	22,786,114	-
Texas Cost of Removal Asset	$0	$0	$0	$0	($298,332)	($106,197)	($171,135)	($178,436)	($173,990)	($170,367)	($155,285)	($169,828)	(1,423,570)	-
Texas Tax Repairs 481(a)								$142,667	$138,170	$133,812	$124,153	$134,502	673,304	
Texas Other Nonprotected plant	(2,329)	27,044	502,638	151,526	174,815	174,815	174,815	174,815	174,815	174,815	67,102	-	1,794,871	-
Texas Other Rate Base Items	1,249,685	1,249,685	1,249,685	1,249,685	288,650	288,650	288,650	288,650	288,650	288,650	-	-	6,730,642	-
TGS Division Plant Assets Depreciation	154,345	167,824	130,080	10,627	32,457	60,384	28,856	66,083	66,526	2,189	2,146	2,180	723,697	-
ONE Gas Plant Assets Depreciation	388,159	359,364	418,187	557,188	383,504	282,582	354,236	347,172	307,139	136,581	18,502	3,028	3,555,643	-
Texas NOL (See NOL tab, Note 6)	(1,471,939)	(1,545,154)	(2,278,000)	(764,838)	(622,382)	(1,005,033)	(1,002,813)	(1,047,218)	(1,016,587)	(988,526)	(912,116)	(998,862)	(13,653,470)	-
ADIT - Accumulated Deferred Income Taxes	Σ $5,099,737	Σ $4,992,179	Σ $4,867,589	Σ $6,149,350	Σ $1,971,033	Σ $2,288,691	Σ $2,272,038	Σ $2,321,127	Σ $2,266,651	Σ $2,016,277	Σ $443,488	Σ $381,949	Σ 35,070,110	-
	$ 5,099,737	$ 4,992,179	$ 4,867,589	$ 6,149,350	$ 1,971,033	$ 2,288,691	$ 2,272,038	$ 2,321,127	$ 2,266,651	$ 2,016,277	$ 443,488	$ 381,949	$ 35,070,110	
							$ (27,872,376)							

	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	1.96%	60.00%	33.63%	790,511	210,136	5,393,006	1,433,584	7,827,237	(1,643,720)	6,183,517	-
Year 2 - 2019 Actuals	1.40%	60.00%	32.05%	755,590	200,853	5,422,379	1,441,392	7,820,214	(1,642,245)	6,177,969	-
Year 3 - 2020 Actuals	2.75%	60.00%	22.97%	829,429	220,481	5,897,973	1,567,816	8,515,699	(1,788,297)	6,727,402	-
Year 4 - 2021 Actuals	3.35%	60.00%	40.83%	815,991	216,909	5,541,010	1,472,927	8,046,836	(1,689,836)	6,357,000	-
Year 5 - 2022 Actuals	3.53%	10.00%	34.20%	1,009,884	268,450	1,200,028	318,995	2,797,356	(587,445)	2,209,911	-
Year 6 - 2023 Est	5.05%	10.00%	25.20%	1,618,981	430,362	1,392,162	370,068	3,811,573	(800,430)	3,011,143	-
Year 7 - 2024 Est	5.43%	10.00%	31.59%	1,593,390	423,559	1,327,225	352,807	3,696,980	(776,366)	2,920,615	-
Year 8 - 2025 Est	5.69%	10.00%	30.96%	1,558,583	414,307	1,462,590	388,790	3,824,270	(803,097)	3,021,174	-
Year 9 - 2026 Est	5.46%	10.00%	27.39%	1,513,559	402,339	1,462,539	388,776	3,767,213	(791,115)	2,976,098	-
Year 10 - 2027 Est	5.27%	10.00%	12.18%	1,406,418	373,858	1,461,804	388,581	3,630,661	(762,439)	2,868,222	-
Year 11 - 2028 Est	4.98%	0.00%	1.65%	1,301,131	345,870	35,970	9,562	1,692,534	(355,432)	1,337,102	-
Year 12 - 2029 Est	5.58%	0.00%	0.27%	1,413,110	375,637	(35,326)	(9,391)	1,744,030	(366,246)	1,377,783	-

	Amortization Period		Amortization				Financial Impact			
NOL	Protected	Unprotected 10	Protected	Protected Gross	Unprotected	Unprotected	Total including	Income Tax	Regulatory	
Year 1 - 2018 Actuals	1.36%	60.00%	(1,471,939)	(391,275)	-	-	(1,863,214)	391,275	(1,471,939)	-
Year 2 - 2019 Actuals	0.89%	60.00%	(1,545,154)	(410,737)	-	-	(1,955,891)	410,737	(1,545,154)	-
Year 3 - 2020 Actuals	1.75%	60.00%	(2,278,000)	(605,544)	-	-	(2,883,544)	605,544	(2,278,000)	-
Year 4 - 2021 Actuals	2.33%	60.00%	(764,838)	(203,311)	-	-	(968,149)	203,311	(764,838)	-
Year 5 - 2022 Actuals	3.53%	10.00%	(622,382)	(165,443)	-	-	(787,826)	165,443	(622,382)	-
Year 6 - 2023 Est	5.05%	10.00%	(1,005,033)	(267,161)	-	-	(1,272,194)	267,161	(1,005,033)	-
Year 7 - 2024 Est	5.43%	10.00%	(1,002,813)	(266,571)	-	-	(1,269,384)	266,571	(1,002,813)	-
Year 8 - 2025 Est	5.69%	10.00%	(1,047,218)	(278,374)	-	-	(1,325,593)	278,374	(1,047,218)	-
Year 9 - 2026 Est	5.46%	10.00%	(1,016,587)	(270,232)	-	-	(1,286,819)	270,232	(1,016,587)	-
Year 10 - 2027 Est	5.27%	10.00%	(988,526)	(262,773)	-	-	(1,251,299)	262,773	(988,526)	-
Year 11 - 2028 Est	4.98%	0.00%	(912,116)	(242,461)	-	-	(1,154,577)	242,461	(912,116)	-
Year 12 - 2029 Est	5.58%	0.00%	(998,862)	(265,520)	-	-	(1,264,383)	265,520	(998,862)	-

	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%	388,159	103,182	-	-	491,341	(103,182)	388,159	-
Year 2 - 2019 Actuals	10.68%	359,364	95,527	-	-	454,892	(95,527)	359,364	-
Year 3 - 2020 Actuals	7.78%	418,187	111,164	-	-	529,351	(111,164)	418,187	-
Year 4 - 2021 Actuals	16.59%	557,188	148,113	-	-	705,301	(148,113)	557,188	-
Year 5 - 2022 Actuals	11.40%	383,504	101,944	-	-	485,448	(101,944)	383,504	-
Year 6 - 2023 Est	8.40%	282,582	75,117	-	-	357,698	(75,117)	282,582	-
Year 7 - 2024 Est	10.53%	354,236	94,164	-	-	448,400	(94,164)	354,236	-
Year 8 - 2025 Est	10.32%	347,172	92,286	-	-	439,458	(92,286)	347,172	-
Year 9 - 2026 Est	9.13%	307,139	81,645	-	-	388,784	(81,645)	307,139	-
Year 10 - 2027 Est	4.06%	136,581	36,306	-	-	172,888	(36,306)	136,581	-
Year 11 - 2028 Est	0.55%	18,502	4,918	-	-	23,421	(4,918)	18,502	-
Year 12 - 2029 Est	0.09%	3,028	805	-	-	3,832	(805)	3,028	-

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024
ARAM Estimate for amounts attributed to the Central Gulf Service Area (CGSA)

Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Non-protected (ARAM)	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount
Central Gulf Direct Plant Assets Depreciation	(33,942,116)	(33,942,116)			(33,942,116)	
Central Gulf Direct Plant Repairs	(10,622,000)			(10,622,000)	(10,622,000)	
Central Gulf Cost of Removal Asset	3,375,204		3,375,204		3,375,204	
Central Gulf Tax Repairs 481(a)	(3,397,437)		(3,397,437)		(3,397,437)	
Central 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)	
ONE Gas Plant Assets Depreciation	(1,542,000)	(1,542,000)				(1,542,000)
Central Gulf NOL (See NOL tab, Note 6)	21,068,802	21,068,802		-	21,068,802	
ADIT - Accumulated Deferred Income Taxes	($28,460,167)	(14,679,887)	(22,233)	(13,758,047)	(26,918,167)	(1,542,000)

CGSA

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization	GrossUp	Total Refund
Year 1 - 2018 Actuals	3,795,203	183,881	(566,040)	566,040	3,413,044	907,265	4,320,309
Year 2 - 2019 Actuals	3,690,070	164,752	(659,073)	659,073	3,195,749	849,503	4,045,252
Year 3 - 2020 Actuals	3,857,074	203,852	(1,375,793)	1,375,793	2,685,133	713,770	3,398,903
Year 4 - 2021 Actuals	3,788,688	256,589	(413,443)	413,443	3,631,834	965,424	4,597,258
Year 5 - 2022 Actuals	492,926	175,788	(269,652)	269,652	399,062	106,080	505,142
Year 6 - 2023 Est	802,452	129,528	(437,004)	437,004	494,976	131,576	626,551
Year 7 - 2024 Est	704,556	162,373	(428,762)	428,762	438,167	116,475	554,642
Year 8 - 2025 Est	755,694	159,134	(449,790)	449,790	465,038	123,618	588,656
Year 9 - 2026 Est	733,721	140,785	(436,032)	436,032	438,474	116,556	555,030
Year 10 - 2027 Est	668,921	62,605	(414,317)	414,317	317,209	84,321	401,531
Year 11 - 2028 Est	625,569	8,481	(387,437)	387,437	246,613	65,555	312,168
Year 12 - 2029 Est	617,376	1,388	(382,345)	382,345	236,419	62,845	299,264
	20,532,250	1,649,156	(6,219,688)	6,219,688	15,961,717	4,242,988	
	20,532,250	1,649,156	(6,219,688)		15,961,717	4,242,988	
	5,457,940	438,383	(1,653,335)				
	25,990,190	2,087,539	(7,873,023)				
	25,990,190	2,087,539	(7,873,023)				

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	2028 Amortization	2029 Amortization	Total
Central Gulf Direct Plant Assets Depreciation	$290,226	$164,051	$357,551	$344,255	$477,896	$774,489	$759,880	$ 724,617	$ 702,454	$ 667,470	$ 624,166	$ 615,963	$6,503,018
Central Gulf Direct Plant Repairs	2,655,500	2,655,500	2,655,500	2,655,500	-	-	-	-	-				10,622,000
Central Gulf Cost of Removal Asset	-	-	-	-	-	-	(68,687)	(72,056)	(69,852)	(66,373)	(62,067)	(61,251)	(400,287)
Central Gulf Tax Repairs 481(a)								72,531	70,312	66,810	62,476	61,655	333,784
Central Gulf Other Rate Base Items	784,012	784,012	784,012	784,012	-	-	-	-	-				3,136,047
TGS Division Plant Assets Depreciation	65,465	86,507	60,011	4,921	15,030	27,963	13,363	30,602	30,807	1,014	994	1,010	337,687
ONE Gas Plant Assets Depreciation	183,881	164,752	203,852	256,589	175,788	129,528	162,373	159,134	140,785	62,605	8,481	1,388	1,649,156
Central Gulf NOL (See NOL tab, Note 6)	(566,040)	(659,073)	(1,375,793)	(413,443)	(269,652)	(437,004)	(428,762)	(449,790)	(436,032)	(414,317)	(387,437)	(382,345)	(6,219,689)
ADIT - Accumulated Deferred Income Taxes	Σ $3,413,043	Σ $3,195,749	Σ $2,685,133	Σ $3,631,834	Σ $399,062	Σ $494,976	Σ $438,167	Σ $465,038	Σ $438,474	Σ $317,209	Σ $246,613	Σ $236,419	Σ 15,961,717
													Σ 15,961,717
Ck Total	3,413,044	3,195,749	2,685,133	3,631,834	399,062	494,976	438,167	465,038	438,474	317,209	246,613	236,419	

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	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	2.07%	0.00%	8.40%	802,452	213,310	-	-	1,015,762	(213,310)	802,452	-
Year 7 - 2024 Est	2.04%	0.00%	10.53%	773,244	205,546	(68,687)	(18,259)	891,843	(187,287)	704,556	-
Year 8 - 2025 Est	2.13%	0.00%	10.32%	755,219	200,754	475	126	956,574	(200,881)	755,694	-
Year 9 - 2026 Est	2.07%	0.00%	9.13%	733,261	194,917	460	122	928,761	(195,040)	733,721	-
Year 10 - 2027 Est	1.97%	0.00%	4.06%	668,484	177,698	437	116	846,735	(177,814)	668,921	(0)
Year 11 - 2028 Est	1.84%	0.00%	0.55%	625,160	166,182	409	109	791,859	(166,290)	625,569	-
Year 12 - 2029 Est	1.81%	0.00%	0.09%	616,973	164,005	403	107	781,489	(164,113)	617,376	0

NOL	Amortization Period			Amortization				Financial Impact			
	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	2.07%	0.00%		(437,004)	(116,166)	-	-	(553,170)	116,166	(437,004)	-
Year 7 - 2024 Est	2.04%	0.00%		(428,762)	(113,975)	-	-	(542,736)	113,975	(428,762)	-
Year 8 - 2025 Est	2.13%	0.00%		(449,790)	(119,564)	-	-	(569,354)	119,564	(449,790)	-
Year 9 - 2026 Est	2.07%	0.00%		(436,032)	(115,907)	-	-	(551,940)	115,907	(436,032)	-
Year 10 - 2027 Est	1.97%	0.00%		(414,317)	(110,135)	-	-	(524,452)	110,135	(414,317)	-
Year 11 - 2028 Est	1.84%	0.00%		(387,437)	(102,990)	-	-	(490,426)	102,990	(387,437)	-
Year 12 - 2029 Est	1.81%	0.00%		$ (382,345)	$ (101,636)	$ -	$ -	$ (483,981)	$ 101,636	$ (382,345)	-

	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	-
Year 11 - 2028 Est	0.55%	8,481	2,254	-	-	10,735	(2,254)	8,481	-
Year 12 - 2029 Est	0.09%	1,388	369	-	-	1,757	(369)	1,388	-

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024
ARAM Estimate for amounts attributed to RGV

Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Non-protected (ARAM)	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount
RGV Direct Plant Assets Depreciation	(9,213,418)	(9,213,418)			(9,213,418)	
RGV Repairs	(1,821,025)			(1,821,025)	(1,821,025)	
RGV Cost of Removal Asset	481,003		481,003		481,003	
RGV Tax Repairs 481(a)	(1,091,953)		(1,091,953)		(1,091,953)	
RGV Other Rate Base Items	(708,090)			(708,090)	(708,090)	
TGS Division Plant Assets Depreciation	(58,101)	(58,101)			(58,101)	
ONEGas Plant Assets Depreciation	(345,123)	(345,123)				(345,123)
RGV NOL (See NOL tab, Note 6)	6,847,849	6,847,849			6,847,849	
ADIT - Accumulated Deferred Income Taxes	($5,908,858)	(2,768,793)	(610,950)	(2,529,115)	(5,563,735)	(345,123)

RGV

	TGS Amortization	ONE Gas Amortization	TGS NOL	Total Amortization	GrossUp	Total Refund
Year 1 - 2018 Actuals	771,158	38,693	(87,652)	722,199	191,977	914,176
Year 2 - 2019 Actuals	856,890	36,874	(143,439)	750,325	199,454	949,779
Year 3 - 2020 Actuals	756,072	25,574	(77,381)	704,265	187,210	891,475
Year 4 - 2021 Actuals	811,328	57,428	(124,049)	744,707	197,960	942,667
Year 5 - 2022 Est	144,324	39,344	(87,978)	95,690	25,437	121,127
Year 6 - 2023 Est	138,085	28,990	(82,314)	84,761	22,532	107,293
Year 7 - 2024 Est	193,540	36,341	(118,910)	110,971	29,499	140,470
Year 8 - 2025 Est	207,894	35,617	(125,503)	118,008	31,369	149,377
Year 9 - 2026 Est	193,301	31,510	(116,371)	108,440	28,826	137,265
Year 10 - 2027 Est	176,587	14,012	(110,026)	80,573	21,418	101,992
Year 11 - 2028 Est	179,344	1,898	(111,748)	69,494	18,473	87,967
Year 12 - 2029 Est	221,949	311	(138,325)	83,934	22,312	106,245

$	4,650,473	$ 346,592	$ (1,323,698)	$ -	$ 3,673,367	976,465
$	4,650,473	$ 346,592	$ (1,323,698)		$ 3,673,367	976,465
	1,236,202	$ 92,132	(351,869)			
	5,886,675	$ 438,724	(1,675,566)			
	5,886,675	438,724	(1,675,566)			
			$ -			
			-			

47.40%

	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization	2027 Amortization	2028 Amortization	2029 Amortization	Total Amortization
RGV Direct Plant Assets Depreciation	$124,502	$205,615	$110,614	$177,969	$147,203	$137,726	$198,958	$189,977	$176,153	$166,549	$169,156	$209,386	$2,013,808
RGV Repairs	455,256	455,256	455,256	455,256	-	-	-	-	-				$1,821,025
RGV Cost of Removal Asset					(6,180)	(5,782)	(8,352)	(8,816)	(8,174)	(7,728)	(7,849)	(9,716)	($62,598)
RGV Tax Repairs 481(a)								20,013	18,556	17,545	17,819	22,057	$95,990
RGV Other Rate Base Items	177,023	177,023	177,023	177,023	-	-	-	-	-				$708,090
TGS Division Plant Assets Depreciation	14,377	18,997	13,179	1,081	3,301	6,141	2,935	6,720	6,765	223	218	222	$74,158
ONEGas Plant Assets Depreciation	38,693	36,874	25,574	57,428	39,344	28,990	36,341	35,617	31,510	14,012	1,898	311	$346,592
RGV NOL (See NOL tab, Note 6)	(87,652)	(143,439)	(77,381)	(124,049)	(87,978)	(82,314)	(118,910)	(125,503)	(116,371)	(110,026)	(111,748)	(138,325)	($1,323,698)
ADIT - Accumulated Deferred Income Taxes	Σ $722,199	Σ $750,325	Σ $704,265	Σ $744,707	Σ $95,690	Σ $84,761	Σ $110,971	Σ $118,008	Σ $108,440	Σ $80,573	Σ $69,494	Σ $83,934	Σ $3,673,367
	$ 722,199	$ 750,325	$ 704,265	$ 744,707	$ 95,690	$ 84,761	$ 110,971	$ 118,008	$ 108,440	$ 80,573	$ 69,494	$ 83,934	Σ 3,673,367

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	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	0.61%	25.00%	11.21%	138,879	36,917	632,279	168,074	976,149	(204,991)	771,158	(0)
Year 2 - 2019 Est	0.52%	25.00%	10.68%	224,612	59,707	632,279	168,074	1,084,671	(227,781)	856,890	(0)
Year 3 - 2020 Est	0.99%	25.00%	7.41%	123,793	32,907	632,279	168,074	957,053	(200,981)	756,072	-
Year 4 - 2021 Est	1.02%	25.00%	7.65%	179,050	47,595	632,279	168,074	1,026,998	(215,670)	811,328	0
Year 5 - 2022 Est	1.28%	0.00%	11.40%	150,504	40,007	(6,180)	(1,643)	182,689	(38,365)	144,324	-
Year 6 - 2023 Est	1.20%	0.00%	8.40%	143,867	38,243	(5,782)	(1,537)	174,791	(36,706)	138,085	-
Year 7 - 2024 Est	1.74%	0.00%	10.53%	201,892	53,668	(8,352)	(2,220)	244,987	(51,447)	193,540	-
Year 8 - 2025 Est	1.83%	0.00%	10.32%	196,697	52,287	11,197	2,976	263,157	(55,263)	207,894	-
Year 9 - 2026 Est	1.70%	0.00%	9.13%	182,919	48,624	10,382	2,760	244,685	(51,384)	193,301	-
Year 10 - 2027 Est	1.61%	0.00%	4.06%	166,771	44,332	9,816	2,609	223,528	(46,941)	176,587	-
Year 11 - 2028 Est	1.63%	0.00%	0.55%	169,374	45,023	9,970	2,650	227,018	(47,674)	179,344	-
Year 12 - 2029 Est	2.02%	0.00%	0.09%	209,608	55,718	12,341	3,281	280,948	(58,999)	221,949	(0)

	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	0.61%	25.00%	(87,652)	(23,300)	-	-	(110,952)	23,300	(87,652)	-
Year 2 - 2019 Est	0.52%	25.00%	(143,439)	(38,129)	-	-	(181,568)	38,129	(143,439)	-
Year 3 - 2020 Est	0.99%	25.00%	(77,381)	(20,570)	-	-	(97,951)	20,570	(77,381)	-
Year 4 - 2021 Est	1.02%	25.00%	(124,049)	(32,975)	-	-	(157,024)	32,975	(124,049)	-
Year 5 - 2022 Est	1.28%	0.00%	(87,978)	(23,387)	-	-	(111,365)	23,387	(87,978)	-
Year 6 - 2023 Est	1.20%	0.00%	(82,314)	(21,881)	-	-	(104,195)	21,881	(82,314)	-
Year 7 - 2024 Est	1.74%	0.00%	(118,910)	(31,609)	-	-	(150,519)	31,609	(118,910)	-
Year 8 - 2025 Est	1.83%	0.00%	(125,503)	(33,362)	-	-	(158,865)	33,362	(125,503)	-
Year 9 - 2026 Est	1.70%	0.00%	(116,371)	(30,934)	-	-	(147,305)	30,934	(116,371)	-
Year 10 - 2027 Est	1.61%	0.00%	(110,026)	(29,247)	-	-	(139,273)	29,247	(110,026)	-
Year 11 - 2028 Est	1.63%	0.00%	(111,748)	(29,705)	-	-	(141,454)	29,705	(111,748)	-
Year 12 - 2029 Est	2.02%	0.00%	(138,325)	(36,770)	-	-	(175,096)	36,770	(138,325)	-

	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%	38,693	10,285	-	-	48,978	(10,285)	38,693	-
Year 2 - 2019 Est	10.68%	36,874	9,802	-	-	46,676	(9,802)	36,874	-
Year 3 - 2020 Est	7.41%	25,574	6,798	-	-	32,372	(6,798)	25,574	-
Year 4 - 2021 Est	7.65%	57,428	15,266	-	-	72,694	(15,266)	57,428	-
Year 5 - 2022 Est	11.40%	39,344	10,459	-	-	49,803	(10,459)	39,344	-
Year 6 - 2023 Est	8.40%	28,990	7,706	-	-	36,697	(7,706)	28,990	-
Year 7 - 2024 Est	10.53%	36,341	9,660	-	-	46,002	(9,660)	36,341	-
Year 8 - 2025 Est	10.32%	35,617	9,468	-	-	45,084	(9,468)	35,617	-
Year 9 - 2026 Est	9.13%	31,510	8,376	-	-	39,886	(8,376)	31,510	-
Year 10 - 2027 Est	4.06%	14,012	3,725	-	-	17,737	(3,725)	14,012	-
Year 11 - 2028 Est	0.55%	1,898	505	-	-	2,403	(505)	1,898	-
Year 12 - 2029 Est	0.09%	311	83	-	-	393	(83)	311	-

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024
ARAM Estimate for amounts attributed to the West North Service Area (WNSA)

Accumulated Deferred Income Taxes for:	Excess ADIT		Protected	Non-protected (ARAM)	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount
West North Direct Plant Assets Depreciation	(33,566,388)		(33,566,388)			(33,566,388)	
West North Repairs	(11,337,295)				(11,337,295)	(11,337,295)	
West North Cost of Removal Asset	5,666,825			5,666,825		5,666,825	
West North Tax Repairs 481(a)	(2,911,333)			(2,911,333)		(2,911,333)	
West North Other Nonprotected plant	(1,794,371)				(1,794,371)	(1,794,371)	
West North Other Rate Base Items	(2,886,504)				(2,886,504)	(2,886,504)	
TGS Division Plant Assets Depreciation	(248,649)		(248,649)			(248,649)	
ONEGas Plant Assets Depreciation	(1,476,945)		(1,476,945)				(1,476,945)
West North NOL (See NOL tab, Note 6)	27,410,692		27,410,692		-	27,410,692	
			$0			$0	
ADIT - Accumulated Deferred Income Taxes	Σ ($21,143,969)	Σ	(7,881,290)	Σ 2,755,492	Σ (16,018,171)	Σ (19,667,024)	Σ ($1,476,945)
Percent Protected			51%				

NOT INCLUDED

WestNorth

	TGS Amortization	ONE Gas Amortization	TGS NOL	OGS NOL	Total Amortization	Total Gross up	Total Refund
Year 1 - 2018 Actuals	1,617,156	165,585	(818,247)	818,247	964,494	256,385	964,494
Year 2 - 2019 Actuals	1,631,009	157,738	(742,642)	742,642	1,046,105	278,078	1,046,105
Year 3 - 2020 Actuals	2,114,256	188,761	(824,826)	824,826	1,478,191	392,937	1,478,191
Year 4 - 2021 Actuals	1,756,984	243,171	(227,346)	227,346	1,772,809	471,253	1,772,809
Year 5 - 2022 Est	1,572,661	168,372	(264,752)	264,752	1,476,281	392,429	1,476,281
Year 6 - 2023 Est	2,070,606	124,063	(485,715)	485,715	1,708,954	454,279	1,708,954
Year 7 - 2024 Est	2,022,518	155,522	(455,141)	455,141	1,722,899	457,986	1,722,899
Year 8 - 2025 Est	2,057,585	152,421	(471,925)	471,925	1,738,081	462,022	1,738,081
Year 9 - 2026 Est	2,049,076	134,845	(464,183)	464,183	1,719,738	457,146	1,719,738
Year 10 - 2027 Est	2,022,714	59,964	(464,183)	464,183	1,618,495	430,233	1,618,495
Year 11 - 2028 Est	532,189	8,123	(412,931)	412,931	127,382	33,861	127,382
Year 12 - 2029 Est	538,459	1,329	(478,192)	478,192	61,596	16,374	61,596

Σ	19,985,214	Σ 1,559,895	Σ (6,110,084)	Σ 6,110,084	Σ 15,435,026	Σ	4,102,981
Σ	19,985,214	$ 1,559,895	Σ (6,110,084)		Σ 15,435,026	Σ	4,102,981
Σ	5,312,525	$ 414,656	Σ (1,624,199)				
Σ	25,297,740	$ 1,974,550	Σ (7,734,283)				
Σ	25,297,740	Σ 1,974,550	Σ (7,734,283)				

36.81%

	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization	2027 Amortization	2028 Amortization	2029 Amortization	Total Amortization
West North Direct Plant Assets Depreciation	$221,438	$218,100	$231,184	$283,140	$352,328	$646,382	$605,695	$577,907	$568,426	$570,211	$505,663	$585,581	$5,366,054
West North Repairs	1,034,894	1,034,894	1,034,894	1,029,043	1,034,894	1,034,894	1,034,894	1,034,894	1,034,894	1,034,894			10,343,089
West North Cost of Removal Asset					(292,152)	(100,416)	(94,095)	(97,565)	(95,964)	(96,266)	(85,368)	(98,860)	(960,686)
West North Tax Repairs 481(a)								50,124	49,302	49,456	43,858	50,789	243,530
West North Other Nonprotected plant	(2,329)	27,044	502,638	151,526	174,815	174,815	174,815	174,815	174,815	174,815	67,102		1,794,871
West North Other Rate Base Items	288,650	288,650	288,650	288,650	288,650	288,650	288,650	288,650	288,650	288,650			2,886,504
TGS Division Plant Assets Depreciation	74,503	62,320	56,890	4,625	14,126	26,280	12,559	28,760	28,953	953	934	949	311,851
ONEGas Plant Assets Depreciation	165,585	157,738	188,761	243,171	168,372	124,063	155,522	152,421	134,845	59,964	8,123	1,329	1,559,895
West North NOL (See NOL tab, Note 6)	(818,247)	(742,642)	(824,826)	(227,346)	(264,752)	(485,715)	(455,141)	(471,925)	(464,183)	(464,183)	(412,931)	(478,192)	(6,110,084)
ADIT - Accumulated Deferred Income Taxes	Σ $964,494	Σ $1,046,105	Σ $1,478,191	Σ $1,772,809	Σ $1,476,281	Σ $1,708,954	Σ $1,722,899	Σ $1,738,081	Σ $1,719,738	Σ $1,618,495	Σ $127,382	Σ $61,596	Σ 15,435,026
	$ 964,494	$ 1,046,105	$ 1,478,191	$ 1,772,809	$ 1,476,281	$ 1,708,954	$ 1,722,899	$ 1,738,081	$ 1,719,738	$ 1,618,495	$ 127,382	$ 61,596	Σ 15,435,026

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2018 EDIT	754,140
2019 EDIT	722,654
2020 Credit	1,476,794

	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	0.61%	10.00%	11.21%	295,941	78,668	1,321,215	351,209	2,047,033	(429,877)	1,617,156	-
Year 2 - 2019 Act	0.52%	10.00%	10.68%	280,420	74,542	1,350,589	359,017	2,064,568	(433,559)	1,631,009	-
Year 3 - 2020 Est	0.99%	10.00%	7.78%	288,074	76,577	1,826,183	485,441	2,676,274	(562,018)	2,114,256	-
Year 4 - 2021 Est	1.02%	10.00%	16.59%	287,765	76,494	1,469,219	390,552	2,224,031	(467,046)	1,756,984	-
Year 5 - 2022 Est	0.97%	10.00%	11.40%	366,454	97,412	1,206,207	320,637	1,990,710	(418,049)	1,572,661	-
Year 6 - 2023 Est	1.77%	10.00%	8.40%	672,662	178,809	1,397,944	371,605	2,621,020	(550,414)	2,070,606	-
Year 7 - 2024 Est	1.66%	10.00%	10.53%	618,254	164,346	1,404,265	373,286	2,560,150	(537,631)	2,022,518	0
Year 8 - 2025 Est	1.72%	10.00%	10.32%	606,667	161,266	1,450,919	385,687	2,604,539	(546,953)	2,057,585	-
Year 9 - 2026 Est	1.69%	10.00%	9.13%	597,379	158,797	1,451,697	385,894	2,593,768	(544,691)	2,049,076	0
Year 10 - 2027 Est	1.70%	10.00%	4.06%	571,164	151,828	1,451,550	385,855	2,560,398	(537,683)	2,022,714	-
Year 11 - 2028 Est	1.51%		0.55%	506,598	134,665	25,592	6,803	673,657	(141,468)	532,189	-
Year 19 - 2029 Est	1.74%		0.09%	586,529	155,913	(48,071)	(12,778)	681,593	(143,135)	538,459	-

NOL	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	0.00%	10.00%	0.00%	(818,247)	(217,509)	-	-	(1,035,756)	217,509	(818,247)	-
Year 2 - 2019 Act	0.00%	10.00%	0.00%	(742,642)	(197,411)	-	-	(940,053)	197,411	(742,642)	-
Year 3 - 2020 Est	0.00%	10.00%	0.00%	(824,826)	(219,258)	-	-	(1,044,084)	219,258	(824,826)	-
Year 4 - 2021 Est	0.00%	10.00%	0.00%	(227,346)	(60,434)	-	-	(287,780)	60,434	(227,346)	-
Year 5 - 2022 Est	0.97%	10.00%	0.00%	(264,752)	(70,377)	-	-	(335,129)	70,377	(264,752)	-
Year 6 - 2023 Est	1.77%	10.00%	0.00%	(485,715)	(129,114)	-	-	(614,829)	129,114	(485,715)	-
Year 7 - 2024 Est	1.66%	10.00%	0.00%	(455,141)	(120,987)	-	-	(576,128)	120,987	(455,141)	-
Year 8 - 2025 Est	1.72%	10.00%	0.00%	(471,925)	(125,448)	-	-	(597,374)	125,448	(471,925)	-
Year 9 - 2026 Est	1.69%	10.00%	0.00%	(464,183)	(123,391)	-	-	(587,574)	123,391	(464,183)	-
Year 10 - 2027 Est	1.70%	10.00%	0.00%	(464,183)	(123,391)	-	-	(587,574)	123,391	(464,183)	-
Year 11 - 2028 Est	1.51%		0.55%	(412,931)	(109,766)	-	-	(522,697)	109,766	(412,931)	-
Year 12 - 2029 Est	1.74%		0.09%	(478,192)	(127,114)	-	-	(605,306)	127,114	(478,192)	-

	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%	165,585	44,016	-	-	209,602	(44,016)	165,585	-
Year 2 - 2019 Act	10.68%	157,738	41,930	-	-	199,668	(41,930)	157,738	-
Year 3 - 2020 Est	7.78%	188,761	50,177	-	-	238,938	(50,177)	188,761	-
Year 4 - 2021 Est	16.59%	243,171	64,640	-	-	307,811	(64,640)	243,171	-
Year 5 - 2022 Est	11.40%	168,372	44,757	-	-	213,129	(44,757)	168,372	-
Year 6 - 2023 Est	8.40%	124,063	32,979	-	-	157,042	(32,979)	124,063	-
Year 7 - 2024 Est	10.53%	155,522	41,341	-	-	196,864	(41,341)	155,522	-
Year 8 - 2025 Est	10.32%	152,421	40,517	-	-	192,938	(40,517)	152,421	-
Year 9 - 2026 Est	9.13%	134,845	35,845	-	-	170,690	(35,845)	134,845	-
Year 10 - 2027 Est	4.06%	59,964	15,940	-	-	75,904	(15,940)	59,964	-
Year 11 - 2028 Est	0.55%	8,123	2,159	-	-	10,283	(2,159)	8,123	-
Year 12 - 2029 Est	0.09%	$ 1,329	$ 353	$ -	$ -	$ 1,683	$ (353)	$ 1,329	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.**													
2	**TWELVE MONTHS ENDED DECEMBER 31, 2024**													
3	**2024 Regulatory EDIT Amortization attributed to Texas GAAP Books**													
4														
5														
6		**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**Total**
7	**CGSA**	(84,973)	(68,363)	(49,551)	(19,283)	(15,649)	(18,794)	(14,909)	(16,580)	(12,509)	(18,216)	(54,302)	(65,038)	(438,167)
8	**RGV**	(21,521)	(17,314)	(12,549)	(4,883)	(3,963)	(4,760)	(3,776)	(4,199)	(3,168)	(4,613)	(13,753)	(16,472)	(110,971)
9	**WNSA**	(334,120)	(268,807)	(194,836)	(75,820)	(61,531)	(73,900)	(58,626)	(65,194)	(49,185)	(71,625)	(213,517)	(255,738)	(1,722,899)
10	**Combined TGS**	(440,614)	(354,484)	(256,936)	(99,986)	(81,143)	(97,454)	(77,311)	(85,973)	(64,862)	(94,454)	(281,572)	(337,249)	(2,272,038)

PowerTax Deferred Tax Summary Report
2024 Year End Accrual
091 Texas Gas Service

Grouped By: TGS

Jurisdiction: Federal Rate Case	" Beginning Difference"	" Current Difference"	" Ending Difference"	"Beginning APB11 DFIT Balance"	" Current DFIT"	"Ending APB11 DFIT Balance"	"End FAS109 Liability @ Stat Rate"	"Regulatory Asset Before Gross-Up"	"Regulatory Liab Before Gross-Up"	"Regulatory Asset After Gross-Up"	"Regulatory Liab After Gross-Up"	
Federal Rate Case 481a Amortization	$0	$0	$0	$3,397,437	$0	$3,397,437	$0	$0	($3,397,437)	$0	($3,397,437)	CGSA
Federal Rate Case 481a Amortization	$0	$0	$0	$1,091,953	$0	$1,091,953	$0	$0	($1,091,953)	$0	($1,091,953)	RGV
Federal Rate Case 481a Amortization	$0	$0	$0	$2,911,333	$0	$2,911,333	$0	$0	($2,911,333)	$0	($2,911,333)	WNSA

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

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 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

SUBSCRIBED AND SWORN TO BEFORE ME by the said Kenneth W. Eakens on this 5th day of June 2025.

JOANNE C. DAVIS NOTARY # 05009895 EXP. 10/25/25 PUBLIC STATE OF OKLAHOMA

Joanne C. Davis
Notary Public in and for the State of Oklahoma

My commission expires: October 25, 2025

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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EXHIBIT TSL-1	Qualifications
EXHIBIT TSL-2	Summary of Lead-Lag Study
EXHIBIT TSL-3	Supporting Calculations for the Lead-Lag Study

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 1 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 have sponsored testimony before more than 30 U.S. and Canadian regulatory agencies, including the Commission. 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 Company ("TGS" or the "Company") to develop a lead-lag study that determines the cash working capital ("CWC") requirement for the Company's proposed statewide Texas jurisdiction, which is a combination of the existing West North Service Area ("WNSA"), Rio Grande Valley Service Area ("RGVSA"), and Central-Gulf Service Area ("CGSA").[1] The lead-lag study summary and supporting calculations for TGS are included, respectively, in Exhibits TSL-2 and TSL-3.

[1] I have also prepared and support individual lead-lag study schedules for WNSA, CGSA, and RGVSA.

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").[2]

Q. DOES THE LEAD-LAG STUDY IN THE PROCEEDING REFLECT ANY REFINEMENTS TO THE LEAD-LAG STUDY APPROVED IN DOCKET NO. 9896?

A. Yes. While the lead-lag study in this proceeding is based on the same methodology approved in Docket No. 9896, the lead-lag study in this proceeding reflects a slight refinement to the calculation of lead days for incentive compensation. The lead-lag study in Docket No. 9896 is based on a single number of lead days for the Company's short-term and long-term incentive plans. The study in this proceeding 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, which is generally in March for the performance

[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,* OS-22-00009896 consol., Final Order at Finding of Fact ("FoF") No. 54 (Jan. 18, 2023).

period that reflects the preceding calendar year. Lead days for the Company's long-term incentive plan is zero since it is a non-cash item.

The approach to apply distinct lead days for the Company's short-term and long-term incentive plans was included in the Company's lead-lag study filed in Docket No. OS-24-00017471.[3]

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 for TGS of negative $13.4 million for the period January 1, 2024 through December 31, 2024.

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 the number of days from the time service is provided to customers until the time customer payments are received by the Company. Expense

[3] *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 Central-Gulf Service Area*, OS-24-00017471 consol., Direct Testimony of Timothy Lyons (Jun. 3, 2024).

leads measure the number of days 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 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 for TGS from January 1, 2024 through December 31, 2024. 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 – and 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 DERIVATION OF LEAD DAYS FOR O&M EXPENSES.

A. Lead days for O&M expenses 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 2023) to the payment date on March 1, 2024.

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, 2024 through December 31, 2024. 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 and then summed by invoice amounts to determine the lead days. The study relied 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, 2024 through December 31, 2024. 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 and then summed by invoice amounts to determine the lead days. The study relied on a full population of invoices because the invoice dates and payment dates were readily available electronically for the full population of invoices.

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.

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 $13.4 million for the period January 1, 2024 through December 31, 2024.

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 more than 30 U.S. and 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 (CalPeco Electric)	9/24	Application No. 24-09-010	Sponsored testimony supporting the marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
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	04/25	Docket No. 25-0346	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
Tidewater Utilities, Inc	08/24	Docket No. 24-0991	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
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			

Sponsor	Date	Docket No.	Subject
Ameren Illinois Company d/b/a Ameren Illinois	6/24	Docket 22-0487/ 23-0082/ 24-0238 (cons.)	Sponsored rebuttal testimony supporting a marginal cost study for a Multi-Year Integrated Grid Plan (Grid Plan) proceeding.
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.
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			
Kentucky Utilities Company	05/25	Case No 2025-00113	Sponsored testimony supporting cost of service and rate design studies for a general rate case proceeding.
Louisville Gas and Electric Company	05/25	Case No 2025-00114	Sponsored testimony supporting cost of service and rate design studies for a general rate case proceeding.
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			
Maine Water Company	12/24	Docket No. 2024-00378	Sponsored testimony supporting a two-phased approach to consolidate or unify rate schedules for 10 water utility divisions.
Maine Water Company	10/24	Docket No. 2024-00291	Sponsored testimony supporting the class cost of service, rate design, and bill impact studies for a general rate case proceeding for the Camden and Rockland Division.
Calpine Corporation and Casco Bay Energy Company	10/24	Docket No. 2024-00137	Sponsored testimony regarding ratemaking treatment of Net Energy Billing stranded cost rate design.
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.

Sponsor	Date	Docket No.	Subject
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.
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			
DTE Energy	04/25	Docket No. U-21860	Sponsored testimony regarding DTE Energy's use of constant dollar averaging to develop its cost forecasts.
Lansing Board of Water & Light and Michigan State University	04/25	Docket No. U-21806	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/24	Docket No. U-21490	Sponsored testimony evaluating Consumer Energy's class cost of service and rate design proposals.
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	04/22	Docket No. U-21148	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

Sponsor	Date	Docket No.	Subject
			market conditions.
Missouri Public Service Commission			
The Empire District Electric Company	11/24	Docket No. ER-2024-0261	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.	11/24	Docket No. GR-2024-0107	Sponsored testimony supporting the class cost of service, rate design, bill impact, and lead-lag studies for a general rate case proceeding.
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.
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.

Sponsor	Date	Docket No.	Subject
New Hampshire Public Utilities Commission			
Unitil Energy Systems, Inc.	05/25	Docket No. DE 25-025	Sponsored testimony supporting a marginal cost study, class cost of service study, rate design, customer bill impacts, and revenue decoupling for a general rate case proceeding.
Unitil (Northern Utilities, Inc.)	08/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	04/21	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.	12/24	Advice Notice No. 105	Sponsored testimony supporting changes in Rule No. 16 – Line Extension Policy.
New Mexico Gas Company, Inc.	7/24	Case No. 18-00038-UT	Sponsored testimony supporting the Weather Normalization Adjustment Mechanism.
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.
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.

Sponsor	Date	Docket No.	Subject
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.
Ohio Public Utilities Commission			
Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company	06/24	Case Nos. 24-0468-EL-AIR, 24-0469-EL-ATA, 24-0470-EL-AAM, 24-0471-EL-UNC	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
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	09/00 01/97 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	08/97	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	11/95	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	07/94	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Providence Gas Company	07/93	Docket No. 2076/ 2082	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.
Railroad Commission of Texas			
Texas Gas Service Company – Central-Gulf Service Area	06/24	Case No. 00017471	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gas Division	10/23	Case No. 00015513	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
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.
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			
Rappahannock Electric Cooperative	3/25	Case No. PUR-2025-00048	Sponsored testimony supporting a new Large Power-Dedicated Facilities (LP-DF) rate schedule
Rappahannock Electric Cooperative	8/24	Case No. PUR-2024-00132	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.
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	03/23	Case No. PUR-2023-00002	Sponsored testimony supporting the Lead/Lag study for the 2023 triennial review of base rates, terms, and conditions.

Sponsor	Date	Docket No.	Subject
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			
American Electric Power - Appalachian Power Company and Wheeling Power Company	11/24	Case No. 24-0854-E-42T	Sponsored testimony supporting the lead-lag study for a general rate case proceeding.
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.
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.
Statewide Texas: West North, Rio Grande Valley, and Central Gulf Service Areas
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	$ 155,312,003	$ 424,350	45.69	A	(41.69)	B	4.00	$ 1,698,205
3	Labor - Regular Payroll Expense	68,042,133	185,907	45.69	A	(22.50)	C	23.19	4,311,510
4	Labor - Annual Performance Bonus Expense	12,340,812	33,718	45.69	A	(243.79)	C	(198.10)	(6,679,502)
5	Non-Labor - Other O&M Expense	81,395,049	222,391	45.69	A	(48.10)	C	(2.41)	(535,584)
6	Total O&M Expenses	$ 317,089,996	$ 866,366						$ (1,205,370)
7	Federal Income Taxes								
8	Current Income Taxes	$ 31,312,410	$ 85,553	45.69	A	(37.50)	D	8.19	$ 700,945
9	Deferred Income Taxes	-	-	0.00		0.00		0.00	-
10	Total Federal Income Taxes	$ 31,312,410	$ 85,553						$ 700,945
11	Taxes Other Than Income Taxes								
12	FICA	$ 4,587,666	$ 12,535	45.69	A	(12.89)	E	32.80	$ 411,134
13	Federal Unemployment	32,615	89	45.69	A	(29.33)	E	16.36	1,458
14	State Unemployment	116,134	317	45.69	A	(29.31)	E	16.39	5,199
15	State Gross Receipts	9,337,497	25,512	45.69	A	(75.12)	E	(29.43)	(750,804)
16	Local Franchise Tax	24,128,040	65,924	45.69	A	(103.94)	E	(58.25)	(3,840,024)
17	State Franchise Tax	1,023,024	2,795	45.69	A	47.58	E	93.28	260,721
18	Ad Valorem	19,470,082	53,197	45.69	A	(215.39)	E	(169.69)	(9,027,245)
19	Sales Tax	12,229,331	33,413	45.69	A	(35.82)	E	9.87	329,868
20	RRC Gas Utility Tax	99,205	271	45.69	A	(88.05)	E	(42.36)	(11,481)
21	Taxes Other Than Income Taxes	$ 71,023,595	$ 194,054						$ (12,621,173)
22	Interest on Customer Deposits	$ 824,647	$ 2,253	45.69	A	(169.00)	F	(123.31)	$ (277,827)
23	Labor - LTI Expense	$ 2,338,331	$ 6,389	0.00		0.00		0.00	$ -
24	Depreciation Expense	$ 86,087,872	$ 235,213	0.00		0.00		0.00	$ -
25	Return	$ 151,258,518	$ 413,275	0.00		0.00		0.00	$ -
26	Total	$ 659,935,370	$ 1,803,102						$ (13,403,426)

(*) 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	7.01	25.12	47.34	WP A-1	$ 396,297,271	$ 18,760,172,372
2	Commercial	15.21	5.54	21.22	41.97	WP A-2	115,737,871	4,857,124,182
3	Industrial	15.21	5.89	17.40	38.49	WP A-3	4,235,680	163,043,777
4	Public Authority	15.21	5.67	16.74	37.61	WP A-4	22,215,489	835,616,950
5	Transportation	15.21	9.93	20.37	45.51	WP A-5	19,051,526	866,962,217
6	Irrigation	15.21	5.54	21.09	41.84	WP A-6	1,898,519	79,437,124
7	Composite Revenue Collection Days	15.21	6.74	23.74	45.69		$ 559,436,356	$ 25,562,356,622

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-2024	01/01/24	01/31/24	$ 32,612,669	31.00	(15.50)	(25.97)	(41.47)	$ (1,352,367,365)	
2	February-2024	02/01/24	02/29/24	19,469,697	29.00	(14.50)	(25.85)	(40.35)	(785,651,498)	
3	March-2024	03/01/24	03/31/24	9,807,963	31.00	(15.50)	(26.00)	(41.50)	(407,030,444)	
4	April-2024	04/01/24	04/30/24	7,557,345	30.00	(15.00)	(29.00)	(44.00)	(332,523,196)	
5	May-2024	05/01/24	05/31/24	7,694,154	31.00	(15.50)	(25.96)	(41.46)	(318,975,277)	
6	June-2024	06/01/24	06/30/24	8,359,521	30.00	(15.00)	(30.00)	(45.00)	(376,178,438)	
7	July-2024	07/01/24	07/31/24	8,356,193	31.00	(15.50)	(26.32)	(41.82)	(349,484,015)	
8	August-2024	08/01/24	08/31/24	6,929,505	31.00	(15.50)	(27.00)	(42.50)	(294,503,941)	
9	September-2024	09/01/24	09/30/24	7,810,789	30.00	(15.00)	(24.00)	(39.00)	(304,620,789)	
10	October-2024	10/01/24	10/31/24	12,073,953	31.00	(15.50)	(25.00)	(40.50)	(488,995,112)	
11	November-2024	11/01/24	11/30/24	13,062,682	30.00	(15.00)	(27.00)	(42.00)	(548,632,625)	
12	December-2024	12/01/24	12/31/24	24,510,592	31.00	(15.50)	(26.87)	(42.37)	(1,038,461,610)	
13			Total	$ 158,245,063					$ (6,597,424,310)	(41.69)

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	(22.50)	WP C-1
2	Annual Performance Bonus Expense	(243.79)	WP C-5
3	Labor-Related - Subtotal		
4	Other O&M Expenses	(48.10)	WP C-5

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Federal Income Tax

Line	Quarter	Service Period Start	Service Period End	Midpoint of Service Period	Payment Date	Percent of Taxes Due	(Lead)/Lag Days Days from Midpoint to Payment Date	(Lead)/Lag Days (Lead)/Lag Days
1	First Quarter	1/1/2024	12/31/2024	(183.00)	4/15/2024	25.00%	260.00	19.25
2	Second Quarter	1/1/2024	12/31/2024	(183.00)	6/15/2024	25.00%	199.00	4.00
3	Third Quarter	1/1/2024	12/31/2024	(183.00)	9/15/2024	25.00%	107.00	(19.00)
4	Fourth Quarter	1/1/2024	12/31/2024	(183.00)	12/15/2024	25.00%	16.00	(41.75)
5	Federal Income Tax (Lead)/Lag Days							(37.50)

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	(12.89)	WP E-1
2	Federal Unemployment	(29.33)	WP E-2
3	State Unemployment	(29.31)	WP E-3
4	State Gross Receipts	(75.12)	WP E-4
5	Local Franchise Tax	(103.94)	WP E-5
6	State Franchise Tax	47.58	WP E-6
7	Ad Valorem	(215.39)	WP E-7
8	Sales Tax	(35.82)	WP E-8
9	RRC Gas Utility Tax	(88.05)	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	Average Monthly Interest	Accrued Interest Balance	Composite (Lead)/Lag Days
1	12/1/2023			$ 200,970	
2	1/1/2024		$ 34,044	235,014	
3	2/1/2024		34,044	269,058	
4	3/1/2024		31,848	300,906	
5	4/1/2024		34,044	334,950	
6	5/1/2024		32,946	367,896	
7	6/1/2024		34,044	-	
8	7/1/2024		32,946	32,946	
9	8/1/2024		34,044	66,990	
10	9/1/2024		34,044	101,034	
11	10/1/2024		32,946	133,980	
12	11/1/2024		34,044	168,024	
13	12/1/2024		32,946	200,970	
14	Average			$ 185,595	
15	Interest Expense	$ 400,842			
16	Daily Interest Expense	$ 1,098			
17	Composite (Lead)/Lag Days				(169.00)

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STATE OF TEXAS §
§
COUNTY OF TRAVIS §

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.

Signed by:
Timothy S. Lyons
40C771491AF44C5...
Timothy S. Lyons

SUBSCRIBED AND SWORN TO BEFORE ME by the said Timothy S. Lyons on this 5th day of June 2025.

DocuSigned by:
Christine Marie Bell
1C45AAFD08DC44A...
Notary Public in and for the State of Texas

My commission expires: 2/23/2028



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. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JANET M. SIMPSON

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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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 accounting and 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 and in my current position, 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, a division of ONE Gas, Inc. ("TGS" or the "Company") Accumulated Deferred Income Tax ("ADIT") amounts that are applicable when determining total TGS system rates and consolidating the Company's existing West North Service Area ("WNSA"), Central-Gulf Service Area (CGSA) and Rio Grande Valley Service Area (RGVSA). Total TGS ADIT is negative $184,129,691. This ADIT balance is reflected as a reduction to rate base on the total TGS Rate Case Schedules, Schedule B, line 8 and is itemized on Schedule B-9.

II. BACKGROUND

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 TOTAL TGS ADIT BALANCE

Q. WHAT ARE THE COMPONENTS OF THE TGS ADIT AMOUNT OF $(184,129,691) REFERENCED PREVIOUSLY?

A. The TGS ADIT balance consists of the following five major components:

TGS Direct Plant-Related	(240,444,309)
TGS Other Direct Rate Base Items	(9,468,151)
TGS Division Plant-Related	(1,362,327)
ONE Gas Plant-Related	(6,220,999)
TGS NOL	73,366,094
Total TGS ADIT	**(184,129,691)**

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 TGS DIRECT PLANT ASSETS.

A. The first component of total TGS ADIT is ADIT associated with the plant-related timing differences (i.e., "direct plant"). I computed ADIT applicable to the TGS plant items as of December 31, 2024, by comparing per Book net plant for those locations as of December 31, 2024 to per Tax net plant for those locations as of December 31, 2024. 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. Additionally, an adjustment was made pertaining to the El Paso portion of the TGS ADIT to comply with the requirements of City of El Paso Ordinance 15316, a copy of which is provided as Exhibit JMS-3. This ordinance contains the consent by the City of El Paso for the assignment by SUCo to ONEOK, Inc. ("ONEOK") of SUCo's franchise to serve customers within the City of El Paso in 2002. This adjustment,

which is identified on Exhibit JMS-2 and JMS-3 as the "El Paso VTGS 2003 Adjustment," pertains to the 2003 vintage of City of El Paso plant that was acquired by ONEOK and is designed to result in the El Paso portion of plant ADIT being calculated as if no acquisition had occurred. The approach used in the current case is consistent with the approach used and included in the ADIT balance approved by the Commission in the Company's last WNSA rate case (Docket No. OS-22-00009896).

The total difference between the adjusted net book and net tax plant amounts, multiplied by the current income tax rate of 21%, represents the TGS direct plant-related ADIT as of December 31, 2024. Total TGS plant-related ADIT as of December 31, 2024, equals $(240,444,309).

Q. PLEASE EXPLAIN THE SECOND COMPONENT OF TGS 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:

- Section 8.209 Regulatory Asset;
- Pension & Other Post Retirement Benefit ("OPEB") Deferral;
- Prepaid Pension Asset; and
- Other Regulatory Assets.

The Section 8.209 Regulatory Asset, Pension and 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 and 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 an additional layer of 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). The difference between the cumulative ASC 715-20 pension expense and the cumulative contributions to the plant amount is referred to as the Prepaid Pension Asset. The reversal of the pension portion of the item identified above as "Pension & Other Post Retirement Benefit ("OPEB") Deferral" adjusts the pension expense deduction for tax purposes to be equal to the amount that would have been expensed per Book in accordance with ASC 715-20 absent the regulatory deferral of a portion of that expense. The reversal of the "Prepaid Pension" item reflects the additional 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 pension expense calculated in accordance with ASC 715-20.

The sum of the four temporary differences referenced above, multiplied by the tax rate of 21% represents the TGS Other Direct Rate Base-related ADIT as of December 31, 2024, which is equal to $(9,468,151).

Q. PLEASE DESCRIBE THE NEXT TWO COMPONENTS OF THE ADIT CALCULATION.

A. The next two components of the TGS ADIT calculation are for (1) ADIT related to 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, 2024. The ONE Gas temporary differences were multiplied by the allocation factors that have been applied to the related plant amounts by Company witness Eric S. Sanford 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%. The result is $(1,362,327) of TGS Division plant ADIT and $(6,220,999) of ONE Gas corporate plant ADIT.

Q. WHAT IS THE FINAL COMPONENT OF THE TOTAL TGS ADIT APPLICABLE TO RATEMAKING?

A. The final component to ADIT is 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, 2024, 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 FOR RATEMAKING PURPOSES AS OF DECEMBER 31, 2024, AND HOW IS IT COMPUTED?

A. The total estimated NOL ADIT applicable to TGS on a stand-alone basis as of December 31, 2024 is $73,366,094. The calculation of this amount starts with cumulative 2003 through December 31, 2024 total TGS taxable income per Book of $(733,848,091). I then made several ratemaking adjustments and tax adjustments to determine the TGS NOL. 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 and also removed non-deductible parking expenses. Next, tax deductions were reflected pertaining to the Rule § 8.209 Regulatory Asset,

Pension and OPEB, 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.

Q. WHAT IS THE RESULTING TGS NOL ADIT AMOUNT?

A. The result is a cumulative TGS Tax NOL of $349,362,351 as of December 31, 2024. Multiplying this amount by the income tax rate of 21% yields the TGS NOL ADIT of $73,366,094, which is the final component of the TGS 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]

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[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 Change Gas Utility Rates Within the Unincorporated Areas of the West Texas Service Area, North Texas Service Area, and Borger Skellytown Service Area*, Docket No. OS-22-00009896 consol., Final Order (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 (Jan. 30, 2024); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order (Nov. 19, 2024).

JANET M. SIMPSON

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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, (2025 plan year), 24-GSEP-04 (2024)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Change Gas Utility Rates within the Unincorporated Areas of the Central-Gulf Service Area – ADIT issues – Case No. 00017471 (2024)
- *Liberty Utilities (New England Natural Gas Company)* – CY2023 Gas System Enhancement Plan Reconciliation Filing, DPU 24-GREC-04 (2024)
- *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 TGS
Year Ended 12/31/2024

Accumulated Deferred Income Taxes for:	ADIT at 21%
Repair Adjustments	(101,911,370)
All Other Plant Related	(138,532,938)
Subtotal Direct Plant Assets Depreciation	(240,444,309)
Other Rate Base Items	(9,468,151)
TGS Division Plant Assets Depreciation	(1,362,327)
ONEGas Plant Assets Depreciation	(6,220,999)
North NOL (See NOL tab, Note 6)	73,366,094
Total ADIT - Accumulated Deferred Income Taxes	(184,129,691)

Accumulated Deferred Income Tax

As of December 31, 2024 Town	Gross Book Basis	Book Reserve	Net Book Basis	Gross Tax Basis	Tax Reserve	Net Tax Basis	Difference in Net Plant Basis	ADIT Asset/(Liability) at 21%
Total TGS	2,449,290,845.03	(447,357,982.85)	2,001,932,862.18	1,645,232,542.98	(788,609,599.90)	856,622,943.08	1,145,309,919.10	(240,515,083.01)
Adjustments	(1,992,383.48)	(59,116.91)	(2,051,500.39)	(1,338,319.68)	(33,535.51)	(1,371,855.19)	(679,645.20)	142,725.49
Subtotal	2,447,298,462	(447,417,100)	1,999,881,362	1,643,894,223	(788,643,135)	855,251,088	1,144,630,274	(240,372,358)
City of El Paso VTGS 2003 Adjustment								
Remove El Paso VTGS Vintage Tax Info per Tax Reports				(75,634,907)	74,612,966	(1,021,942)	1,021,942	(214,608)
Replace with El Paso Method VTGS Vintage Tax Info				128,908,232	(128,228,915)	679,317	(679,317)	142,657
Subtotal - City of El paso VTGS 2003 Adjustment				53,273,325	(53,615,949)	(342,624)	342,624	(71,951)
Adjusted TGS	2,447,298,462	(447,417,100)	1,999,881,362	1,697,167,548	(842,259,085)	854,908,464	1,144,972,898	(240,444,309)
			-			-		(0)
TGS Division	11,724,133	(3,414,790)	8,309,343	5,415,852	(3,593,781)	1,822,071	6,487,272	(1,362,327)
ONEGas	92,032,383	(45,898,924)	46,133,460	76,239,164	(59,729,506)	16,509,657	29,623,803	(6,220,999)
	733,763,655	(116,959,260)	616,804,395	513,524,034	(289,019,479)	224,504,555	392,299,840	(82,382,966)

Accumulated Deferred Income Tax Analysis For North Texas Service Area Other Rate Base Items

	Balance Sheet Impact per Book	Balance Sheet Impact per Tax	Difference	ADIT Asset/(Liability)
Pension/OPEB Expense Regulatory Deferrals	(6,518,193)		(6,518,193)	1,368,821
Prepaid Pension (funding in excess of FAS87 expense)	44,728,624		44,728,624	(9,393,011)
Section 8.209 Deferral	4,757,745	-	4,757,745	(999,126)
Other Regulatory Assets	2,118,256		2,118,256	(444,834)
Total Other Rate Base Items	45,086,432	-	45,086,432	(9,468,151)

ORDINANCE NO. 15316

AN ORDINANCE GRANTING TO SOUTHERN UNION COMPANY, A DELAWARE CORPORATION, PERMISSION AND AUTHORITY TO ASSIGN AND TRANSFER TO ONEOK, INC., AN OKLAHOMA CORPORATION, ITS RIGHTS AND OBLIGATIONS UNDER ORDINANCE NO. 014360, AS AMENDED BY ORDINANCE NO. 014496, WHICH GRANTS CERTAIN NON-EXLUSIVE POWERS, LICENSES, RIGHTS-OF-WAY, PRIVILEGES AND FRANCHISE TO CONSTRUCT, OPERATE AND MAINTAIN IN THE CITY OF EL PASO, TEXAS A NATURAL GAS DISTRIBUTION SYSTEM

WHEREAS, SOUTHERN UNION COMPANY ("SOUTHERN UNION"), its legal representatives, successors, lessees and assigns were granted the right, privilege and franchise to contract, operate and maintain a natural gas distribution system in the City of El Paso, Texas ("the City") pursuant to the terms and conditions of Ordinance No. 014360, as amended by Ordinance No. 014496, (the "Franchise Ordinance"), which Ordinances were duly passed and adopted by the City Council on February 22, 2000, and May 30, 2000, respectively; and

WHEREAS, pursuant to the terms of the Franchise Ordinance, SOUTHERN UNION has requested the express consent of the City to transfer and assign the Franchise Ordinance to ONEOK, INC., an Oklahoma corporation, or its designated division or affiliate ("ONEOK"), and ONEOK has likewise requested the express consent of the City, that it be allowed to accept the assignment and transfer of the Franchise Ordinance.

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COUNCIL OF EL PASO, TEXAS, THAT:

SECTION I. SOUTHERN UNION has complied with the Franchise Ordinance in requesting the express consent of the City for the transfer and assignment of the Franchise Ordinance to ONEOK, and ONEOK has likewise appeared by its agents and employees before the City Council of El Paso, Texas ("City Council"), and requested the ONEOK be approved as assignee of the Franchise Ordinance.

SECTION II. Pursuant to Section III, and subject to the conditions in Section IV of this Ordinance, the City Council, hereby gives its consent and permission to the assignment and transfer by SOUTHERN UNION to ONEOK of the Franchise Ordinance, and to the substitution of ONEOK for SOUTHERN UNION in the Franchise Ordinance, which Franchise Ordinance is incorporated herein by reference, the same as if repeated verbatim.

SECTION III. Subject to the to the conditions in Section IV of this Ordinance, the City hereby grants its consent to the assignment and transfer of the Franchise Ordinance to ONEOK subject to the requirement that ONEOK sign the acceptance of this ordinance, which shall indicate ONEOK's agreement to accept and assume to pay, perform and discharge all of the obligations, duties and liabilities of SOUTHERN UNION in and under the terms and conditions of the Franchise Ordinance and to be in all respects subrogated to the rights and liabilities of SOUTHERN UNION.

SECTION IV. This consent is given subject to the following conditions:

1. As a condition of and in consideration for the City's consent to this assignment, ONEOK, Inc. agrees on behalf of itself and its successors in interest that if the employees in the El Paso area decrease by 20% or more from the current level of 220 employees for more than 9 consecutive months for reasons other than technological improvements or improved customer service on a local basis, that the term in Ordinance

014369 shall be reduced and that the termination date shall be amended to February 22, 2015 or 2 years after the reduction in staff whichever occurs later.

2. As a condition of and in consideration for the City's consent to this assignment, ONEOK, Inc. agrees on behalf of itself and its successors in interest, that it will not request recovery of an acquisition adjustment related to the transaction giving rise to this assignment in the rates to be charged within the City of El Paso.

3. As a condition of and in consideration for the City's consent to this assignment, ONEOK, Inc., agrees on behalf of itself and its successors in interest, and the City of El Paso intends that, for rates to be charged within the City of El Paso, the calculation of invested capital or adjusted value of invested capital calculated in accordance with Tex. Util. Code Sec. 104.051, 104.052, and 104.053, or as the Gas Utility Regulatory Act may be amended, will reflect an adjustment and/or adjustments, as necessary, so that Accumulated Deferred Income Taxes are calculated as if the transaction giving rise to this assignment had not occurred.

SECTION V. The assignment of the Franchise Ordinance shall be effective upon (1) the sale of substantially all of the assets of the Southern Union Gas division of SOUTHERN UNION in accordance with the terms and conditions of that certain Purchase and Sale Agreement between SOUTHERN UNION and ONEOK dated October 16, 2002, and (2) the date of the filing by ONEOK of the written acceptance of the terms of this assignment of the Franchise Ordinance with the City Clerk (the "Effective Date"). SOUTHERN UNION shall remain responsible for the duties, liabilities and obligations under the Franchise Ordinance until the Effective Date. SOUTHERN UNION shall be fully and finally released from any further duties, liabilities or obligations under the Franchise Ordinance upon the Effective Date of this ordinance.

The City Clerk is hereby authorized and directed to make appropriate endorsements over his or her official hand and the seal of the City of El Paso, on a form provided at the conclusion of this ordinance.

PASSED AND APPROVED this 23rd day of December, 2002.

CITY OF EL PASO

Raymond G. Caballero
Mayor PRO-TEM
LARRY M. MEDINA

ATTEST:

Diana Nunez
Richarda Duffy Momsen for Deputy City Clerk
City Clerk

APPROVED AS TO FORM:

Rita Rodriguez
City Attorney

APPROVED AS TO CONTENT:

David Almonte, Director
Office of Management & Budget

ORDINANCE NO. 15316
88119

ACCEPTANCE OF ORDINANCE NO. 014360
(AS AMENDED BY ORDINANCE NO. 014496)

ONEOK, Inc., an Oklahoma corporation, accepts the franchise that was assigned to it by Southern Union Company and approved by the City of El Paso, Texas, pursuant to City of El Paso Ordinance No. 014360, as amended by Ordinance No. 014496, (the Franchise Ordinance") passed and approved on February 22, 2000, and May 30, 2000, respectively. This franchise acceptance is filed in full acceptance of the rights and liabilities set forth in Section III of Ordinance No. 15316. ONEOK, Inc. hereby accepts, assumes and agrees to pay, perform and discharge all of the obligations, duties and liabilities of Southern Union Company in and under the terms and conditions of the Franchise Ordinance and ONEOK is in all respects subrogated to the rights and liabilities of Southern Union Company.

This franchise acceptance is executed on 23rd day of December, 2002 with the intent that it be effective upon filing with the City Clerk of El Paso, Texas.

ONEOK, INC.

_____
Name Printed: _____
Title: _____

Diana Nuñez
Richarda Duffy Momsen Deputy City Clerk
City Clerk

_____
Dated

15316

88119

Docusign Envelope ID: 9E9E2E5A-065F-421E-99BD-365C82D0FB42

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

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.

Signed by:
Janet M. Simpson
6562C44F11D54DE...
Janet M. Simpson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Janet M. Simpson on this 9th day of June 2025.

DocuSigned by:
Christine Marie Bell
1C45AAFD08DC44A...
Notary Public in and for the State of Texas

My commission expires: 2/23/2028

NOTARY PUBLIC STATE OF TEXAS
CHRISTINE MARIE BELL
Notary ID 130547096
My Commission Expires 2/23/2028

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. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

RONALD E. WHITE, Ph.D.

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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 2025 Statewide Depreciation Rate Study. TGS plant facilities, previously labeled "Service Areas," are located in the Central–Gulf (CGSA), Rio Grande Valley (RGVSA) and West–North Texas (WNSA). In addition to reporting separately, the 2025 study combines CGSA, RGVSA and WNSA to derive Statewide depreciation rates and accruals. The study also includes the TGS Division, supporting common facilities shared among all TGS Service Areas and Fort Bliss. The purpose of my testimony is to sponsor and describe the 2025 depreciation study (2025 study) as contained in accompanying Exhibit REW–1.

II. SUMMARY

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR TGS IN THE 2025 STUDY.

A. Table 1 below provides a summary of the changes in annual rates and accruals recommended for Texas Gas Service. Primary account depreciation rates equivalent to a composite rate of 3.68% are recommended for TGS.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Statewide	3.19%	3.46%	0.27%	$ 76,708,760	$ 83,244,031	$ 6,535,271
TGS Division	7.11%	6.95%	-0.16%	781,602	764,307	(17,295)
Fort Bliss	2.47%	2.80%	0.33%	245,263	278,171	32,908
Total	3.40%	3.68%	0.29%	$ 77,735,626	$ 84,286,509	$ 6,550,883

Table 1. TGS Total Rates and Accruals

Depreciation expense is currently accrued at rates that composite to 3.40 percent. The recommended change in the composite depreciation rate is an increase of 0.29 percentage points. A continued application of current rates would produce annualized depreciation expense of $77,735,626 compared with an annualized expense of $84,286,509 using the rates developed in the 2025 study. Proposed annualized accruals of $84,286,509 include a $3,796,176 annualized amortization of a $152,093,773 reserve shortfall, largely attributable to cost of removal. The remaining portion of the change in accruals is attributable to adjustments in service–life and net salvage statistics recommended in the 2025 study.

Table 2 below provides a summary of changes in accrual rates and annualized accruals for combined CGSA, RGVSA and WNSA (*i.e.*, Statewide) service areas.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	2.76%	3.02%	0.26%	$ 3,869,355	$ 4,226,132	$ 356,777
Distribution	2.92%	3.24%	0.32%	59,628,924	66,230,383	6,601,459
General Plant	5.94%	5.75%	-0.19%	13,210,482	12,787,516	(422,966)
Total	3.19%	3.46%	0.27%	$ 76,708,760	$ 83,244,031	$ 6,535,271

Table 2. Statewide Rates and Accruals

Table 3 below provides a summary of changes in annual rates and annualized accruals for the TGS Division.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	7.11%	6.95%	-0.16%	781,602	764,307	(17,295)
Total	7.11%	6.95%	-0.16%	$ 781,602	$ 764,307	$ (17,295)

Table 3. TGS Division Rates and Accruals

Table 4 below provides a summary of changes in annual rates and annualized accruals for the Fort Bliss service area.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	2.44%	2.77%	0.33%	$ 241,222	$ 274,130	$ 32,908
General Plant	6.67%	6.67%	0.00%	4,041	$ 4,041	0
Total	2.47%	2.80%	0.33%	$ 245,263	$ 278,171	$ 32,908

Table 4. Fort Bliss Rates and Accruals

III. Development of Depreciation Rates

Q. PLEASE EXPLAIN THE GOAL OF DEPRECIATION ACCOUNTING AND WHY DEPRECIATION STUDIES ARE CONDUCTED PERIODICALLY.

A. The goal of depreciation accounting is to charge to operations an 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 approximate the goal of depreciation accounting using time–based methods.

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 an 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 sets 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 continuance of such practices may not comply with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or timing of depreciation expense for a non–regulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenue, which is a function of authorized levels of depreciation

expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

Additionally, to the extent that after tax revenue is sufficient to cover non–cash expenses, depreciation and other non–cash expenses (*e.g.*, deferred income taxes) provide an economic source of internally generated funds available for financing 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 appropriate depreciation rates.

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 a subject company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe 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 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 estimated projection–life curves; and economic conditions that may warrant greater or lesser weight to be given to net salvage observed in the past.

A comprehensive depreciation 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 needed 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 required (*i.e.*, theoretical or computed) reserves and recorded reserves provides an estimate of likely excesses or shortfalls that will remain in recorded depreciation reserves 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, retirement dispersions 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 dispersions 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 provide a baseline against which future reserve comparisons can be made.

Lastly, 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.

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

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. 2025 DEPRECIATION RATE STUDY

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY TGS.

A. Current depreciation rates for CGSA were developed in a 2024 study based on December 31, 2023 plant and depreciation reserves. Proposed depreciation rates were derived from a weighted average of accrual rates developed separately for Central Texas Service Area (CTSA) and Gulf Coast Service Area (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. Rates developed for CGSA were approved by the Railroad Commission of

Texas pursuant to a Settlement Agreement in OS–24–00017471 (Order dated November 20, 2024).

Current depreciation rates for RGVSA were developed in a 2023 study based on December 31, 2022 plant and depreciation reserves. Rates developed for RGVSA were approved by the Commission pursuant to a Settlement Agreement in OS–23-14399 (Order dated January 31, 2024).

Current depreciation rates for WNSA and the TGS Division were developed in a 2022 study based on December 31, 2021 plant and depreciation reserves. Proposed rates were derived by combining the West Texas Service Area (WTSA), the North Texas Service Area (NTSA) and the Borger/Skellytown Service Area (BSSA). TGS also requested removal of the Fort Bliss Service Area (FBSA) from WTSA before combining WTSA, NTSA and BSSA into WNSA. FBSA was therefore included in the 2022 study as a standalone service area. Rates developed for WNSA and the Division were approved by the Commission pursuant to a Settlement Agreement in OS–22–00009896 (Order dated January 19, 2023).

Q. DID TGS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2025 DEPRECIATION STUDY?

A. Yes. The database used in the 2025 study was assembled by appending 2024 plant and reserve activity to the statewide database used in conducting the 2024 CGSA study. Detailed asset accounting entries were assigned transaction codes to identify the nature of plant 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 are also assigned to transfers, gross salvage, cost of removal and other recorded accounting activity.

Age distributions (*i.e.*, plant in service by vintage year of placement) on December 31, 2024 were derived by Foster Associates in a forward–flow calculation in which accounting activity was appended to the database used in conducting the 2024 study. The accuracy and completeness of the assembled database was validated for 2024 by

comparing beginning plant balances, additions, retirements, transfers and adjustments, and ending plant balances derived for each rate category to the official plant records of TGS. Derived age distributions on December 31, 2024 were also reconciled to the continuing property records of TGS. Annual plant activity prior to 2024 was reconciled in the 2024 and prior depreciation rate studies.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR TGS PLANT AND EQUIPMENT?

A. Yes. As discussed in Exhibit REW–1, full mortality plant accounts were analyzed using a technique in which first, second– and third–degree polynomials were fitted to a set of observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. Observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using the projection life derived from a 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 expectations about the future to obtain an appropriate projection life and curve for each plant category.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS IN THE 2025 STUDY?

A. Yes. A five–year moving average analysis of the ratio of realized salvage and cost of removal to the associated retirements was used in the 2025 Study to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) provide a basis for estimating future net salvage rates.

Future net salvage rates currently used by TGS were estimated in the 2022 WNSA study and retained in the 2024 CGSA study. Given the sustained upward trend in realized net salvage rates, Foster Associates and TGS concluded that a 50 percent increase in current net salvage rates used for transmission mains, distribution mains and distribution services is warranted to marginally reduce depreciation reserve deficiencies, largely attributable to realized net salvage far exceeding future net salvage accruals. Although reserve deficiencies will be amortized over future accounting

periods using remaining–life accrual rates, revenue requirements for cost recovery will also be shifted to future time periods.

Table 5 below provides a comparison of realized, current and proposed net salvage rates recommended in the 2025 depreciation study. It can be observed from this comparison that proposed net salvage rates (Column D) are relatively modest increases from current rates (Column C) and far lower than average realized rates escalating over the period 1999–2024 (Column B).

	Future Net Salvage Rates Sf		
Account	Realized	Current	Proposed
A	B	C	D
Transmission Mains	-351%	-40%	-60%
Distribution Mains	-215%	-40%	-60%
Services	-259%	-60%	-90%

Table 5. Future Net Salvage Rates

Average net salvage rates were estimated using direct dollar weighting of historical retirements with historical net salvage rates, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rates. The computation of estimated average net salvage rates is shown in Exhibit REW–1, Statement E.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Exhibit REW–1, Statement C provides a comparison of recorded, computed and redistributed reserves on December 31, 2024, by primary account within service areas and the TGS Division. Table 6 below provides a summary of recorded, computed and reserve imbalances for the four TGS service areas and the TGS Division.

Service Area	Plant	Recorded	Ratio	Computed	Ratio	Imbalance
A	B	C	D=C/A	E	F=E/A	G=C-E
CGSA	$1,200,417,573	$237,520,900	19.8%	$304,772,905	25.4%	$ (67,252,005)
RGVSA	278,141,368	40,489,100	14.6%	64,760,225	23.3%	(24,271,125)
WNSA	929,560,491	164,536,899	17.7%	224,262,860	24.1%	(59,725,961)
Statewide	$2,408,119,432	$442,546,899	18.4%	$593,795,990	24.7%	$(151,249,091)
TGS Division	10,992,264	3,252,516	29.6%	3,244,775	29.5%	7,741
Fort Bliss	9,946,539	1,030,036	10.4%	1,882,459	18.9%	(852,423)
TGS Total	$2,429,058,235	$446,829,451	18.4%	$598,923,225	24.7%	$(152,093,773)

Table 6. Depreciation Reserves

Q. IS FOSTER ASSOCIATES RECOMMENDING REBALANCING OF DEPRECIATION RESERVES?

A. Yes. A redistribution of recorded reserves is again considered appropriate for TGS. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the 2025 Study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

Recorded reserves were rebalanced within each service area and the TGS Division 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 amortizable categories were adjusted by replacing recorded reserves with estimated theoretical reserves and distributing amortizable reserve imbalances to depreciable categories within the associated function.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED FOR TGS.

A. Current depreciation rates were derived and approved for each primary account using a depreciation system composed of the straight–line method, vintage group procedure and remaining–life technique.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM USED BY TGS?

A. No. It is the opinion of Foster Associates that the vintage group procedure remains appropriate for TGS, provided depreciation studies are conducted periodically and estimated parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting retained in the 2025 study is consistent with the goals and objectives of depreciation accounting derived from cost allocation and depreciation accounting theory and remains appropriate for TGS.

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. E–01933A–22–0107, 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. G–04204A–11-0105, UNS Gas, Inc.; testimony supporting proposed depreciation rates.
- Arizona Corporation Commission, Docket No. G–042011A–24, 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.
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FACULTY

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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

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SPEAKER

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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.

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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.

April 2025

Exhibit REW–1

2025 Depreciation Rate Study

Texas Gas Service
A Division of ONE Gas

– *Statewide*
  Central–Gulf
  Rio Grande Valley
  West–North
– *TGS Division*
– *Fort Bliss*

foster associates

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EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2025 depreciation study conducted by Foster Associates Consultants, LLC (Foster Associates) for gas plant owned and operated by Texas Gas Service (TGS), a division of ONE Gas, Inc. TGS plant facilities, previously labeled "Service Areas," are located in the Central–Gulf Service Area (CGSA), Rio Grande Valley Service Area (RGVSA) and West–North Texas Service Area (WNSA). In addition to reporting separately, the 2025 study combines CGSA, RGVSA and WNSA to derive Statewide depreciation rates and accruals. The study also includes the TGS Division, supporting common facilities shared among all TGS Service Areas and Fort Bliss as illustrated in Figure 1 below.

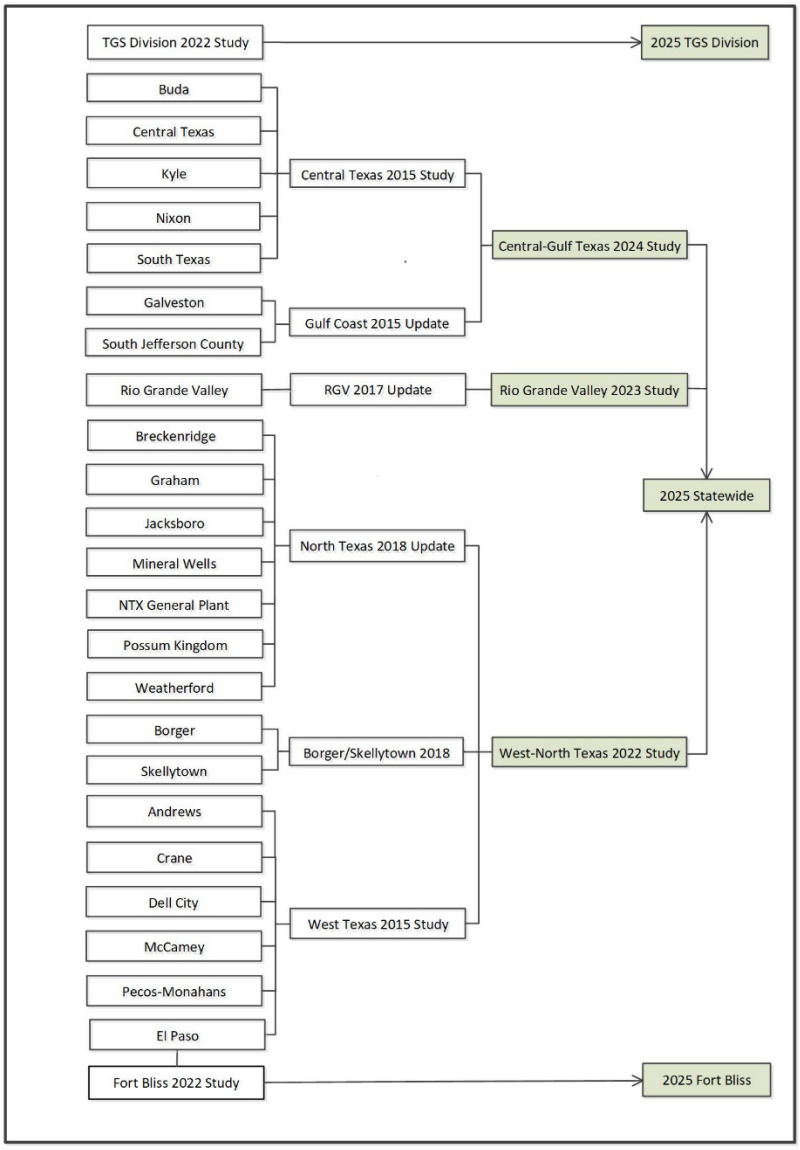


Figure 1. Texas Gas Service Areas

Foster Associates (FA) 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 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.

Current depreciation rates for CGSA were developed in a 2024 study based on December 31, 2023 plant and depreciation reserves. Proposed depreciation rates were derived from a weighted average of accrual rates developed separately for Central Texas Service Area (CTSA) and Gulf Coast Service Area (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. Rates developed for CGSA were approved by the Railroad Commission of Texas pursuant to a Settlement Agreement in OS–24–00017471 (Order dated November 20, 2024).

Current depreciation rates for RGVSA were developed in a 2023 study based on December 31, 2022 plant and depreciation reserves. Rates developed for RGVSA were approved by the Commission pursuant to a Settlement Agreement in OS–23-14399 (Order dated January 31, 2024).

Current depreciation rates for WNSA and the TGS Division were developed in a 2022 study based on December 31, 2021 plant and depreciation reserves. Proposed rates were derived by combining the West Texas Service Area (WTSA), the North Texas Service Area (NTSA) and the Borger/Skellytown Service Area (BSSA). TGS also requested removal of the Fort Bliss Service Area (FBSA) from WTSA before combining WTSA, NTSA and BSSA into WNSA. FBSA was therefore included in the 2022 study as a stand–alone service area. Rates developed for WNSA and the Division were approved by the Commission pursuant to a Settlement Agreement in OS–22–00009896 (Order dated January 19, 2023).

The principal findings and recommendations of the 2025 Statewide 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 compari-

son 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 TGS official source records;
- Discussions with TGS operations and plant accounting personnel;
- Statistical studies of historical retirement activity;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- 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 Statewide rate categories and the TGS Division. 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 changes in accrual rates and annualized accruals resulting from an application of the parameters and depreciation rates recommended for Texas Gas Service.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Statewide	3.19%	3.46%	0.27%	$ 76,708,760	$ 83,244,031	$ 6,535,271
TGS Division	7.11%	6.95%	-0.16%	781,602	764,307	(17,295)
Fort Bliss	2.47%	2.80%	0.33%	245,263	278,171	32,908
Total	3.40%	3.68%	0.29%	$ 77,735,626	$ 84,286,509	$ 6,550,883

Table 1. TGS Total Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.68 percent. Depreciation expense is currently accrued at rates that composite to 3.40 percent. The recommended change in the composite depreciation rate is an increase of 0.29 percentage points.

A continued application of current rates would produce annualized depreciation expense of $77,735,626 compared with an annualized expense of $84,286,509 using the rates developed in the 2025 study. Proposed annualized accruals of $84,286,509 include a $3,796,176 annualized amortization of a $152,093,773 reserve shortfall, largely attributable to cost of removal. The remaining portion of the change in accruals is attributable to adjustments in service–life and net salvage statistics recommended in the 2025 study.

Table 2 below provides a summary of changes in accrual rates and annualized accruals for combined CGSA, RGVSA and WNSA (*i.e.*, Statewide).

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	2.76%	3.02%	0.26%	$ 3,869,355	$ 4,226,132	$ 356,777
Distribution	2.92%	3.24%	0.32%	59,628,924	66,230,383	6,601,459
General Plant	5.94%	5.75%	-0.19%	13,210,482	12,787,516	(422,966)
Total	3.19%	3.46%	0.27%	$ 76,708,760	$ 83,244,031	$ 6,535,271

Table 2. Statewide Rates and Accruals

Table 3 below provides a summary of changes in annual rates and annualized accruals for the TGS Division.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	7.11%	6.95%	-0.16%	781,602	764,307	(17,295)
Total	7.11%	6.95%	-0.16%	$ 781,602	$ 764,307	$ (17,295)

Table 3. TGS Division Rates and Accruals

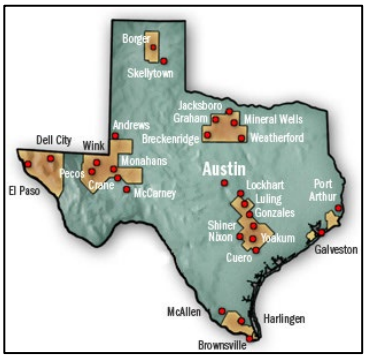
Table 4 below provides a summary of changes in annual rates and annualized accruals for Fort Bliss.

	Accrual Rates			2025 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	2.44%	2.77%	0.33%	$ 241,222	$ 274,130	$ 32,908
General Plant	6.67%	6.67%	0.00%	4,041	$ 4,041	0
Total	2.47%	2.80%	0.33%	$ 245,263	$ 278,171	$ 32,908

Table 4. Fort Bliss Rates and Accruals

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 approximately 2.3 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, 2024, Texas Gas Service owned and operated approximately 11,300 miles of distribution mains and 255 miles of transmission mains. The distribution system consists of 5,493 miles of cathodically protected pipe, 339 miles of unprotected steel pipe, 16 miles of cast/wrought iron and 5,437 miles of plastic mains. All transmission mains are cathodically protected.

At the end of 2024, Texas Gas Service maintained 718,373 service lines consisting of 43,585 unprotected lines, 216,710 cathodically protected lines, 1 copper lines and 422,626 plastic lines.

The Company owns and operates 158 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 700,00 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 for CGSA, RGVSA and WNSA (*i.e.*, Statewide), the TGS Division and Fort Bliss.

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.

The scope of the 2025 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. Age distributions of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of a study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. Statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of a study year. All activity year transactions with vintage year identification are coded in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed

information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by TGS provides aged transactions for all plant accounts.

The database used in the 2025 study was assembled by appending 2024 plant and reserve activity to the statewide database used in conducting the 2024 CGSA study. Detailed accounting entries were assigned transaction codes to identify the nature of the 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 are also assigned to transfers, gross salvage, cost of removal and other recorded accounting activity.

Age distributions on December 31, 2024 were derived by Foster Associates in a forward–flow calculation in which accounting activity was appended to the database used in conducting the 2024 study. The accuracy and completeness of the assembled database was validated for 2024 by comparing beginning plant balances, additions, retirements, transfers and adjustments, and ending plant balances derived for each rate category to the official plant records of TGS. Derived age distributions on December 31, 2024 were also reconciled to the continuing property records of TGS. Annual plant activity prior to 2024 was reconciled in the 2024 and prior depreciation rate studies.

LIFE ANALYSIS AND ESTIMATION

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 2025 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 probabilities 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. Such a calculated "retirement ratio" 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 is graduating or smoothing life tables and fitting the smoothed series to a family of survival functions. The functions used in the 2025 study are the Iowa–type curves, mathematically described by the Pearson frequency curve family. Observed life tables were smoothed using a weighted least–squares procedure in which first, second- and third-degree polynomials were fitted to the observed retirement ratios. The resulting hazard 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 combined projection life/dispersion description (*e.g.*, 50–R2) of Iowa–type probability density functions.

Service life indications derived from the statistical analyses were then blended with informed judgment and expectations about the future to decide an appropri-

ate projection life/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 estimation of descriptive dispersions and projection lives.

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.

Plant accounting and depreciation reserve records are currently maintained by TGS for four service areas and the TGS Division that supports all service areas.[1] Projection lives and projection curves were estimated in the TGS study from the combined database of the four service areas. Average service lives and remaining service lives were distinguished among service areas in the development of vintage–group depreciation rates.

[1] Service areas include: CGSA, RGVSA, WNSA and Fort Bliss.

NET SALVAGE ANALYSIS

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. Consideration should also be given, however, 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 projection life curves; 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.

As noted above, depreciation reserve records are maintained by TGS for four service areas and the TGS Division. Future net salvage rates were estimated in the TGS study from the combined database of the service areas and division. Average net salvage rates were distinguished among service areas in the development of vintage–group depreciation 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 2025 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. The computation of estimated average net salvage rates is shown in Statement E.

Future net salvage rates currently approved for transmission mains (Account 367.00), distribution mains (Account 376.00) and distribution services (Account

380.00) are significantly lower than historical indications would suggest. Increasing net salvage rates (*i.e*., the ratio of net salvage to retirements) observed over the last ten years is partially attributable to cost of removal stated in current dollars divided by retirements stated in dollars at the year of installation. The cost per foot to retire a gas main today, for example, is no different for a main that was installed yesterday or a main that was installed many years ago. The percentage rate applied to the cost of an old asset to accrue the same cost per unit to retire a new asset, however, depends upon the relative difference in the cost per unit incurred to install the assets. The percentage rate required to accrue for $100 per foot of removal expense on a main costing $50 per foot to install is twice the rate required to accrue the same amount of removal expense on a main costing $100 per foot to install.

The extent to which past inflation is captured in the ratio of cost of removal to retirements is a function of both the rate of change in the cost of labor required to abandon or remove plant from service and the rate of change in the installed unit cost of plant retired from service. While realized net salvage is independent of the age of retirements, revenue requirements created for cost of removal must be recovered in dollars sufficient to pay the cost of removal or abandonment when the associated plant is retired from service.

A second contributing factor to increasing net salvage rates is costs imposed by local requirements such as mandatory police traffic control or curb–to–curb refurbishment when a much smaller section of roadway is disturbed in a plant replacement project.

ONE Gas in general and TGS in particular, became increasingly concerned over the apparent upward trend in net savage rates. Based on an internal investigation, standard material and labor costs were assigned to retirement units for both installation and retirement/removal activities. The new standards were adopted in March 2018.

Future net salvage rates currently used by TGS were estimated in the 2022 WNSA study and retained in the 2024 CGSA study. Given that the sustained upward trend in realized net salvage rates, it was concluded, in consultation with TGS, that a 50 percent increase in current net salvage rates used for transmission mains, distribution mains and distribution services is warranted to marginally reduce depreciation reserve deficiencies, largely attributable to realized net salvage far exceeding future net salvage accruals. Although reserve deficiencies will be amortized over future accounting periods using remaining–life accrual rates, revenue requirements for cost recovery will also be shifted to future time periods.

Table 5 below provides a comparison of realized, current and proposed net salvage rates recommended in the 2025 depreciation study. It can be observed from this comparison that proposed net salvage rates (Column D) are relatively modest

increases from current rates (Column C) and far lower than average realized rates escalating over the period 1999–2024 (Column B).

Account	Future Net Salvage Rates Sf		
	Realized	Current	Proposed
A	B	C	D
Transmission Mains	-351%	-40%	-60%
Distribution Mains	-215%	-40%	-60%
Services	-259%	-60%	-90%

Table 5. Future Net Salvage Rates

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 computed (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 expected changes in the parameters chosen to describe the underlying forces of mortality.

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. If statistical life studies have not been conducted or retirement dispersion has been overlooked in setting depreciation rates, it is likely that some ac-

counts will be over–depreciated and other accounts will be under–depreciated relative to a computed or theoretical reserve. Differences between computed reserves and recorded reserves also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of service lives, retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for TGS 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 should also be realigned to eliminate reserve imbalances created by the implementation of amortization accounting.

Recorded reserves were rebalanced within each service area and the TGS Division 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 amortizable categories were adjusted by replacing recorded reserves with estimated theoretical reserves and distributing amortizable reserve imbalances to depreciable categories within the associated function.

Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2024, by primary account within service areas and the TGS Division. Table 6 below provides a summary of recorded, computed and reserve imbalances for the four TGS service areas and the TGS Division.

Service Area	Plant	Recorded	Ratio	Computed	Ratio	Imbalance
A	B	C	D=C/A	E	F=E/A	G=C-E
CGSA	$1,200,417,573	$237,520,900	19.8%	$304,772,905	25.4%	$ (67,252,005)
RGVSA	278,141,368	40,489,100	14.6%	64,760,225	23.3%	(24,271,125)
WNSA	929,560,491	164,536,899	17.7%	224,262,860	24.1%	(59,725,961)
Statewide	$2,408,119,432	$442,546,899	18.4%	$593,795,990	24.7%	$(151,249,091)
TGS Division	10,992,264	3,252,516	29.6%	3,244,775	29.5%	7,741
Fort Bliss	9,946,539	1,030,036	10.4%	1,882,459	18.9%	(852,423)
TGS Total	$2,429,058,235	$446,829,451	18.4%	$598,923,225	24.7%	$(152,093,773)

Table 6. Depreciation Reserves

Table 7 below provides 2025 annualized accruals, formulated as the sum of a) whole–life accruals and b) the amortization of computed reserve imbalances allocated over the composite weighted–average remaining life of each rate category proposed in the 2025 study.

Service Area	Whole-Life	Amortization	Total
A	B	C	D=B+C
CGSA	$ 39,019,721	$ 1,628,959	$ 40,648,680
RGVSA	9,642,256	639,266	10,281,522
WNSA	30,802,568	1,511,261	32,313,829
Statewide	$ 79,464,545	$ 3,779,486	$ 83,244,031
TGS Division	764,307	0	764,307
Fort Bliss	261,481	16,690	278,171
TGS Total	$ 80,490,333	$ 3,796,176	$ 84,286,509

Table 7. Depreciation Accruals (2025 Annualized)

It can be observed from Table 7 (Column C) that $4.0 million (or about five percent) of TGS Total 2025 annualized accruals of $84 million (Column D) is attributable to amortization of TGS Total $152 million reserve shortfall (Table 6, Column G).

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over 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 dictated 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. The 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 2025 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. (See Table 7 above).

As noted earlier, plant accounting and depreciation reserve records are maintained by TGS for four service areas and the TGS Division that supports all service areas. Projection lives, projection curves and future net salvage rates were estimated in the TGS study from the combined database of the four service areas and the TGS Division. Average service lives and remaining service lives were distinguished among service areas and the Division in the development of generation arrangements unique to each service area and the Division. Average net salvage rates were similarly distinguished 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 estimated future net salvage rates common to all service area and the Division.

It is the opinion of Foster Associates that the vintage group procedure will remain appropriate for TGS, 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 eventually 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 retained in the 2025 study is consistent with the goals and objectives of depreciation accounting derived from cost allocation and depreciation accounting theory. Amortization accounting for the selected certain 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. Amortization rates reported in Statement A (Column G) are reciprocals of approved amortization periods, that should be applied to plant categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

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 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, 2024.
- 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 at December 31, 2024. 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 - Statewide Statement A

Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2024) Investment	Salvage	Total	Proposed (at 12/31/2024) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
STATEWIDE						
TRANSMISSION PLANT						
366.20 Structures and Improvements	2.57%	0.14%	2.71%	2.62%	0.13%	2.75%
367.00 Mains	1.77%	0.83%	2.60%	1.76%	1.16%	2.92%
368.00 Compressor Station Equipment	2.44%	0.25%	2.69%	2.27%	0.23%	2.50%
369.00 Meas. and Reg. Station Equipment	2.70%	0.77%	3.47%	2.26%	1.21%	3.47%
371.00 Other Equipment	3.25%	1.96%	5.21%	3.13%	2.09%	5.22%
Total Transmission Plant	1.95%	0.81%	2.76%	1.86%	1.16%	3.02%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	3.29%	0.32%	3.61%	3.47%	0.34%	3.80%
376.00 Mains	1.55%	0.71%	2.26%	1.51%	0.96%	2.47%
376.90 Mains - Cathodic Protection	6.67%		6.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	1.72%	0.48%	2.20%	1.89%	0.70%	2.59%
379.00 Meas. and Reg. Station Equip. - City Gate	1.59%	0.42%	2.01%	1.60%	0.58%	2.18%
380.00 Services	1.89%	1.29%	3.19%	1.92%	1.86%	3.78%
381.00 Meters	3.53%	0.61%	4.14%	3.13%	0.97%	4.10%
383.00 House Regulators	3.03%	0.53%	3.56%	3.22%	1.01%	4.23%
385.00 Industrial Meas. and Reg. Station Equip.	1.80%	0.58%	2.37%	1.75%	0.63%	2.38%
386.00 Other Property on Customers' Premises	12.83%	-0.04%	12.79%	20.86%	-0.04%	20.82%
Total Distribution Plant	2.06%	0.85%	2.92%	2.03%	1.21%	3.24%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.40%	0.24%	2.63%	2.20%	0.21%	2.41%
392.00 Transportation Equipment	7.82%	-0.80%	7.02%	7.33%	-0.77%	6.56%
396.00 Power Operated Equipment	5.64%	-0.31%	5.33%	4.80%	-0.29%	4.51%
Total Depreciable	5.26%	-0.31%	4.96%	4.88%	-0.30%	4.58%
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	6.67%		6.67%	← 15 Year Amortization →		6.67%
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			6.67%			6.67%
Total Amortizable	6.92%		6.92%	6.92%		6.92%
Total General Plant	6.09%	-0.15%	5.94%	5.90%	-0.15%	5.75%
TOTAL STATEWIDE	2.43%	0.76%	3.19%	2.38%	1.08%	3.46%
CENTRAL-GULF TEXAS						
TRANSMISSION PLANT						
366.20 Structures and Improvements						
367.00 Mains	1.90%	0.76%	2.66%	1.87%	1.15%	3.02%
368.00 Compressor Station Equipment						
369.00 Meas. and Reg. Station Equipment	2.75%	0.68%	3.43%	2.28%	1.15%	3.43%
371.00 Other Equipment						
Total Transmission Plant	2.18%	0.73%	2.91%	2.01%	1.15%	3.16%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	2.87%	0.22%	3.09%	3.55%	0.29%	3.84%
376.00 Mains	1.53%	0.70%	2.23%	1.49%	0.96%	2.45%
376.90 Mains - Cathodic Protection	6.67%		6.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	1.69%	0.44%	2.13%	1.88%	0.67%	2.55%
379.00 Meas. and Reg. Station Equip. - City Gate	1.57%	0.40%	1.97%	1.60%	0.57%	2.17%
380.00 Services	1.87%	1.29%	3.16%	1.91%	1.86%	3.77%
381.00 Meters	3.48%	0.60%	4.08%	3.10%	0.95%	4.05%
383.00 House Regulators	2.93%	0.47%	3.40%	3.10%	0.92%	4.02%
385.00 Industrial Meas. and Reg. Station Equip.	1.79%	0.59%	2.38%	1.75%	0.65%	2.40%
386.00 Other Property on Customers' Premises	11.92%	-0.03%	11.89%	19.54%	-0.03%	19.51%
Total Distribution Plant	1.99%	0.85%	2.83%	1.96%	1.21%	3.17%

TEXAS GAS SERVICE - Statewide Statement A

Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2024) Investment	Salvage	Total	Proposed (at 12/31/2024) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.29%	0.23%	2.52%	2.18%	0.21%	2.39%
392.00 Transportation Equipment	7.25%	-0.82%	6.43%	7.12%	-0.82%	6.30%
396.00 Power Operated Equipment	5.07%	-0.27%	4.80%	4.65%	-0.29%	4.36%
Total Depreciable	4.48%	-0.23%	4.25%	4.34%	-0.24%	4.10%
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	6.67%		6.67%	← 15 Year Amortization →		6.67%
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	6.67%		6.67%			6.67%
Total Amortizable	6.90%		6.90%	6.90%		6.90%
Total General Plant	5.60%	-0.12%	5.48%	5.52%	-0.13%	5.40%
TOTAL CENTRAL-GULF TEXAS	2.35%	0.75%	3.10%	2.31%	1.07%	3.39%
RIO GRANDE VALLEY						
TRANSMISSION PLANT						
366.20 Structures and Improvements	2.57%	0.14%	2.71%	2.62%	0.13%	2.75%
367.00 Mains	1.77%	0.91%	2.68%	1.75%	1.22%	2.97%
368.00 Compressor Station Equipment	2.44%	0.25%	2.69%	2.27%	0.23%	2.50%
369.00 Meas. and Reg. Station Equipment	2.67%	0.82%	3.49%	2.26%	1.26%	3.52%
371.00 Other Equipment	3.25%	1.96%	5.21%	3.13%	2.09%	5.22%
Total Transmission Plant	2.05%	0.86%	2.90%	1.92%	1.19%	3.11%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	3.82%	0.36%	4.18%	4.26%	0.41%	4.67%
376.00 Mains	1.62%	0.69%	2.31%	1.56%	0.97%	2.53%
376.90 Mains - Cathodic Protection	6.67%		6.67%			6.67%
378.00 Meas. and Reg. Station Equip. - General	1.84%	0.49%	2.33%	2.01%	0.71%	2.72%
379.00 Meas. and Reg. Station Equip. - City Gate	1.59%	0.43%	2.02%	1.60%	0.61%	2.21%
380.00 Services	1.95%	1.23%	3.18%	1.96%	1.78%	3.74%
381.00 Meters	3.95%	0.61%	4.56%	3.35%	1.02%	4.37%
383.00 House Regulators	3.38%	0.54%	3.92%	3.18%	0.97%	4.15%
385.00 Industrial Meas. and Reg. Station Equip.	1.77%	0.53%	2.30%	1.68%	0.57%	2.25%
386.00 Other Property on Customers' Premises	17.03%		17.03%	22.32%		22.32%
Total Distribution Plant	2.31%	0.83%	3.14%	2.22%	1.21%	3.43%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.48%	0.24%	2.72%	2.34%	0.23%	2.57%
392.00 Transportation Equipment	8.07%	-0.81%	7.26%	8.03%	-0.82%	7.21%
396.00 Power Operated Equipment	6.37%	-0.47%	5.90%	5.57%	-0.43%	5.14%
Total Depreciable	6.12%	-0.44%	5.68%	6.02%	-0.45%	5.57%
Amortizable						
391.10 Office Furniture and Fixtures	6.67%		6.67%			6.67%
391.90 Computers and Electronic Equipment	14.29%		14.29%			14.29%
393.00 Stores Equipment	6.67%		6.67%			6.67%
394.00 Tools, Shop and Garage Equipment	6.67%		6.67%			6.67%
397.00 Communication Equipment	6.67%		6.67%			6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	6.90%		6.90%	6.90%		6.90%
Total General Plant	6.58%	-0.18%	6.40%	6.54%	-0.18%	6.36%
TOTAL RIO GRANDE VALLEY	2.73%	0.73%	3.46%	2.64%	1.06%	3.70%

TEXAS GAS SERVICE - Statewide Statement A

Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2024) Investment	Salvage	Total	Proposed (at 12/31/2024) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
WEST-NORTH TEXAS						
TRANSMISSION PLANT						
366.20 Structures and Improvements						
367.00 Mains	1.73%	0.81%	2.54%	1.73%	1.13%	2.86%
368.00 Compressor Station Equipment						
369.00 Meas. and Reg. Station Equipment	2.72%	0.76%	3.48%	2.24%	1.17%	3.41%
371.00 Other Equipment						
Total Transmission Plant	1.80%	0.81%	2.60%	1.76%	1.13%	2.90%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	3.18%	0.32%	3.50%	3.19%	0.32%	3.51%
376.00 Mains	1.57%	0.73%	2.30%	1.52%	0.97%	2.49%
376.90 Mains - Cathodic Protection	6.67%		6.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	1.73%	0.51%	2.24%	1.88%	0.72%	2.60%
379.00 Meas. and Reg. Station Equip. - City Gate	1.60%	0.43%	2.03%	1.60%	0.58%	2.18%
380.00 Services	1.91%	1.31%	3.22%	1.93%	1.88%	3.81%
381.00 Meters	3.46%	0.61%	4.07%	3.09%	0.98%	4.07%
383.00 House Regulators	2.97%	0.57%	3.54%	3.33%	1.10%	4.43%
385.00 Industrial Meas. and Reg. Station Equip.	1.81%	0.57%	2.38%	1.76%	0.62%	2.38%
386.00 Other Property on Customers' Premises	14.31%	-0.07%	14.24%	23.04%	-0.05%	22.99%
Total Distribution Plant	2.11%	0.86%	2.97%	2.08%	1.21%	3.28%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.69%	0.26%	2.95%	2.21%	0.22%	2.43%
392.00 Transportation Equipment	8.45%	-0.77%	7.68%	7.32%	-0.68%	6.64%
396.00 Power Operated Equipment	6.14%	-0.33%	5.81%	4.85%	-0.27%	4.58%
Total Depreciable	6.39%	-0.40%	5.99%	5.44%	-0.35%	5.09%
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	6.67%		6.67%	← 15 Year Amortization →		6.67%
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	6.95%		6.95%	6.95%		6.95%
Total General Plant	6.68%	-0.19%	6.49%	6.23%	-0.17%	6.07%
TOTAL WEST-NORTH TEXAS	2.45%	0.77%	3.22%	2.38%	1.09%	3.48%
TGS DIVISION						
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.56%	0.26%	2.82%	2.22%	0.22%	2.44%
392.00 Transportation Equipment						
396.00 Power Operated Equipment						
Total Depreciable	2.56%	0.26%	2.82%	2.22%	0.22%	2.44%
Amortizable						
391.10 Office Furniture and Fixtures	6.67%		6.67%			6.67%
391.90 Computers and Electronic Equipment	14.29%		14.29%			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	10.14%		10.14%	10.14%		10.14%
Total General Plant	7.00%	0.11%	7.11%	6.86%	0.09%	6.95%
TOTAL TGS DIVISION	7.00%	0.11%	7.11%	6.86%	0.09%	6.95%

TEXAS GAS SERVICE - Statewide Statement A

Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2024) Investment	Salvage	Total	Proposed (at 12/31/2024) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
FORT BLISS						
DISTRIBUTION PLANT						
375.10 Structures and Improvements						
376.00 Mains	1.55%	0.64%	2.19%	1.53%	0.94%	2.47%
376.90 Mains - Cathodic Protection	6.67%		6.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	1.69%	0.42%	2.11%	2.01%	0.69%	2.70%
379.00 Meas. and Reg. Station Equip. - City Gate						
380.00 Services	1.89%	1.17%	3.06%	1.94%	1.78%	3.72%
381.00 Meters	3.74%	0.56%	4.30%	3.63%	1.09%	4.72%
383.00 House Regulators	3.01%	0.46%	3.47%	3.43%	1.02%	4.45%
385.00 Industrial Meas. and Reg. Station Equip.	1.78%	0.54%	2.32%	1.69%	0.58%	2.27%
386.00 Other Property on Customers' Premises						
Total Distribution Plant	1.74%	0.70%	2.44%	1.74%	1.03%	2.77%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements						
392.00 Transportation Equipment						
396.00 Power Operated Equipment						
Total Depreciable						
Amortizable						
391.10 Office Furniture and Fixtures						
391.90 Computers and Electronic Equipment						
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	6.67%		6.67%	6.67%		6.67%
Total General Plant	6.67%		6.67%	6.67%		6.67%
TOTAL FORT BLISS	1.77%	0.69%	2.47%	1.77%	1.02%	2.80%

TEXAS GAS SERVICE - Statewide

Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/24 Investment	Current 2025 Annualized Accrual Investment	Net Salvage	Total	Proposed 2025 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STATEWIDE								
TRANSMISSION PLANT								
366.20 Structures and Improvements	$ 1,812,996	$ 46,594	$ 2,538	$ 49,132	$ 47,500	$ 2,357	$ 49,857	$ 725
367.00 Mains	112,427,864	1,984,580	937,507	2,922,087	1,973,140	1,304,459	3,277,599	355,512
368.00 Compressor Station Equipment	157,464	3,842	394	4,236	3,574	362	3,937	(299)
369.00 Meas. and Reg. Station Equipment	25,674,215	693,789	197,298	891,087	580,805	311,116	891,921	834
371.00 Other Equipment	53,986	1,755	1,058	2,813	1,690	1,128	2,818	5
Total Transmission Plant	$ 140,126,525	$ 2,730,560	$ 1,138,795	$ 3,869,355	$ 2,606,710	$ 1,619,422	$ 4,226,132	$ 356,777
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 507,802	$ 16,728	$ 1,622	$ 18,350	$ 17,596	$ 1,713	$ 19,309	$ 959
376.00 Mains	968,382,823	15,027,298	6,879,238	21,906,536	14,589,047	9,339,925	23,928,972	2,022,436
376.90 Mains - Cathodic Protection	72,278,134	4,820,952		4,820,952	4,820,952		4,820,952	
378.00 Meas. and Reg. Station Equip. - General	54,849,760	943,841	260,538	1,204,379	1,037,502	381,416	1,418,917	214,538
379.00 Meas. and Reg. Station Equip. - City Gate	21,025,445	333,959	88,281	422,240	336,407	122,199	458,606	36,365
380.00 Services	673,243,352	12,751,717	8,692,106	21,443,823	12,947,358	12,514,840	25,462,198	4,018,375
381.00 Meters	179,139,977	6,323,605	1,083,870	7,407,475	5,601,400	1,737,704	7,339,104	(68,371)
383.00 House Regulators	35,526,251	1,076,327	187,442	1,263,769	1,143,167	358,783	1,501,949	238,180
385.00 Industrial Meas. and Reg. Station Equip.	38,895,299	699,227	223,822	923,049	680,174	244,662	924,836	1,787
386.00 Other Property on Customers' Premises	1,707,620	219,116	(766)	218,350	356,178	(638)	355,540	137,189
Total Distribution Plant	$ 2,045,556,463	$ 42,212,769	$ 17,416,154	$ 59,628,924	$ 41,529,779	$ 24,700,604	$ 66,230,383	$ 6,601,459
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 48,782,088	$ 1,168,434	$ 115,871	$ 1,284,306	$ 1,073,362	$ 104,360	$ 1,177,722	$ (106,583)
392.00 Transportation Equipment	53,561,735	4,186,372	(428,439)	3,757,932	3,923,775	(411,219)	3,512,556	(245,376)
396.00 Power Operated Equipment	8,626,236	486,467	(26,683)	459,784	413,701	(24,923)	388,778	(71,006)
Total Depreciable	$ 110,970,059	$ 5,841,273	$ (339,251)	$ 5,502,022	$ 5,410,838	$ (331,782)	$ 5,079,056	$ (422,966)
Amortizable								
391.10 Office Furniture and Fixtures	$ 3,969,865	$ 264,790	$ -	$ 264,790	$ 264,790	$ -	$ 264,790	$ -
391.90 Computers and Electronic Equipment	3,591,237	513,188		513,188	513,188		513,188	
393.00 Stores Equipment	97,883	6,529		6,529	6,529		6,529	
394.00 Tools, Shop and Garage Equipment	33,274,951	2,219,439		2,219,439	2,219,439		2,219,439	
397.00 Communication Equipment	70,526,100	4,704,091		4,704,091	4,704,091		4,704,091	
398.00 Miscellaneous Equipment	6,349	423		423	423		423	
Total Amortizable	$ 111,466,385	$ 7,708,460	$ -	$ 7,708,460	$ 7,708,460	$ -	$ 7,708,460	$ -
Total General Plant	$ 222,436,444	$ 13,549,733	$ (339,251)	$ 13,210,482	$ 13,119,298	$ (331,782)	$ 12,787,516	$ (422,966)
TOTAL STATEWIDE	$ 2,408,119,432	$ 58,493,063	$ 18,215,697	$ 76,708,760	$ 57,255,787	$ 25,988,243	$ 83,244,031	$ 6,535,271

TEXAS GAS SERVICE - Statewide

Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/24 Investment	Current 2025 Annualized Accrual Investment	Net Salvage	Total	Proposed 2025 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
CENTRAL-GULF TEXAS								
TRANSMISSION PLANT								
366.20 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367.00 Mains	15,179,870	288,418	115,367	403,785	283,864	174,569	458,432	54,648
368.00 Compressor Station Equipment								
369.00 Meas. and Reg. Station Equipment	7,466,891	205,340	50,775	256,114	170,245	85,869	256,114	
371.00 Other Equipment								
Total Transmission Plant	$ 22,646,761	$ 493,757	$ 166,142	$ 659,899	$ 454,109	$ 260,438	$ 714,546	$ 54,648
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 48,629	$ 1,396	$ 107	$ 1,503	$ 1,726	$ 141	$ 1,867	$ 365
376.00 Mains	533,881,689	8,168,390	3,737,172	11,905,562	7,954,837	5,125,264	13,080,101	1,174,540
376.90 Mains - Cathodic Protection	30,023,583	2,002,573		2,002,573	2,002,573		2,002,573	
378.00 Meas. and Reg. Station Equip. - General	26,032,264	439,945	114,542	554,487	489,407	174,416	663,823	109,336
379.00 Meas. and Reg. Station Equip. - City Gate	7,093,230	111,364	28,373	139,737	113,492	40,431	153,923	14,186
380.00 Services	341,843,979	6,392,482	4,409,787	10,802,270	6,529,220	6,358,298	12,887,518	2,085,248
381.00 Meters	88,835,492	3,091,475	533,013	3,624,488	2,753,900	843,937	3,597,837	(26,651)
383.00 House Regulators	13,122,585	384,492	61,676	446,168	406,800	120,728	527,528	81,360
385.00 Industrial Meas. and Reg. Station Equip.	17,241,979	308,631	101,728	410,359	301,735	112,073	413,807	3,448
386.00 Other Property on Customers' Premises	1,063,249	126,739	(319)	126,420	207,759	(319)	207,440	81,020
Total Distribution Plant	$ 1,059,186,679	$ 21,027,487	$ 8,986,079	$ 30,013,566	$ 20,761,449	$ 12,774,970	$ 33,536,418	$ 3,522,852
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 33,766,807	$ 773,260	$ 77,664	$ 850,924	$ 736,116	$ 70,910	$ 807,027	$ (43,897)
392.00 Transportation Equipment	25,856,810	1,874,619	(212,026)	1,662,593	1,841,005	(212,026)	1,628,979	(33,614)
396.00 Power Operated Equipment	4,143,841	210,093	(11,188)	198,904	192,689	(12,017)	180,671	(18,233)
Total Depreciable	$ 63,767,458	$ 2,857,971	$ (145,551)	$ 2,712,421	$ 2,769,810	$ (153,133)	$ 2,616,677	$ (95,744)
Amortizable								
391.10 Office Furniture and Fixtures	$ 2,471,209	$ 164,830	$ -	$ 164,830	$ 164,830		$ 164,830	$ -
391.90 Computers and Electronic Equipment	1,637,343	233,976		233,976	233,976		233,976	
393.00 Stores Equipment	68,516	4,570		4,570	4,570		4,570	
394.00 Tools, Shop and Garage Equipment	16,304,622	1,087,518		1,087,518	1,087,518		1,087,518	
397.00 Communication Equipment	34,328,636	2,289,720		2,289,720	2,289,720		2,289,720	
398.00 Miscellaneous Equipment	6,349	423		423	423		423	
Total Amortizable	$ 54,816,675	$ 3,781,038	$ -	$ 3,781,038	$ 3,781,038		$ 3,781,038	$ -
Total General Plant	$ 118,584,133	$ 6,639,009	$ (145,551)	$ 6,493,459	$ 6,550,848	$ (153,133)	$ 6,397,715	$ (95,744)
TOTAL CENTRAL-GULF TEXAS	$ 1,200,417,573	$ 28,160,254	$ 9,006,670	$ 37,166,924	$ 27,766,405	$ 12,882,275	$ 40,648,680	$ 3,481,756

TEXAS GAS SERVICE - Statewide

Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/24 Investment	Current 2025 Annualized Accrual Investment	Net Salvage	Total	Proposed 2025 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
RIO GRANDE VALLEY								
TRANSMISSION PLANT								
366.20 Structures and Improvements	$ 1,812,996	$ 46,594	$ 2,538	$ 49,132	$ 47,500	$ 2,357	$ 49,857	$ 725
367.00 Mains	34,430,900	609,427	313,321	922,748	602,541	420,057	1,022,598	99,850
368.00 Compressor Station Equipment	157,464	3,842	394	4,236	3,574	362	3,937	(299)
369.00 Meas. and Reg. Station Equipment	13,578,894	362,556	111,347	473,903	306,883	171,094	477,977	4,074
371.00 Other Equipment	53,986	1,755	1,058	2,813	1,690	1,128	2,818	5
Total Transmission Plant	$ 50,034,240	$ 1,024,174	$ 428,658	$ 1,452,832	$ 962,188	$ 594,998	$ 1,557,187	$ 104,355
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 114,218	$ 4,363	$ 411	$ 4,774	$ 4,866	$ 468	$ 5,334	$ 560
376.00 Mains	74,480,881	1,206,590	513,918	1,720,508	1,161,902	722,465	1,884,366	163,858
376.90 Mains - Cathodic Protection	9,439,275	629,600		629,600	629,600		629,600	
378.00 Meas. and Reg. Station Equip. - General	4,866,276	89,539	23,845	113,384	97,812	34,551	132,363	18,978
379.00 Meas. and Reg. Station Equip. - City Gate	3,201,209	50,899	13,765	64,664	51,219	19,527	70,747	6,082
380.00 Services	73,765,831	1,438,434	907,320	2,345,753	1,445,810	1,313,032	2,758,842	413,089
381.00 Meters	21,958,066	867,344	133,944	1,001,288	735,595	223,972	959,567	(41,720)
383.00 House Regulators	6,450,328	218,021	34,832	252,853	205,120	62,568	267,689	14,836
385.00 Industrial Meas. and Reg. Station Equip.	3,323,547	58,827	17,615	76,442	55,836	18,944	74,780	(1,662)
386.00 Other Property on Customers' Premises	6,144	1,046		1,046	1,371		1,371	325
Total Distribution Plant	$ 197,605,775	$ 4,564,663	$ 1,645,650	$ 6,210,313	$ 4,389,131	$ 2,395,527	$ 6,784,659	$ 574,346
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 4,160,244	$ 103,174	$ 9,985	$ 113,159	$ 97,350	$ 9,569	$ 106,918	$ (6,240)
392.00 Transportation Equipment	7,713,998	622,520	(62,483)	560,036	619,434	(63,255)	556,179	(3,857)
396.00 Power Operated Equipment	502,270	31,995	(2,361)	29,634	27,976	(2,160)	25,817	(3,817)
Total Depreciable	$ 12,376,512	$ 757,688	$ (54,859)	$ 702,829	$ 744,760	$ (55,846)	$ 688,914	$ (13,915)
Amortizable								
391.10 Office Furniture and Fixtures	$ 381,756	$ 25,463	$ -	$ 25,463	$ 25,463		$ 25,463	$ -
391.90 Computers and Electronic Equipment	549,020	78,455		78,455	78,455		78,455	
393.00 Stores Equipment	7,313	488		488	488		488	
394.00 Tools, Shop and Garage Equipment	6,245,742	416,591		416,591	416,591		416,591	
397.00 Communication Equipment	10,941,010	729,765		729,765	729,765		729,765	
398.00 Miscellaneous Equipment								
Total Amortizable	$ 18,124,841	$ 1,250,762	$ -	$ 1,250,762	$ 1,250,762		$ 1,250,762	$ -
Total General Plant	$ 30,501,353	$ 2,008,451	$ (54,859)	$ 1,953,591	$ 1,995,522	$ (55,846)	$ 1,939,676	$ (13,915)
TOTAL RIO GRANDE VALLEY	$ 278,141,368	$ 7,597,288	$ 2,019,448	$ 9,616,736	$ 7,346,842	$ 2,934,680	$ 10,281,522	$ 664,786

TEXAS GAS SERVICE - Statewide

Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/24 Investment	Current 2025 Annualized Accrual Investment	Net Salvage	Total	Proposed 2025 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
WEST-NORTH TEXAS								
TRANSMISSION PLANT								
366.20 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367.00 Mains	62,817,094	1,086,736	508,818	1,595,554	1,086,736	709,833	1,796,569	201,015
368.00 Compressor Station Equipment								
369.00 Meas. and Reg. Station Equipment	4,628,430	125,893	35,176	161,069	103,677	54,153	157,829	(3,240)
371.00 Other Equipment								
Total Transmission Plant	$ 67,445,524	$ 1,212,629	$ 543,995	$ 1,756,624	$ 1,190,413	$ 763,986	$ 1,954,398	$ 197,775
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 344,955	$ 10,970	$ 1,104	$ 12,073	$ 11,004	$ 1,104	$ 12,108	$ 34
376.00 Mains	360,020,253	5,652,318	2,628,148	8,280,466	5,472,308	3,492,196	8,964,504	684,038
376.90 Mains - Cathodic Protection	32,815,276	2,188,779		2,188,779	$ 2,188,779		2,188,779	
378.00 Meas. and Reg. Station Equip. - General	23,951,220	414,356	122,151	536,507	450,283	172,449	622,732	86,224
379.00 Meas. and Reg. Station Equip. - City Gate	10,731,006	171,696	46,143	217,839	171,696	62,240	233,936	16,097
380.00 Services	257,633,542	4,920,801	3,374,999	8,295,800	4,972,327	4,843,511	9,815,838	1,520,038
381.00 Meters	68,346,419	2,364,786	416,913	2,781,699	2,111,904	669,795	2,781,699	
383.00 House Regulators	15,953,338	473,814	90,934	564,748	531,246	175,487	706,733	141,985
385.00 Industrial Meas. and Reg. Station Equip.	18,329,773	331,769	104,480	436,249	322,604	113,645	436,249	
386.00 Other Property on Customers' Premises	638,227	91,330	(447)	90,884	147,048	(319)	146,728	55,845
Total Distribution Plant	$ 788,764,009	$ 16,620,619	$ 6,784,426	$ 23,405,044	$ 16,379,199	$ 9,530,107	$ 25,909,306	$ 2,504,261
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 10,855,037	$ 292,000	$ 28,223	$ 320,224	$ 239,896	$ 23,881	$ 263,777	$ (56,446)
392.00 Transportation Equipment	19,990,927	1,689,233	(153,930)	1,535,303	1,463,336	(135,938)	1,327,398	(207,906)
396.00 Power Operated Equipment	3,980,125	244,380	(13,134)	231,245	193,036	(10,746)	182,290	(48,956)
Total Depreciable	$ 34,826,089	$ 2,225,614	$ (138,841)	$ 2,086,772	$ 1,896,268	$ (122,804)	$ 1,773,465	$ (313,307)
Amortizable								
391.10 Office Furniture and Fixtures	$ 1,116,900	$ 74,497	$ -	$ 74,497	$ 74,497		$ 74,497	$ -
391.90 Computers and Electronic Equipment	1,404,874	200,756		200,756	200,756		200,756	
393.00 Stores Equipment	22,054	1,471		1,471	1,471		1,471	
394.00 Tools, Shop and Garage Equipment	10,724,587	715,330		715,330	715,330		715,330	
397.00 Communication Equipment	25,256,454	1,684,605		1,684,605	1,684,605		1,684,605	
398.00 Miscellaneous Equipment								
Total Amortizable	$ 38,524,869	$ 2,676,660	$ -	$ 2,676,660	$ 2,676,660		$ 2,676,660	$ -
Total General Plant	$ 73,350,958	$ 4,902,274	$ (138,841)	$ 4,763,432	$ 4,572,928	$ (122,804)	$ 4,450,125	$ (313,307)
TOTAL WEST-NORTH TEXAS	$ 929,560,491	$ 22,735,521	$ 7,189,579	$ 29,925,100	$ 22,142,540	$ 10,171,289	$ 32,313,829	$ 2,388,729

TEXAS GAS SERVICE - Statewide

Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/24 Investment	Current 2025 Annualized Accrual Investment	Net Salvage	Total	Proposed 2025 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
TGS DIVISION								
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 4,551,359	$ 116,515	$ 11,834	$ 128,348	$ 101,040	$ 10,013	$ 111,053	$ (17,295)
392.00 Transportation Equipment								
396.00 Power Operated Equipment								
Total Depreciable	$ 4,551,359	$ 116,515	$ 11,834	$ 128,348	$ 101,040	$ 10,013	$ 111,053	$ (17,295)
Amortizable								
391.10 Office Furniture and Fixtures	$ 2,555,384	$ 170,444	$ -	$ 170,444	$ 170,444		$ 170,444	$ -
391.90 Computers and Electronic Equipment	2,934,982	419,409		419,409	419,409		419,409	
393.00 Stores Equipment								
394.00 Tools, Shop and Garage Equipment	100,146	6,680		6,680	6,680		6,680	
397.00 Communication Equipment	850,393	56,721		56,721	56,721		56,721	
398.00 Miscellaneous Equipment								
Total Amortizable	$ 6,440,905	$ 653,254	$ -	$ 653,254	$ 653,254		$ 653,254	$ -
Total General Plant	$ 10,992,264	$ 769,769	$ 11,834	$ 781,602	$ 754,294	$ 10,013	$ 764,307	$ (17,295)
TOTAL TGS DIVISION	$ 10,992,264	$ 769,769	$ 11,834	$ 781,602	$ 754,294	$ 10,013	$ 764,307	$ (17,295)
FORT BLISS								
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376.00 Mains	7,081,047	109,756	45,319	155,075	108,340	66,562	174,902	19,827
376.90 Mains - Cathodic Protection	151,083	10,077		10,077	10,072		10,072	(5)
378.00 Meas. and Reg. Station Equip. - General	325,537	5,502	1,367	6,869	6,543	2,246	8,789	1,921
379.00 Meas. and Reg. Station Equip. - City Gate								
380.00 Services	1,525,735	28,836	17,851	46,687	29,599	27,158	56,757	10,070
381.00 Meters	152,811	5,715	856	6,571	5,547	1,666	7,213	642
383.00 House Regulators	75,571	2,275	348	2,622	2,592	771	3,363	741
385.00 Industrial Meas. and Reg. Station Equip.	574,172	10,220	3,101	13,321	9,704	3,330	13,034	(287)
386.00 Other Property on Customers' Premises								
Total Distribution Plant	$ 9,885,956	$ 172,382	$ 68,841	$ 241,222	$ 172,397	$ 101,733	$ 274,130	$ 32,908

TEXAS GAS SERVICE - Statewide

Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/24 Investment	Current 2025 Annualized Accrual Investment	Net Salvage	Total	Proposed 2025 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
392.00 Transportation Equipment								
396.00 Power Operated Equipment								
Total Depreciable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortizable								
391.10 Office Furniture and Fixtures	$ -	$ -	$ -	$ -	$ -		$ -	$ -
391.90 Computers and Electronic Equipment								
393.00 Stores Equipment								
394.00 Tools, Shop and Garage Equipment	11,690	780		780	780		780	
397.00 Communication Equipment	48,893	3,261		3,261	3,261		3,261	
398.00 Miscellaneous Equipment								
Total Amortizable	$ 60,583	$ 4,041	$ -	$ 4,041	$ 4,041		$ 4,041	$ -
Total General Plant	$ 60,583	$ 4,041	$ -	$ 4,041	$ 4,041	$ -	$ 4,041	$ -
TOTAL FORT BLISS	$ 9,946,539	$ 176,422	$ 68,841	$ 245,263	$ 176,438	$ 101,733	$ 278,171	$ 32,908

TEXAS GAS SERVICE - Statewide

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2024

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
STATEWIDE							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ 1,812,996	$ 173,770	9.58%	$ 221,320	12.21%	$ 143,473	7.91%
367.00 Mains	112,427,864	6,664,613	5.93%	12,474,440	11.10%	7,363,468	6.55%
368.00 Compressor Station Equipment	157,464	7,545	4.79%	11,737	7.45%	7,608	4.83%
369.00 Meas. and Reg. Station Equipment	25,674,215	2,740,800	10.68%	3,816,652	14.87%	2,075,089	8.08%
371.00 Other Equipment	53,986	10,497	19.44%	11,702	21.68%	7,586	14.05%
Total Transmission Plant	$ 140,126,525	$ 9,597,225	6.85%	$ 16,535,851	11.80%	$ 9,597,225	6.85%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 507,802	$ 304,582	59.98%	$ 301,871	59.45%	$ 195,450	38.49%
376.00 Mains	968,382,823	143,510,373	14.82%	197,110,827	20.35%	136,988,806	14.15%
376.90 Mains - Cathodic Protection	72,278,134	30,862,644	42.70%	34,494,827	47.73%	34,494,827	47.73%
378.00 Meas. and Reg. Station Equip. - General	54,849,760	6,547,154	11.94%	8,347,131	15.22%	5,715,950	10.42%
379.00 Meas. and Reg. Station Equip. - City Gate	21,025,445	2,729,482	12.98%	3,296,260	15.68%	2,283,221	10.86%
380.00 Services	673,243,352	82,651,330	12.28%	161,676,775	24.01%	111,610,874	16.58%
381.00 Meters	179,139,977	67,861,118	37.88%	69,060,197	38.55%	47,378,969	26.45%
383.00 House Regulators	35,526,251	12,965,835	36.50%	17,467,294	49.17%	11,550,796	32.51%
385.00 Industrial Meas. and Reg. Station Equip.	38,895,299	9,986,296	25.67%	11,099,362	28.54%	7,754,117	19.94%
386.00 Other Property on Customers' Premises	1,707,620	1,690,766	99.01%	1,600,803	93.74%	1,136,572	66.56%
Total Distribution Plant	$ 2,045,556,463	$ 359,109,581	17.56%	$ 504,455,348	24.66%	$ 359,109,581	17.56%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 48,782,088	$ 6,604,825	13.54%	$ 9,124,018	18.70%	$ 9,597,880	19.68%
392.00 Transportation Equipment	53,561,735	19,194,077	35.84%	14,068,139	26.27%	14,535,663	27.14%
396.00 Power Operated Equipment	8,626,236	2,808,239	32.55%	2,241,435	25.98%	2,335,351	27.07%
Total Depreciable	$ 110,970,059	$ 28,607,141	25.78%	$ 25,433,592	22.92%	$ 26,468,894	23.85%
Amortizable							
391.10 Office Furniture and Fixtures	$ 3,969,865	$ 1,657,809	41.76%	$ 1,809,218	45.57%	$ 1,809,218	45.57%
391.90 Computers and Electronic Equipment	3,591,237	2,464,800	68.63%	2,274,936	63.35%	2,274,936	63.35%
393.00 Stores Equipment	97,883	19,372	19.79%	18,753	19.16%	18,753	19.16%
394.00 Tools, Shop and Garage Equipment	33,274,951	11,371,057	34.17%	11,708,905	35.19%	11,708,905	35.19%
397.00 Communication Equipment	70,526,100	29,719,014	42.14%	31,557,482	44.75%	31,557,482	44.75%
398.00 Miscellaneous Equipment	6,349	899	14.17%	1,905	30.00%	1,905	30.00%
Total Amortizable	$ 111,466,385	$ 45,232,952	40.58%	$ 47,371,199	42.50%	$ 47,371,199	42.50%
Total General Plant	$ 222,436,444	$ 73,840,093	33.20%	$ 72,804,791	32.73%	$ 73,840,093	33.20%
TOTAL STATEWIDE	$ 2,408,119,432	$ 442,546,899	18.38%	$ 593,795,990	24.66%	$ 442,546,899	18.38%

TEXAS GAS SERVICE - Statewide

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2024

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
CENTRAL-GULF TEXAS							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ -	$ -		$ -		$ -	
367.00 Mains	15,179,870	(25,251)	-0.17%	1,856,788	12.23%	230,536	1.52%
368.00 Compressor Station Equipment							
369.00 Meas. and Reg. Station Equipment	7,466,891	356,932	4.78%	814,647	10.91%	101,145	1.35%
371.00 Other Equipment							
Total Transmission Plant	$ 22,646,761	$ 331,681	1.46%	$ 2,671,435	11.80%	$ 331,681	1.46%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 48,629	$ 85,738	176.31%	$ 38,465	79.10%	$ 28,168	57.92%
376.00 Mains	533,881,689	85,770,803	16.07%	109,836,885	20.57%	80,432,595	15.07%
376.90 Mains - Cathodic Protection	30,023,583	13,392,070	44.61%	16,481,014	54.89%	16,481,014	54.89%
378.00 Meas. and Reg. Station Equip. - General	26,032,264	4,472,459	17.18%	4,573,413	17.57%	3,349,071	12.87%
379.00 Meas. and Reg. Station Equip. - City Gate	7,093,230	1,614,558	22.76%	1,396,383	19.69%	1,022,559	14.42%
380.00 Services	341,843,979	42,498,661	12.43%	86,817,924	25.40%	63,576,010	18.60%
381.00 Meters	88,835,492	38,714,559	43.58%	32,903,952	37.04%	24,095,278	27.12%
383.00 House Regulators	13,122,585	5,090,902	38.79%	6,155,047	46.90%	4,507,288	34.35%
385.00 Industrial Meas. and Reg. Station Equip.	17,241,979	5,606,952	32.52%	5,568,677	32.30%	4,077,893	23.65%
386.00 Other Property on Customers' Premises	1,063,249	1,050,342	98.79%	993,004	93.39%	727,168	68.39%
Total Distribution Plant	$ 1,059,186,679	$ 198,297,044	18.72%	$ 264,764,764	25.00%	$ 198,297,044	18.72%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 33,766,807	$ 3,377,925	10.00%	$ 4,998,372	14.80%	$ 5,615,680	16.63%
392.00 Transportation Equipment	25,856,810	10,701,353	41.39%	6,644,118	25.70%	7,464,679	28.87%
396.00 Power Operated Equipment	4,143,841	1,419,010	34.24%	952,203	22.98%	1,069,801	25.82%
Total Depreciable	$ 63,767,458	$ 15,498,288	24.30%	$ 12,594,693	19.75%	$ 14,150,161	22.19%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,471,209	$ 944,263	38.21%	$ 1,083,566	43.85%	$ 1,083,566	43.85%
391.90 Computers and Electronic Equipment	1,637,343	1,092,320	66.71%	1,031,436	62.99%	1,031,436	62.99%
393.00 Stores Equipment	68,516	9,412	13.74%	9,883	14.42%	9,883	14.42%
394.00 Tools, Shop and Garage Equipment	16,304,622	5,449,218	33.42%	5,648,687	34.64%	5,648,687	34.64%
397.00 Communication Equipment	34,328,636	15,897,774	46.31%	16,966,537	49.42%	16,966,537	49.42%
398.00 Miscellaneous Equipment	6,349	899	14.17%	1,905	30.00%	1,905	30.00%
Total Amortizable	$ 54,816,675	$ 23,393,887	42.68%	$ 24,742,014	45.14%	$ 24,742,014	45.14%
Total General Plant	$ 118,584,133	$ 38,892,175	32.80%	$ 37,336,707	31.49%	$ 38,892,175	32.80%
TOTAL CENTRAL-GULF TEXAS	$ 1,200,417,573	$ 237,520,900	19.79%	$ 304,772,905	25.39%	$ 237,520,900	19.79%

TEXAS GAS SERVICE - Statewide

Statement C

Depreciation Reserve Summary
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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
RIO GRANDE VALLEY							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ 1,812,996	$ 173,770	9.58%	$ 221,320	12.21%	$ 143,473	7.91%
367.00 Mains	34,430,900	935,648	2.72%	1,965,896	5.71%	1,274,416	3.70%
368.00 Compressor Station Equipment	157,464	7,545	4.79%	11,737	7.45%	7,608	4.83%
369.00 Meas. and Reg. Station Equipment	13,578,894	1,626,505	11.98%	2,037,574	15.01%	1,320,882	9.73%
371.00 Other Equipment	53,986	10,497	19.44%	11,702	21.68%	7,586	14.05%
Total Transmission Plant	$ 50,034,240	$ 2,753,965	5.50%	$ 4,248,229	8.49%	$ 2,753,965	5.50%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 114,218	$ 46,645	40.84%	$ 72,279	63.28%	$ 38,287	33.52%
376.00 Mains	74,480,881	8,729,674	11.72%	16,160,917	21.70%	8,560,616	11.49%
376.90 Mains - Cathodic Protection	9,439,275	3,973,220	42.09%	3,960,176	41.95%	3,960,176	41.95%
378.00 Meas. and Reg. Station Equip. - General	4,866,276	620,210	12.75%	1,240,131	25.48%	656,911	13.50%
379.00 Meas. and Reg. Station Equip. - City Gate	3,201,209	(28,612)	-0.89%	148,772	4.65%	78,806	2.46%
380.00 Services	73,765,831	7,069,029	9.58%	17,139,890	23.24%	9,079,188	12.31%
381.00 Meters	21,958,066	5,417,835	24.67%	7,705,302	35.09%	4,081,583	18.59%
383.00 House Regulators	6,450,328	2,724,562	42.24%	4,072,422	63.14%	2,157,207	33.44%
385.00 Industrial Meas. and Reg. Station Equip.	3,323,547	265,306	7.98%	389,412	11.72%	206,276	6.21%
386.00 Other Property on Customers' Premises	6,144	4,142	67.42%	5,592	91.01%	2,962	48.21%
Total Distribution Plant	$ 197,605,775	$ 28,822,012	14.59%	$ 50,894,894	25.76%	$ 28,822,012	14.59%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,160,244	$ 833,682	20.04%	$ 931,241	22.38%	$ 726,832	17.47%
392.00 Transportation Equipment	7,713,998	2,458,107	31.87%	2,073,540	26.88%	1,618,394	20.98%
396.00 Power Operated Equipment	502,270	225,739	44.94%	202,384	40.29%	157,960	31.45%
Total Depreciable	$ 12,376,512	$ 3,517,529	28.42%	$ 3,207,164	25.91%	$ 2,503,185	20.23%
Amortizable							
391.10 Office Furniture and Fixtures	$ 381,756	$ 151,445	39.67%	$ 153,750	40.27%	$ 153,750	40.27%
391.90 Computers and Electronic Equipment	549,020	330,521	60.20%	361,474	65.84%	361,474	65.84%
393.00 Stores Equipment	7,313	1,426	19.50%	243	3.32%	243	3.32%
394.00 Tools, Shop and Garage Equipment	6,245,742	2,089,227	33.45%	2,229,432	35.70%	2,229,432	35.70%
397.00 Communication Equipment	10,941,010	2,822,976	25.80%	3,665,039	33.50%	3,665,039	33.50%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 18,124,841	$ 5,395,594	29.77%	$ 6,409,938	35.37%	$ 6,409,938	35.37%
Total General Plant	$ 30,501,353	$ 8,913,123	29.22%	$ 9,617,102	31.53%	$ 8,913,123	29.22%
TOTAL RIO GRANDE VALLEY	$ 278,141,368	$ 40,489,100	14.56%	$ 64,760,225	23.28%	$ 40,489,100	14.56%

TEXAS GAS SERVICE - Statewide

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
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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
WEST-NORTH TEXAS							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ -	$ -		$ -		$ -	
367.00 Mains	62,817,094	5,754,216	9.16%	8,651,757	13.77%	5,858,517	9.33%
368.00 Compressor Station Equipment							
369.00 Meas. and Reg. Station Equipment	4,628,430	757,363	16.36%	964,431	20.84%	653,062	14.11%
371.00 Other Equipment							
Total Transmission Plant	$ 67,445,524	$ 6,511,579	9.65%	$ 9,616,187	14.26%	$ 6,511,579	9.65%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 344,955	$ 172,199	49.92%	$ 191,127	55.41%	$ 128,995	37.39%
376.00 Mains	360,020,253	49,009,896	13.61%	71,113,025	19.75%	47,995,595	13.33%
376.90 Mains - Cathodic Protection	32,815,276	13,497,354	41.13%	14,053,637	42.83%	14,053,637	42.83%
378.00 Meas. and Reg. Station Equip. - General	23,951,220	1,454,485	6.07%	2,533,587	10.58%	1,709,968	7.14%
379.00 Meas. and Reg. Station Equip. - City Gate	10,731,006	1,143,536	10.66%	1,751,105	16.32%	1,181,855	11.01%
380.00 Services	257,633,542	33,083,640	12.84%	57,718,961	22.40%	38,955,675	15.12%
381.00 Meters	68,346,419	23,728,724	34.72%	28,450,943	41.63%	19,202,108	28.10%
383.00 House Regulators	15,953,338	5,150,371	32.28%	7,239,824	45.38%	4,886,302	30.63%
385.00 Industrial Meas. and Reg. Station Equip.	18,329,773	4,114,038	22.44%	5,141,273	28.05%	3,469,948	18.93%
386.00 Other Property on Customers' Premises	638,227	636,283	99.70%	602,208	94.36%	406,442	63.68%
Total Distribution Plant	$ 788,764,009	$ 131,990,525	16.73%	$ 188,795,690	23.94%	$ 131,990,525	16.73%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 10,855,037	$ 2,393,218	22.05%	$ 3,194,406	29.43%	$ 3,255,368	29.99%
392.00 Transportation Equipment	19,990,927	6,034,617	30.19%	5,350,482	26.76%	5,452,590	27.28%
396.00 Power Operated Equipment	3,980,125	1,163,490	29.23%	1,086,849	27.31%	1,107,590	27.83%
Total Depreciable	$ 34,826,089	$ 9,591,324	27.54%	$ 9,631,736	27.66%	$ 9,815,548	28.18%
Amortizable							
391.10 Office Furniture and Fixtures	$ 1,116,900	$ 562,101	50.33%	$ 571,902	51.20%	$ 571,902	51.20%
391.90 Computers and Electronic Equipment	1,404,874	1,041,959	74.17%	882,026	62.78%	882,026	62.78%
393.00 Stores Equipment	22,054	8,534	38.69%	8,627	39.12%	8,627	39.12%
394.00 Tools, Shop and Garage Equipment	10,724,587	3,832,613	35.74%	3,830,786	35.72%	3,830,786	35.72%
397.00 Communication Equipment	25,256,454	10,998,265	43.55%	10,925,906	43.26%	10,925,906	43.26%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 38,524,869	$ 16,443,471	42.68%	$ 16,219,247	42.10%	$ 16,219,247	42.10%
Total General Plant	$ 73,350,958	$ 26,034,795	35.49%	$ 25,850,983	35.24%	$ 26,034,795	35.49%
TOTAL WEST-NORTH TEXAS	$ 929,560,491	$ 164,536,899	17.70%	$ 224,262,860	24.13%	$ 164,536,899	17.70%

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Statement C

Depreciation Reserve Summary
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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							
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,551,359	$ 612,852	13.47%	$ 568,389	12.49%	$ 576,130	12.66%
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ 4,551,359	$ 612,852	13.47%	$ 568,389	12.49%	$ 576,130	12.66%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,555,384	$ 888,650	34.78%	$ 891,160	34.87%	$ 891,160	34.87%
391.90 Computers and Electronic Equipment	2,934,982	1,140,604	38.86%	1,170,712	39.89%	1,170,712	39.89%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	100,146	17,752	17.73%	17,300	17.27%	17,300	17.27%
397.00 Communication Equipment	850,393	592,658	69.69%	597,214	70.23%	597,214	70.23%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 6,440,905	$ 2,639,664	40.98%	$ 2,676,386	41.55%	$ 2,676,386	41.55%
Total General Plant	$ 10,992,264	$ 3,252,516	29.59%	$ 3,244,775	29.52%	$ 3,252,516	29.59%
TOTAL TGS DIVISION	$ 10,992,264	$ 3,252,516	29.59%	$ 3,244,775	29.52%	$ 3,252,516	29.59%
FORT BLISS							
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains	7,081,047	600,313	8.48%	1,216,079	17.17%	636,844	8.99%
376.90 Mains - Cathodic Protection	151,083	59,117	39.13%	61,051	40.41%	61,051	40.41%
378.00 Meas. and Reg. Station Equip. - General	325,537	60,179	18.49%	85,373	26.23%	44,709	13.73%
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services	1,525,735	149,423	9.79%	307,434	20.15%	160,999	10.55%
381.00 Meters	152,811	65,882	43.11%	75,417	49.35%	39,495	25.85%
383.00 House Regulators	75,571	23,792	31.48%	29,344	38.83%	15,367	20.33%
385.00 Industrial Meas. and Reg. Station Equip.	574,172	39,539	6.89%	75,960	13.23%	39,779	6.93%
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ 9,885,956	$ 998,245	10.10%	$ 1,850,658	18.72%	$ 998,245	10.10%

TEXAS GAS SERVICE - Statewide

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
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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
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ -	$ -		$ -		$ -	
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ -	$ -		$ -		$ -	
Amortizable							
391.10 Office Furniture and Fixtures	$ -	$ -		$ -		$ -	
391.90 Computers and Electronic Equipment							
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	11,690	3,503	29.96%	3,507	30.00%	3,507	30.00%
397.00 Communication Equipment	48,893	28,289	57.86%	28,294	57.87%	28,294	57.87%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 60,583	$ 31,792	52.48%	$ 31,801	52.49%	$ 31,801	52.49%
Total General Plant	$ 60,583	$ 31,792	52.48%	$ 31,801	52.49%	$ 31,801	52.49%
TOTAL FORT BLISS	$ 9,946,539	$ 1,030,036	10.36%	$ 1,882,459	18.93%	$ 1,030,046	10.36%

TEXAS GAS SERVICE - Statewide

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2024

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
STATEWIDE							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ 1,812,996	$ 138,616	7.65%	$ 4,857	0.27%	$ 143,473	7.91%
367.00 Mains	112,427,864	8,155,166	7.25%	(1,022,234)	-0.91%	7,132,932	6.34%
368.00 Compressor Station Equipment	157,464	257,237	163.36%	(19,093)	-12.13%	238,144	151.24%
369.00 Meas. and Reg. Station Equipment	25,674,215	1,909,581	7.44%	165,508	0.64%	2,075,089	8.08%
371.00 Other Equipment	53,986	22,956	42.52%	(15,369)	-28.47%	7,586	14.05%
Total Transmission Plant	$ 140,126,525	$ 10,483,556	7.48%	$ (886,331)	-0.63%	$ 9,597,225	6.85%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 507,802	$ 176,878	34.83%	$ 18,572	3.66%	$ 195,450	38.49%
376.00 Mains	968,382,823	106,316,945	10.98%	30,671,861	3.17%	136,988,806	14.15%
376.90 Mains - Cathodic Protection	72,278,134	34,494,827	47.73%			34,494,827	47.73%
378.00 Meas. and Reg. Station Equip. - General	54,849,760	4,786,728	8.73%	929,222	1.69%	5,715,950	10.42%
379.00 Meas. and Reg. Station Equip. - City Gate	21,025,445	1,849,672	8.80%	433,548	2.06%	2,283,221	10.86%
380.00 Services	673,243,352	78,819,052	11.71%	32,791,822	4.87%	111,610,874	16.58%
381.00 Meters	179,139,977	37,636,533	21.01%	9,742,436	5.44%	47,378,969	26.45%
383.00 House Regulators	35,526,251	9,143,751	25.74%	2,407,045	6.78%	11,550,796	32.51%
385.00 Industrial Meas. and Reg. Station Equip.	38,895,299	6,048,501	15.55%	1,705,616	4.39%	7,754,117	19.94%
386.00 Other Property on Customers' Premises	1,707,620	1,135,558	66.50%	1,014	0.06%	1,136,572	66.56%
Total Distribution Plant	$ 2,045,556,463	$ 280,408,445	13.71%	$ 78,701,136	3.85%	$ 359,109,581	17.56%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 48,782,088	$ 8,653,458	17.74%	$ 944,421	1.94%	$ 9,597,880	19.68%
392.00 Transportation Equipment	53,561,735	15,942,882	29.77%	(1,407,219)	-2.63%	14,535,663	27.14%
396.00 Power Operated Equipment	8,626,236	2,389,339	27.70%	(53,988)	-0.63%	2,335,351	27.07%
Total Depreciable	$ 110,970,059	$ 26,985,680	24.32%	$ (516,786)	-0.47%	$ 26,468,894	23.85%
Amortizable							
391.10 Office Furniture and Fixtures	$ 3,969,865	$ 1,809,218	45.57%	$ -		$ 1,809,218	45.57%
391.90 Computers and Electronic Equipment	3,591,237	2,274,936	63.35%			2,274,936	63.35%
393.00 Stores Equipment	97,883	18,753	19.16%			18,753	19.16%
394.00 Tools, Shop and Garage Equipment	33,274,951	11,708,905	35.19%			11,708,905	35.19%
397.00 Communication Equipment	70,526,100	31,557,482	44.75%			31,557,482	44.75%
398.00 Miscellaneous Equipment	6,349	1,905	30.00%			1,905	30.00%
Total Amortizable	$ 111,466,385	$ 47,371,199	42.50%	$ -		$ 47,371,199	42.50%
Total General Plant	$ 222,436,444	$ 74,356,879	33.43%	$ (516,786)	-0.23%	$ 73,840,093	33.20%
TOTAL STATEWIDE	$ 2,408,119,432	$ 365,248,880	15.17%	$ 77,298,019	3.21%	$ 442,546,899	18.38%

TEXAS GAS SERVICE - Statewide

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2024

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
CENTRAL-GULF TEXAS							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ -	$ -		$ -		$ -	
367.00 Mains	15,179,870	250,320	1.65%	(19,784)	-0.13%	230,536	1.52%
368.00 Compressor Station Equipment							
369.00 Meas. and Reg. Station Equipment	7,466,891	72,557	0.97%	28,588	0.38%	101,145	1.35%
371.00 Other Equipment							
Total Transmission Plant	$ 22,646,761	$ 322,878	1.43%	$ 8,804	0.04%	$ 331,681	1.46%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 48,629	$ 25,239	51.90%	$ 2,928	6.02%	$ 28,168	57.92%
376.00 Mains	533,881,689	61,393,149	11.50%	19,039,446	3.57%	80,432,595	15.07%
376.90 Mains - Cathodic Protection	30,023,583	16,481,014	54.89%			16,481,014	54.89%
378.00 Meas. and Reg. Station Equip. - General	26,032,264	2,566,333	9.86%	782,738	3.01%	3,349,071	12.87%
379.00 Meas. and Reg. Station Equip. - City Gate	7,093,230	773,824	10.91%	248,736	3.51%	1,022,559	14.42%
380.00 Services	341,843,979	44,407,435	12.99%	19,168,576	5.61%	63,576,010	18.60%
381.00 Meters	88,835,492	18,960,304	21.34%	5,134,973	5.78%	24,095,278	27.12%
383.00 House Regulators	13,122,585	3,457,680	26.35%	1,049,608	8.00%	4,507,288	34.35%
385.00 Industrial Meas. and Reg. Station Equip.	17,241,979	3,270,155	18.97%	807,738	4.68%	4,077,893	23.65%
386.00 Other Property on Customers' Premises	1,063,249	726,701	68.35%	467	0.04%	727,168	68.39%
Total Distribution Plant	$ 1,059,186,679	$ 152,061,833	14.36%	$ 46,235,211	4.37%	$ 198,297,044	18.72%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 33,766,807	$ 5,045,361	14.94%	$ 570,320	1.69%	$ 5,615,680	16.63%
392.00 Transportation Equipment	25,856,810	7,989,884	30.90%	(525,205)	-2.03%	7,464,679	28.87%
396.00 Power Operated Equipment	4,143,841	1,088,559	26.27%	(18,757)	-0.45%	1,069,801	25.82%
Total Depreciable	$ 63,767,458	$ 14,123,803	22.15%	$ 26,358	0.04%	$ 14,150,161	22.19%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,471,209	$ 1,083,566	43.85%			$ 1,083,566	43.85%
391.90 Computers and Electronic Equipment	1,637,343	1,031,436	62.99%			1,031,436	62.99%
393.00 Stores Equipment	68,516	9,883	14.42%			9,883	14.42%
394.00 Tools, Shop and Garage Equipment	16,304,622	5,648,687	34.64%			5,648,687	34.64%
397.00 Communication Equipment	34,328,636	16,966,537	49.42%			16,966,537	49.42%
398.00 Miscellaneous Equipment	6,349	1,905	30.00%			1,905	30.00%
Total Amortizable	$ 54,816,675	$ 24,742,014	45.14%			$ 24,742,014	45.14%
Total General Plant	$ 118,584,133	$ 38,865,817	32.77%	$ 26,358	0.02%	$ 38,892,175	32.80%
TOTAL CENTRAL-GULF TEXAS	$ 1,200,417,573	$ 191,250,528	15.93%	$ 46,270,372	3.85%	$ 237,520,900	19.79%

TEXAS GAS SERVICE - Statewide

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2024

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
RIO GRANDE VALLEY							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ 1,812,996	$ 138,616	7.65%	$ 4,857	0.27%	$ 143,473	7.91%
367.00 Mains	34,430,900	2,708,641	7.87%	(1,434,225)	-4.17%	1,274,416	3.70%
368.00 Compressor Station Equipment	157,464	6,917	4.39%	692	0.44%	7,608	4.83%
369.00 Meas. and Reg. Station Equipment	13,578,894	1,338,397	9.86%	(17,515)	-0.13%	1,320,882	9.73%
371.00 Other Equipment	53,986	22,956	42.52%	(15,369)	-28.47%	7,586	14.05%
Total Transmission Plant	$ 50,034,240	$ 4,215,526	8.43%	$ (1,461,561)	-2.92%	$ 2,753,965	5.50%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 114,218	$ 34,475	30.18%	$ 3,812	3.34%	$ 38,287	33.52%
376.00 Mains	74,480,881	6,121,191	8.22%	2,439,425	3.28%	8,560,616	11.49%
376.90 Mains - Cathodic Protection	9,439,275	3,960,176	41.95%			3,960,176	41.95%
378.00 Meas. and Reg. Station Equip. - General	4,866,276	483,498	9.94%	173,413	3.56%	656,911	13.50%
379.00 Meas. and Reg. Station Equip. - City Gate	3,201,209	125,822	3.93%	(47,016)	-1.47%	78,806	2.46%
380.00 Services	73,765,831	5,011,583	6.79%	4,067,606	5.51%	9,079,188	12.31%
381.00 Meters	21,958,066	3,198,064	14.56%	883,519	4.02%	4,081,583	18.59%
383.00 House Regulators	6,450,328	1,672,805	25.93%	484,402	7.51%	2,157,207	33.44%
385.00 Industrial Meas. and Reg. Station Equip.	3,323,547	135,950	4.09%	70,326	2.12%	206,276	6.21%
386.00 Other Property on Customers' Premises	6,144	2,962	48.21%			2,962	48.21%
Total Distribution Plant	$ 197,605,775	$ 20,746,526	10.50%	$ 8,075,486	4.09%	$ 28,822,012	14.59%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,160,244	$ 656,045	15.77%	$ 70,787	1.70%	$ 726,832	17.47%
392.00 Transportation Equipment	7,713,998	1,784,093	23.13%	(165,699)	-2.15%	1,618,394	20.98%
396.00 Power Operated Equipment	502,270	156,351	31.13%	1,609	0.32%	157,960	31.45%
Total Depreciable	$ 12,376,512	$ 2,596,489	20.98%	$ (93,303)	-0.75%	$ 2,503,185	20.23%
Amortizable							
391.10 Office Furniture and Fixtures	$ 381,756	$ 153,750	40.27%			$ 153,750	40.27%
391.90 Computers and Electronic Equipment	549,020	361,474	65.84%			361,474	65.84%
393.00 Stores Equipment	7,313	243	3.32%			243	3.32%
394.00 Tools, Shop and Garage Equipment	6,245,742	2,229,432	35.70%			2,229,432	35.70%
397.00 Communication Equipment	10,941,010	3,665,039	33.50%			3,665,039	33.50%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 18,124,841	$ 6,409,938	35.37%			$ 6,409,938	35.37%
Total General Plant	$ 30,501,353	$ 9,006,427	29.53%	$ (93,303)	-0.31%	$ 8,913,123	29.22%
TOTAL RIO GRANDE VALLEY	$ 278,141,368	$ 33,968,479	12.21%	$ 6,520,621	2.34%	$ 40,489,100	14.56%

TEXAS GAS SERVICE - Statewide

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2024

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
WEST-NORTH TEXAS							
TRANSMISSION PLANT							
366.20 Structures and Improvements	$ -	$ -		$ -		$ -	
367.00 Mains	62,817,094	5,446,525	8.67%	411,991		5,858,517	
368.00 Compressor Station Equipment							
369.00 Meas. and Reg. Station Equipment	4,628,430	498,627	10.77%	154,435		653,062	
371.00 Other Equipment							
Total Transmission Plant	$ 67,445,524	$ 5,945,152	8.81%	$ 566,426	0.84%	$ 6,511,579	9.65%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 344,955	$ 117,163	33.96%	$ 11,832	3.43%	$ 128,995	37.39%
376.00 Mains	360,020,253	38,802,606	10.78%	9,192,990	2.55%	47,995,595	13.33%
376.90 Mains - Cathodic Protection	32,815,276	14,053,637	42.83%			14,053,637	42.83%
378.00 Meas. and Reg. Station Equip. - General	23,951,220	1,736,897	7.25%	(26,929)	-0.11%	1,709,968	7.14%
379.00 Meas. and Reg. Station Equip. - City Gate	10,731,006	950,027	8.85%	231,829	2.16%	1,181,855	11.01%
380.00 Services	257,633,542	29,400,035	11.41%	9,555,641	3.71%	38,955,675	15.12%
381.00 Meters	68,346,419	15,478,164	22.65%	3,723,943	5.45%	19,202,108	28.10%
383.00 House Regulators	15,953,338	4,013,266	25.16%	873,036	5.47%	4,886,302	30.63%
385.00 Industrial Meas. and Reg. Station Equip.	18,329,773	2,642,396	14.42%	827,551	4.51%	3,469,948	18.93%
386.00 Other Property on Customers' Premises	638,227	405,895	63.60%	547	0.09%	406,442	63.68%
Total Distribution Plant	$ 788,764,009	$ 107,600,086	13.64%	$ 24,390,439	3.09%	$ 131,990,525	16.73%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 10,855,037	$ 2,952,052	27.20%	$ 303,315	2.79%	$ 3,255,368	29.99%
392.00 Transportation Equipment	19,990,927	6,168,905	30.86%	(716,315)	-3.58%	5,452,590	27.28%
396.00 Power Operated Equipment	3,980,125	1,144,430	28.75%	(36,840)	-0.93%	1,107,590	27.83%
Total Depreciable	$ 34,826,089	$ 10,265,388	29.48%	$ (449,840)	-1.29%	$ 9,815,548	28.18%
Amortizable							
391.10 Office Furniture and Fixtures	$ 1,116,900	$ 571,902	51.20%			$ 571,902	51.20%
391.90 Computers and Electronic Equipment	1,404,874	882,026	62.78%			882,026	62.78%
393.00 Stores Equipment	22,054	8,627	39.12%			8,627	39.12%
394.00 Tools, Shop and Garage Equipment	10,724,587	3,830,786	35.72%			3,830,786	35.72%
397.00 Communication Equipment	25,256,454	10,925,906	43.26%			10,925,906	43.26%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 38,524,869	$ 16,219,247	42.10%			$ 16,219,247	42.10%
Total General Plant	$ 73,350,958	$ 26,484,635	36.11%	$ (449,840)	-0.61%	$ 26,034,795	35.49%
TOTAL WEST-NORTH TEXAS	$ 929,560,491	$ 140,029,873	15.06%	$ 24,507,026	2.64%	$ 164,536,899	17.70%

TEXAS GAS SERVICE - Statewide

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2024

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							
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,551,359	$ 523,754	11.51%	$ 52,375	1.15%	$ 576,130	12.66%
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ 4,551,359	$ 523,754	11.51%	$ 52,375	1.15%	$ 576,130	12.66%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,555,384	$ 891,160	34.87%			$ 891,160	34.87%
391.90 Computers and Electronic Equipment	2,934,982	1,170,712	39.89%			1,170,712	39.89%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	100,146	17,300	17.27%			17,300	17.27%
397.00 Communication Equipment	850,393	597,214	70.23%			597,214	70.23%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 6,440,905	$ 2,676,386	41.55%			$ 2,676,386	41.55%
Total General Plant	$ 10,992,264	$ 3,200,140	29.11%	$ 52,375	0.48%	$ 3,252,516	29.59%
TOTAL TGS DIVISION	$ 10,992,264	$ 3,200,140	29.11%	$ 52,375	0.48%	$ 3,252,516	29.59%
FORT BLISS							
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains	7,081,047	464,921	6.57%	171,923	2.43%	636,844	8.99%
376.90 Mains - Cathodic Protection	151,083	61,051	40.41%			61,051	40.41%
378.00 Meas. and Reg. Station Equip. - General	325,537	31,886	9.79%	12,823	3.94%	44,709	13.73%
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services	1,525,735	100,184	6.57%	60,815	3.99%	160,999	10.55%
381.00 Meters	152,811	30,381	19.88%	9,114	5.96%	39,495	25.85%
383.00 House Regulators	75,571	11,821	15.64%	3,546	4.69%	15,367	20.33%
385.00 Industrial Meas. and Reg. Station Equip.	574,172	27,238	4.74%	12,541	2.18%	39,779	6.93%
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ 9,885,956	$ 727,482	7.36%	$ 270,763	2.74%	$ 998,245	10.10%

TEXAS GAS SERVICE - Statewide

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2024

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
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ -	$ -		$ -		$ -	
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ -	$ -		$ -		$ -	
Amortizable							
391.10 Office Furniture and Fixtures	$ -	$ -				$ -	
391.90 Computers and Electronic Equipment							
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	11,690	3,507	30.00%			3,507	30.00%
397.00 Communication Equipment	48,893	28,294	57.87%			28,294	57.87%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 60,583	$ 31,801	52.49%			$ 31,801	52.49%
Total General Plant	$ 60,583	$ 31,801	52.49%	$ -		$ 31,801	52.49%
TOTAL FORT BLISS	$ 9,946,539	$ 759,283	7.63%	$ 270,763	2.72%	$ 1,030,046	10.36%

TEXAS GAS SERVICE - Statewide
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
STATEWIDE									
TRANSMISSION PLANT									
366.20 Structures and Improvements	$ 1,814,881	$1,885	$ 1,812,996	-206.2%	-5.0%	$ (3,887)	$ (90,650)	($94,537)	-5.2%
367.00 Mains	100,324,057	3,076,063	97,247,994	-406.4%	-60.0%	(12,500,233)	(58,348,796)	(70,849,030)	-70.6%
368.00 Compressor Station Equipment	16,514,577	1,177,243	15,337,334	-205.0%	-59.5%	(2,413,348)	(9,123,668)	(11,537,017)	-69.9%
369.00 Meas. and Reg. Station Equipment	26,727,822	1,053,607	25,674,215	-199.9%	-50.0%	(2,106,230)	(12,837,108)	(14,943,337)	-55.9%
371.00 Other Equipment	79,000	25,014	53,986	-473.3%	-10.0%	(118,391)	(5,399)	(123,790)	-156.7%
Total Transmission Plant	$ 145,460,337	$ 5,333,812	$ 140,126,525	-321.4%	-57.4%	$ (17,142,090)	$ (80,405,621)	$ (97,547,710)	-67.1%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 554,637	$ 46,835	$ 507,802	1.1%	-10.0%	$ 536	$ (50,780)	$ (50,244)	-9.1%
376.00 Mains	1,006,564,315	38,181,492	968,382,823	-214.7%	-60.0%	(81,976,005)	(581,029,694)	(663,005,699)	-65.9%
376.90 Mains - Cathodic Protection	101,053,208	28,775,074	72,278,134						
378.00 Meas. and Reg. Station Equip. - General	58,563,513	3,713,753	54,849,760	-69.8%	-35.0%	(2,591,938)	(19,197,416)	(21,789,354)	-37.2%
379.00 Meas. and Reg. Station Equip. - City Gate	22,134,753	1,109,308	21,025,445	-74.0%	-35.0%	(820,944)	(7,358,906)	(8,179,850)	-37.0%
380.00 Services	714,127,565	40,884,213	673,243,352	-258.3%	-90.0%	(105,591,592)	(605,919,017)	(711,510,608)	-99.6%
381.00 Meters	198,791,602	19,651,625	179,139,977	-48.4%	-30.0%	(9,502,432)	(53,741,993)	(63,244,425)	-31.8%
383.00 House Regulators	38,681,583	3,155,332	35,526,251	-57.5%	-30.0%	(1,813,004)	(10,657,875)	(12,470,879)	-32.2%
385.00 Industrial Meas. and Reg. Station Equip.	41,562,712	2,667,413	38,895,299	-64.9%	-35.0%	(1,730,130)	(13,613,355)	(15,343,484)	-36.9%
386.00 Other Property on Customers' Premises	2,035,929	328,309	1,707,620	8.5%		27,788		27,788	1.4%
Total Distribution Plant	$ 2,184,069,817	$ 138,513,354	$ 2,045,556,463	-147.3%	-63.1%	$ (203,997,720)	$ (1,291,569,036)	$ (1,495,566,756)	-68.5%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 50,264,156	$ 1,482,068	$ 48,782,088	-3.4%	-10.0%	$ (50,040)	$ (4,878,209)	$ (4,928,249)	-9.8%
392.00 Transportation Equipment	65,112,237	11,550,502	53,561,735	9.2%	10.0%	1,058,961	5,356,174	6,415,134	9.9%
396.00 Power Operated Equipment	10,994,951	2,368,715	8,626,236	6.6%	5.0%	156,594	431,312	587,906	5.3%
Total Depreciable	$ 126,371,344	$ 15,401,285	$ 110,970,059	7.6%	0.8%	$ 1,165,515	$ 909,277	$ 2,074,792	1.6%
Amortizable									
391.10 Office Furniture and Fixtures	$ 9,375,197	$5,405,332	$ 3,969,865			$ -	$ -		
391.90 Computers and Electronic Equipment	14,121,343	10,530,106	3,591,237						
393.00 Stores Equipment	368,695	270,812	97,883						
394.00 Tools, Shop and Garage Equipment	45,063,782	11,788,831	33,274,951						
397.00 Communication Equipment	78,152,639	7,626,539	70,526,100						
398.00 Miscellaneous Equipment	1,203,825	1,197,476	6,349						
Total Amortizable	$ 148,285,481	$ 36,819,096	$ 111,466,385			$ -	$ -		
Total General Plant	$ 274,656,825	$ 52,220,381	$ 222,436,444	2.2%	0.4%	$ 1,165,515	$ 909,277	$ 2,074,792	0.8%
TOTAL STATEWIDE	$ 2,604,186,979	$ 196,067,547	$ 2,408,119,432	-112.2%	-56.9%	$ (219,974,295)	$ (1,371,065,380)	$ (1,591,039,674)	-61.1%

TEXAS GAS SERVICE - Statewide
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
CENTRAL-GULF TEXAS									
TRANSMISSION PLANT									
366.20 Structures and Improvements	$ -	$ -	$ -			$ -	$ -	$ -	$ -
367.00 Mains	16,357,113	1,177,243	15,179,870	-205.0%	-60.0%	(2,413,348)	(9,107,922)	(11,521,270)	(1)
368.00 Compressor Station Equipment									
369.00 Meas. and Reg. Station Equipment	7,504,252	37,361	7,466,891	-231.0%	-50.0%	(86,304)	(3,733,446)	(3,819,749)	(1)
371.00 Other Equipment									
Total Transmission Plant	$ 23,861,365	$ 1,214,604	$ 22,646,761	-205.8%	-56.7%	$ (2,499,652)	$ (12,841,368)	$ (15,341,020)	-64.3%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 79,827	$ 31,198	$ 48,629		-10.0%		$ (4,863)	$ (4,863)	-6.1%
376.00 Mains	549,813,915	15,932,226	533,881,689	-247.6%	-60.0%	(39,448,192)	(320,329,013)	(359,777,205)	-65.4%
376.90 Mains - Cathodic Protection	44,238,419	14,214,836	30,023,583						
378.00 Meas. and Reg. Station Equip. - General	27,015,861	983,597	26,032,264	-54.8%	-35.0%	(539,011)	(9,111,292)	(9,650,304)	-35.7%
379.00 Meas. and Reg. Station Equip. - City Gate	7,288,792	195,562	7,093,230	-53.9%	-35.0%	(105,408)	(2,482,631)	(2,588,038)	-35.5%
380.00 Services	359,205,899	17,361,920	341,843,979	-299.3%	-90.0%	(51,964,227)	(307,659,581)	(359,623,808)	-100.1%
381.00 Meters	101,076,541	12,241,049	88,835,492	-39.8%	-30.0%	(4,871,938)	(26,650,648)	(31,522,585)	-31.2%
383.00 House Regulators	15,358,835	2,236,250	13,122,585	-28.8%	-30.0%	(644,040)	(3,936,776)	(4,580,816)	-29.8%
385.00 Industrial Meas. and Reg. Station Equip.	18,122,870	880,891	17,241,979	-109.9%	-35.0%	(968,099)	(6,034,693)	(7,002,792)	-38.6%
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	$ 1,123,512,323	$ 64,325,644	$ 1,059,186,679	-153.2%	-63.8%	$ (98,529,004)	$ (676,209,496)	$ (774,738,500)	-69.0%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 34,574,111	$ 807,304	$ 33,766,807	-0.3%	-10.0%	$ (2,422)	$ (3,376,681)	$ (3,379,103)	-9.8%
392.00 Transportation Equipment	29,874,017	4,017,207	25,856,810	19.4%	10.0%	779,338	2,585,681	3,365,019	11.3%
396.00 Power Operated Equipment	4,607,028	463,187	4,143,841	15.3%	5.0%	70,868	207,192	278,060	6.0%
Total Depreciable	$ 69,055,156	$ 5,287,698	$ 63,767,458	16.0%	-0.9%	$ 847,784	$ (583,808)	$ 263,976	0.4%
Amortizable									
391.10 Office Furniture and Fixtures	$4,210,393	$1,739,184	$2,471,209						
391.90 Computers and Electronic Equipment	7,066,935	5,429,592	1,637,343						
393.00 Stores Equipment	161,018	92,502	68,516						
394.00 Tools, Shop and Garage Equipment	20,535,254	4,230,632	16,304,622						
397.00 Communication Equipment	37,223,828	2,895,192	34,328,636						
398.00 Miscellaneous Equipment	1,203,825	1,197,476	6,349						
Total Amortizable	$ 70,401,253	$ 15,584,578	$ 54,816,675						
Total General Plant	$ 139,456,409	$ 20,872,276	$ 118,584,133	4.1%	-0.5%	$ 847,784	$ (583,808)	$ 263,976	0.2%
TOTAL CENTRAL-GULF TEXAS	$ 1,286,830,097	$ 86,412,524	$ 1,200,417,573	-115.9%	-57.4%	$ (100,180,873)	$ (689,634,671)	$ (789,815,544)	-61.4%

TEXAS GAS SERVICE - Statewide
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
RIO GRANDE VALLEY									
TRANSMISSION PLANT									
366.20 Structures and Improvements	$ 1,814,881	$1,885	$ 1,812,996	-206.2%	-5.0%	$ (3,887)	$ (90,650)	($94,537)	-5.2%
367.00 Mains	36,853,315	2,422,415	34,430,900	-297.0%	-60.0%	(7,194,573)	(20,658,540)	(27,853,113)	-75.6%
368.00 Compressor Station Equipment	157,464		157,464		-10.0%		(15,746)	(15,746)	-10.0%
369.00 Meas. and Reg. Station Equipment	14,510,361	931,467	13,578,894	-194.0%	-50.0%	(1,807,046)	(6,789,447)	(8,596,493)	-59.2%
371.00 Other Equipment	79,000	25,014	53,986	-473.3%	-10.0%	(118,391)	(5,399)	(123,790)	-156.7%
Total Transmission Plant	$ 53,415,021	$ 3,380,781	$ 50,034,240	-269.9%	-55.1%	$ (9,123,897)	$ (27,559,782)	$ (36,683,678)	-68.7%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 127,293	$ 13,075	$ 114,218	4.1%	-10.0%	$536	$ (11,422)	$ (10,886)	-8.6%
376.00 Mains	79,295,086	4,814,205	74,480,881	-121.4%	-60.0%	(5,844,445)	(44,688,529)	(50,532,973)	-63.7%
376.90 Mains - Cathodic Protection	12,842,283	3,403,008	9,439,275						
378.00 Meas. and Reg. Station Equip. - General	6,058,364	1,192,088	4,866,276	-33.9%	-35.0%	(404,118)	(1,703,197)	(2,107,314)	-34.8%
379.00 Meas. and Reg. Station Equip. - City Gate	3,710,639	509,430	3,201,209	-77.6%	-35.0%	(395,318)	(1,120,423)	(1,515,741)	-40.8%
380.00 Services	87,595,232	13,829,401	73,765,831	-98.1%	-90.0%	(13,566,642)	(66,389,248)	(79,955,890)	-91.3%
381.00 Meters	23,172,373	1,214,307	21,958,066	-47.1%	-30.0%	(571,939)	(6,587,420)	(7,159,358)	-30.9%
383.00 House Regulators	6,545,779	95,451	6,450,328	-101.2%	-30.0%	(96,596)	(1,935,098)	(2,031,695)	-31.0%
385.00 Industrial Meas. and Reg. Station Equip.	3,720,629	397,082	3,323,547	-22.2%	-35.0%	(88,152)	(1,163,241)	(1,251,394)	-33.6%
386.00 Other Property on Customers' Premises	6,144		6,144						
Total Distribution Plant	$ 223,073,822	$ 25,468,047	$ 197,605,775	-82.3%	-62.5%	$ (20,966,674)	$ (123,598,578)	$ (144,565,252)	-64.8%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 4,232,249	$ 72,005	$ 4,160,244	0.9%	-10.0%	$ 648	$ (416,024)	$ (415,376)	-9.8%
392.00 Transportation Equipment	10,808,840	3,094,842	7,713,998	10.9%	10.0%	337,338	771,400	1,108,738	10.3%
396.00 Power Operated Equipment	1,410,976	908,706	502,270	11.2%	5.0%	101,775	25,114	126,889	9.0%
Total Depreciable	$ 16,452,065	$ 4,075,553	$ 12,376,512	10.8%	3.1%	$ 439,761	$ 380,489	$ 820,250	5.0%
Amortizable									
391.10 Office Furniture and Fixtures	$1,433,861	$1,052,105	$381,756						
391.90 Computers and Electronic Equipment	2,141,637	1,592,617	549,020						
393.00 Stores Equipment	43,198	35,885	7,313						
394.00 Tools, Shop and Garage Equipment	9,104,029	2,858,287	6,245,742						
397.00 Communication Equipment	13,146,495	2,205,485	10,941,010						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 25,869,220	$ 7,744,379	$ 18,124,841						
Total General Plant	$ 42,321,285	$ 11,819,932	$ 30,501,353	3.7%	1.2%	$ 439,761	$ 380,489	$ 820,250	1.9%
TOTAL RIO GRANDE VALLEY	$ 318,810,128	$ 40,668,760	$ 278,141,368	-72.9%	-54.2%	$ (29,650,810)	$ (150,777,871)	$ (180,428,680)	-56.6%

TEXAS GAS SERVICE - Statewide
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
WEST-NORTH TEXAS									
TRANSMISSION PLANT									
366.20 Structures and Improvements	$ -		$ -			$ -	$ -		
367.00 Mains	63,470,742	653,648	62,817,094	-811.7%	-60.0%	(5,305,661)	(37,690,256)	(42,995,917)	-67.7%
368.00 Compressor Station Equipment									
369.00 Meas. and Reg. Station Equipment	4,713,209	84,779	4,628,430	-251.1%	-50.0%	(212,880)	(2,314,215)	(2,527,095)	-53.6%
371.00 Other Equipment									
Total Transmission Plant	$ 68,183,951	$ 738,427	$ 67,445,524	-747.3%	-59.3%	$ (5,518,541)	$ (40,004,471)	$ (45,523,012)	-66.8%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 347,517	$ 2,562	$ 344,955		-10.0%		$ (34,496)	$ (34,496)	-9.9%
376.00 Mains	377,455,314	17,435,061	360,020,253	-210.4%	-60.0%	(36,683,368)	(216,012,152)	(252,695,520)	-66.9%
376.90 Mains - Cathodic Protection	43,972,506	11,157,230	32,815,276						
378.00 Meas. and Reg. Station Equip. - General	25,489,288	1,538,068	23,951,220	-107.2%	-35.0%	(1,648,809)	(8,382,927)	(10,031,736)	-39.4%
379.00 Meas. and Reg. Station Equip. - City Gate	11,135,322	404,316	10,731,006	-79.2%	-35.0%	(320,218)	(3,755,852)	(4,076,070)	-36.6%
380.00 Services	267,326,434	9,692,892	257,633,542	-413.3%	-90.0%	(40,060,723)	(231,870,188)	(271,930,910)	-101.7%
381.00 Meters	74,542,688	6,196,269	68,346,419	-65.5%	-30.0%	(4,058,556)	(20,503,926)	(24,562,482)	-33.0%
383.00 House Regulators	16,776,969	823,631	15,953,338	-130.2%	-30.0%	(1,072,368)	(4,786,001)	(5,858,369)	-34.9%
385.00 Industrial Meas. and Reg. Station Equip.	19,719,213	1,389,440	18,329,773	-48.5%	-35.0%	(673,878)	(6,415,421)	(7,089,299)	-36.0%
386.00 Other Property on Customers' Premises	718,421	80,194	638,227	19.8%		15,878		15,878	2.2%
Total Distribution Plant	$ 837,483,672	$ 48,719,663	$ 788,764,009	-173.4%	-62.3%	$ (84,502,042)	$ (491,760,962)	$ (576,263,004)	-68.8%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 11,457,796	$ 602,759	$ 10,855,037	-7.9%	-10.0%	$ (47,618)	$ (1,085,504)	$ (1,133,122)	-9.9%
392.00 Transportation Equipment	24,429,380	4,438,453	19,990,927	6.3%	10.0%	279,623	1,999,093	2,278,715	9.3%
396.00 Power Operated Equipment	4,976,947	996,822	3,980,125	8.6%	5.0%	85,727	199,006	284,733	5.7%
Total Depreciable	$ 40,864,123	$ 6,038,034	$ 34,826,089	5.3%	3.2%	$ 317,731	$ 1,112,595	$ 1,430,327	3.5%
Amortizable									
391.10 Office Furniture and Fixtures	$3,730,943	$2,614,043	$1,116,900						
391.90 Computers and Electronic Equipment	4,912,771	3,507,897	1,404,874						
393.00 Stores Equipment	164,479	142,425	22,054						
394.00 Tools, Shop and Garage Equipment	15,424,499	4,699,912	10,724,587						
397.00 Communication Equipment	27,782,316	2,525,862	25,256,454						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 52,015,008	$ 13,490,139	$ 38,524,869						
Total General Plant	$ 92,879,131	$ 19,528,173	$ 73,350,958	1.6%	1.5%	$ 317,731	$ 1,112,595	$ 1,430,327	1.5%
TOTAL WEST-NORTH TEXAS	$ 998,546,754	$ 68,986,263	$ 929,560,491	-130.0%	-57.1%	$ (89,702,852)	$ (530,652,838)	$ (620,355,690)	-62.1%

TEXAS GAS SERVICE - Statewide
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
TGS DIVISION									
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 4,570,673	$ 19,314	$ 4,551,359		-10.0%	$ -	$ (455,136)	$ (455,136)	-10.0%
392.00 Transportation Equipment									
396.00 Power Operated Equipment									
Total Depreciable	$ 4,570,673	$ 19,314	$ 4,551,359		-10.0%	$ -	$ (455,136)	$ (455,136)	-10.0%
Amortizable									
391.10 Office Furniture and Fixtures	$3,471,394	$916,010	$2,555,384						
391.90 Computers and Electronic Equipment	15,625,945	12,690,963	2,934,982						
393.00 Stores Equipment									
394.00 Tools, Shop and Garage Equipment	218,853	118,707	100,146						
397.00 Communication Equipment	1,568,667	718,274	850,393						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 20,884,859	$ 14,443,954	$ 6,440,905						
Total General Plant	$ 25,455,532	$ 14,463,268	$ 10,992,264		-4.1%	$ -	$ (455,136)	$ (455,136)	-1.8%
TOTAL TGS DIVISION	$ 25,455,532	$ 14,463,268	$ 10,992,264		-4.1%	$ -	$ (455,136)	$ (455,136)	-1.8%
FORT BLISS									
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ -	$ -	$ -				$ -	$ -	
376.00 Mains	7,623,812	542,765	7,081,047	-105.8%	-60.0%	(574,245)	(4,248,628)	(4,822,874)	-63.3%
376.90 Mains - Cathodic Protection	204,496	53,413	151,083						
378.00 Meas. and Reg. Station Equip. - General	342,163	16,626	325,537	-11.1%	-35.0%	(1,845)	(113,938)	(115,783)	-33.8%
379.00 Meas. and Reg. Station Equip. - City Gate									
380.00 Services	1,589,591	63,856	1,525,735	-193.5%	-90.0%	(123,561)	(1,373,162)	(1,496,723)	-94.2%
381.00 Meters	152,811		152,811		-30.0%		(45,843)	(45,843)	-30.0%
383.00 House Regulators	75,571		75,571		-30.0%		(22,671)	(22,671)	-30.0%
385.00 Industrial Meas. and Reg. Station Equip.	598,447	24,275	574,172	-8.1%	-35.0%	(1,966)	(200,960)	(202,926)	-33.9%
386.00 Other Property on Customers' Premises									
Total Distribution Plant	$ 10,586,891	$ 700,935	$ 9,885,956	-100.1%	-60.7%	$ (701,618)	$ (6,005,202)	$ (6,706,821)	-63.4%

TEXAS GAS SERVICE - Statewide
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
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ -	$ -	$ -			$ -	$ -	$ -	
392.00 Transportation Equipment									
396.00 Power Operated Equipment									
Total Depreciable	$ -	$ -	$ -			$ -	$ -	$ -	
Amortizable									
391.10 Office Furniture and Fixtures									
391.90 Computers and Electronic Equipment									
393.00 Stores Equipment									
394.00 Tools, Shop and Garage Equipment	25,605	13,915	11,690						
397.00 Communication Equipment	48,893		48,893						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 74,498	$ 13,915	$ 60,583						
Total General Plant	$ 74,498	$ 13,915	$ 60,583			$ -	$ -	$ -	
TOTAL FORT BLISS	$ 10,661,389	$ 714,850	$ 9,946,539	-98.1%	-60.4%	$ (701,618)	$ (6,005,202)	$ (6,706,821)	-62.9%

TEXAS GAS SERVICE - Statewide

Statement F

Current and Proposed Parameters
Vintage Group Procedure

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2024) 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
STATEWIDE												
TRANSMISSION PLANT												
366.20 Structures and Improvements	40.00	R4				-5.0	40.00	R4	40.02	35.30	-5.2	-5.0
367.00 Mains	60.00	L1				-40.0	60.00	L1	60.29	52.65	-70.6	-60.0
368.00 Compressor Station Equipment	45.00	R1				-10.0	45.00	R1	45.16	42.10	-69.9	-59.5
369.00 Meas. and Reg. Station Equipment	40.00	L1				-25.0	47.00	L1	47.04	40.84	-55.9	-50.0
371.00 Other Equipment	45.00	R1				-10.0	45.00	R1	53.39	18.37	-156.7	-10.0
Total Transmission Plant									56.95	49.68	-67.1	-57.4
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4				-10.0	40.00	R4	54.45	19.89	-9.1	-10.0
376.00 Mains	67.00	R2				-40.0	70.00	R2	75.99	59.06	-65.9	-60.0
376.90 Mains - Cathodic Protection	15.00	SQ					15.00	SQ	17.25	7.72		
378.00 Meas. and Reg. Station Equip. - General	60.00	R1				-25.0	55.00	R1	60.65	48.55	-37.2	-35.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5				-25.0	65.00	R1.5	77.14	56.36	-37.0	-35.0
380.00 Services	55.00	R2				-60.0	55.00	R2	62.08	45.67	-99.6	-90.0
381.00 Meters	30.00	R2.5				-15.0	35.00	R2.5	41.71	25.23	-31.8	-30.0
383.00 House Regulators	35.00	R3				-15.0	35.00	R3	44.45	23.03	-32.2	-30.0
385.00 Industrial Meas. and Reg. Station Equip.	58.00	R1.5				-30.0	62.00	R2	68.03	47.56	-36.9	-35.0
386.00 Other Property on Customers' Premises	20.00	S3					20.00	S3	25.46	1.61	1.4	
Total Distribution Plant									58.96	43.05	-68.5	-63.1
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	43.00	R3				-10.0	45.00	R3	49.21	37.56	-9.8	-10.0
392.00 Transportation Equipment	13.00	L1				10.0	13.00	L1	15.71	9.59	9.9	10.0
396.00 Power Operated Equipment	18.00	L1.5				5.0	20.00	L1.5	21.85	15.28	5.3	5.0
Total Depreciable									23.14	15.84	1.6	0.8
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ					15.00	SQ	16.60	8.08		
391.90 Computers and Electronic Equipment	7.00	SQ					7.00	SQ	8.26	2.60		
393.00 Stores Equipment	15.00	SQ					15.00	SQ	16.21	11.94		
394.00 Tools, Shop and Garage Equipment	15.00	SQ					15.00	SQ	18.46	9.74		
397.00 Communication Equipment	15.00	SQ					15.00	SQ	17.74	7.98		
398.00 Miscellaneous Equipment	15.00	SQ					15.00	SQ	15.00	10.50		
Total Amortizable									17.26	8.11		
Total General Plant									19.77	11.41	0.8	0.4
TOTAL STATEWIDE									46.85	36.03	-61.1	-56.9

TEXAS GAS SERVICE - Statewide

Statement F

Current and Proposed Parameters
Vintage Group Procedure

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2024) 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
CENTRAL-GULF TEXAS												
TRANSMISSION PLANT												
366.20 Structures and Improvements												
367.00 Mains	60.00	L1	60.64	52.75	-49.1	-40.0	60.00	L1	60.61	52.56	-70.4	-60.0
368.00 Compressor Station Equipment												
369.00 Meas. and Reg. Station Equipment	40.00	L1	40.02	36.47	-26.4	-25.0	47.00	L1	47.02	43.34	-50.9	-50.0
371.00 Other Equipment												
Total Transmission Plant									55.34	48.98	-64.3	-56.7
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	46.96	14.14	-6.0	-10.0	40.00	R4	46.56	13.56	-6.1	-10.0
376.00 Mains	67.00	R2	67.31	55.30	-46.4	-40.0	70.00	R2	70.24	59.21	-65.4	-60.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	6.88			15.00	SQ	15.00	6.77		
378.00 Meas. and Reg. Station Equip. - General	60.00	R1	60.28	52.91	-26.1	-25.0	55.00	R1	55.34	47.89	-35.7	-35.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.35	56.32	-25.5	-25.0	65.00	R1.5	65.38	55.64	-35.5	-35.0
380.00 Services	55.00	R2	55.33	45.00	-70.7	-60.0	55.00	R2	55.30	45.49	-100.1	-90.0
381.00 Meters	30.00	R2.5	30.87	20.60	-17.6	-15.0	35.00	R2.5	35.82	25.38	-31.2	-30.0
383.00 House Regulators	35.00	R3	37.50	22.75	-16.5	-15.0	35.00	R3	37.13	23.77	-29.8	-30.0
385.00 Industrial Meas. and Reg. Station Equip.	58.00	R1.5	58.94	43.73	-34.1	-30.0	62.00	R2	62.51	46.32	-38.6	-35.0
386.00 Other Property on Customers' Premises	20.00	S3	23.57	1.81	0.9		20.00	S3	24.30	1.62	0.9	
Total Distribution Plant									54.27	43.94	-69.0	-63.8
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	43.00	R3	43.05	37.92	-9.8	-10.0	45.00	R3	45.04	39.05	-9.8	-10.0
392.00 Transportation Equipment	13.00	L1	13.34	9.99	11.2	10.0	13.00	L1	13.38	9.70	11.3	10.0
396.00 Power Operated Equipment	18.00	L1.5	18.97	13.66	5.3	5.0	20.00	L1.5	20.70	15.86	6.0	5.0
Total Depreciable									22.12	17.76	0.4	-0.9
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	9.29			15.00	SQ	15.00	8.42		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	4.01			7.00	SQ	7.00	2.59		
393.00 Stores Equipment	15.00	SQ	15.00	13.86			15.00	SQ	15.00	12.84		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	10.37			15.00	SQ	15.00	9.80		
397.00 Communication Equipment	15.00	SQ	15.00	8.45			15.00	SQ	15.00	7.59		
398.00 Miscellaneous Equipment	15.00	SQ	15.00	11.50			15.00	SQ	15.00	10.50		
Total Amortizable									14.50	7.96		
Total General Plant									17.80	12.20	0.2	-0.5
TOTAL CENTRAL-GULF TEXAS									45.15	36.06	-61.4	-57.4

TEXAS GAS SERVICE - Statewide
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, 2024) 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
RIO GRANDE VALLEY												
TRANSMISSION PLANT												
366.20 Structures and Improvements	40.00	R4	40.01	37.29	-5.2	-5.0	40.00	R4	40.02	35.30	-5.2	-5.0
367.00 Mains	60.00	L1	60.02	52.05	-6.2	-40.0	60.00	L1	59.99	52.71	-75.6	-60.0
368.00 Compressor Station Equipment	45.00	R1	45.73	35.67	-10.0	-10.0	45.00	R1	45.16	42.10	-10.0	-10.0
369.00 Meas. and Reg. Station Equipment	40.00	L1	40.02	34.45	-36.0	-25.0	47.00	L1	46.96	39.82	-59.2	-50.0
371.00 Other Equipment	45.00	R1	52.67	19.35	-156.7	-10.0	45.00	R1	53.39	18.37	-156.7	-10.0
Total Transmission Plant											-68.7	-56.7
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	38.18	18.07	-8.6	-10.0	40.00	R4	38.10	16.39	-8.6	-10.0
376.00 Mains	67.00	R2	66.61	55.58	-44.3	-40.0	70.00	R2	69.61	58.81	-63.7	-60.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	8.92			15.00	SQ	15.00	8.71		
378.00 Meas. and Reg. Station Equip. - General	60.00	R1	59.93	47.78	-27.2	-25.0	55.00	R1	55.02	44.70	-34.8	-35.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	64.65	60.24	-28.5	-25.0	65.00	R1.5	64.69	59.89	-40.8	-35.0
380.00 Services	55.00	R2	54.48	47.34	-65.7	-60.0	55.00	R2	54.50	47.51	-91.3	-90.0
381.00 Meters	30.00	R2.5	30.37	20.48	-15.8	-15.0	35.00	R2.5	35.17	25.50	-30.9	-30.0
383.00 House Regulators	35.00	R3	35.24	24.03	-16.5	-15.0	35.00	R3	45.59	23.27	-31.0	-30.0
385.00 Industrial Meas. and Reg. Station Equip.	58.00	R1.5	57.92	54.31	-29.1	-30.0	62.00	R2	61.90	57.12	-33.6	-35.0
386.00 Other Property on Customers' Premises	20.00	S3	24.19	2.83			20.00	S3	25.82	2.32		
Total Distribution Plant											-64.8	-56.7
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	43.00	R3	43.04	32.18	-9.7	-10.0	45.00	R3	45.04	35.94	-9.8	-10.0
392.00 Transportation Equipment	13.00	L1	13.52	9.32	10.1	10.0	13.00	L1	13.60	9.57	10.3	10.0
396.00 Power Operated Equipment	18.00	L1.5	18.51	9.83	8.5	5.0	20.00	L1.5	20.56	12.36	9.0	5.0
Total Depreciable											5.0	3.1
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	8.59			15.00	SQ	15.00	8.96		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	4.08			7.00	SQ	7.00	2.39		
393.00 Stores Equipment							15.00	SQ	15.00	14.50		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	7.81			15.00	SQ	15.00	9.73		
397.00 Communication Equipment	15.00	SQ	15.00	7.91			15.00	SQ	15.00	9.98		
398.00 Miscellaneous Equipment												
Total Amortizable												
Total General Plant											1.9	1.2
TOTAL RIO GRANDE VALLEY											-56.6	-54.2

TEXAS GAS SERVICE - Statewide
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, 2024) 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
WEST-NORTH TEXAS												
TRANSMISSION PLANT												
366.20 Structures and Improvements												
367.00 Mains	60.00	L1	60.45	52.68	-49.7	-40.0	60.00	L1	60.37	52.64	-67.7	-60.0
368.00 Compressor Station Equipment												
369.00 Meas. and Reg. Station Equipment	40.00	L1	40.50	31.81	-30.2	-25.0	47.00	L1	47.33	39.80	-53.6	-50.0
371.00 Other Equipment												
Total Transmission Plant									59.25	51.54	-66.8	-59.3
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	41.44	20.57	-9.9	-10.0	40.00	R4	41.65	20.69	-9.9	-10.0
376.00 Mains	67.00	R2	67.10	55.71	-48.6	-40.0	70.00	R2	70.01	58.83	-66.9	-60.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	8.84			15.00	SQ	15.00	8.58		
378.00 Meas. and Reg. Station Equip. - General	60.00	R1	60.35	52.72	-31.9	-25.0	55.00	R1	55.19	49.26	-39.4	-35.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.72	55.23	-27.9	-25.0	65.00	R1.5	65.41	56.83	-36.6	-35.0
380.00 Services	55.00	R2	55.33	45.35	-72.5	-60.0	55.00	R2	55.24	45.90	-101.7	-90.0
381.00 Meters	30.00	R2.5	32.89	21.20	-19.0	-15.0	35.00	R2.5	37.67	25.03	-33.0	-30.0
383.00 House Regulators	35.00	R3	39.58	23.03	-20.9	-15.0	35.00	R3	35.79	22.45	-34.9	-30.0
385.00 Industrial Meas. and Reg. Station Equip.	58.00	R1.5	58.24	47.29	-31.4	-30.0	62.00	R2	61.94	48.71	-36.0	-35.0
386.00 Other Property on Customers' Premises	20.00	S3	25.03	2.18	2.2		20.00	S3	27.38	1.58	2.2	
Total Distribution Plant									51.96	41.91	-68.8	-62.3
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	43.00	R3	42.95	30.17	-9.8	-10.0	45.00	R3	44.93	32.94	-9.9	-10.0
392.00 Transportation Equipment	13.00	L1	13.62	8.79	8.1	10.0	13.00	L1	13.54	9.44	9.3	10.0
396.00 Power Operated Equipment	18.00	L1.5	18.61	11.86	6.0	5.0	20.00	L1.5	20.45	14.68	5.7	5.0
Total Depreciable									18.21	12.94	3.5	3.2
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	6.50			15.00	SQ	15.00	7.32		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	4.44			7.00	SQ	7.00	2.61		
393.00 Stores Equipment	15.00	SQ	15.00	3.81			15.00	SQ	15.00	9.13		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	9.09			15.00	SQ	15.00	9.64		
397.00 Communication Equipment	15.00	SQ	15.00	11.29			15.00	SQ	15.00	8.51		
398.00 Miscellaneous Equipment												
Total Amortizable									14.40	8.34		
Total General Plant									15.99	10.26	1.5	1.5
TOTAL WEST-NORTH TEXAS									44.46	35.48	-62.1	-57.1

TEXAS GAS SERVICE - Statewide

Statement F

Current and Proposed Parameters
Vintage Group Procedure

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2024) 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												
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	43.00	R3	43.00	40.77	-10.0	-10.0	45.00	R3	45.01	39.90	-10.0	-10.0
392.00 Transportation Equipment												
396.00 Power Operated Equipment												
Total Depreciable									45.01	39.90	-10.0	-10.0
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	12.08			15.00	SQ	15.00	9.77		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	3.09			7.00	SQ	7.00	4.21		
393.00 Stores Equipment												
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	14.07			15.00	SQ	15.00	12.41		
397.00 Communication Equipment	15.00	SQ	15.00	5.39			15.00	SQ	15.00	4.47		
398.00 Miscellaneous Equipment												
Total Amortizable									9.86	5.77		
Total General Plant									14.58	10.34	-1.8	-4.1
TOTAL TGS DIVISION									14.58	10.34	-1.8	-4.1
FORT BLISS												
DISTRIBUTION PLANT												
375.10 Structures and Improvements												
376.00 Mains	67.00	R2	67.16	57.40	-42.1	-40.0	70.00	R2	70.03	61.25	-63.3	-60.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	9.64			15.00	SQ	15.00	8.94		
378.00 Meas. and Reg. Station Equip. - General	60.00	R1	60.07	56.59	-25.1	-25.0	55.00	R1	55.23	44.90	-33.8	-35.0
379.00 Meas. and Reg. Station Equip. - City Gate												
380.00 Services	55.00	R2	55.14	46.65	-62.3	-60.0	55.00	R2	55.11	48.20	-94.2	-90.0
381.00 Meters	30.00	R2.5	30.49	19.25	-15.0	-15.0	35.00	R2.5	35.56	22.06	-30.0	-30.0
383.00 House Regulators	35.00	R3	35.05	28.33	-15.0	-15.0	35.00	R3	35.12	24.63	-30.0	-30.0
385.00 Industrial Meas. and Reg. Station Equip.	58.00	R1.5	58.14	51.25	-30.8	-30.0	62.00	R2	62.04	56.42	-33.9	-35.0
386.00 Other Property on Customers' Premises												
Total Distribution Plant									61.61	53.30	-63.4	-62.3

TEXAS GAS SERVICE - Statewide

Statement F

Current and Proposed Parameters
Vintage Group Procedure

Account Description	Current Parameters						Proposed Parameters (at December 31, 2024)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	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
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements												
392.00 Transportation Equipment												
396.00 Power Operated Equipment												
Total Depreciable												
Amortizable												
391.10 Office Furniture and Fixtures												
391.90 Computers and Electronic Equipment												
393.00 Stores Equipment												
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	13.50			15.00	SQ	15.00	10.50		
397.00 Communication Equipment	15.00	SQ	15.00	9.32			15.00	SQ	15.00	6.32		
398.00 Miscellaneous Equipment												
Total Amortizable									15.00	7.13		
Total General Plant									15.00	7.13		
TOTAL FORT BLISS									60.46	52.16	-62.9	-60.4

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the TGS depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for WNSA Account 376.00 – Distribution Mains. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the TGS study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 8. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a

historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive 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.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the observed proportions surviving and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and pro-

jection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area

Schedule A
Page 1 of 3

Distribution Plant
Account: 376.00 Mains

Dispersion: 70 - R2
Procedure: Vintage Group

Generation Arrangement

	December 31, 2024				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2024	0.5	29,522,196	70.00	69.55	0.9935	1.0000	29,331,229	421,744
2023	1.5	23,337,463	70.00	68.64	0.9806	1.0000	22,884,857	333,384
2022	2.5	21,115,004	70.00	67.74	0.9677	1.0000	20,433,281	301,624
2021	3.5	18,456,077	70.01	66.85	0.9549	1.0000	17,622,918	263,625
2020	4.5	35,635,492	70.01	65.96	0.9421	1.0000	33,570,654	508,983
2019	5.5	11,723,696	70.02	65.07	0.9292	1.0000	10,894,133	167,428
2018	6.5	14,267,820	70.01	64.18	0.9168	1.0000	13,081,042	203,808
2017	7.5	13,030,493	69.98	63.30	0.9046	1.0000	11,787,219	186,205
2016	8.5	13,281,040	70.05	62.43	0.8911	1.0000	11,835,348	189,591
2015	9.5	11,019,474	70.07	61.55	0.8785	1.0000	9,680,491	157,270
2014	10.5	15,208,206	70.08	60.68	0.8660	1.0000	13,170,163	217,026
2013	11.5	12,948,918	70.10	59.82	0.8534	1.0000	11,050,279	184,722
2012	12.5	15,856,556	70.09	58.96	0.8412	1.0000	13,339,094	226,236
2011	13.5	9,379,413	70.14	58.11	0.8285	1.0000	7,770,510	133,730
2010	14.5	9,941,628	70.11	57.25	0.8167	1.0000	8,118,874	141,802
2009	15.5	4,220,260	70.02	56.41	0.8056	1.0000	3,399,766	60,271
2008	16.5	11,521,813	70.18	55.57	0.7918	1.0000	9,122,406	164,169
2007	17.5	5,955,912	70.09	54.73	0.7808	1.0000	4,650,364	84,970
2006	18.5	4,587,299	69.52	53.90	0.7753	1.0000	3,556,494	65,986
2005	19.5	4,496,044	70.28	53.07	0.7551	1.0000	3,394,853	63,969
2004	20.5	4,793,470	69.67	52.25	0.7499	1.0000	3,594,646	68,800
2003	21.5	5,859,626	69.33	51.43	0.7418	1.0000	4,346,718	84,517
2002	22.5	1,253,986	69.42	50.62	0.7292	1.0000	914,356	18,064
2001	23.5	2,607,009	70.46	49.81	0.7070	1.0000	1,843,100	37,002
2000	24.5	4,525,704	70.31	49.01	0.6971	1.0000	3,154,667	64,371
1999	25.5	4,736,125	70.47	48.21	0.6841	1.0000	3,240,159	67,207
1998	26.5	2,456,666	70.25	47.42	0.6751	1.0000	1,658,383	34,972
1997	27.5	3,897,865	70.46	46.63	0.6618	1.0000	2,579,671	55,318
1996	28.5	267,845	67.12	45.85	0.6832	1.0000	182,991	3,991
1995	29.5	351,273	67.58	45.08	0.6671	1.0000	234,317	5,198
1994	30.5	951,914	67.42	44.31	0.6572	1.0000	625,603	14,119
1993	31.5	1,383,879	67.84	43.54	0.6419	1.0000	888,248	20,399
1992	32.5	1,427,753	70.18	42.79	0.6096	1.0000	870,394	20,343
1991	33.5	6,395,400	67.53	42.03	0.6225	1.0000	3,980,892	94,706
1990	34.5	2,222,545	67.51	41.29	0.6116	1.0000	1,359,318	32,923
1989	35.5	1,594,869	66.85	40.55	0.6066	1.0000	967,427	23,859
1988	36.5	1,262,465	67.70	39.81	0.5881	1.0000	742,445	18,648

Distribution Plant
Account: 376.00 Mains

Dispersion: 70 - R2
Procedure: Vintage Group

Generation Arrangement

	December 31, 2024				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1987	37.5	1,643,291	64.88	39.09	0.6024	1.0000	989,985	25,328
1986	38.5	1,599,170	67.17	38.36	0.5711	1.0000	913,340	23,807
1985	39.5	999,508	65.47	37.65	0.5751	1.0000	574,815	15,267
1984	40.5	1,512,713	67.62	36.94	0.5463	1.0000	826,374	22,370
1983	41.5	1,051,545	66.46	36.24	0.5452	1.0000	573,344	15,821
1982	42.5	1,793,707	68.63	35.54	0.5179	1.0000	928,999	26,137
1981	43.5	1,561,075	69.69	34.85	0.5001	1.0000	780,771	22,401
1980	44.5	1,428,205	70.42	34.17	0.4853	1.0000	693,054	20,281
1979	45.5	2,299,591	71.60	33.50	0.4679	1.0000	1,075,892	32,118
1978	46.5	1,320,233	71.30	32.83	0.4605	1.0000	607,910	18,517
1977	47.5	928,784	70.69	32.17	0.4551	1.0000	422,668	13,139
1976	48.5	753,835	69.29	31.52	0.4548	1.0000	342,877	10,879
1975	49.5	988,611	71.59	30.87	0.4312	1.0000	426,303	13,810
1974	50.5	898,534	71.11	30.23	0.4252	1.0000	382,015	12,637
1973	51.5	935,123	73.01	29.60	0.4054	1.0000	379,094	12,807
1972	52.5	657,032	72.89	28.98	0.3975	1.0000	261,193	9,014
1971	53.5	621,595	73.09	28.36	0.3880	1.0000	241,189	8,505
1970	54.5	500,351	73.15	27.75	0.3794	1.0000	189,813	6,840
1969	55.5	388,920	73.36	27.15	0.3701	1.0000	143,948	5,302
1968	56.5	377,520	73.24	26.56	0.3626	1.0000	136,893	5,154
1967	57.5	478,769	73.57	25.97	0.3531	1.0000	169,035	6,508
1966	58.5	426,389	73.32	25.40	0.3464	1.0000	147,698	5,815
1965	59.5	148,112	71.60	24.83	0.3468	1.0000	51,362	2,069
1964	60.5	166,153	72.14	24.27	0.3364	1.0000	55,897	2,303
1963	61.5	284,571	75.29	23.72	0.3150	1.0000	89,642	3,780
1962	62.5	647,104	76.19	23.17	0.3041	1.0000	196,813	8,493
1961	63.5	409,220	77.38	22.64	0.2926	1.0000	119,726	5,289
1960	64.5	450,659	76.91	22.11	0.2875	1.0000	129,573	5,860
1959	65.5	479,404	77.20	21.59	0.2797	1.0000	134,088	6,210
1958	66.5	565,563	78.43	21.08	0.2688	1.0000	152,038	7,211
1957	67.5	505,732	78.13	20.58	0.2635	1.0000	133,242	6,473
1956	68.5	387,092	79.22	20.09	0.2536	1.0000	98,163	4,886
1955	69.5	416,250	78.36	19.61	0.2502	1.0000	104,145	5,312
1954	70.5	252,255	80.24	19.13	0.2384	1.0000	60,145	3,144
1953	71.5	122,575	78.75	18.66	0.2370	1.0000	29,049	1,556
1952	72.5	40,702	75.79	18.21	0.2402	1.0000	9,777	537
1951	73.5	43,180	74.49	17.75	0.2384	1.0000	10,293	580

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area

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Distribution Plant
Account: 376.00 Mains

Dispersion: 70 - R2
Procedure: Vintage Group

Generation Arrangement

	December 31, 2024				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1950	74.5	67,831	76.42	17.31	0.2265	1.0000	15,367	888
1949	75.5	70,413	76.14	16.88	0.2217	1.0000	15,610	925
1948	76.5	37,115	75.35	16.45	0.2184	1.0000	8,105	493
1947	77.5	23,400	72.43	16.04	0.2214	1.0000	5,181	323
1946	78.5	64,415	78.50	15.63	0.1991	1.0000	12,824	821
1945	79.5	5,836	75.67	15.23	0.2012	1.0000	1,174	77
1944	80.5	24	65.52	14.83	0.2264	1.0000	6	
1942	82.5	4,990	77.40	14.07	0.1818	1.0000	907	64
1941	83.5	190	67.15	13.70	0.2040	1.0000	39	3
1940	84.5	1,214	73.16	13.33	0.1823	1.0000	221	17
1939	85.5	464	70.75	12.98	0.1834	1.0000	85	7
1938	86.5	27	72.02	12.62	0.1753	1.0000	5	
1937	87.5	8	74.31	12.28	0.1653	1.0000	1	
1931	93.5	2,964	83.41	10.32	0.1238	1.0000	367	36
1930	94.5	84	83.73	10.01	0.1196	1.0000	10	1
1929	95.5	153,126	92.11	9.71	0.1054	1.0000	16,137	1,662
1928	96.5	751	82.17	9.40	0.1144	1.0000	86	9
1927	97.5	347	84.97	9.10	0.1071	1.0000	37	4
1924	100.5	1	82.73	8.21	0.0993	1.0000		
1923	101.5	842	87.32	7.92	0.0907	1.0000	76	10
1922	102.5	1,938	91.84	7.63	0.0830	1.0000	161	21
1921	103.5	611	90.84	7.34	0.0807	1.0000	49	7
1919	105.5	19	83.63	6.75	0.0808	1.0000	2	
1917	107.5	3,094	107.58	6.17	0.0574	1.0000	178	29
1914	110.5	3,804	101.71	5.31	0.0522	1.0000	199	37
1913	111.5	34	88.20	5.02	0.0569	1.0000	2	
1912	112.5	433	99.75	4.73	0.0475	1.0000	21	4
1900	124.5	2	116.35	1.51	0.0129	1.0000		
Total	13.3	$360,020,253	70.01	58.83	0.8403	1.0000	$302,535,321	$5,142,577

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area
Distribution Plant
Account: 376.00 Mains

Schedule B
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Age Distribution

Vintage	Age as of 12/31/2024	Derived Additions	1999 Opening Balance	Experience to 12/31/2024		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2024	0.5	29,522,196		29,522,196	1.0000	0.5000
2023	1.5	23,337,462		23,337,463	1.0000	1.5000
2022	2.5	21,115,115		21,115,004	1.0000	2.5000
2021	3.5	18,456,167		18,456,077	1.0000	3.5000
2020	4.5	35,741,569		35,635,492	0.9970	4.4985
2019	5.5	11,723,696		11,723,696	1.0000	5.5000
2018	6.5	14,403,317		14,267,820	0.9906	6.4747
2017	7.5	13,210,723		13,030,493	0.9864	7.4367
2016	8.5	13,295,581		13,281,040	0.9989	8.4955
2015	9.5	11,029,194		11,019,474	0.9991	9.4968
2014	10.5	15,257,085		15,208,206	0.9968	10.4879
2013	11.5	12,967,304		12,948,918	0.9986	11.4928
2012	12.5	15,993,710		15,856,556	0.9914	12.4606
2011	13.5	9,411,509		9,379,413	0.9966	13.4851
2010	14.5	10,024,124		9,941,628	0.9918	14.4309
2009	15.5	4,308,996		4,220,260	0.9794	15.3149
2008	16.5	11,657,366		11,521,813	0.9884	16.4438
2007	17.5	6,245,657		5,955,912	0.9536	17.3214
2006	18.5	4,983,271		4,587,299	0.9205	17.7092
2005	19.5	4,531,903		4,496,044	0.9921	19.4342
2004	20.5	5,124,123		4,793,470	0.9355	19.7787
2003	21.5	6,523,386		5,859,626	0.8982	20.3905
2002	22.5	1,400,288		1,253,986	0.8955	21.4285
2001	23.5	2,675,063		2,607,009	0.9746	23.4109
2000	24.5	4,787,060		4,525,704	0.9454	24.2046
1999	25.5	4,875,371		4,736,125	0.9714	25.3071
1998	26.5		2,618,091	2,456,666	0.9383	26.0174
1997	27.5		4,080,761	3,897,865	0.9552	27.1650
1996	28.5		459,702	267,845	0.5826	24.7435
1995	29.5		510,172	351,273	0.6885	26.1274
1994	30.5		1,826,302	951,914	0.5212	26.8864
1993	31.5		1,809,838	1,383,879	0.7646	28.2208
1992	32.5		1,519,077	1,427,753	0.9399	31.4720
1991	33.5		9,179,923	6,395,400	0.6967	29.7183
1990	34.5		2,701,708	2,222,545	0.8226	30.5938
1989	35.5		2,005,966	1,594,869	0.7951	30.8235
1988	36.5		1,516,696	1,262,465	0.8324	32.5629
1987	37.5		2,869,376	1,643,291	0.5727	30.6220

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area
Distribution Plant
Account: 376.00 Mains

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Age Distribution

Vintage	Age as of 12/31/2024	Derived Additions	1999 Opening Balance	Experience to 12/31/2024		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1986	38.5		1,999,890	1,599,170	0.7996	33.7874
1985	39.5		1,388,743	999,508	0.7197	32.9490
1984	40.5		1,966,215	1,512,713	0.7694	35.9647
1983	41.5		1,602,668	1,051,545	0.6561	35.6603
1982	42.5		2,225,316	1,793,707	0.8060	38.6699
1981	43.5		1,904,935	1,561,075	0.8195	40.5702
1980	44.5		1,696,555	1,428,205	0.8418	42.1355
1979	45.5		2,524,962	2,299,591	0.9107	44.1346
1978	46.5		1,514,547	1,320,233	0.8717	44.6528
1977	47.5		1,111,251	928,784	0.8358	44.8501
1976	48.5		1,027,600	753,835	0.7336	44.2490
1975	49.5		1,209,436	988,611	0.8174	47.3371
1974	50.5		1,109,911	898,534	0.8096	47.6353
1973	51.5		1,058,133	935,123	0.8837	50.3166
1972	52.5		775,014	657,032	0.8478	50.9518
1971	53.5		716,604	621,595	0.8674	51.9055
1970	54.5		596,179	500,351	0.8393	52.7099
1969	55.5		457,292	388,920	0.8505	53.6451
1968	56.5		466,361	377,520	0.8095	54.2518
1967	57.5		578,894	478,769	0.8270	55.2852
1966	58.5		546,393	426,389	0.7804	55.7367
1965	59.5		202,773	148,112	0.7304	54.7009
1964	60.5		236,412	166,153	0.7028	55.9178
1963	61.5		327,685	284,571	0.8684	59.7304
1962	62.5		710,859	647,104	0.9103	61.2833
1961	63.5		422,820	409,220	0.9678	63.1051
1960	64.5		490,398	450,659	0.9190	63.2570
1959	65.5		516,961	479,404	0.9274	64.1657
1958	66.5		584,254	565,563	0.9680	65.9876
1957	67.5		580,898	505,732	0.8706	66.2664
1956	68.5		399,654	387,092	0.9686	67.9335
1955	69.5		498,221	416,250	0.8355	67.6284
1954	70.5		260,069	252,255	0.9700	70.0426
1953	71.5		250,177	122,575	0.4900	69.0830
1952	72.5		185,622	40,702	0.2193	66.6311
1951	73.5		117,957	43,180	0.3661	65.8226
1950	74.5		243,201	67,831	0.2789	68.2399
1949	75.5		197,061	70,413	0.3573	68.4253

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area
Distribution Plant
Account: 376.00 Mains

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Age Distribution

Vintage	Age as of 12/31/2024	Derived Additions	1999 Opening Balance	Experience to 12/31/2024		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1948	76.5		116,960	37,115	0.3173	68.0817
1947	77.5		64,811	23,400	0.3611	65.5988
1946	78.5		131,777	64,415	0.4888	72.0822
1945	79.5		26,740	5,836	0.2182	69.6605
1944	80.5		12,239	24	0.0020	59.8914
1942	82.5		30,721	4,990	0.1624	72.4986
1941	83.5		23,933	190	0.0080	62.5903
1940	84.5		7,807	1,214	0.1555	68.9240
1939	85.5		15,872	464	0.0292	66.8253
1938	86.5		3,138	27	0.0087	68.3892
1937	87.5		3,088	8	0.0024	70.9630
1936	88.5		58,343		0.0000	79.0174
1935	89.5		12,341		0.0000	73.8567
1934	90.5		319		0.0000	67.0000
1933	91.5		8,272		0.0000	77.6122
1932	92.5		4,514		0.0000	76.9635
1931	93.5		134,432	2,964	0.0220	81.4453
1930	94.5		30,725	84	0.0027	81.9487
1929	95.5		261,329	153,126	0.5860	90.4977
1928	96.5		9,087	751	0.0827	80.7211
1927	97.5		4,587	347	0.0757	83.6737
1926	98.5		4,246		0.0000	83.4959
1924	100.5		1,769	1	0.0006	81.8140
1923	101.5		6,473	842	0.1300	86.5102
1922	102.5		5,437	1,938	0.3564	91.1296
1921	103.5		11,456	611	0.0534	90.2200
1920	104.5		994		0.0000	79.0000
1919	105.5		215	19	0.0881	83.1593
1918	106.5		475		0.0000	81.0000
1917	107.5		3,248	3,094	0.9527	107.2399
1916	108.5		10,678		0.0000	91.1372
1915	109.5		839		0.0000	84.0002
1914	110.5		6,417	3,804	0.5928	101.5021
1913	111.5		427	34	0.0798	88.0350
1912	112.5		6,834	433	0.0633	99.6132
1911	113.5		4,100		0.0000	88.0000
1910	114.5		5,449		0.0000	92.2409
1909	115.5		10		0.0000	90.0000

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area
Distribution Plant
Account: 376.00 Mains

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Age Distribution

Vintage	Age as of 12/31/2024	Derived Additions	1999 Opening Balance	Experience to 12/31/2024		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1908	116.5		327		0.0000	91.0000
1907	117.5		1,037		0.0000	108.9089
1906	118.5		4,371		0.0000	101.9933
1905	119.5		17,387		0.0000	95.2237
1900	124.5		1,323	2	0.0016	116.3436
Total	13.3	$312,601,235	$64,854,079	$360,020,253	0.9538	

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area
Distribution Plant
Account: 376.00 Mains

Schedule C
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Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	68,295,699	5,082,132	170,641		73,207,189
2000	73,207,189	7,107,529	253,801		80,060,918
2001	80,060,918	2,915,382	3,585,521		79,390,779
2002	79,390,779	1,116,632	137,130		80,370,282
2003	80,370,282	4,565,907	5,702		84,930,486
2004	84,930,486	10,031,141	283,398		94,678,230
2005	94,678,230	7,645,486	314,004		102,009,712
2006	102,009,712	5,461,133	44,117		107,426,727
2007	107,426,727	7,869,499	231,734	(413,655)	114,650,837
2008	114,650,837	11,275,035	608,221		125,317,650
2009	125,317,650	4,671,452	498,165	1,107,978	130,598,915
2010	130,598,915	11,897,458	730,900		141,765,473
2011	141,765,473	10,531,780	778,618		151,518,636
2012	151,518,636	16,856,282	665,792	(119,784)	167,589,342
2013	167,589,342	12,828,537	1,592,322	(1,941,365)	176,884,192
2014	176,884,192	18,466,262	694,373	17,442	194,673,523
2015	194,673,523	12,723,498	2,285,083	(145,783)	204,966,155
2016	204,966,155	15,145,992	237,640	(16,953,992)	202,920,514
2017	202,920,514	15,027,024	653,860	(567,023)	216,726,654
2018	216,726,654	13,715,220	143,462	(3,354,210)	226,944,202
2019	226,944,202	11,286,357	284,120	(6,803,624)	231,142,815
2020	231,142,815	36,334,889	1,263,725		266,213,978
2021	266,213,978	18,915,432	528,331	(678,059)	283,923,020
2022	283,923,020	23,932,525	478,267	(154,880)	307,222,398
2023	307,222,398	24,223,770	188,455	(164)	331,257,549
2024	331,257,549	29,351,660	588,955		360,020,253

TEXAS GAS SERVICE COMPANY
West-North Texas Service Area
Distribution Plant
Account: 376.00 Mains

Schedule C
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Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	73,253,275	5,129,340	174,752	182	78,208,046
2000	78,208,046	4,935,132	381,725	55,693	82,817,146
2001	82,817,146	2,924,556	3,641,074	131,712	82,232,341
2002	82,232,341	1,515,324	137,130		83,610,535
2003	83,610,535	7,137,685	5,702		90,742,518
2004	90,742,518	6,628,809	283,398		97,087,929
2005	97,087,929	4,900,329	313,526		101,674,732
2006	101,674,732	5,442,552	44,117		107,073,167
2007	107,073,167	6,726,333	224,292	(413,655)	113,161,554
2008	113,161,554	12,580,217	607,327		125,134,444
2009	125,134,444	5,623,066	495,935	1,107,978	131,369,554
2010	131,369,554	11,993,591	730,788		142,632,357
2011	142,632,357	10,313,506	778,618		152,167,245
2012	152,167,245	17,284,325	627,848	(119,784)	168,703,939
2013	168,703,939	14,768,465	1,575,348	(1,941,365)	179,955,690
2014	179,955,690	17,588,962	677,310	17,442	196,884,784
2015	196,884,784	13,645,095	2,350,221	(145,783)	208,033,875
2016	208,033,875	14,598,470	241,036	(16,953,542)	205,437,767
2017	205,437,767	14,916,745	653,860	(567,023)	219,133,629
2018	219,133,629	15,277,167	158,041	(3,354,210)	230,898,545
2019	230,898,545	11,363,022	284,120	(6,803,624)	235,173,823
2020	235,173,823	35,779,698	1,264,785	682	269,689,419
2021	269,689,419	18,973,273	528,432	(678,059)	287,456,202
2022	287,456,202	21,115,115	478,267	(154,880)	307,938,169
2023	307,938,169	23,337,462	188,455	(164)	331,087,013
2024	331,087,013	29,522,196	588,955		360,020,253

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

T-Cut: None

Placement Band: 1900-2024

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2003	1.5	72.1	L0	10.04	114.6	O3 *	17.45	58.7	R1 *	8.55
2000-2004	11.9	99.0	O3	7.00	137.5	SC *	14.00	64.7	R1 *	12.66
2001-2005	13.6	105.0	O2	8.54	139.8	SC *	15.98	64.6	R1.5 *	13.29
2002-2006	28.0	151.9	R1	14.27	88.8	R2.5	5.71	79.8	R3	13.71
2003-2007	11.2	138.6	R0.5	24.38	82.0	R2.5	6.11	75.1	R3	6.67
2004-2008	0.2	127.3	SC	29.54	78.1	R2	11.01	71.7	R3	4.30
2005-2009	0.0	108.6	S-.5	25.68	74.3	R2	9.96	68.7	R3	3.46
2006-2010	1.8	110.8	SC	25.39	77.9	R1.5	12.82	69.5	R3	3.85
2007-2011	0.8	105.8	SC	24.85	78.8	R1	15.00	68.9	R2.5	4.58
2008-2012	1.0	98.9	L0	21.94	77.5	R1	13.32	68.1	R2.5 *	2.58
2009-2013	1.1	81.8	L0.5	17.02	68.0	R1.5	8.53	63.9	R2.5 *	2.15
2010-2014	2.4	84.9	L1	17.27	71.9	R1.5	9.73	66.0	R2.5 *	2.99
2011-2015	0.9	68.9	L1.5*	11.19	63.1	S1	6.24	60.9	R2 *	3.44
2012-2016	0.0	70.4	L1.5*	13.16	64.2	S1	7.79	61.6	R2 *	4.39
2013-2017	0.0	71.6	L1.5*	13.78	65.2	S1	8.27	62.4	R2 *	4.83
2014-2018	0.0	82.1	L1.5*	18.82	73.7	S1	13.38	69.2	R2 *	9.20
2015-2019	0.0	85.7	L1.5*	20.79	75.6	S1	14.29	71.5	R2.5 *	10.68
2016-2020	0.0	103.2	L1	28.59	83.9	S1.5	19.35	75.0	R3 *	11.25
2017-2021	0.0	100.5	L1	27.44	82.5	S1	18.81	74.7	R2.5 *	11.90
2018-2022	0.0	102.2	L1	24.23	86.1	S1	17.01	78.5	R2.5	11.37
2019-2023	0.1	100.6	L1	9.17	89.3	S0.5	5.86	81.3	R2	6.63
2020-2024	0.9	102.4	L1	7.98	94.9	S0	6.30	85.1	R2	6.63

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

T-Cut: None

Placement Band: 1900-2024

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2024	0.0	91.1	L1	16.04	79.8	S0.5	9.92	71.8	R2 *	3.06
2001-2024	0.0	92.5	L1	16.13	81.7	S0.5	10.64	72.4	R2 *	3.45
2003-2024	0.0	94.8	L1	16.99	80.1	S1	8.66	73.8	R2.5 *	3.51
2005-2024	0.0	93.2	L1	16.40	79.7	S1	8.56	73.5	R2.5 *	3.49
2007-2024	0.0	91.9	L1	15.97	79.6	S1	8.88	73.3	R2 *	3.62
2009-2024	0.0	90.9	L1	15.16	79.9	S0.5	8.87	73.4	R2 *	3.75
2011-2024	0.0	91.0	L1	14.83	80.1	S1	8.45	74.3	R2 *	3.83
2013-2024	0.0	90.6	L1*	14.59	80.3	S1	8.56	74.8	R2 *	4.29
2015-2024	0.0	94.2	L1*	14.69	84.3	S0.5	9.41	78.7	R2 *	5.17
2017-2024	0.0	106.5	L1	26.67	91.8	S1	20.68	83.2	R2.5	15.28
2019-2024	0.1	105.0	L1	10.09	94.8	S0.5	7.02	85.2	R2	5.78
2021-2024	50.0	111.3	L1	3.81	103.9	S0	5.10	93.1	R2	9.04
2023-2024	65.6	124.6	S0*	5.00	134.2	S-.5 *	3.78	109.7	R2 *	7.37

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

T-Cut: None

Placement Band: 1900-2024

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2000	0.0	65.4	L1.5 *	13.10	56.9	R2.5	6.05	57.2	R3	6.72
1999-2002	0.6	60.8	O2	7.92	99.1	O4 *	14.90	53.4	R1 *	7.90
1999-2004	0.9	80.7	O2	12.30	110.2	O3 *	16.26	60.6	R1.5 *	7.48
1999-2006	3.3	91.6	L0	14.09	83.7	L0.5	12.28	64.3	R2 *	7.26
1999-2008	1.0	96.7	L0	18.96	78.4	S0	12.96	65.7	R2	4.64
1999-2010	1.5	96.5	L0	19.46	78.1	R0.5	13.17	65.7	R2	3.69
1999-2012	1.0	96.2	L0	19.78	77.7	R1	12.69	66.5	R2 *	2.57
1999-2014	0.9	88.8	L0.5	18.31	73.2	R1	10.43	65.2	R2.5 *	2.15
1999-2016	0.3	81.2	L0.5	15.36	70.3	S0.5	8.69	64.2	R2 *	1.53
1999-2018	0.4	84.7	L0.5	16.80	72.7	S0.5	9.60	66.0	R2.5 *	1.82
1999-2020	0.0	85.8	L1	16.92	73.9	S0.5	9.78	66.9	R2.5 *	1.91
1999-2022	0.0	87.5	L1	16.76	75.6	S0.5	9.80	68.5	R2 *	2.48
1999-2024	0.0	91.1	L1	16.04	79.8	S0.5	9.92	71.8	R2 *	3.06

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

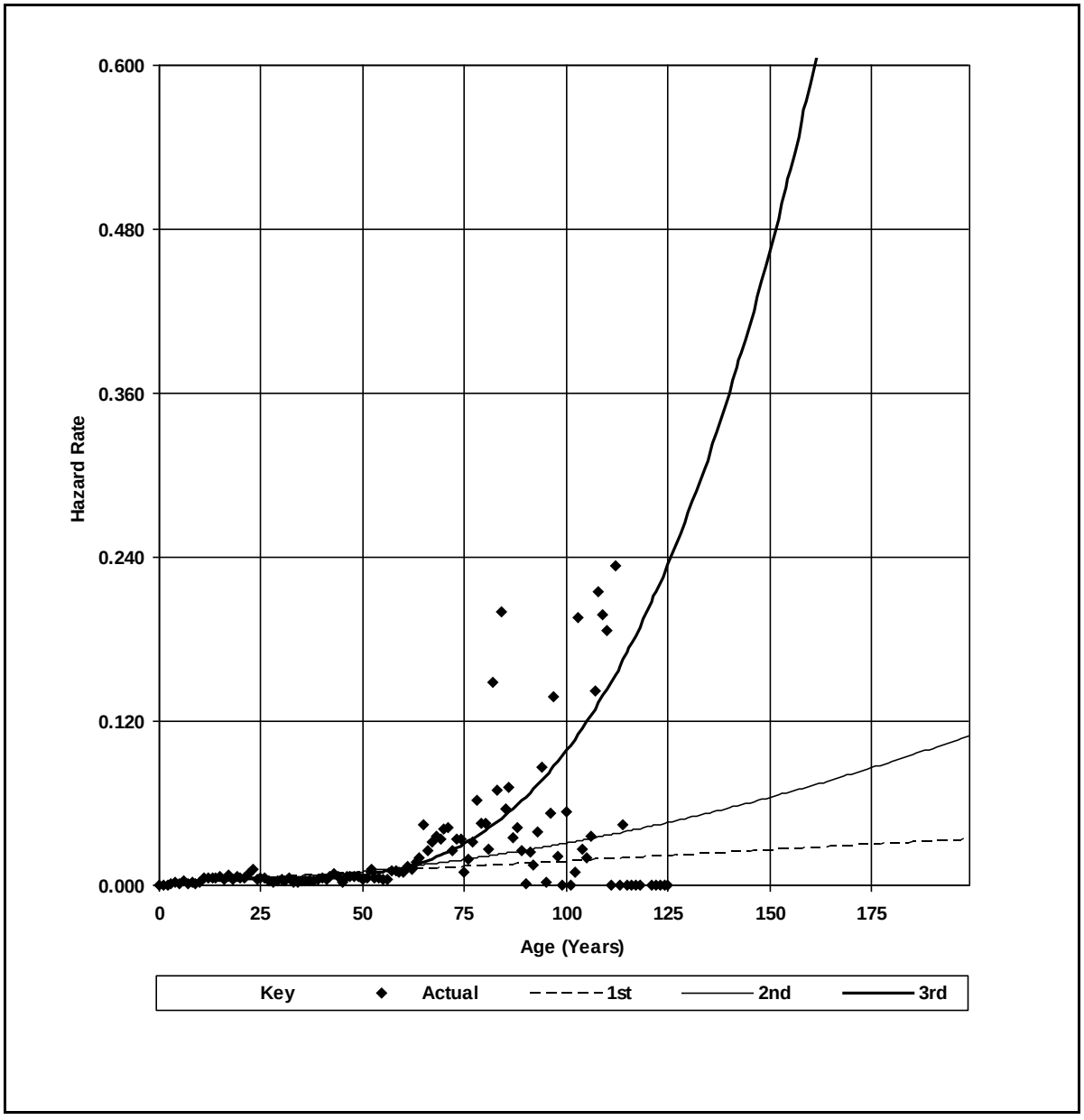
T-Cut: None

Placement Band: 1900-2024 Observation Band: 1999-2024

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Functions **1st: 91.1-L1 2nd: 79.8-S0.5 3rd: 71.8-R2**



TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

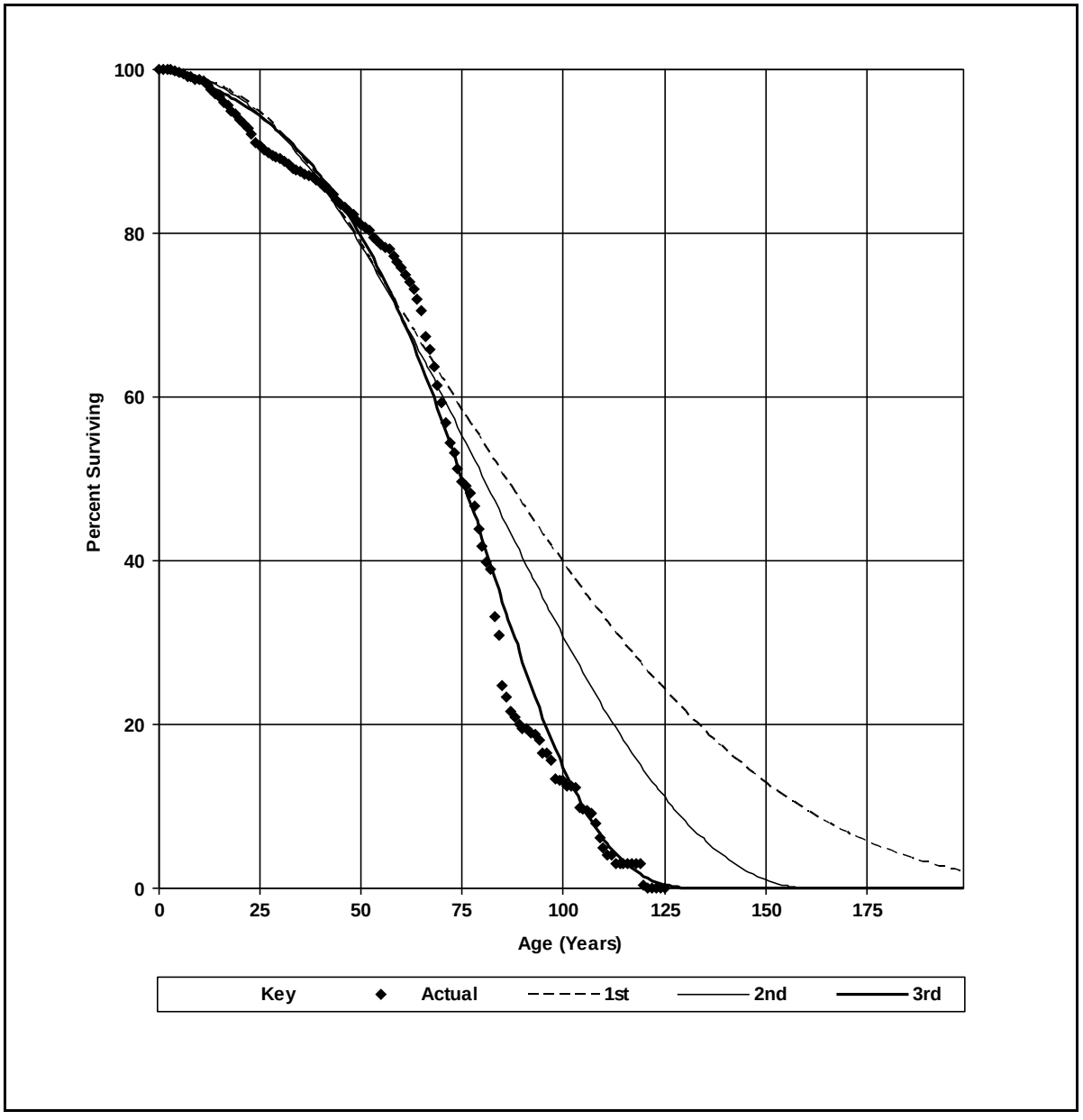
T-Cut: None

Placement Band: 1900-2024 Observation Band: 1999-2024

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions **1st: 91.1-L1 2nd: 79.8-S0.5 3rd: 71.8-R2**



TEXAS GAS SERVICE COMPANY

Distribution Plant

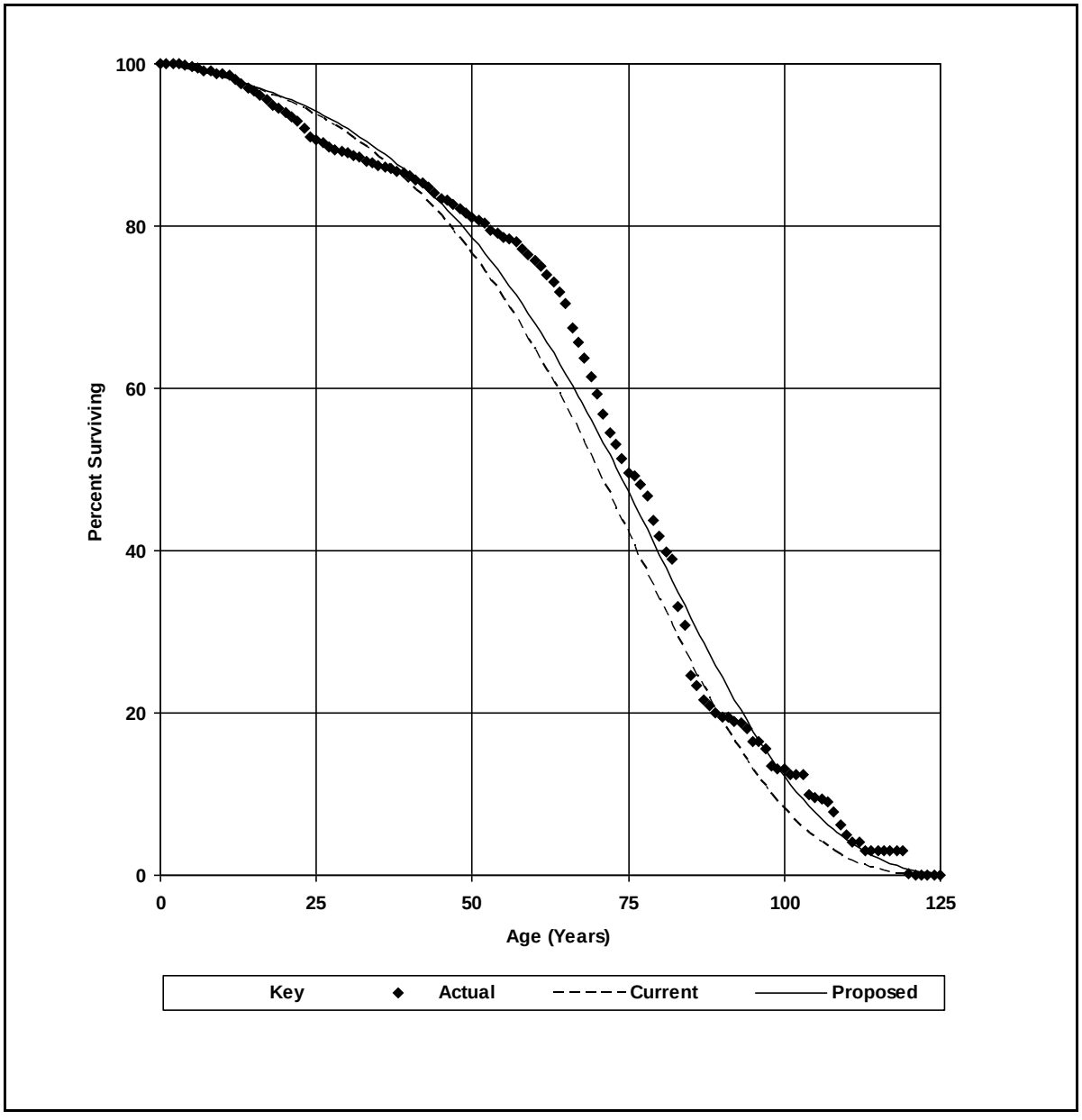
Account: 376.00 Mains

T-Cut: None

Placement Band: 1900-2024

Observation Band: 1999-2024

Projection Life Curves **Current: 67.0-R2** **Proposed: 70.0-R2**



TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1999	773,997		0.0		53,120	6.9		(53,120)	-6.9	
2000	751,804		0.0		14,248	1.9		(14,248)	-1.9	
2001	6,684,246		0.0		13,664	0.2		(13,664)	-0.2	
2002	144,335		0.0		4,684	3.2		(4,684)	-3.2	
2003	8,627		0.0	0.0	1,210	14.0	1.0	(1,210)	-14.0	-1.0
2004	1,913,538	167,115	8.7	1.8	183,511	9.6	2.3	(16,396)	-0.9	-0.5
2005	633,389	(867)	-0.1	1.8	592,533	93.5	8.5	(593,400)	-93.7	-6.7
2006	408,971		0.0	5.3	335,894	82.1	36.0	(335,894)	-82.1	-30.6
2007	716,565		0.0	4.5	657,681	91.8	48.1	(657,681)	-91.8	-43.6
2008	1,196,624		0.0	3.4	1,182,690	98.8	60.6	(1,182,690)	-98.8	-57.2
2009	2,354,484		0.0	0.0	2,678,543	113.8	102.6	(2,678,543)	-113.8	-102.6
2010	1,502,064		0.0	0.0	1,540,338	102.5	103.5	(1,540,338)	-102.5	-103.5
2011	1,434,276		0.0	0.0	2,009,998	140.1	112.0	(2,009,998)	-140.1	-112.0
2012	1,438,530		0.0	0.0	3,619,199	251.6	139.2	(3,619,199)	-251.6	-139.2
2013	2,088,090	10,758	0.5	0.1	10,147,038	485.9	226.8	(10,136,280)	-485.4	-226.6
2014	1,491,778		0.0	0.1	4,461,615	299.1	273.8	(4,461,615)	-299.1	-273.6
2015	3,413,823		0.0	0.1	6,879,716	201.5	274.8	(6,879,716)	-201.5	-274.7
2016	1,011,727		0.0	0.1	5,806,324	573.9	327.3	(5,806,324)	-573.9	-327.2
2017	1,060,845		0.0	0.1	7,919,927	746.6	388.4	(7,919,927)	-746.6	-388.3
2018	219,438		0.0	0.0	2,928,884	1e+3	389.0	(2,928,884)	-1e+3	-389.0
2019	722,249		0.0	0.0	3,348,617	463.6	418.2	(3,348,617)	-463.6	-418.2
2020	2,901,219		0.0	0.0	10,688,902	368.4	518.9	(10,688,902)	-368.4	-518.9
2021	2,826,968		0.0	0.0	6,098,114	215.7	400.8	(6,098,114)	-215.7	-400.8
2022	1,527,358		0.0	0.0	5,359,539	350.9	346.8	(5,359,539)	-350.9	-346.8
2023	955,722		0.0	0.0	3,018,732	315.9	319.2	(3,018,732)	-315.9	-319.2
2024	1,039,717		0.0	0.0	3,608,475	347.1	311.0	(3,608,475)	-347.1	-311.0
Total	39,220,385	177,005	0.5		83,153,198	212.0		(82,976,192)	-211.6	

TEXAS GAS SERVICE COMPANY

Distribution Plant

Account: 376.00 Mains

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1999	783,733		0.0		53,120	6.8		(53,120)	-6.8	
2000	876,768		0.0		14,248	1.6		(14,248)	-1.6	
2001	6,739,799		0.0		13,664	0.2		(13,664)	-0.2	
2002	144,335		0.0		4,684	3.2		(4,684)	-3.2	
2003	8,627		0.0	0.0	1,210	14.0	1.0	(1,210)	-14.0	-1.0
2004	1,226,060		0.0	0.0	183,511	15.0	2.4	(183,511)	-15.0	-2.4
2005	632,239	(867)	-0.1	0.0	592,533	93.7	9.1	(593,400)	-93.9	-9.1
2006	408,971		0.0	0.0	335,894	82.1	46.2	(335,894)	-82.1	-46.2
2007	707,990		0.0	0.0	657,681	92.9	59.3	(657,681)	-92.9	-59.4
2008	1,192,550		0.0	0.0	1,182,690	99.2	70.8	(1,182,690)	-99.2	-70.9
2009	2,344,652		0.0	0.0	2,678,543	114.2	103.0	(2,678,543)	-114.2	-103.1
2010	1,473,667		0.0	0.0	1,540,338	104.5	104.4	(1,540,338)	-104.5	-104.4
2011	1,434,276		0.0	0.0	2,009,998	140.1	112.8	(2,009,998)	-140.1	-112.8
2012	1,375,266		0.0	0.0	3,619,199	263.2	141.1	(3,619,199)	-263.2	-141.1
2013	2,085,077	10,758	0.5	0.1	10,147,038	486.7	229.5	(10,136,280)	-486.1	-229.4
2014	1,475,926		0.0	0.1	4,461,615	302.3	277.6	(4,461,615)	-302.3	-277.5
2015	3,482,617		0.0	0.1	6,879,716	197.5	275.2	(6,879,716)	-197.5	-275.1
2016	1,061,731		0.0	0.1	5,806,324	546.9	326.1	(5,806,324)	-546.9	-326.0
2017	1,058,507		0.0	0.1	7,919,927	748.2	384.3	(7,919,927)	-748.2	-384.2
2018	237,355		0.0	0.0	2,928,884	1e+3	382.7	(2,928,884)	-1e+3	-382.7
2019	721,967		0.0	0.0	3,348,617	463.8	409.7	(3,348,617)	-463.8	-409.7
2020	2,902,278		0.0	0.0	10,688,902	368.3	513.1	(10,688,902)	-368.3	-513.1
2021	2,827,069		0.0	0.0	6,098,114	215.7	399.9	(6,098,114)	-215.7	-399.9
2022	1,527,358		0.0	0.0	5,359,539	350.9	346.0	(5,359,539)	-350.9	-346.0
2023	955,722		0.0	0.0	3,018,732	315.9	319.1	(3,018,732)	-315.9	-319.1
2024	1,039,717		0.0	0.0	3,608,475	347.1	311.0	(3,608,475)	-347.1	-311.0
Total	38,724,257	9,891	0.0		83,153,198	214.7		(83,143,307)	-214.7	

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 4th day of June 2025.

LYNNETTE A. JAY
Notary Public
State of Florida
Comm# HH622019
Expires 3/7/2029

Lynnette A. Jay
Notary Public in and for the State of Florida

My commission expires: March 07, 2029

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. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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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 Texas service area.

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 ("ROE") FOR TGS?

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") responding to persistent increases in the Consumer Price Index ("CPI") and the impacts of recent fiscal policies on capital markets and the economy. With this background, I develop a mix of investor-supplied capital (i.e., debt and equity) to be used as weightings to calculate 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 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.

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 its invested capital of 8.02%. This rate of return is based on capital structure ratios of 40.08% debt and 59.92% equity, a cost of debt of 4.45%, and an ROE of 10.40%.

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED CAPITAL STRUCTURE RATIOS FOR TGS?

A. My recommended capital structure ratios of 40.08% debt and 59.92% equity are based on the capitalization of ONE Gas, Inc. ("ONE Gas"), of which TGS is a division, at March 31, 2025, excluding securitized debt in Kansas attributable to Winter Storm Uri. These 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 of TGS 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?

A. My recommended 4.45% cost of debt is the average cost of the $2.15 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 10.40%?

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 9.90% to 10.90%, and recommend an ROE for TGS of 10.40%, 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 current 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 700,000 sales and transport customers in 100 communities throughout Texas, including the cities of Austin, El Paso, Beaumont, and Galveston. In total, TGS serves approximately 13% of the natural gas customers in Texas. At December 31, 2024, TGS had total assets of approximately

$2.3 billion, with operating revenues for calendar year 2024 being approximately $540 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, 2024, ONE Gas had total assets of approximately $8.4 billion, with revenues during 2024 totaling some $2.1 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?

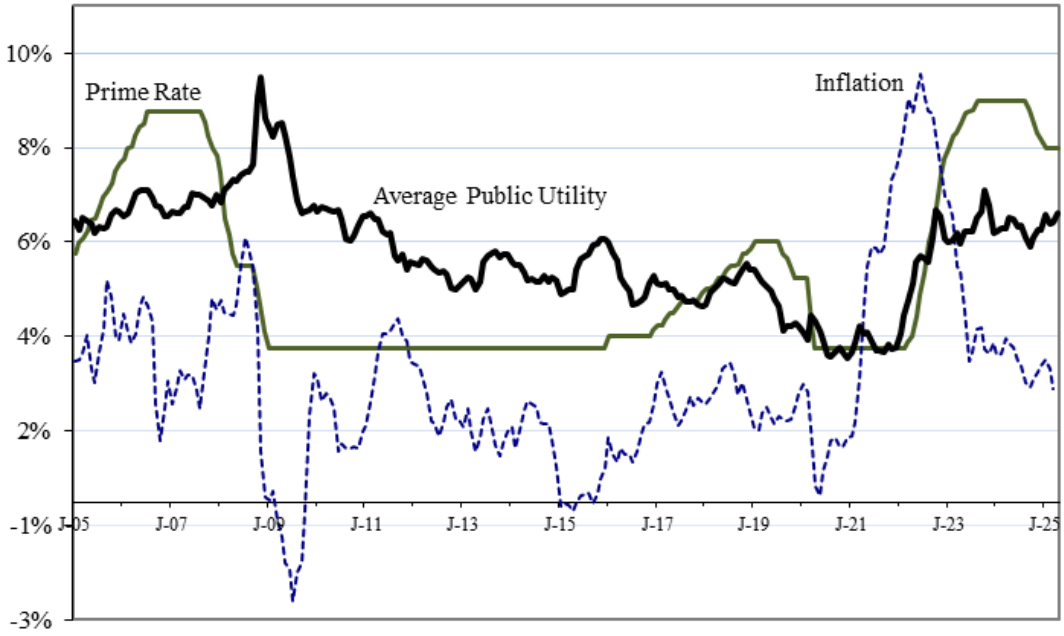
A. Yes. Attached to my testimony as Appendix C are the pages from ONE Gas' 2024 Form 10-K filed with the Securities and Exchange Commission that list the operational risks; regulatory and legislative risks; and financial, economic, and market risks faced by ONE Gas. This list documents that TGS is exposed to the same risk factors 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 2006, the average yield on long-term public utility bonds was fairly steady because of monetary and fiscal policies designed to keep the economy growing. This 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, inflation began to skyrocket, with the CPI jumping from an

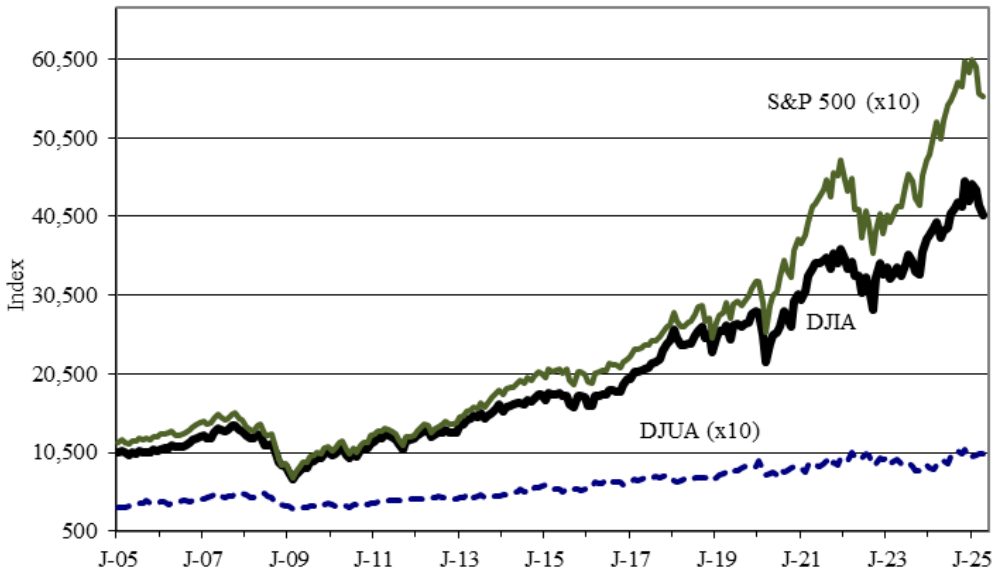
average of around 2% over the prior 20 years to 7% in 2021, and peaking at over 9% in June 2022. To reduce inflation, the Fed began raising interest rates, and since the third quarter of 2023, inflation has ranged between 2.4% and 3.5%:



Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED OVER THIS SAME PERIOD?

A. Following the "dot-com" bust in the early 2000s, common stock prices generally recovered and reached then-record highs, buoyed in large part by widespread acquisition activity. In 2008, the capital market crisis and Great Recession occurred. Stock prices tumbled by some 40%, and while they rebounded 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 new highs, but subsequently receded some 20% into bear market territory in response to inflation and global events (e.g., the 2022 Russian invasion of Ukraine). They then

recovered as inflation abated and the Fed discontinued hiking interest rates. In January 2025, stock prices began a gradual decline until April 2, 2025, when tariffs on most foreign goods were announced and stock indices fell over 10% in two days. While a temporary suspension of tariffs allowed stock prices to partially recover, uncertainty remains. Additionally, even before the most recent events, the stock market had become more volatile, with share prices routinely changing more than full percentage points during a single day of trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 2005 (the latter two indices are scaled for comparability):



Q. HOW HAS THE U.S. ECONOMY PERFORMED OVER THE LAST SEVERAL YEARS?

A. The U.S. economy had fully recovered from the Great Recession when the coronavirus pandemic struck in early 2020 causing the world economy to come to

a virtual stand-still and 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. While the combined effect of these fiscal and monetary policies allowed the U.S. economy to recover, the aid and stimulus spending, along with the subsequent Inflation Reduction Act, led to the increase in inflation described earlier. In response, the Fed embarked on its most aggressive effort in more than two decades to curb inflation by increasing short-term interest rates and reducing its $9 trillion inventory of Treasury debt and mortgage-backed securities. As inflation moderated, the Fed indicated that it might begin to reduce interest rates, but has not done so because inflation has stubbornly remained above its 2% target level. Whether the unprecedented actions during 2022-2023 and subsequently by the Fed will sufficiently reduce inflation remains unknown.

Q. WHAT IS THE CURRENT OUTLOOK FOR THE U.S. ECONOMY?

A. Early this year, the current presidential administration began a major overhaul of the federal government, including the creation of the Department of Government Efficiency and, more recently, the imposition of tariffs on most foreign goods. The effects of these actions, coupled with foreign policy changes, on the economy are unknown at this time but have created uncertainties for individuals, businesses, and government. The U.S. economy shrank in the first quarter of 2025 and many economists are warning of an impending recession and its attendant consequences.

Q. HOW DO THE FED'S ACTIONS AND THE OUTLOOK FOR THE ECONOMY AFFECT THE COST OF CAPITAL?

A. Hikes in the federal funds rate by the Fed and significant reductions in its long-term bond inventory were 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. Meanwhile, the uncertain outlook for the economy due to changes in fiscal, budgetary, and foreign policies has increased the risks faced by both bond and stock investors. These factors, coupled with the greater volatility in stock prices that further increases the risk of investing in common equities, supports the conclusion that the relatively low capital cost environment that existed for most of 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 LDC's 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 ONE Gas' equity ratio was at the upper end of the range maintained by the LDC industry, 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%
2024	40.7%	59.3%

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. This includes its most recent fiscal year-end of December 31, 2024 where ONE Gas' capital structure ratios have been restored to their targets of approximately 40% long-term debt and 60% common equity.

Q. WHAT ARE ONE GAS' CURRENT CAPITAL STRUCTURE RATIOS?

A. ONE Gas' capitalization at March 31, 2025, excluding Winter Storm Uri debt securitized in Kansas, is displayed in the table below:

Capital	March 31, 2025	
Long-term	$2,130,830	40.08%
Common	3,185,035	59.92%
Total	$5,315,865	100%

Also shown are ONE Gas' current capital structure ratios of 40.08% long-term debt and 59.92% common equity.

Q. HOW DO ONE GAS' RECENT 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 2019 and 2023:

Capital Component	2023	2022	2021	2020	2019
Long-term Debt	43.3%	42.3%	43.6%	42.3%	41.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.9%
Common Equity	56.7%	57.7%	56.4%	57.7%	58.1%
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' recent ratios.

Alternatively, Schedule BHF-2 displays the capital structure ratios at fiscal year-ends 2020 through 2024 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 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, 6) Southwest Gas, and 7) Spire, Inc. While ONE Gas' 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%
06/16/2020	10920	CP Energy-Beaumont	43.05%	56.95%
08/04/2020	10928	TGS – CGSA	41.00%	59.00%
01/18/2023	9896	TGS – WNSA	40.26%	59.74%
01/30/2024	14399	TGS – RGV	40.93%	59.07%
06/25/2024	15513	CP Energy	39.39%	60.61%
11/19/2024	17471	TGS – CGSA	40.42%	59.58%
05/13/2025	18879	Atmos – West Texas	39.03%	60.97%

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE USED TO CALCULATE TGS'S RATE OF RETURN?

A. I recommend that ONE Gas' capital structure ratios at its most recent quarter-end, March 31, 2025, of 40.08% debt and 59.92% equity be used to calculate the rate of return for TGS. In addition to reflecting how the TGS's permanent assets 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. At March 31, 2025, there were five issues of long-term senior notes comprising ONE Gas' capitalization, excluding the Kansas securitized debt, which have a total face value of $2.15 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, ONE Gas issued $550 million in debt in 2023 and 2024, which carries an interest rate of 5.10%. Reducing the face amount of the senior notes at March 31, 2025 is approximately $19.2 million in unamortized issuance and discount/premium costs and $2.5 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 4.45% (dollar amounts in 000s):

Description	Amount	Interest Rate	Annual Expense
5.10% due 2029	$ 550,000	5.100%	$28,050
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	(15,551)		1,503
ebt Discounts/Prem.	(3,618)		(200)
Debt Retirement Costs	(2,531)		723
Total	**$2,128,299**		$94,774
Cost of Debt		**4.45%**	

I recommend that this 4.45% cost be applied to the debt component of ONE Gas' adjusted capital structure to determine the rate of return for TGS.

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 trade off 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 April 2025 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.

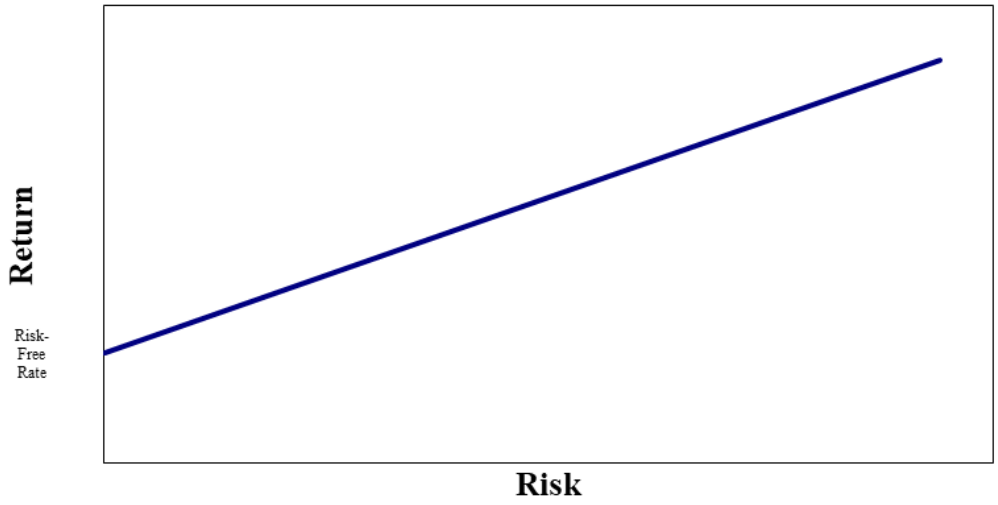
Bond and Rating	April 2025 Yield	Risk Premium Over 30-Year Treasury
U.S. Treasury		
30-Year	4.71%	--
Public Utility		
Aa	5.78%	1.07%
A	5.91%	1.20%
Baa	6.11%	1.40%

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:

$$P_0 = \frac{D_1}{(1+K_e)^1} + \frac{D_2}{(1+K_e)^2} + \cdots + \frac{D_t}{(1+K_e)^t} + \frac{P_t}{(1+K_e)^t}$$

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, and then excluded UGI Corp. because it is not predominantly engaged in natural gas distribution. This resulted in a proxy group consisting of the eight 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* May 2, 2025 edition, by the average closing price of each firm's stock during the month of April 2025. The expected dividends, representative price, and resulting dividend yield for each of the eight LDCs are displayed on Schedule BHF-3. As calculated there, the average dividend yield for the industry group is 3.33%. Also shown is the median for the group of 3.50%, 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 eight gas utilities reported by *Value Line*, LSEG's *Institutional Brokers Estimate System* (*"I/B/E/S"*), and *Zacks Investment Research* ("*Zacks*") as of the end of April 2025 are displayed on Schedule BHF-4, with the averages for the group being 8.4%, 8.5%, and 7.3%, respectively. Again, to eliminate the impact of extreme values

(e.g., Southwest Gas), the medians for the group, which range between 5.5% and 7.5%, are also calculated. 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 eight gas utilities, which average 2.9% and 5.1%, respectively, and have medians of 5.5% and 7.5%, 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 eight gas utilities in the industry group based on *Value Line's* projections for 2028-2030 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 5.6%, and 5.9% 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 eight gas utilities in the industry group. The averages for the LDC group range from 3.0% (5-year historical price growth) to 6.3% (5-year historical dividend growth), with the medians ranging from 4.3% to 7.3%. Besides the fact that some of these growth rates, when combined with the group's approximately 3.4% 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 5.5% and 7.5%. Taken together, and giving the most

weight to security analysts' projections, I conclude that investors expect long-term growth from the LDC group in the 6.0% to 7.0% range.

Q. DID YOU EXPLICITLY INCORPORATE ANY GENERAL MEASURE OF ECONOMIC GROWTH, SUCH AS GROSS DOMESTIC PRODUCT ("GDP"), INTO YOUR ESTIMATE OF INVESTOR GROWTH EXPECTATIONS?

A. No, not separately from the economic growth implicit in the company-specific projected and historical growth rates discussed above. A "two-stage" or "multi-stage" DCF model, which uses a general measure of economic growth (e.g., GDP) for later years, may be applicable to a "start-up" company or firms experiencing rapid near-term growth that is expected to slow in later years. But that is not the case for the LDCs in the group, all of which are mature, stable companies. The assumption that the long-term growth of the LDCs will revert to that of the general economy ignores the fact that the average growth rates in the earnings and dividends of the LDC group have exceeded GDP historically and that investors expect it to continue to do so prospectively. Utilities are regarded as "widows and orphans" stocks because they provide an essential service and produce a stable and growing income stream. The DCF model that best describes the valuation of LDC stocks is the "steady-state" constant growth form using projected and historical company-specific data, not a two-stage DCF model that erroneously assumes investors expect the longer-term growth of all companies to be equal to the growth in the economy as a whole.

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 3.4% with my growth rate range of a 6.0% to 7.0% developed earlier indicates a current DCF cost of equity for the LDC industry group of between 9.40% and 10.40%.

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 12.17% over the period 1926 through 2024 while the annual average income rate of return on 30-year Treasury bonds over this same period averaged 4.86%. Thus, the market risk premium based on historical average annual rates of return is 7.31%, 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 1.64% 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 10.25% produces a required rate of return from the market portfolio (R_m) of 11.90%.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN?

A. From the 11.90% 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 April 2025 of 4.71%. This produces a forward-looking market risk premium of 7.19%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CAPM?

A. Having calculated market risk premiums of 7.31% and 7.19% 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 0.80, calculated using firm betas obtained from *Value Line* and shown on Schedule BHF-8, which produces LDC industry risk premiums of 5.85% and 5.91%.

Q. WHAT ARE THE RESULTING THEORETICAL CAPM COST OF EQUITY ESTIMATES FOR THE LDC GROUP?

A. Summing the industry risk premiums of 5.85% and 5.75% with a risk-free interest rate equal to the April 2025 30-year Treasury bond yield of 4.71% produces current theoretical CAPM cost of equity estimates for LDCs of 10.56% and 10.46%.

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 0.75%. This means that the theoretical CAPM cost of equity estimates need to be increased by 75 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 11.31% and 11.21%, 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 commission's 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.

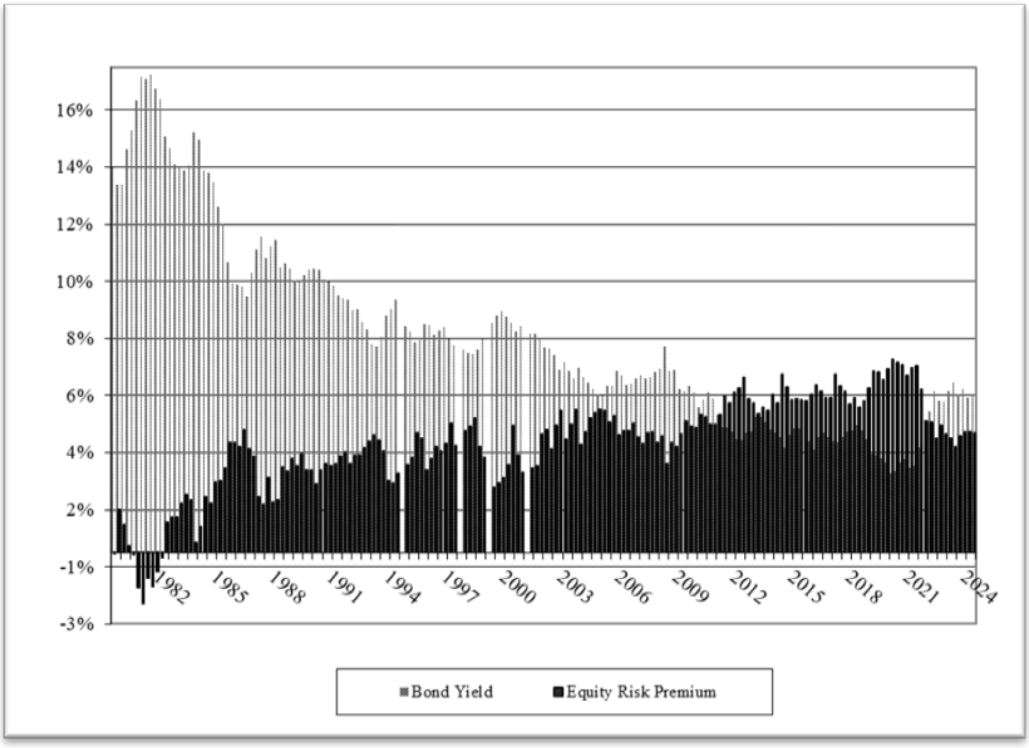
Q. WHAT WAS THE PRINCIPAL SOURCE OF THE DATA USED TO APPLY THIS RISK PREMIUM METHOD?

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 2025 are displayed in Schedule BHF-9. As shown there, the ROEs granted to LDCs over this approximately 44-year period have averaged 11.32%, while the average utility bond yield has averaged 7.50%, resulting in an average risk premium of 3.82%.

Q. IS THIS 3.82% 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 April 2025 yield of 5.93% on average utility bonds into the regression equations indicates that the equity risk premium at current interest rate levels is between 4.54% and 5.21%.

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 4.54% and 5.21% equity risk premiums developed on Schedule BHF-9 to the April 2025 yield on single-A utility bonds of 5.91% produces a current risk premium cost of equity range of between 10.45% and 11.12%.

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 2025, 2026, and the 2028-2030 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 8.8% in 2025, 9.0% in 2026, and 9.7% for 2028-2030, with medians of 8.1%, 8.6%, and 9.1%, 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 9.4% and 10.4%, and the CAPM indicates a cost of equity range of between approximately 11.2% and 11.3%, or 10.5% to 10.6% 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 10.5% and 11.1%, and the comparable earnings method shows that other LDCs are expected to earn between 8.1% and 9.7% 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 9.9% to 10.9% range.

Q. WHAT ROE DO YOU RECOMMEND FOR TGS?

A. I recommend an ROE for TGS 10.40%, which is the midpoint of my cost of equity range. This ROE is at the top of my DCF model range, below the range indicated by my CAPM analyses, both with and without the size adjustment, and just below the bottom 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 10.40% ROE for TGS 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%
06/16/2020	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	9896	TGS – WNSA	9.60%
01/30/2024	14399	TGS – RGV	9.70%
06/25/2024	15513	CP Energy	9.80%
11/19/2024	17471	TGS – CGSA	9.70%
05/13/2025	18879	Atmos – West Texas	9.80%

Although the allowed ROE range of 9.50% to 10.10% is below my recommended 10.4%, all but the five 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 5.93% in April 2025. Because of the increase in capital costs that has already occurred, an ROE in the 9.5% to 10.1% range previously allowed by the Commission 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 are in effect, my recommended 10.40% ROE is reasonable.

Q. HAVE YOU PERFORMED ANY OTHER TESTS OF REASONABLENESS OF YOUR RECOMMENDED 10.40% ROE?

A. Yes. In Docket No. OS-24-00018879 ("Docket No. 18879") involving Atmos West Texas, Commission Staff presented testimony supporting its recommended ROE. The Staff methodology consisted of three applications of the DCF model, one based on 30-day prices, another on 90-day prices, and the other on 180-day prices, and a CAPM analysis. In Schedule BHF-11, Staff's DCF and CAPM analyses are replicated using current market data applied to a proxy group of LDCs that excludes ONE Gas, as Staff did with Atmos Energy in Docket No. 18879. Although omitted by Staff in Docket No. 18879, I also make the 25-basis point adjustment for stock market uncertainty that Staff has historically included in its ROE recommendation. This adjustment is particularly applicable now due to the current economic and

capital market turmoil discussed earlier. Shown at the bottom left of Schedule BHF-11, the end-result of averaging the cost of equity estimates produced by the Staff's three DCF models and CAPM analysis, and including the market uncertainty adjustment, is an ROE of 10.27%.

I conducted another test using the Staff's methodology but removed a downward bias in the DCF analyses attributable to the use of low-mean growth rates, which places disproportionately greater weight on low growth rates. Eliminating this bias by using just the mean growth rates in the DCF analyses, and including the 25-basis point market uncertainty adjustment, produces an ROE of 10.51%, as shown at the bottom right of Schedule BHF-11.

These two applications of the Staff's methodology produce an ROE range of 10.27% to 10.51%, which fully supports the reasonableness of my recommended ROE for TGS of 10.40%.

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.

Bibliography

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).

"An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies", with William E. Avera, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982).

"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).

"Regulatory Effects on Electric Utilities' Cost of Capital Reexamined," with Louis E. Buck, Jr., *Public Utilities Fortnightly* (September 2, 1982).

"Capital Needs for Electric Utility Companies in Texas: 1976-1985", *Texas Business Review* (January-February 1979), reprinted in "The Energy Picture: Problems and Prospects", J. E. Pluta, ed., *Bureau of Business Research* (1980).

"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).

"The Effects of Regulation on Fair Market Value: P.H. Robinson – A Case Study," Annual Meeting of the Texas Committee of Utility and Railroad Tax Representatives, Austin, Texas (September 1987).

"How to Value Closely-held Businesses," TSCPA 1987 Entrepreneurs Conference, San Antonio, Texas (May 1987).

"Revenue Requirements" and "Determining the Rate of Return", New Mexico State University Regulation and the Rate-Making Process, Southwestern Water Utilities Conference, Albuquerque, New Mexico (July 1986) and El Paso, Texas (November 1980).

"How to Evaluate Personal Service Practices," TSCPA CPE Exposition 1985, Houston and Dallas, Texas (December 1985).

"How to Start a Small Business – Accounting and Record Keeping," University of Texas Management Development Program, Austin, Texas (October 1984).

"Project Financing of Public Utility Facilities", TSCPA Conference on Public Utilities Accounting and Ratemaking, San Antonio, Texas (April 1984).

"Valuation of Closely-Held Businesses," Concho Valley Estate Planning Council, San Angelo, Texas (September 1982).

"Rating Regulatory Performance and Its Impact on the Cost of Capital," New Mexico State University Seminar on Regulation and the Cost of Capital, El Paso, Texas (May 1982).

"Effect of Inflation on Rate of Return," Cost of Capital Conference and Workshop, Pinehurst, North Carolina (April 1981).

"Original Cost Versus Current Cost Regulation: A Re-examination," Financial Management Association, New Orleans, Louisiana (October 1980).

"Capital Investment Analysis for Electric Utilities," The University of Texas at Dallas, Richardson, Texas (June 1980).

"The Determinants of Capital Costs to the Electric Utility Industry," with Cedric E. Grice, Southwestern Finance Association, San Antonio, Texas (March 1980).

"The Entrepreneur and Management: A Case Study," Small Business Administration Seminar, Austin, Texas (October 1979).

"Capital Budgeting by Public Utilities: A New Perspective," with W. Clifford Atherton, Jr., Financial Management Association, Boston, Massachusetts (October 1979).

"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).

"The Economics of Regulated Industries," Consumer Economics Forum, Houston, Texas (November 1977).

"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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

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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Summary of Testimony Before Regulatory Agencies

(Continued)

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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Summary of Testimony Before Regulatory Agencies

(Continued)

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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Summary of Testimony Before Regulatory Agencies

(Continued)

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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Summary of Testimony Before Regulatory Agencies

(Continued)

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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

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

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Summary of Testimony Before Regulatory Agencies

(Continued)

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	Jan 23	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 Jul 24	Rate of Return on Equity
281.	Delaware Link Ventures, LLC	Texas RRC	00016812	Mar 24	Revenue Requirements

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Summary of Testimony Before Regulatory Agencies

(Continued)

282. Texas Gas Service	Texas RRC	00017471	Jun 24 Sep 24	Rate of Return
283. West Texas Gas, Inc.	Texas RRC	00017816	Jul 24	Revenue Requirements, Rate of Return, and Cost of Service Study
284. Wind Energy Transmission Texas	Texas PUC	57299	Dec 24 Mar 25	Revenue Requirements
285. Pecan Pipeline Company	Texas RRC	00020190	Mar 25	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, 2024.
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, 2024, was $3.5 billion.

On February 14, 2025, we had 59,877,552 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 22, 2025, are incorporated by reference in Part III.

Actuaries to estimate mortality rates. In determining the projected benefit costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize.

For the year ended December 31, 2024, we contributed $1.6 million to our defined benefit pension plans and no contributions were made to our other postemployment benefit plans. For the year ended December 31, 2023, we contributed $1.3 million to our defined benefit pension plans and $2.5 million to our other postemployment benefit plans. In 2025, our contributions are expected to be $9.8 million to our defined benefit pension plans, and no contributions are expected to be made to our other postemployment benefit plans.

We recorded net periodic benefit credits for our defined benefit pension plans, prior to regulatory deferrals, of $5.5 million in 2024, and estimate that in 2025, we will record net periodic benefit cost of approximately $5.7 million. Net periodic benefits credits for our postemployment benefit plans, prior to regulatory deferrals, were $0.4 million in 2024, and we estimate that in 2025, we will record a credit of approximately $0.2 million, prior to regulatory deferrals.

The following table sets forth the significant assumptions used to determine our estimated 2025 net periodic benefit cost related to our defined benefit pension and other postemployment benefit plans and sensitivity to changes with respect to these assumptions:

	Rate Used	Cost Sensitivity (a)	Obligation Sensitivity (b)
		(Millions of dollars)	
Discount rate for pension	5.70 %	$ 2.0	$ 18.6
Discount rate for other postemployment benefits	5.75 %	(0.1)	3.2
Expected long-term return on plan assets for pension	5.85 %	2.0	—
Expected long-term return on plan assets for other postemployment benefits	5.10 %	0.4	—

(a) Approximate impact a quarter percentage point decrease in the assumed rate would have on net periodic pension costs.
(b) Approximate impact a quarter percentage point decrease in the assumed rate would have on defined benefit pension obligation.

See Note 11 of the Notes to Consolidated Financial Statements in this Annual Report for additional information regarding our pension and other postretirement benefit plans.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effect on earnings or cash flows for the years ended December 31, 2024, 2023 and 2022. Environmental issues may exist with respect to these MGP sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

See "Environmental Matters" and Note 15 of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management's plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of

1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking and other statements in this Annual Report regarding our environmental, social and other sustainability plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the SEC. In addition, historical, current, and forward-looking environmental, social and sustainability-related statements may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve, and assumptions that are subject to change in the future.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," "should," "goal," "forecast," "guidance," "could," "may," "continue," "might," "potential," "scheduled," "likely," and other words and terms of similar meaning.

One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Annual Report. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, costs, liquidity, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- our ability to recover costs, income taxes and amounts equivalent to the cost of property, plant and equipment, regulatory assets and our allowed rate of return in our regulated rates or other recovery mechanisms;
- cyber-attacks, which, continue to increase in volume and sophistication, or breaches of technology systems that could disrupt our operations or result in the loss or exposure of confidential or sensitive customer, employee, vendor, counterparty or Company information; further, increased remote working arrangements have required enhancements and modifications to our IT infrastructure (e.g. Internet, Virtual Private Network, remote collaboration systems, etc.), and any failures of the technologies, including third-party service providers, that facilitate working remotely could limit our ability to conduct ordinary operations or expose us to increased risk or effect of an attack;
- our ability to manage our operations and maintenance costs;
- changes in regulation of natural gas distribution services, particularly those in Oklahoma, Kansas and Texas;
- the economic climate and, particularly, its effect on the natural gas requirements of our residential and commercial customers;
- the length and severity of a pandemic or other health crisis which could significantly disrupt or prevent us from operating our business in the ordinary course for an extended period;
- competition from alternative forms of energy, including, but not limited to, electricity, solar power, wind power, geothermal energy and biofuels;
- adverse weather conditions and variations in weather, including seasonal effects on demand and/or supply, the occurrence of severe storms in the territories in which we operate, and climate change, and the related effects on supply, demand, and costs;
- indebtedness, which could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantage compared with competitors;
- our ability to secure reliable, competitively priced and flexible natural gas transportation and supply, including decisions by natural gas producers to reduce production or shut-in producing natural gas wells and expiration of existing supply and transportation and storage arrangements that are not replaced with contracts with similar terms and pricing;
- our ability to complete necessary or desirable expansion or infrastructure development projects, which may delay or prevent us from serving our customers or expanding our business;
- operational and mechanical hazards or interruptions;
- adverse labor relations;
- the effectiveness of our strategies to reduce earnings lag, revenue protection strategies and risk mitigation strategies, which may be affected by risks beyond our control such as commodity price volatility, counterparty performance or creditworthiness and interest rate risk;
- the capital-intensive nature of our business, and the availability of and access to, in general, funds to meet our debt obligations prior to or when they become due and to fund our operations and capital expenditures, either through (i) cash on hand, (ii) operating cash flow, or (iii) access to the capital markets and other sources of liquidity;
- our ability to obtain capital on commercially reasonable terms, or on terms acceptable to us, or at all;

- limitations on our operating flexibility, earnings and cash flows due to restrictions in our financing arrangements;
- cross-default provisions in our borrowing arrangements, which may lead to our inability to satisfy all of our outstanding obligations in the event of a default on our part;
- changes in the financial markets during the periods covered by the forward-looking statements, particularly those affecting the availability of capital and our ability to refinance existing debt and fund investments and acquisitions to execute our business strategy;
- actions of rating agencies, including the ratings of debt, general corporate ratings and changes in the rating agencies' ratings criteria;
- changes in inflation and interest rates;
- our ability to recover the costs of natural gas purchased for our customers and any related financing required to support our purchase of natural gas supply;
- impact of potential impairment charges;
- volatility and changes in markets for natural gas and our ability to secure additional and sufficient liquidity on reasonable commercial terms to cover costs associated with such volatility;
- possible loss of LDC franchises or other adverse effects caused by the actions of municipalities;
- payment and performance by counterparties and customers as contracted and when due, including our counterparties maintaining ordinary course terms of supply and payments;
- changes in existing or the addition of new environmental, safety, tax, cybersecurity and other laws or regulations to which we and our subsidiaries are subject, including those that may require significant expenditures, significant increases in operating costs or, in the case of noncompliance, substantial fines or penalties;
- the effectiveness of our risk-management policies and procedures, and employees violating our risk-management policies;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- advances in technology, including technologies that increase efficiency or that improve electricity's competitive position relative to natural gas;
- population growth rates and changes in the demographic patterns of the markets we serve in Oklahoma, Kansas and Texas, and economic conditions in these areas;
- acts of nature and naturally occurring disasters;
- political unrest and the potential effects of threatened or actual terrorism and war;
- the sufficiency of insurance coverage to cover losses;
- the effects of our strategies to reduce tax payments;
- changes in accounting standards;
- changes in corporate governance standards;
- existence of material weaknesses in our internal controls;
- our ability to comply with all covenants in our indentures and the ONE Gas Credit Agreement, a violation of which, if not cured in a timely manner, could trigger a default of our obligations;
- our ability to attract and retain talented employees, management and directors, and any shortage of skilled-labor;
- unexpected increases in the costs of providing health care benefits, along with pension and postemployment health care benefits, as well as declines in the discount rates on, declines in the market value of the debt and equity securities of, and increases in funding requirements for, our defined benefit plans; and
- our ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part I, Item 1A, Risk Factors, in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in commodity prices or interest rates and the timing of transactions.

Commodity Price Risk

Our commodity price risk, driven primarily by fluctuations in the price of natural gas, is mitigated by our purchased-gas cost adjustment mechanisms through which we pass-through natural gas costs to our customers without profit. We may use fixed-price natural gas contracts or derivative instruments to hedge the cost of a portion of our anticipated natural gas purchases during the winter heating months to reduce the impact on our customers of upward market price volatility of natural gas. Additionally, we inject natural gas into storage during the warmer months, when natural gas prices are typically lower, and withdraw the natural gas during the colder months of the year. Gains or losses associated with these derivative instruments and the costs of our fixed-price natural gas contracts and storage activities are included in, and recoverable through our purchased-gas cost adjustment mechanisms, which are subject to review by regulatory authorities.

Interest-Rate Risk

We are exposed to interest-rate risk primarily associated with commercial paper borrowings, borrowings under our credit agreement, and new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. We may manage interest-rate risk on future borrowings through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates.

Counterparty Credit Risk

We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits or other forms of collateral, when appropriate and allowed by tariff. With approximately 2.3 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain a provision for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We recover the fuel-related portion of bad debts through our purchased-gas cost adjustment mechanisms.

TEXAS GAS SERVICE
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OVERALL RATE OF RETURN

Capital Component	March 31, 2025 Amounts	Percent of Total	Component Cost	Weighted Cost
Long-term Debt	$ 2,130,830	40.08%	4.45%	1.78%
Common Equity	3,185,035	59.92%	10.40%	6.23%
Total	**$ 5,315,865**	**100.00%**		**8.02%**

LDC PROXY GROUP CAPITAL STRUCTURE RATIOS

	2024 (a)		2023 (a)		2022 (a)		2021 (a)		2020 (a)	
Company	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**
Atmos Energy	39.3%	60.7%	37.9%	62.1%	37.9%	62.1%	38.4%	61.6%	40.0%	60.0%
Chesapeake Utilities	46.5%	53.5%	48.8%	51.2%	41.0%	59.0%	41.5%	58.5%	42.2%	57.8%
New Jersey Resources	56.7%	43.3%	58.2%	41.8%	57.8%	42.2%	57.0%	43.0%	55.1%	44.9%
NiSource	54.0%	46.0%	57.2%	42.8%	55.7%	44.3%	56.9%	43.1%	61.6%	38.4%
Northwest Natural Gas	52.5%	47.5%	52.6%	47.4%	51.5%	48.5%	52.8%	47.2%	49.2%	50.8%
Southwest Gas	55.0%	45.0%	58.2%	41.8%	59.0%	41.0%	58.2%	41.8%	50.5%	49.5%
Spire	53.4%	46.6%	54.9%	45.1%	51.2%	48.8%	52.5%	47.5%	49.0%	51.0%
LDC GROUP AVERAGE	**51.1%**	**48.9%**	**52.5%**	**47.5%**	**50.6%**	**49.4%**	**51.0%**	**49.0%**	**49.7%**	**50.3%**
Minimum	39.3%	43.3%	37.9%	41.8%	37.9%	41.0%	38.4%	41.8%	40.0%	38.4%
Maximum	56.7%	60.7%	58.2%	62.1%	59.0%	62.1%	58.2%	61.6%	61.6%	60.0%

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 21, 2025).

DCF MODEL -- DIVIDEND YIELD

Company	Ticker	Expected Dividend (a)	Price (b)	Dividend Yield (c)
Atmos Energy	ATO	$ 3.58	$ 154.91	2.31%
Chesapeake Utilities	CPK	$ 2.68	$ 131.47	2.04%
New Jersey Resources	NJR	$ 1.80	$ 48.77	3.69%
NiSource	NI	$ 1.12	$ 38.95	2.88%
Northwest Natural Gas	NWN	$ 1.96	$ 42.52	4.61%
ONE Gas	OGS	$ 2.69	$ 76.24	3.53%
Southwest Gas	SWX	$ 2.48	$ 71.63	3.46%
Spire	SR	$ 3.17	$ 76.70	4.13%
AVERAGE				**3.33%**
MEDIAN				**3.50%**

(a) *The Value Line Investment Survey* "Summary & Index" (May 2, 2025).
(b) Fidelity Investments (average of daily closing prices during April 2025).
(c) Expected Dividend / Price.

DCF MODEL -- EARNINGS GROWTH RATES

	Projected Growth			Historical Growth	
Company	**Value Line (a)**	**I/B/E/S LSEG (b)**	**Zacks (c)**	**10-Year (a)**	**5-Year (a)**
Atmos Energy	6.0%	7.3%	7.2%	9.5%	9.0%
Chesapeake Utilities	5.0%	N/R	N/R	9.0%	10.0%
New Jersey Resources	6.5%	N/R	N/R	5.5%	5.0%
NiSource	8.0%	7.7%	7.9%	1.0%	10.5%
Northwest Natural Gas	4.5%	6.0%	N/R	1.0%	25.0%
ONE Gas	4.0%	N/R	5.6%	N/R	6.0%
Southwest Gas	29.0%	13.0%	9.5%	-11.5%	-25.5%
Spire	4.5%	N/R	6.5%	5.5%	1.0%
AVERAGE	**8.4%**	**8.5%**	**7.3%**	**2.9%**	**5.1%**
MEDIAN	**5.5%**	**7.5%**	**7.2%**	**5.5%**	**7.5%**

(a) *The Value Line Investment Survey* "Stock Screener" (May 1, 2025).
(b) LSEG Stock Reports Plus (April 30, 2025).
(c) Zacks.com "Snapshot" (Retrieved May 1, 2025).

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Schedule BHF-5
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DCF MODEL -- SUSTAINABLE GROWTH RATES

Company	2028-2030 Projected (a) Earnings per Share	Dividends per Share	Book Value per Share	Price per Share	Shares Outstanding (a) 2024	Shares Outstanding (a) Proj. 28-30	Earnings Retention Growth Retention Ratio	Return on Equity	"b x r"	External Financing Growth 2028-2030 Market-to-Book Ratio	Growth Rate in Shares	"s"	"v"	"s x v"	Sustainable Growth
Atmos Energy	$ 8.65	$ 4.45	$ 97.30	$ 155.00	155.23	185.00	48.6%	8.9%	4.3%	1.59	3.6%	5.7%	37.2%	2.1%	6.4%
Chesapeake Utilities	$ 6.80	$ 3.35	$ 72.80	$ 135.00	23.00	25.00	50.7%	9.3%	4.7%	1.85	1.7%	3.1%	46.1%	1.4%	6.2%
New Jersey Resources	$ 3.90	$ 2.20	$ 27.00	$ 65.00	99.46	105.00	43.6%	14.4%	6.3%	2.41	1.1%	2.6%	58.5%	1.5%	7.8%
NiSource	$ 2.55	$ 1.44	$ 25.70	$ 47.50	470.00	525.00	43.5%	9.9%	4.3%	1.85	2.2%	4.1%	45.9%	1.9%	6.2%
Northwest Natural Gas	$ 3.45	$ 2.00	$ 44.20	$ 70.00	41.00	50.00	42.0%	7.8%	3.3%	1.58	4.0%	6.4%	36.9%	2.4%	5.6%
ONE Gas	$ 5.25	$ 2.90	$ 69.45	$ 95.00	56.50	57.00	44.8%	7.6%	3.4%	1.37	0.2%	0.2%	26.9%	0.1%	3.4%
Southwest Gas	$ 4.85	$ 3.00	$ 58.65	$ 87.50	72.00	75.00	38.1%	8.3%	3.2%	1.49	0.8%	1.2%	33.0%	0.4%	3.6%
Spire	$ 5.25	$ 3.70	$ 57.80	$ 92.50	57.70	72.00	29.5%	9.1%	2.7%	1.60	4.5%	7.2%	37.5%	2.7%	5.4%
AVERAGE									**4.0%**					**1.6%**	**5.6%**
MEDIAN									**3.9%**					**1.7%**	**5.9%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 21, 2025).

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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 (c)	
Company	jected	10-Year	5-Year	jected	10-Year	5-Year	jected (b)	10-Year	5-Year
Atmos Energy	5.0%	10.0%	11.5%	7.0%	7.5%	9.0%	0.0%	10.9%	8.5%
Chesapeake Utilities	6.0%	10.5%	10.5%	7.5%	8.0%	10.0%	0.7%	10.0%	8.5%
New Jersey Resources	4.5%	7.0%	5.0%	5.5%	7.0%	7.0%	7.4%	4.5%	8.1%
NiSource	8.0%	-2.0%	3.5%	6.5%	N/R	6.0%	5.1%	8.5%	9.0%
Northwest Natural Gas	4.5%	2.0%	3.5%	0.5%	1.0%	0.5%	13.3%	-1.2%	-7.4%
ONE Gas	6.0%	N/R	4.5%	2.5%	N/R	8.5%	5.7%	N/R	-2.1%
Southwest Gas	3.0%	5.0%	4.0%	3.0%	7.5%	4.5%	5.1%	2.2%	-1.0%
Spire	2.5%	5.0%	3.0%	4.5%	5.5%	5.0%	4.8%	4.0%	0.7%
AVERAGE	**4.9%**	**5.4%**	**5.7%**	**4.6%**	**6.1%**	**6.3%**	**5.3%**	**5.6%**	**3.0%**
MEDIAN	**4.8%**	**5.0%**	**4.3%**	**5.0%**	**7.3%**	**6.5%**	**5.1%**	**4.5%**	**4.4%**

(a) *The Value Line Investment Survey* "Stock Screener" (May 1, 2025).
(b) *The Value Line Investment Survey* "Ratings & Reports" (February 21, 2025).
(c) Fidelity Investments (Average April 2015 and 2020 closing prices to average April 2025 closing price).

N/R -- None reported.

CAPITAL ASSET PRICING MODEL

Description	Historical Rates of Return (a)	Forward-Looking Rates of Return (b)
Market Required Rate of Return	12.17%	11.90%
Long-term Government Bond Return (a)(c)	4.86%	4.71%
Market Risk Premium (d)	7.31%	7.19%
LDC Group Beta (e)	0.80	0.80
LDC Group Risk Premium (f)	5.85%	5.75%
Risk-free Rate of Interest (c)	4.71%	4.71%
Theoretical CAPM Cost of Equity Estimate (g)	**10.56%**	**10.46%**
Size Premium (e)	0.75%	0.75%
CAPM Cost of Equity Estimates (h)	**11.31%**	**11.21%**

(a) *Kroll Cost of Capital Navigator.*

(b) Calculated by applying DCF model applied to S&P 500 firms paying dividends (May 8, 2025):

Expected Dividend Yield		1.64%
Projected Earnings Growth Rate:		
Value Line	9.36%	
I/B/E/S	10.63%	
Zacks	10.77%	
Average		10.25%
Market Required Rate of Return		11.90%

(c) April 2025 yield on 30-year U.S. Treasury bonds (Federal Reserve). 4.71%

(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 (d) (millions)	Premium(e)
Atmos Energy	A-	A2	0.75	$ 22,600	0.33%
Chesapeake Utilities	N/R	N/R	0.75	$ 2,800	1.00%
New Jersey Resources	N/R	A1	0.85	$ 4,600	0.74%
NiSource	BBB+	Baa2	0.85	$ 17,800	0.49%
Northwest Natural Gas	A+	Baa1	0.80	$ 1,600	1.19%
ONE Gas	A-	A3	0.80	$ 4,000	0.74%
Southwest Gas	BBB	Baa1	0.80	$ 5,500	0.74%
Spire	BBB+	Baa2	0.80	$ 4,200	0.74%
LDC GROUP AVERAGE	**A-**	**A3**	**0.80**	**$ 7,888**	**0.75%**

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	$ 47,157	-	$ 3,522,211	-0.01%
2	$ 20,191	-	$ 46,949	0.33%
3	$ 9,938	-	$ 20,178	0.49%
4	$ 6,197	-	$ 9,937	0.50%
5	$ 3,948	-	$ 6,181	0.74%
6	$ 2,482	-	$ 3,946	1.00%
7	$ 1,423	-	$ 2,465	1.19%
8	$ 731	-	$ 1,417	0.88%
9	$ 305	-	$ 730	1.73%
10- Smallest	$ 1	-	$ 304	4.47%

(a) Moody's.com (Retreived May 1, 2025).
(b) Standard and Poors.com (Retrieved May 1, 2025).
(c) *The Value Line Investment Survey* "Stock Screener" (May 1, 2025).
(d) *The Value Line Investment Survey* "Ratings & Reports" (February 21, 2025).
(e) Kroll Cost of Capital Navigator (Retrieved February 4, 2025).

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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%
	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%
2024	1		9.62%	5.56%	4.06%
	2		9.93%	5.75%	4.18%
	3		9.64%	5.44%	4.20%
	4		9.70%	5.54%	4.16%
2025	1		9.72%	5.80%	3.92%
Average			**11.32%**	**7.50%**	**3.82%**

Unadusted:

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.07238	+	-0.45518	X 5.93%
RP	=	0.07238	+	-0.02699	
RP	**=**	**4.54%**			

Adjusted (Using Iterative Prais-Winsten algorithm):

Risk Premium = Intercept + (Slope X Interest Rate) (d)

RP	=	0.10432	+	-0.88040	X 5.93%
RP	=	0.10432	+	-0.05221	
RP	**=**	**5.21%**			

(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 April 2025.

COMPARABLE EARNINGS METHOD

Company	Projected Earned Return on Book Equity (a) 2025	2026	2028-30
Atmos Energy	8.9%	9.0%	8.9%
Chesapeake Utilities	8.7%	8.8%	9.3%
New Jersey Resources	13.7%	13.7%	14.4%
NiSource	8.1%	8.6%	9.9%
Northwest Natural Gas	8.1%	8.0%	7.8%
Southwest Gas	6.8%	7.3%	8.3%
Spire	7.5%	7.7%	9.1%
LDC GROUP AVERAGE	**8.8%**	**9.0%**	**9.7%**
MEDIAN	**8.1%**	**8.6%**	**9.1%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (February 21, 2025).

APPLICATION OF STAFF RATE OF RETURN ON EQUITY METHODOLOGY

CONSTANT GROWTH DCF 30-Day Share Price

Company		[1] Stock Price (Average through 4/30/25	[2] Annualized Dividend	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line EPS Growth Rate	[6] IBES EPS Growth Rate	[7] Zacks EPS Growth Rate	[8] Average Growth Rate	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
Atmos Energy Inc.	ATO	$153.64	$3.58	2.33%	2.41%	6.00%	7.30%	7.19%	6.83%	8.41%	9.24%	9.71%
Chesapeake Utilities	CPK	$129.79	$2.68	2.06%	2.12%	5.00%	N/R	N/R	5.00%	7.12%	7.12%	7.12%
New Jersey Resources	NJR	$48.75	$1.80	3.69%	3.81%	6.50%	N/R	N/R	6.50%	10.31%	10.31%	10.31%
NiSource Inc.	NI	$39.18	$1.12	2.86%	2.97%	8.00%	7.70%	7.88%	7.86%	10.67%	10.83%	10.97%
Northwest Natural Gas	NWN	$42.29	$1.96	4.63%	4.76%	4.50%	6.00%	N/R	5.25%	9.26%	10.01%	10.76%
Southwest Gas	SWX	$72.29	$2.48	3.43%	3.62%	(a)	13.00%	9.50%	11.25%	13.12%	14.87%	16.62%
Spire	SR	$76.88	$3.17	4.12%	4.24%	4.50%	N/R	6.54%	5.52%	8.74%	9.76%	10.78%
			Mean:	3.30%	3.42%	5.75%	8.50%	7.78%	6.89%	**9.66%**	**10.31%**	**10.90%**
			Median:							**9.26%**	**10.01%**	**10.76%**

CONSTANT GROWTH DCF 90-Day Share Price

Company		[1] Stock Price	[2] Annualized Dividend	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] Yahoo EPS Growth	[7] Value Line EPS Growth	[8] Average Growth Rate	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
Atmos Energy Inc.	ATO	$147.30	$3.58	2.43%	2.51%	6.00%	7.30%	7.19%	6.83%	8.51%	9.34%	9.81%
Chesapeake Utilities	CPK	$125.42	$2.68	2.14%	2.19%	5.00%	N/R	N/R	5.00%	7.19%	7.19%	7.19%
New Jersey Resources	NJR	$47.62	$1.80	3.78%	3.90%	6.50%	N/R	N/R	6.50%	10.40%	10.40%	10.40%
NiSource Inc.	NI	$38.41	$1.12	2.92%	3.03%	8.00%	7.70%	7.88%	7.86%	10.73%	10.89%	11.03%
Northwest Natural Gas	NWN	$41.05	$1.96	4.77%	4.90%	4.50%	6.00%	N/R	5.25%	9.40%	10.15%	10.90%
Southwest Gas	SWX	$73.06	$2.48	3.39%	3.59%	(a)	13.00%	9.50%	11.25%	13.09%	14.84%	16.59%
Spire	SR	$73.06	$3.17	4.34%	4.46%	4.50%	N/R	6.54%	5.52%	8.96%	9.98%	11.00%
			Mean:	3.40%	3.51%	5.75%	8.50%	7.78%	6.89%	**9.75%**	**10.40%**	**10.99%**
			Median:							**9.40%**	**10.15%**	**10.90%**

CONSTANT GROWTH DCF 180-Day Share Price

Company		[1] Stock Price	[2] Annualized Dividend	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] Yahoo EPS Growth	[7] Value Line EPS Growth	[8] Average Growth Rate	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
Atmos Energy Inc.	ATO	$143.13	$3.58	2.50%	2.59%	6.00%	7.30%	7.19%	6.83%	8.59%	9.42%	9.89%
Chesapeake Utilities	CPK	$123.89	$2.68	2.16%	2.22%	5.00%	N/R	N/R	5.00%	7.22%	7.22%	7.22%
New Jersey Resources	NJR	$47.35	$1.80	3.80%	3.92%	6.50%	N/R	N/R	6.50%	10.42%	10.42%	10.42%
NiSource Inc.	NI	$36.61	$1.12	3.06%	3.18%	8.00%	7.70%	7.88%	7.86%	10.88%	11.04%	11.18%
Northwest Natural Gas	NWN	$40.76	$1.96	4.81%	4.94%	4.50%	6.00%	N/R	5.25%	9.44%	10.19%	10.94%
Southwest Gas	SWX	$73.47	$2.48	3.38%	3.57%	(a)	13.00%	9.50%	11.25%	13.07%	14.82%	16.57%
Spire	SR	$69.93	$3.17	4.53%	4.66%	4.50%	N/R	6.54%	5.52%	9.16%	10.18%	11.20%
			Mean:	3.46%	3.58%	5.75%	8.50%	7.78%	6.89%	**9.82%**	**10.47%**	**11.06%**
			Median:							**9.44%**	**10.19%**	**10.94%**

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	0.75	4.28%	7.00%	9.53%
Chesapeake Utilities	CPK	0.85	4.28%	7.00%	10.23%
New Jersey Resources	NJR	0.85	4.28%	7.00%	10.23%
NiSource Inc.	NI	0.80	4.28%	7.00%	9.88%
Northwest Natural Gas	NWN	0.80	4.28%	7.00%	9.88%
Southwest Gas	SWX	0.80	4.28%	7.00%	9.88%
Spire	SR	0.80	4.28%	7.00%	9.88%
Mean		0.80			**9.88%**
Median		0.80			**9.88%**

Market Risk Premium derived from average S&P total return of 11.79% - 4.79%.

RATE OF RETURN ON EQUITY

30-day Low-Mean DCF ROE	9.98%	30-day Mean DCF ROE	10.31%
90-day Low-Mean DCF ROE	10.08%	90-day Mean DCF ROE	10.40%
180-day Low-Mean DCF ROE	10.15%	180-day Mean DCF ROE	10.47%
CAPM	9.88%	CAPM	9.88%
Rate of Return on Equity	**10.02%**	**Rate of Return on Equity**	**10.26%**
Adjustment for Market Uncertainty	0.25%	Adjustment for Market Uncertainty	0.25%
Rate of Return on Equity	**10.27%**	**Rate of Return on Equity**	**10.51%**

(a) *Value Line's* projected growth of 26% was excluded as anomalous.

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 28 day of May 2025.

Notary Public in and for the State of Texas

TAMMY MITCHELL
Notary Public, State of Texas
Comm. Expires 03-28-2029
Notary ID 6939192

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. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

TERESA D. SERNA

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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EXHIBIT TDS-1	Texas Gas Service – Class Cost of Service Study
EXHIBIT TDS-2	Texas Gas Service – Class Revenue Allocation
EXHIBIT TDS-3	West North Service Area – Class Cost of Service Study
EXHIBIT TDS-4	West North Service Area – Class Revenue Allocation
EXHIBIT TDS-5	Central-Gulf Service Area – Class Cost of Service Study
EXHIBIT TDS-6	Central-Gulf Service Area – Class Revenue Allocation
EXHIBIT TDS-7	Rio Grande Valley Service Area – Class Cost of Service Study
EXHIBIT TDS-8	Rio Grande Valley Service Area – Class Revenue Allocation

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 Nos. 10094, 10285, 10488, 10506, 10526, Docket Nos. OS-22-00009896 ("Docket No. 9896"), OS-23-00014399 ("Docket No. 14399") and OS-24-00017471 ("Docket No. 17471") 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 I prepared for the Company's proposed statewide rates and the Class Revenue Allocation based on the CCOS study results. I support the CCOS study tabs listed in the table below in the statewide integrated model.[1]

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

[1] I have also prepared and support individual CCOS studies and their respective class revenue allocations for West North Service Area (WNSA), Central-Gulf Service Area (CGSA), and Rio Grande Valley Service Area (RGVSA).

Mains Study Summary
Meter & Regulator Factors
Odorization Summary
Peak Demand
Service Charges Summary
Service Line Factors
As Adj. 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.[2]

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.

[2] 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.[3]

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.

[3] 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.

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 "reasonable to use" and that it "classifies and allocates costs in a fair, just, and reasonable manner."[4] In addition, this is the same method I used in Docket No. 17471.[5]

Q. PLEASE DESCRIBE EXHIBIT TDS-1, WHICH IS THE CCOS STUDY IN THIS CASE.

A. The CCOS study results for TGS are provided in Exhibit TDS-1. 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.

[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 Finding of Fact Nos. 92-93 (Jan. 18, 2023).

[5] *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 Central-Gulf Service Area,* Docket No. OS-24-00017471 consol., Direct Testimony of Teresa D. Serna at 5-14 (Jun. 3, 2024).

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 customer classes.[6] 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.

[6] 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.

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 of service today. Classes with revenue-to-cost ratios greater than one [line 10, columns (d) through (j) and column (l)], indicate that the 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 13 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 8 of Exhibit TDS-1 show the classification of the individual components of the cost of service, or revenue requirement. Pages 9 through 13 provide the classification factors used on pages 2 through 8 of Exhibit TDS-1.

Q. PLEASE EXPLAIN WHERE THE ALLOCATION STEP IS FOUND IN EXHIBIT TDS-1.

A. Pages 14 through 59 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 14 through 27. The allocation of each of the classified components of the cost of service to customer classes is shown on pages 28 through 51 of Exhibit TDS-1. The components of the allocated cost of service before revenue credits (shown on page 39 and 51, lines 509 through 512) are carried forward to lines 1 through 3 of the Cost of Service Study Summary (page 1, Exhibit TDS-1). Pages 52 through 59 of Exhibit TDS-1 provide the customer, demand and commodity allocation factors applied in the allocation of the rate base (pages 14 through 27) and the cost of service (pages 28 through 51) components.

Q. IS YOUR CCOS METHODOLOGY CONSISTENT WITH THE APPROACH THAT WAS PERFORMED AND APPROVED IN DOCKET NOS. 9896, 14399, AND 17471 ?

A. Yes.

IV. CLASS REVENUE ALLOCATION

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 TGS 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. The Company supports basing the class revenue allocation on the actual TGS 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 residential, electric generation transport, public authority transport, and Fort Bliss classes and a revenue decrease for commercial, public authority, industrial, CNG, commercial transport, industrial transport and CNG transport.

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.[7] 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.

[7] 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.

Q. PLEASE DESCRIBE THE THREE REVENUE ALLOCATIONS YOU CONSIDERED.

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 decreases to those classes requiring a decrease. The remaining decrease is assigned to the residential class and reduces the amount allocated 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.

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 commercial, industrial, public authority, CNG, commercial transport, industrial transport, and CNG transport, as shown by

comparing the revenue-to-cost ratio in line 1, columns (d) through (j) and column (l) to the ratio in line 15, in columns (d) through (j) and column (l).

Q. WHAT REVENUE ALLOCATION DO YOU RECOMMEND FOR THE PROPOSED RATES?

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 classes that require a decrease. 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.

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	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Costs	$ 347,226,026	$ 324,517,516	$ 19,239,537	$ 86,351	$ 1,663,055	$ 962	$ —	$ 329,760	$ 74,220	$ 321,574	$ 8,303	$ 1,105	$ 983,643
2	Demand Costs	$ 109,466,318	$ 70,138,757	$ 21,487,572	$ 511,190	$ 5,569,300	$ —	$ —	$ 3,511,998	$ 2,800,810	$ 2,648,169	$ 384,142	$ 324,509	$ 2,089,871
3	Commodity Costs	$ 2,136,950	$ 1,078,495	$ 528,560	$ 20,996	$ 87,854	$ —	$ —	$ 131,184	$ 146,429	$ 67,114	$ 29,116	$ 19,527	$ 27,673
4	Cost of Service Before Revenue Credits	$ 458,829,294	$ 395,734,768	$ 41,255,670	$ 618,538	$ 7,320,209	$ 962	$ —	$ 3,972,943	$ 3,021,458	$ 3,036,857	$ 421,561	$ 345,141	$ 3,101,187
5	Revenues Credited to Cost of Service (1)	$ 10,229,085	$ 9,262,295	$ 704,389	$ 7,773	$ 88,889	$ 11	$ —	$ 47,399	$ 36,074	$ 36,218	$ 5,017	$ 4,108	$ 36,910
6	Total Cost of Service	$ 448,600,209	$ 386,472,473	$ 40,551,280	$ 610,765	$ 7,231,321	$ 951	$ —	$ 3,925,544	$ 2,985,384	$ 3,000,639	$ 416,543	$ 341,033	$ 3,064,276
7	Revenue at Current Rates	$ 407,530,300	$ 317,492,536	$ 62,686,696	$ 2,225,175	$ 9,464,406	$ 4,533	$ —	$ 4,655,868	$ 4,778,368	$ 2,887,898	$ 658,287	$ 197,869	$ 2,478,665
8	Revenue Deficiency	$ 41,069,909	$ 68,979,937	$ (22,135,415)	$ (1,614,410)	$ (2,233,085)	$ (3,582)	$ —	$ (730,324)	$ (1,792,984)	$ 112,741	$ (241,743)	$ 143,164	$ 585,611
9	Revenue-to-Cost Ratios:													
10	Current Revenue	0.9105	0.8257	1.5365	3.6100	1.3051	4.7222	0.0000	1.1838	1.5934	0.9629	1.5734	0.5852	0.8112
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge revenue including Company recommended changes, special contract (other than Fort Bliss), irrigation, unmetered gas service, and other 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	$ 4,768,085
Special Contract	$ 4,950,541
Irrigation	$ 508,480
Unmetered Gas Service	$ 1,980
Other Revenue	$ —
	$ 10,229,085

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	$ 186,679	$ 135,677	$ 50,724	$ 278
2	302	Franchises and Consents	NONINTPLT	$ 402,970	$ 292,876	$ 109,495	$ 599
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 1,908,172	$ 1,386,845	$ 518,488	$ 2,838
4		Total Intangible Plant		$ 2,497,821	$ 1,815,397	$ 678,708	$ 3,715
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ 251,776	$ —	$ 251,776	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ 1,812,971	$ —	$ 1,812,971	$ —
9	367	Transmission Mains	DEM	$ 112,424,671	$ —	$ 112,424,671	$ —
10	368	Compression Station Equipment	DEM	$ 157,464	$ —	$ 157,464	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 24,967,021	$ —	$ 24,967,021	$ —
12	369	Odorization	COM	$ 707,150	$ —	$ —	$ 707,150
13	371	Other Equipment	DEM	$ 53,986	$ —	$ 53,986	$ —
14		Total Transmission Plant		$ 140,375,039	$ —	$ 139,667,889	$ 707,150
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 2,018,957	$ 1,201,536	$ 817,421	$ —
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ 19,533	$ 10,458	$ 9,076	$ —
19	375	Structures and Improvements	DIS376-379-ALL	$ 514,432	$ 306,153	$ 208,280	$ —
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 1,045,319,513	$ 665,916,824	$ 379,402,689	$ —
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
22	376	Odorization	COM	$ 144,153	$ —	$ —	$ 144,153
23	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
24	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 53,871,432	$ —	$ 53,871,432	$ —
25	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ 325,537	$ —	$ 325,537	$ —
26	378	Odorization Tank	COM	$ 1,103,014	$ —	$ —	$ 1,103,014
27	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 19,757,746	$ —	$ 19,757,746	$ —
28	379	Odorization	COM	$ 1,337,096	$ —	$ —	$ 1,337,096
29	380	Services - Allocated	CUS	$ 682,183,854	$ 682,183,854	$ —	$ —
30	380	Services - Directly Assigned	CUS	$ 1,524,955	$ 1,524,955	$ —	$ —
31	381	Meters - Allocated	CUS	$ 179,264,438	$ 179,264,438	$ —	$ —
32	381	Meters - Directly Assigned	CUS	$ 152,811	$ 152,811	$ —	$ —
33	382	Meter Installations	CUS	$ —	$ —	$ —	$ —
34	383	House Regulators - Allocated	CUS	$ 35,698,116	$ 35,698,116	$ —	$ —
35	383	House Regulators - Directly Assigned	CUS	$ 75,571	$ 75,571	$ —	$ —
36	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 38,880,705	$ —	$ 38,880,705	$ —
37	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ 574,172	$ —	$ 574,172	$ —
38	385	Odorization	COM	$ 51,841	$ —	$ —	$ 51,841
39	386	Other Property - Customer Premises	CUS	$ 1,707,620	$ 1,707,620	$ —	$ —

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)
40	387	Other Equipment	DIS376-379-ALL	$ —	$ —	$ —	$ —
41		Total Distribution Plant		$ 2,071,757,626	$ 1,572,088,582	$ 497,032,940	$ 2,636,104
42							
43		**General Plant**					
44	389	Land & Land Rights	GENPLT	$ 10,640,853	$ 8,182,513	$ 2,445,371	$ 12,969
45	390	Structures & Improvements	GENPLT	$ 57,253,648	$ 45,518,418	$ 11,673,319	$ 61,912
46	391	Office Furniture and Equipment	GENPLT	$ 100,750,525	$ 98,936,714	$ 1,804,241	$ 9,569
47	392	Transportation Equipment	GENPLT	$ 53,822,941	$ 40,907,992	$ 12,846,813	$ 68,135
48	393	Stores Equipment	GENPLT	$ 97,883	$ 74,276	$ 23,483	$ 125
49	394	Tools, Shop & Garage - Allocated	GENPLT	$ 33,407,511	$ 25,418,870	$ 7,946,495	$ 42,146
50	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ 11,690	$ 6,857	$ 4,833	$ —
51	394	Odorization	COM	$ 151,878	$ —	$ —	$ 151,878
52	395	CNG Equipment	GENPLT	$ —	$ —	$ —	$ —
53	396	Major Work Equipment	GENPLT	$ 8,626,236	$ 6,545,750	$ 2,069,510	$ 10,976
54	397	Communication Equipment - Allocated	GENPLT	$ 71,606,087	$ 54,558,777	$ 16,957,374	$ 89,937
55	397	Communication Equipment - Dir. Assn.	GENPLT	$ 48,893	$ 28,680	$ 20,212	$ —
56	398	Miscellaneous General Plant	GENPLT	$ 6,349	$ 4,818	$ 1,523	$ 8
57		Total General Plant		$ 336,424,493	$ 280,183,664	$ 55,793,175	$ 447,655
58							
59		Total Plant in Service		$ 2,551,054,979	$ 1,854,087,642	$ 693,172,712	$ 3,794,624
60							
61		**Depreciation & Amortization Reserve**					
62	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (1,803,478)	$ (1,409,488)	$ (392,042)	$ (1,948)
63	325-371	Transmission Plant	DEM	$ (9,635,404)	$ —	$ (9,635,404)	$ —
64	369	Odorization	COM	$ (70,589)	$ —	$ —	$ (70,589)
65	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (361,205,079)	$ (282,295,641)	$ (78,519,194)	$ (390,244)
66	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ (8,660)	$ (4,636)	$ (4,023)	$ —
67	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ (697,875)	$ (390,448)	$ (307,426)	$ —
68	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ (44,709)	$ —	$ (44,709)	$ —
69	380	Services - Directly Assigned	CUS	$ (160,974)	$ (160,974)	$ —	$ —
70	381	Meters - Directly Assigned	CUS	$ (39,495)	$ (39,495)	$ —	$ —
71	383	House Regulators - Directly Assigned	CUS	$ (15,367)	$ (15,367)	$ —	$ —
72	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
73	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (123,017,392)	$ (105,219,590)	$ (17,675,252)	$ (122,550)
74	389-398	General Plant - Directly Assigned	GEN-DARES	$ (31,792)	$ (18,649)	$ (13,143)	$ —
75		Total Depreciation & Amortization Reserve		$ (496,730,814)	$ (389,554,288)	$ (106,591,194)	$ (585,332)
76							
77		Net Plant in Service		$ 2,054,324,164	$ 1,464,533,354	$ 586,581,518	$ 3,209,292
78							

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)
79		Customer Deposits	CUS	$ (16,329,640)	$ (16,329,640)	$ —	$ —
80							
81		Customer Advances	MAINS/SVCS	$ (6,534,399)	$ (5,094,531)	$ (1,439,868)	$ —
82							
83		Accumulated Deferred Income Taxes	TOTPLT	$ (184,129,691)	$ (133,824,080)	$ (50,031,724)	$ (273,888)
84							
85		Excess Deferred Income Taxes	TOTPLT	$ (27,872,376)	$ (20,257,434)	$ (7,573,483)	$ (41,459)
86							
87		Negative Acquisition Adjustment on OPC Assets	MAINS-ALLOC	$ (1,949,023)	$ (1,241,617)	$ (707,405)	$ —
88							
89		Materials and Supplies	TOTPLT	$ 26,639,992	$ 19,361,746	$ 7,238,619	$ 39,626
90							
91		Prepayments	OPEXP	$ 11,080,303	$ 8,807,394	$ 2,155,797	$ 117,112
92							
93		Pension & FAS 106 Regulatory Asset	OPEXP	$ 38,210,431	$ 30,372,303	$ 7,434,266	$ 403,862
94							
95		DIMP Deferrals	OPEXP	$ 4,757,745	$ 3,781,786	$ 925,672	$ 50,287
96							
97		Regulatory Assets	OPEXP	$ 2,118,256	$ 1,683,737	$ 412,130	$ 22,389
98							
99		Cash Working Capital	OPEXP	$ (13,403,426)	$ (10,653,973)	$ (2,607,786)	$ (141,666)
100							
101		Total Rate Base		$ 1,886,912,337	$ 1,341,139,045	$ 542,387,737	$ 3,385,554

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	814-865	Transmission Expenses	DEM	$ 9,124,268	$ —	$ 9,124,268	$ —
3	8650	Odorization	COM	$ 2,471	$ —	$ —	$ 2,471.13
4	8700	Operation Supervision & Engineering	DIS871-879	$ 2,734,374	$ 2,296,831	$ 389,559	$ 47,984
5	8710	Distribution Load Dispatch	COM	$ 585,292	$ —	$ —	$ 585,292
6	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 15,691,623	$ 12,245,352	$ 3,446,270	$ —
7	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ 79,312	$ 50,458	$ 28,854	$ —
8	8740	Odorization	COM	$ (45,825)	$ —	$ —	$ (45,825)
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 1,078,584	$ —	$ 1,078,584	$ —
10	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ 8,173	$ —	$ 8,173	$ —
11	8750	Odorization	COM	$ 273,994	$ —	$ —	$ 273,994
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 89,782	$ —	$ 89,782	$ —
13	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ 1,326	$ —	$ 1,326	$ —
14	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 98,743	$ —	$ 98,743	$ —
15	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 15,692,849	$ 15,692,849	$ —	$ —
16	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ 16,673	$ 16,673	$ —	$ —
17	8780	Odorization	COM	$ 81	$ —	$ —	$ 81
18	8790	Customer Installation Expenses	CUS	$ 10,745	$ 10,745	$ —	$ —
19	8800	Other Expenses	DIS871-879	$ 3,288,333	$ 2,762,147	$ 468,481	$ 57,705
20	8800	Odorization	COM	$ 1,505	$ —	$ —	$ 1,505
21	8810	Rents	DIS871-879	$ 117,124	$ 98,383	$ 16,686	$ 2,055
22	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
23		Total Transmission & Distribution Oper. Exp.		$ 48,849,427	$ 33,173,437	$ 14,750,728	$ 925,262
24							
25		**Distribution Maintenance Expenses**					
26	8850	Maintenance Supervision and Engineering	DIS887-893	$ 18,992	$ 10,488	$ 8,504	$ —
27	8860	Structures and Improvements	DIS887-893	$ 2,374,207	$ 1,311,078	$ 1,063,129	$ —
28	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 8,461,317	$ 5,390,250	$ 3,071,067	$ —
29	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ 58,540	$ 32,752	$ 25,788	$ —
30	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 2,784,748	$ —	$ 2,784,748	$ —
31	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ 18,902	$ —	$ 18,902	$ —
32	8890	Odorization	COM	$ 343,209	$ —	$ —	$ 343,209
33	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 1,536,947	$ —	$ 1,536,947	$ —
34	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ 22,697	$ —	$ 22,697	$ —
35	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 69,264	$ —	$ 69,264	$ —
36	8910	Odorization	COM	$ 100	$ —	$ —	$ 100
37	8920	Maintenance of Services - Allocated	CUS	$ 3,825,896	$ 3,825,896	$ —	$ —
38	8920	Maintenance of Services - Directly Assn.	CUS	$ 8,552	$ 8,552	$ —	$ —

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)
39	8930	Main. of Meters & House Reg. - Allocated	CUS	$ 27,992	$ 27,992	$ —	$ —
40	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ 30	$ 30	$ —	$ —
41	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
42	8950	Clearing - Meter Shop - Small Meters	CUS	$ —	$ —	$ —	$ —
43	8960	Clearing - Meter Shop - Large Meters	CUS	$ —	$ —	$ —	$ —
44		Total Distribution Maintenance Expenses		$ 19,551,393	$ 10,607,039	$ 8,601,046	$ 343,309
45							
46		Total Operations & Maintenance Expenses		$ 68,400,820	$ 43,780,476	$ 23,351,773	$ 1,268,571
47							
48		**Customer Accounting Expenses**					
49	9010	Supervision	CUS	$ 645	$ 645	$ —	$ —
50	9020	Meter Reading Expense	CUS	$ 1,423,705	$ 1,423,705	$ —	$ —
51	9030	Customer Accounting	CUS	$ 11,808,882	$ 11,808,882	$ —	$ —
52	9040	Bad Debts (includes gross up)	CUS	$ 3,374,231	$ 3,374,231	$ —	$ —
53	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 869,396	$ 869,396	$ —	$ —
54		Total Customer Accounts Expenses		$ 17,476,858	$ 17,476,858	$ —	$ —
55							
56		**Customer Information Expenses**					
57	9070	Supervision	CUS	$ —	$ —	$ —	$ —
58	9080	Customer Assistance	CUS	$ 2,348,730	$ 2,348,730	$ —	$ —
59	9090	Informational and Instructional Advertising	CUS	$ 160,487	$ 160,487	$ —	$ —
60	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —
61		Total Customer Information Expenses		$ 2,509,218	$ 2,509,218	$ —	$ —
62							
63		**Sales and Advertising Expenses**					
64	9110	Supervision	CUS	$ —	$ —	$ —	$ —
65	9120	Demonstrating and Selling	CUS	$ 1,630	$ 1,630	$ —	$ —
66	9130	Advertising	CUS	$ 191,835	$ 191,835	$ —	$ —
67	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —
68	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —
69		Total Sales and Advertising Expenses		$ 193,465	$ 193,465	$ —	$ —
70							
71		**Administrative & General Expenses**					
72	920-940	Administrative & General Expenses	ADMINGEN	$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
73		Total Administrative & General Expenses		$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
74							
75		**Depreciation and Amortization Expense**					
76	301-303	Intangible Plant - Allocated	PLT301-03	$ 87,330	$ 63,471	$ 23,729	$ 130
77	301-303	Intangible Plant - Directly Assigned	PLT301-03	$ —	$ —	$ —	$ —
78	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —

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)
79	366	Meas. and Reg. Station Structures	PLT366	$ 49,857	$ —	$ 49,857	$ —
80	367	Transmission Mains	PLT367	$ 3,282,834	$ —	$ 3,282,834	$ —
81	368	Compression Station Equipment	PLT368	$ 3,937	$ —	$ 3,937	$ —
82	369	Measuring and Reg. Station Equipment	PLT369	$ 890,894	$ —	$ 890,894	$ —
83	371	Other Equipment	PLT371	$ 2,818	$ —	$ 2,818	$ —
84	375	Structures and Improvements	PLT375	$ 19,226	$ 11,442	$ 7,784	$ —
85	376	Mains - Allocated	MAINS-ALLOC	$ 28,937,751	$ 18,434,684	$ 10,503,067	$ —
86	376	Mains - Directly Assigned	MAINS-DA	$ 184,979	$ 103,492	$ 81,487	$ —
87	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
88	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 1,415,814	$ —	$ 1,415,814	$ —
89	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ 7,213	$ —	$ 7,213	$ —
90	378	Odorization	COM	$ 10,130	$ —	$ —	$ 10,130
91	379	Meas. & Reg. Sta. Equipment - City Gate - Alloc.	PLT379	$ 459,933	$ —	$ 459,933	$ —
92	379	Meas. & Reg. Sta. Equipment - City Gate - Dir. Assn.	PLT379	$ —	$ —	$ —	$ —
93	379	Odorization	COM	$ —	$ —	$ —	$ —
94	380	Services - Allocated	PLT380	$ 25,906,053	$ 25,906,053	$ —	$ —
95	380	Services - Directly Assigned	PLT380	$ 56,728	$ 56,728	$ —	$ —
96	381	Meters - Allocated	PLT381	$ 7,349,631	$ 7,349,631	$ —	$ —
97	381	Meters - Directly Assigned	PLT381	$ 7,213	$ 7,213	$ —	$ —
98	382	Meter Installations	PLT382	$ —	$ —	$ —	$ —
99	383	House Regulators - Allocated	PLT383	$ 1,510,038	$ 1,510,038	$ —	$ —
100	383	House Regulators - Directly Assigned	PLT383	$ 3,363	$ 3,363	$ —	$ —
101	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 940,499	$ —	$ 940,499	$ —
102	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ —	$ —	$ —	$ —
103	386	Other Property - Customer Premises	PLT386	$ 355,527	$ 355,527	$ —	$ —
104	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —
105	389-398	General Plant - Allocated	GENDEP	$ 17,598,856	$ 15,397,496	$ 2,179,682	$ 21,678
106	389-398	General Plant - Directly Assigned	GENDEP	$ 2,481	$ 2,171	$ 307	$ 3
107	389-398	General Plant - Odorization	COM	$ 10,130	$ —	$ —	$ 10,130
108	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ (733,323)	$ (582,896)	$ (142,676)	$ (7,751)
109		Total Depreciation and Amortization Expense		$ 88,359,910	$ 68,618,412	$ 19,707,177	$ 34,321
110							
111		**Taxes Other Than Income**					
112	4080	Payroll and Other	OPEXP	$ 6,430,224	$ 5,111,189	$ 1,251,072	$ 67,964
113	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 19,394,025	$ 14,106,095	$ 5,258,969	$ 28,961
114	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ 76,057	$ 44,614	$ 31,442	$ —
115	4080	Revenue Related (includes gross up)	CUS	$ 329,692	$ 329,692	$ —	$ —
116		Total Taxes Other Than Income		$ 26,229,998	$ 19,591,590	$ 6,541,483	$ 96,925
117							
118	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ (9,917)	$ (5,769)	$ (4,148)	$ —
119	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (2,262,121)	$ (1,613,973)	$ (644,598)	$ (3,549)

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)
120							
121	4310	Interest on Customer Deposits	CUS	$ 824,647	$ 824,647	$ —	$ —
122							
123		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 150,598,327	$ 107,448,563	$ 42,913,466	$ 236,298
124		Required Return - Directly Assigned	RB-DA	$ 660,191	$ 384,051	$ 276,140	$ —
125		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 31,175,742	$ 22,243,200	$ 8,883,626	$ 48,917
126		Income Taxes - Directly Assigned	RB-DA	$ 136,668	$ 79,503	$ 57,164	$ —
127		Total Cost of Service Before Revenue Credits		$ 458,829,294	$ 347,226,026	$ 109,466,318	$ 2,136,950

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	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			Total Transmission Plant	$ 140,375,039	$ —	$ 139,667,889	$ 707,150
8			Total Distribution Plant	$ 2,071,757,626	$ 1,572,088,582	$ 497,032,940	$ 2,636,104
9			Total General Plant	$ 336,424,493	$ 280,183,664	$ 55,793,175	$ 447,655
10			Total Non-Intangible Plant	$ 2,548,557,158	$ 1,852,272,245	$ 692,494,004	$ 3,790,909
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.72679	0.27172	0.00149
12							
13	376		Distribution Mains-Allocated	$ 1,045,319,513	$ 665,916,824	$ 379,402,689	$ —
14	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 53,871,432	$ —	$ 53,871,432	$ —
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 19,757,746	$ —	$ 19,757,746	$ —
17			Total Accounts 376-379	$ 1,118,948,691	$ 665,916,824	$ 453,031,867	$ —
18		DIS376-379-ALL	Accounts 376-379 Allocated Factor	1.00000	0.59513	0.40487	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ 325,537	$ —	$ 325,537	$ —
22			Total Accounts 376-379 Directly Assigned	$ 7,557,666	$ 4,046,246	$ 3,511,420	$ —
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	1.00000	0.53538	0.46462	0.00000
24							
25	376		Mains-Allocated	$ 1,045,319,513	$ 665,916,824	$ 379,402,689	$ —
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.63705	0.36295	0.00000
27							
28	376		Mains-Directly Assigned	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.55948	0.44052	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ 8,757,084	$ 5,571,201	$ 3,185,884	$ —
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	1.00000	0.63619	0.36381	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 1,727,503,367	$ 1,348,100,678	$ 379,402,689	$ —
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.78038	0.21962	0.00000
36							
37	376/380		Mains and Services	$ 1,736,260,452	$ 1,353,671,879	$ 382,588,573	$ —
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.77965	0.22035	0.00000
39							
40	374-387		Total Distribution Plant	$ 2,071,757,626	$ 1,572,088,582	$ 497,032,940	$ 2,636,104

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
41		DISPLT	Distribution Plant Factor	1.00000	0.75882	0.23991	0.00127
42							
43	374		Land & Land Rights - Directly Assigned	$ 19,533	$ 10,458	$ 9,076	$ —
44	376		Mains - Directly Assigned	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ 325,537	$ —	$ 325,537	$ —
46	380		Service - Directly Assigned	$ 1,524,955	$ 1,524,955	$ —	$ —
47	381		Meters - Directly Assigned	$ 152,811	$ 152,811	$ —	$ —
48	383		House Regulators - Directly Assigned	$ 75,571	$ 75,571	$ —	$ —
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ 574,172	$ —	$ 574,172	$ —
50			Total Distribution Plant - Directly Assigned	$ 9,904,708	$ 5,810,040	$ 4,094,668	$ —
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	1.00000	0.58659	0.41341	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (94,703)	$ (56,360)	$ (38,343)	$ —
54	375		Structures and Improvements	$ (335,608)	$ (199,729)	$ (135,878)	$ —
55	376		Distribution Mains - Allocated	$ (172,170,008)	$ (109,680,250)	$ (62,489,759)	$ —
56	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (5,542,020)	$ —	$ (5,542,020)	$ —
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (2,085,232)	$ —	$ (2,085,232)	$ —
59	378-379		Odorization Tank	$ (390,202)	$ —	$ —	$ (390,202)
60	380		Services - Allocated	$ (112,646,444)	$ (112,646,444)	$ —	$ —
61	381		Meters - Allocated	$ (47,294,132)	$ (47,294,132)	$ —	$ —
62	382		Meter Installations	$ (126,749)	$ (126,749)	$ —	$ —
63	383		House Regulators - Allocated	$ (11,583,951)	$ (11,583,951)	$ —	$ —
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (7,758,786)	$ —	$ (7,758,786)	$ —
65	386		Other Property-Customer Premises	$ (1,137,465)	$ (676,937)	$ (460,529)	$ —
66	387		Other Equipment	$ —	$ —	$ —	$ —
67			Total Distribution Plant - Allocated Reserve	$ (361,165,300)	$ (282,264,552)	$ (78,510,546)	$ (390,202)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.78154	0.21738	0.00108
69							
70	376		Distribution Mains - Directly Assigned	$ (697,875)	$ (390,448)	$ (307,426)	$ —
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	1.00000	0.55948	0.44052	0.00000
72							
73			General Plant - Allocated Reserve	$ (123,017,392)	$ (105,219,590)	$ (17,675,252)	$ (122,550)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.85532	0.14368	0.00100
75							
76			General Plant - Directly Assigned Reserve	$ (31,792)	$ (18,649)	$ (13,143)	$ —
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	1.00000	0.58659	0.41341	0.00000
78							
79			Total Plant - Allocated	$ 2,541,089,688	$ 1,848,242,065	$ 689,052,999	$ 3,794,624
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.72734	0.27116	0.00149

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
81							
82			Total Plant - Directly Assigned	$ 9,965,290	$ 5,845,578	$ 4,119,713	$ —
83		TPLT-DA	Total Plant Directly Assigned Factor	$ 1.00000	$ 0.58659	$ 0.41341	$ —
84							
85			Total Plant	$ 2,551,054,979	$ 1,854,087,642	$ 693,172,712	$ 3,794,624
86		TOTPLT	Total Plant Factor	1.00000	0.72679	0.27172	0.00149
87							
88			Total Operations and Maintenance Expenses	$ 68,400,820	$ 43,780,476	$ 23,351,773	$ 1,268,571
89			Total Customer Accounts Expenses	$ 17,476,858	$ 17,476,858	$ —	$ —
90			Total Customer Information Expenses	$ 2,509,218	$ 2,509,218	$ —	$ —
91			Total Sales and Advertising Expenses	$ 193,465	$ 193,465	$ —	$ —
92			Administrative and General Expenses	$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
93			Total Operating Expenses	$ 163,115,848	$ 129,655,800	$ 31,736,009	$ 1,724,039
94		OPEXP	Operating Expense Factor	1.00000	0.79487	0.19456	0.01057
95							
96	8710		Distribution Load Dispatch	$ 585,292	$ —	$ —	$ 585,292
97	8740		Mains and Services Expenses - Allocated	$ 15,691,623	$ 12,245,352	$ 3,446,270	$ —
98	8740		Mains and Services Expenses - Dir. Assn.	$ 79,312	$ 50,458	$ 28,854	$ —
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 1,078,584	$ —	$ 1,078,584	$ —
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ 8,173	$ —	$ 8,173	$ —
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 89,782	$ —	$ 89,782	$ —
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ 1,326	$ —	$ 1,326	$ —
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 98,743	$ —	$ 98,743	$ —
104	8780		Meter and House Regulator Exp.- Allocated	$ 15,692,849	$ 15,692,849	$ —	$ —
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ 16,673	$ 16,673	$ —	$ —
106	8790		Customer Installation Expenses	$ 10,745	$ 10,745	$ —	$ —
107			Total Accounts 871-879	$ 33,353,101	$ 28,016,076	$ 4,751,733	$ 585,292
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.83998	0.14247	0.01755
109							
110	8870		Maintenance of Mains-Allocated	$ 8,461,317	$ 5,390,250	$ 3,071,067	$ —
111	8870		Maintenance of Mains - Directly Assn.	$ 58,540	$ 32,752	$ 25,788	$ —
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 2,784,748	$ —	$ 2,784,748	$ —
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ 18,902	$ —	$ 18,902	$ —
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 1,536,947	$ —	$ 1,536,947	$ —
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ 22,697	$ —	$ 22,697	$ —
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 69,264	$ —	$ 69,264	$ —
117	8920		Maintenance of Services - Allocated	$ 3,825,896	$ 3,825,896	$ —	$ —
118	8920		Maintenance of Services - Directly Assn.	$ 8,552	$ 8,552	$ —	$ —
119	8930		Main. of Meters & House Reg. - Allocated	$ 27,992	$ 27,992	$ —	$ —
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ 30	$ 30	$ —	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
121			Total Accounts 887-893	$ 16,814,886	$ 9,285,473	$ 7,529,413	$ —
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.55222	0.44778	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 68,400,820	$ 43,780,476	$ 23,351,773	$ 1,268,571
125			Total Customer Accounts Expenses	$ 17,476,858	$ 17,476,858	$ —	$ —
126			Total Customer Service Expenses	$ 2,509,218	$ 2,509,218	$ —	$ —
127			Total Sales and Advertising Expenses	$ 193,465	$ 193,465	$ —	$ —
128			Total Operating Exp. Without A&G Expenses	$ 88,580,361	$ 63,960,017	$ 23,351,773	$ 1,268,571
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.72206	0.26362	0.01432
130							
131	920-932		Administrative and General Expenses	$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.88140	0.11249	0.00611
133							
134	366		Meas. and Reg. Station Structures	$ 1,812,971	$ —	$ 1,812,971	$ —
135		PLT366	Measuring and Reg. Station Structures Factor	1.00000	0.00000	1.00000	0.00000
136							
137	367		Transmission Mains	$ 112,424,671	$ —	$ 112,424,671	$ —
138		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
139							
140	368		Compression Station Equipment	$ 157,464	$ —	$ 157,464	$ —
141		PLT368	Compression Station Equipment Factor	0.00000	0.00000	1.00000	0.00000
142							
143	369		Measuring and Reg. Station Equipment	$ 24,967,021	$ —	$ 24,967,021	$ —
144		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
145							
146	371		Other Equipment	$ 53,986	$ —	$ 53,986	$ —
147		PLT371	Other Equipment Factor	1.00000	0.00000	1.00000	0.00000
148							
149	375		Structures and Improvements	$ 514,432	$ 306,153	$ 208,280	$ —
150		PLT375	Structures and Improvements Factor	1.00000	0.59513	0.40487	0.00000
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 53,871,432	$ —	$ 53,871,432	$ —
153		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
154							
155	379		Meas. & Reg. Sta. Equip.- City Gate	$ 19,757,746	$ —	$ 19,757,746	$ —
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services - Allocated	$ 682,183,854	$ 682,183,854	$ —	$ —
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters - Allocated	$ 179,264,438	$ 179,264,438	$ —	$ —
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
163							
164	382		Meter Installations	$ —	$ —	$ —	$ —
165		PLT382	Meter Installations Factor	—	0.00000	0.00000	0.00000
166							
167	383		House Regulators - Allocated	$ 35,698,116	$ 35,698,116	$ —	$ —
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 38,880,705	$ —	$ 38,880,705	$ —
171		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
172							
173	386		Other Property - Customer Premises	$ 1,707,620	$ 1,707,620	$ —	$ —
174		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
175							
176	387		Other Equipment	$ —	$ —	$ —	$ —
177		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
178							
179	301-303		Intangible Plant	$ 2,497,821	$ 1,815,397	$ 678,708	$ 3,715
180		PLT301-03	Intangible Plant	1.00000	0.72679	0.27172	0.00149
181							
182	389-398		General Plant Depreciation Expense	$ 17,611,467	$ 15,408,530	$ 2,181,244	$ 21,693
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.87491	0.12385	0.00123
184							
185			Net Plant Directly Assigned	$ 8,966,419	$ 5,216,008	$ 3,750,411	$ —
186		NETPLT-DA	Net Plant Directly Assigned Factor	1.00000	0.58173	0.41827	0.00000
187							
188			Net Plant Allocated	$ 2,045,357,745	$ 1,459,317,346	$ 582,831,107	$ 3,209,292
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.71348	0.28495	0.00157
190							
191			Rate Base Directly Assigned	$ 8,235,724	$ 4,790,943	$ 3,444,781	$ —
192		RB-DA	Rate Base Directly Assigned Factor	1.00000	0.58173	0.41827	0.00000
193							
194			Rate Base Allocated	$ 1,878,676,612	$ 1,340,394,058	$ 535,334,795	$ 2,947,759
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.71348	0.28495	0.00157
196							
197			Required Return	$ 151,258,518	$ 107,832,614	$ 43,189,606	$ 236,298
198		REQRET	Required Return Factor	1.00000	0.71290	0.28554	0.00156
199							
200			Non-Plant Rate Base	$ (167,411,828)	$ (123,394,309)	$ (44,193,781)	$ 176,262
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.73707	0.26398	-0.00105

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	301-303	**Intangible Plant**							
2		Customer	NONINCUS	$ 1,815,397	$ 1,717,061	$ 88,586	$ 236	$ 7,029	$ 3
3		Demand	NONINDEM	$ 678,708	$ 452,400	$ 125,632	$ 2,989	$ 32,562	$ —
4		Commodity	COM	$ 3,715	$ 1,875	$ 919	$ 37	$ 153	$ —
5		Total Intangible Plant		$ 2,497,821	$ 2,171,336	$ 215,137	$ 3,261	$ 39,744	$ 3
6	365-371	**Transmission Plant**							
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 139,667,889	$ 93,097,051	$ 25,853,282	$ 615,050	$ 6,700,835	$ —
9		Commodity	COM	$ 707,150	$ 356,891	$ 174,909	$ 6,948	$ 29,072	$ —
10		Total Transmission Plant		$ 140,375,039	$ 93,453,942	$ 26,028,191	$ 621,998	$ 6,729,908	$ —
11		**Distribution Plant**							
12	374	**Land & Land Rights - Allocated**							
13		Customer	376-379CUS	$ 1,201,536	$ 1,129,588	$ 58,277	$ 155	$ 4,624	$ 2
14		Demand	DEM	$ 817,421	$ 544,860	$ 151,309	$ 3,600	$ 39,217	$ —
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 2,018,957	$ 1,674,448	$ 209,586	$ 3,755	$ 43,841	$ 2
17	374	**Land & Land Rights - DA**							
18		Customer	CUS-DA	$ 10,458	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM-DA	$ 9,076	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ 19,533	$ —	$ —	$ —	$ —	$ —
22	375	**Structures and Improvements**							
23		Customer	376-379CUS	$ 306,153	$ 287,820	$ 14,849	$ 39	$ 1,178	$ 0
24		Demand	DEM	$ 208,280	$ 138,831	$ 38,554	$ 917	$ 9,993	$ —
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 514,432	$ 426,651	$ 53,403	$ 957	$ 11,171	$ 0
27	376	**Distribution Mains-Allocated**							
28		Customer	CUS	$ 665,916,824	$ 629,845,609	$ 32,494,688	$ 86,433	$ 2,578,333	$ 945
29		Demand	DEM	$ 379,402,689	$ 252,894,719	$ 70,229,490	$ 1,670,762	$ 18,202,572	$ —
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 1,045,319,513	$ 882,740,328	$ 102,724,179	$ 1,757,195	$ 20,780,905	$ 945
32	376	**Odorization**							
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ 144,153	$ 72,753	$ 35,655	$ 1,416	$ 5,926	$ —
36		Total Odorization		$ 144,153	$ 72,753	$ 35,655	$ 1,416	$ 5,926	$ —
37		**Distribution Mains - Directly Assn.**							
38		Customer	CUS-DA	$ 4,046,246	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM-DA	$ 3,185,884	$ —	$ —	$ —	$ —	$ —
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ 7,232,130	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
42	377	**Compressor Station Equipment**							
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**							
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 53,871,432	$ 35,908,551	$ 9,971,894	$ 237,232	$ 2,584,585	$ —
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 53,871,432	$ 35,908,551	$ 9,971,894	$ 237,232	$ 2,584,585	$ —
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**							
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ 325,537	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 325,537	$ —	$ —	$ —	$ —	$ —
57	378	**Odorization**							
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 1,103,014	$ 556,680	$ 272,824	$ 10,838	$ 45,347	$ —
61		Total Odorization		$ 1,103,014	$ 556,680	$ 272,824	$ 10,838	$ 45,347	$ —
62	379	**Meas. & Reg. Station - City Gate**							
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 19,757,746	$ 13,169,726	$ 3,657,266	$ 87,006	$ 947,916	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 19,757,746	$ 13,169,726	$ 3,657,266	$ 87,006	$ 947,916	$ —
67	379	**Odorization**							
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 1,337,096	$ 674,818	$ 330,722	$ 13,137	$ 54,971	$ —
71		Total Odorization		$ 1,337,096	$ 674,818	$ 330,722	$ 13,137	$ 54,971	$ —
72	380	**Services - Allocated**							
73		Customer	SERCUS-ALL	$ 682,183,854	$ 639,603,935	$ 38,061,699	$ 123,174	$ 3,028,852	$ 1,110
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 682,183,854	$ 639,603,935	$ 38,061,699	$ 123,174	$ 3,028,852	$ 1,110
77	380	**Services-Directly Assigned**							
78		Customer	CUS-DA	$ 1,524,955	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ 1,524,955	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
82	381	**Meters - Allocated**							
83		Customer	METCUS-ALL	$ 179,264,438	$ 162,975,157	$ 13,618,098	$ 94,279	$ 1,673,901	$ 1,518
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 179,264,438	$ 162,975,157	$ 13,618,098	$ 94,279	$ 1,673,901	$ 1,518
87	381	**Meters-Directly Assigned**							
88		Customer	CUS-DA	$ 152,811	$ —	$ —	$ —	$ —	$ —
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ 152,811	$ —	$ —	$ —	$ —	$ —
92	382	**Meter Installations**							
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**							
98		Customer	REGCUS-ALL	$ 35,698,116	$ 30,642,573	$ 3,793,501	$ 48,556	$ 744,024	$ 1,004
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 35,698,116	$ 30,642,573	$ 3,793,501	$ 48,556	$ 744,024	$ 1,004
102	383	**House Regulators - Directly Assigned**							
103		Customer	CUS-DA	$ 75,571	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ 75,571	$ —	$ —	$ —	$ —	$ —
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**							
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 38,880,705	$ —	$ 21,584,190	$ 513,489	$ 5,594,342	$ —
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 38,880,705	$ —	$ 21,584,190	$ 513,489	$ 5,594,342	$ —
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**							
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ 574,172	$ —	$ —	$ —	$ —	$ —
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ 574,172	$ —	$ —	$ —	$ —	$ —
117	385	**Odorization**							
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ 51,841	$ 26,164	$ 12,823	$ 509	$ 2,131	$ —
121		Total Odorization		$ 51,841	$ 26,164	$ 12,823	$ 509	$ 2,131	$ —
122	386	**Other Prop.-Customer Premises**							
123		Customer	CUS	$ 1,707,620	$ 1,615,122	$ 83,327	$ 222	$ 6,612	$ 2
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 1,707,620	$ 1,615,122	$ 83,327	$ 222	$ 6,612	$ 2

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
127	387	**Other Equipment**							
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**							
133		Customer		$ 1,572,088,582	$ 1,466,099,805	$ 88,124,439	$ 352,858	$ 8,037,523	$ 4,581
134		Demand		$ 497,032,940	$ 302,656,687	$ 105,632,702	$ 2,513,006	$ 27,378,625	$ —
135		Commodity		$ 2,636,104	$ 1,330,414	$ 652,024	$ 25,901	$ 108,376	$ —
136		Total Distribution Plant		$ 2,071,757,626	$ 1,770,086,906	$ 194,409,165	$ 2,891,765	$ 35,524,524	$ 4,581
137		**General Plant**							
138		**General Plant - Allocated**							
139		Customer	GENPTCUS	$ 280,148,126	$ 263,261,462	$ 14,607,972	$ 48,589	$ 1,244,964	$ 591
140		Demand	DISPLTDEM	$ 55,768,130	$ 33,958,710	$ 11,852,209	$ 281,964	$ 3,071,939	$ —
141		Commodity	COM	$ 447,655	$ 225,927	$ 110,725	$ 4,398	$ 18,404	$ —
142		Total General Plant - Allocated		$ 336,363,911	$ 297,446,099	$ 26,570,906	$ 334,952	$ 4,335,307	$ 591
143		**Total General Plant - Directly Assigned**							
144		Customer	CUS-DA	$ 35,537	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM-DA	$ 25,045	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ 60,583	$ —	$ —	$ —	$ —	$ —
148		**Total General Plant**							
149		Customer		$ 280,183,664	$ 263,261,462	$ 14,607,972	$ 48,589	$ 1,244,964	$ 591
150		Demand		$ 55,793,175	$ 33,958,710	$ 11,852,209	$ 281,964	$ 3,071,939	$ —
151		Commodity		$ 447,655	$ 225,927	$ 110,725	$ 4,398	$ 18,404	$ —
152		Total General Plant		$ 336,424,493	$ 297,446,099	$ 26,570,906	$ 334,952	$ 4,335,307	$ 591
153		**Total Plant in Service**							
154		Customer		$ 1,854,087,642	$ 1,731,078,328	$ 102,820,997	$ 401,683	$ 9,289,516	$ 5,175
155		Demand		$ 693,172,712	$ 430,164,848	$ 143,463,826	$ 3,413,009	$ 37,183,962	$ —
156		Commodity		$ 3,794,624	$ 1,915,107	$ 938,576	$ 37,284	$ 156,005	$ —
157		Total Plant in Service		$ 2,551,054,979	$ 2,163,158,283	$ 247,223,399	$ 3,851,976	$ 46,629,483	$ 5,175
158		**Depreciation & Amort. Reserve**							
159		**Intangible Plant**							
160		Customer	NONINCUS	$ (1,409,488)	$ (1,333,139)	$ (68,779)	$ (183)	$ (5,457)	$ (2)
161		Demand	NONINDEM	$ (392,042)	$ (261,320)	$ (72,569)	$ (1,726)	$ (18,809)	$ —
162		Commodity	COM	$ (1,948)	$ (983)	$ (482)	$ (19)	$ (80)	$ —
163		Total Intangible Plant		$ (1,803,478)	$ (1,595,442)	$ (141,830)	$ (1,929)	$ (24,346)	$ (2)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
164		**Transmission Plant**							
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (9,635,404)	$ (6,422,577)	$ (1,783,565)	$ (42,431)	$ (462,277)	$ —
167		Commodity	COM	$ (70,589)	$ (35,626)	$ (17,460)	$ (694)	$ (2,902)	$ —
168		Total Transmission Plant		$ (9,705,994)	$ (6,458,202)	$ (1,801,025)	$ (43,125)	$ (465,179)	$ —
169		**Distribution Plant - Allocated**							
170		Customer	DISPLTCUS	$ (282,295,641)	$ (263,263,527)	$ (15,824,264)	$ (63,362)	$ (1,443,276)	$ (823)
171		Demand	DISPLTDEM	$ (78,519,194)	$ (47,812,443)	$ (16,687,414)	$ (396,994)	$ (4,325,161)	$ —
172		Commodity	COM	$ (390,244)	$ (196,952)	$ (96,525)	$ (3,834)	$ (16,044)	$ —
173		Total Distribution Plant - Allocated		$ (361,205,079)	$ (311,272,922)	$ (32,608,203)	$ (464,190)	$ (5,784,481)	$ (823)
174		**Distribution Plant - Dir. Assn.**							
175		Customer	CUS-DA	$ (610,921)	$ —	$ —	$ —	$ —	$ —
176		Demand	DEM-DA	$ (356,159)	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ (967,079)	$ —	$ —	$ —	$ —	$ —
179		**General Plant - Allocated**							
180		Customer	GENPTCUS	$ (105,219,590)	$ (98,877,203)	$ (5,486,543)	$ (18,249)	$ (467,591)	$ (222)
181		Demand	DISPLTDEM	$ (17,675,252)	$ (10,762,935)	$ (3,756,461)	$ (89,366)	$ (973,626)	$ —
182		Commodity	COM	$ (122,550)	$ (61,850)	$ (30,312)	$ (1,204)	$ (5,038)	$ —
183		Total General Plant - Allocated		$ (123,017,392)	$ (109,701,987)	$ (9,273,316)	$ (108,820)	$ (1,446,255)	$ (222)
184		**General Plant - Directly Assigned**							
185		Customer	CUS-DA	$ (18,649)	$ —	$ —	$ —	$ —	$ —
186		Demand	DEM-DA	$ (13,143)	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ (31,792)	$ —	$ —	$ —	$ —	$ —
189		**Total Depr. & Amort. Reserve**							
190		Customer		$ (389,554,288)	$ (363,473,869)	$ (21,379,586)	$ (81,794)	$ (1,916,324)	$ (1,047)
191		Demand		$ (106,591,194)	$ (65,259,274)	$ (22,300,009)	$ (530,518)	$ (5,779,873)	$ —
192		Commodity		$ (585,332)	$ (295,411)	$ (144,778)	$ (5,751)	$ (24,064)	$ —
193		Total Depr. & Amortization Reserve		$ (496,730,814)	$ (429,028,554)	$ (43,824,374)	$ (618,063)	$ (7,720,261)	$ (1,047)
194		**Net Plant in Service**							
195		Customer		$ 1,464,533,354	$ 1,367,604,460	$ 81,441,411	$ 319,889	$ 7,373,192	$ 4,128
196		Demand		$ 586,581,518	$ 364,905,574	$ 121,163,816	$ 2,882,491	$ 31,404,088	$ —
197		Commodity		$ 3,209,292	$ 1,619,696	$ 793,798	$ 31,532	$ 131,941	$ —
198		Total Net Plant in Service		$ 2,054,324,164	$ 1,734,129,729	$ 203,399,026	$ 3,233,913	$ 38,909,221	$ 4,128
199		**Customer Deposits**							
200		Customer	DEPCUS	$ (16,329,640)	$ (7,757,745)	$ (8,199,802)	$ (103,027)	$ (84,295)	$ —
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (16,329,640)	$ (7,757,745)	$ (8,199,802)	$ (103,027)	$ (84,295)	$ —
204		**Customer Advances**							
205		Customer	MSCUS-ALL	$ (5,094,531)	$ (4,797,305)	$ (266,636)	$ (792)	$ (21,190)	$ (8)
206		Demand	DEM	$ (1,439,868)	$ (959,759)	$ (266,527)	$ (6,341)	$ (69,080)	$ —
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (6,534,399)	$ (5,757,064)	$ (533,163)	$ (7,133)	$ (90,270)	$ (8)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
209		**Accum. Deferred Income Taxes**							
210		Customer	TPLTCUS	$ (133,824,080)	$ (124,945,531)	$ (7,421,400)	$ (28,993)	$ (670,497)	$ (373)
211		Demand	TPLTDEM	$ (50,031,724)	$ (31,048,379)	$ (10,354,912)	$ (246,344)	$ (2,683,859)	$ —
212		Commodity	COM	$ (273,888)	$ (138,228)	$ (67,744)	$ (2,691)	$ (11,260)	$ —
213		Total Accum. Deferred Inc. Taxes		$ (184,129,691)	$ (156,132,138)	$ (17,844,056)	$ (278,027)	$ (3,365,616)	$ (373)
214		**Excess Deferred Income Taxes**							
215		Customer	TPLTCUS	$ (20,257,434)	$ (18,913,456)	$ (1,123,404)	$ (4,389)	$ (101,496)	$ (57)
216		Demand	TPLTDEM	$ (7,573,483)	$ (4,699,905)	$ (1,567,460)	$ (37,290)	$ (406,265)	$ —
217		Commodity	COM	$ (41,459)	$ (20,924)	$ (10,255)	$ (407)	$ (1,704)	$ —
218		**Total Excess Deferred Income Taxes**		$ (27,872,376)	$ (23,634,285)	$ (2,701,119)	$ (42,086)	$ (509,465)	$ (57)
219		**Negative Acquisition Adjustment on OPC Assets**							
220		Customer	DISPLTCUS	$ (1,241,617)	$ (1,157,909)	$ (69,600)	$ (279)	$ (6,348)	$ (4)
221		Demand	DISPLTDEM	$ (707,405)	$ (430,758)	$ (150,342)	$ (3,577)	$ (38,967)	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ (1,949,023)	$ (1,588,667)	$ (219,942)	$ (3,855)	$ (45,315)	$ (4)
224		**Materials and Supplies**							
225		Customer	TPLTCUS	$ 19,361,746	$ 18,077,193	$ 1,073,732	$ 4,195	$ 97,008	$ 54
226		Demand	TPLTDEM	$ 7,238,619	$ 4,492,098	$ 1,498,155	$ 35,641	$ 388,302	$ —
227		Commodity	COM	$ 39,626	$ 19,999	$ 9,801	$ 389	$ 1,629	$ —
228		Total Materials and Supplies		$ 26,639,992	$ 22,589,289	$ 2,581,689	$ 40,225	$ 486,939	$ 54
229		**Prepayments**							
230		Customer	OPEXPCUS	$ 8,807,394	$ 8,201,853	$ 511,963	$ 2,610	$ 47,551	$ 33
231		Demand	OPEXPDEM	$ 2,155,797	$ 1,331,140	$ 451,887	$ 10,750	$ 117,123	$ —
232		Commodity	COM	$ 117,112	$ 59,105	$ 28,967	$ 1,151	$ 4,815	$ —
233		Total Prepayments		$ 11,080,303	$ 9,592,098	$ 992,817	$ 14,511	$ 169,489	$ 33
234		**Pension & FAS 106 Reg. Asset**							
235		Customer	OPEXPCUS	$ 30,372,303	$ 28,284,095	$ 1,765,505	$ 9,001	$ 163,979	$ 113
236		Demand	OPEXPDEM	$ 7,434,266	$ 4,590,436	$ 1,558,333	$ 37,073	$ 403,900	$ —
237		Commodity	COM	$ 403,862	$ 203,825	$ 99,893	$ 3,968	$ 16,604	$ —
238		Total Pen. & FAS 106 Reg. Asset		$ 38,210,431	$ 33,078,356	$ 3,423,731	$ 50,042	$ 584,482	$ 113
239		**DIMP Deferrals**							
240		Customer	TPLTCUS	$ 3,781,786	$ 3,530,884	$ 209,724	$ 819	$ 18,948	$ 11
241		Demand	TPLTDEM	$ 925,672	$ 574,448	$ 191,584	$ 4,558	$ 49,656	$ —
242		Commodity	COM	$ 50,287	$ 25,379	$ 12,438	$ 494	$ 2,067	$ —
243		Total DIMP Deferrals		$ 4,757,745	$ 4,130,711	$ 413,746	$ 5,871	$ 70,671	$ 11
244		**Regulatory Asset**							
245		Customer	TPLTCUS	$ 1,683,737	$ 1,572,029	$ 93,374	$ 365	$ 8,436	$ 5
246		Demand	TPLTDEM	$ 412,130	$ 255,757	$ 85,297	$ 2,029	$ 22,108	$ —
247		Commodity	COM	$ 22,389	$ 11,299	$ 5,538	$ 220	$ 920	$ —
248		**Total Regulatory Asset**		$ 2,118,256	$ 1,839,086	$ 184,209	$ 2,614	$ 31,464	$ 5

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
249		**Cash Working Capital**							
250		Customer	OPEXPCUS	$ (10,653,973)	$ (9,921,473)	$ (619,302)	$ (3,157)	$ (57,520)	$ (40)
251		Demand	OPEXPDEM	$ (2,607,786)	$ (1,610,230)	$ (546,631)	$ (13,004)	$ (141,680)	$ —
252		Commodity	COM	$ (141,666)	$ (71,498)	$ (35,040)	$ (1,392)	$ (5,824)	$ —
253		Total Cash Working Capital		$ (13,403,426)	$ (11,603,200)	$ (1,200,974)	$ (17,554)	$ (205,024)	$ (40)
254		**Total Rate Base**							
255		Customer		$ 1,341,139,045	$ 1,259,777,095	$ 67,395,566	$ 196,242	$ 6,767,768	$ 3,862
256		Demand		$ 542,387,737	$ 337,400,422	$ 112,063,199	$ 2,665,987	$ 29,045,327	$ —
257		Commodity		$ 3,385,554	$ 1,708,654	$ 837,395	$ 33,264	$ 139,187	$ —
258		Total Rate Base		$ 1,886,912,337	$ 1,598,886,171	$ 180,296,161	$ 2,895,494	$ 35,952,282	$ 3,862

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	301-303	**Intangible Plant**								
2		Customer	NONINCUS	$ —	$ 915	$ 190	$ 1,306	$ 21	$ 3	$ 49
3		Demand	NONINDEM	$ —	$ 20,534	$ 16,376	$ 15,483	$ 2,246	$ 1,897	$ 8,589
4		Commodity	COM	$ —	$ 228	$ 255	$ 117	$ 51	$ 34	$ 48
5		Total Intangible Plant		$ —	$ 21,677	$ 16,820	$ 16,905	$ 2,317	$ 1,934	$ 8,686
6	365-371	**Transmission Plant**								
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ —	$ 4,225,544	$ 3,369,861	$ 3,186,208	$ 462,190	$ 390,441	$ 1,767,428
9		Commodity	COM	$ —	$ 43,411	$ 48,456	$ 22,209	$ 9,635	$ 6,462	$ 9,157
10		Total Transmission Plant		$ —	$ 4,268,955	$ 3,418,317	$ 3,208,417	$ 471,825	$ 396,903	$ 1,776,584
11		**Distribution Plant**								
12	374	**Land & Land Rights - Allocated**								
13		Customer	376-379CUS	$ —	$ 602	$ 125	$ 859	$ 14	$ 2	$ 7,289
14		Demand	DEM	$ —	$ 24,730	$ 19,722	$ 18,648	$ 2,705	$ 2,285	$ 10,344
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ —	$ 25,333	$ 19,847	$ 19,507	$ 2,719	$ 2,287	$ 17,633
17	374	**Land & Land Rights - DA**								
18		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 10,458
19		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 9,076
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ 19,533
22	375	**Structures and Improvements**								
23		Customer	376-379CUS	$ —	$ 153	$ 32	$ 219	$ 3	$ 0	$ 1,857
24		Demand	DEM	$ —	$ 6,301	$ 5,025	$ 4,751	$ 689	$ 582	$ 2,636
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ —	$ 6,455	$ 5,057	$ 4,970	$ 693	$ 583	$ 4,493
27	376	**Distribution Mains-Allocated**								
28		Customer	CUS	$ —	$ 335,816	$ 69,706	$ 478,908	$ 7,561	$ 945	$ 17,879
29		Demand	DEM	$ —	$ 11,478,534	$ 9,154,104	$ 8,655,217	$ 1,255,521	$ 1,060,618	$ 4,801,152
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ —	$ 11,814,350	$ 9,223,809	$ 9,134,125	$ 1,263,082	$ 1,061,563	$ 4,819,031
32	376	**Odorization**								
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ —	$ 8,849	$ 9,878	$ 4,527	$ 1,964	$ 1,317	$ 1,867
36		Total Odorization		$ —	$ 8,849	$ 9,878	$ 4,527	$ 1,964	$ 1,317	$ 1,867
37		**Distribution Mains - Directly Assn.**								
38		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 4,046,246
39		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,185,884
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ 7,232,130

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
42	377	**Compressor Station Equipment**								
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**								
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ 1,629,838	$ 1,299,792	$ 1,228,955	$ 178,272	$ 150,597	$ 681,716
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ —	$ 1,629,838	$ 1,299,792	$ 1,228,955	$ 178,272	$ 150,597	$ 681,716
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**								
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 325,537
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ 325,537
57	378	**Odorization**								
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ —	$ 67,713	$ 75,581	$ 34,642	$ 15,029	$ 10,079	$ 14,282
61		Total Odorization		$ —	$ 67,713	$ 75,581	$ 34,642	$ 15,029	$ 10,079	$ 14,282
62	379	**Meas. & Reg. Station - City Gate**								
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ —	$ 597,755	$ 476,708	$ 450,728	$ 65,382	$ 55,233	$ 250,024
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ —	$ 597,755	$ 476,708	$ 450,728	$ 65,382	$ 55,233	$ 250,024
67	379	**Odorization**								
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ 82,083	$ 91,621	$ 41,994	$ 18,218	$ 12,218	$ 17,313
71		Total Odorization		$ —	$ 82,083	$ 91,621	$ 41,994	$ 18,218	$ 12,218	$ 17,313
72	380	**Services - Allocated**								
73		Customer	SERCUS-ALL	$ —	$ 513,349	$ 107,906	$ 731,131	$ 11,255	$ 1,444	$ —
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ —	$ 513,349	$ 107,906	$ 731,131	$ 11,255	$ 1,444	$ —
77	380	**Services-Directly Assigned**								
78		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 1,524,955
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ 1,524,955

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
82	381	**Meters - Allocated**								
83		Customer	METCUS-ALL	$ —	$ 470,261	$ 110,307	$ 307,238	$ 12,161	$ 1,518	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ —	$ 470,261	$ 110,307	$ 307,238	$ 12,161	$ 1,518	$ —
87	381	**Meters-Directly Assigned**								
88		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 152,811
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ 152,811
92	382	**Meter Installations**								
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**								
98		Customer	REGCUS-ALL	$ —	$ 262,929	$ 60,196	$ 136,058	$ 8,274	$ 1,004	$ —
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ —	$ 262,929	$ 60,196	$ 136,058	$ 8,274	$ 1,004	$ —
102	383	**House Regulators - Directly Assigned**								
103		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 75,571
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ 75,571
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**								
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ —	$ 3,527,790	$ 2,813,404	$ 2,660,077	$ 385,869	$ 325,968	$ 1,475,576
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ —	$ 3,527,790	$ 2,813,404	$ 2,660,077	$ 385,869	$ 325,968	$ 1,475,576
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**								
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 574,172
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ 574,172
117	385	**Odorization**								
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ —	$ 3,182	$ 3,552	$ 1,628	$ 706	$ 474	$ 671
121		Total Odorization		$ —	$ 3,182	$ 3,552	$ 1,628	$ 706	$ 474	$ 671
122	386	**Other Prop.-Customer Premises**								
123		Customer	CUS	$ —	$ 861	$ 179	$ 1,228	$ 19	$ 2	$ 46
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ —	$ 861	$ 179	$ 1,228	$ 19	$ 2	$ 46

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
127	387	**Other Equipment**								
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**								
133		Customer		$ —	$ 1,583,972	$ 348,449	$ 1,655,640	$ 39,287	$ 4,915	$ 5,837,111
134		Demand		$ —	$ 17,264,949	$ 13,768,756	$ 13,018,376	$ 1,888,438	$ 1,595,283	$ 11,316,116
135		Commodity		$ —	$ 161,827	$ 180,632	$ 82,791	$ 35,917	$ 24,089	$ 34,134
136		Total Distribution Plant		$ —	$ 19,010,749	$ 14,297,838	$ 14,756,808	$ 1,963,643	$ 1,624,287	$ 17,187,361
137		**General Plant**								
138		**General Plant - Allocated**								
139		Customer	GENPTCUS	$ —	$ 206,283	$ 44,434	$ 244,614	$ 4,942	$ 618	$ 483,656
140		Demand	DISPLTDEM	$ —	$ 1,937,163	$ 1,544,883	$ 1,460,689	$ 211,887	$ 178,994	$ 1,269,692
141		Commodity	COM	$ —	$ 27,481	$ 30,674	$ 14,059	$ 6,099	$ 4,091	$ 5,796
142		Total General Plant - Allocated		$ —	$ 2,170,927	$ 1,619,991	$ 1,719,362	$ 222,928	$ 183,703	$ 1,759,144
143		**Total General Plant - Directly Assigned**								
144		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 35,537
145		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ 25,045
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ 60,583
148		**Total General Plant**								
149		Customer		$ —	$ 206,283	$ 44,434	$ 244,614	$ 4,942	$ 618	$ 519,193
150		Demand		$ —	$ 1,937,163	$ 1,544,883	$ 1,460,689	$ 211,887	$ 178,994	$ 1,294,737
151		Commodity		$ —	$ 27,481	$ 30,674	$ 14,059	$ 6,099	$ 4,091	$ 5,796
152		Total General Plant		$ —	$ 2,170,927	$ 1,619,991	$ 1,719,362	$ 222,928	$ 183,703	$ 1,819,727
153		**Total Plant in Service**								
154		Customer		$ —	$ 1,791,171	$ 393,073	$ 1,901,560	$ 44,250	$ 5,535	$ 6,356,354
155		Demand		$ —	$ 23,448,190	$ 18,699,876	$ 17,680,756	$ 2,564,760	$ 2,166,616	$ 14,386,869
156		Commodity		$ —	$ 232,947	$ 260,017	$ 119,176	$ 51,702	$ 34,675	$ 49,135
157		Total Plant in Service		$ —	$ 25,472,308	$ 19,352,966	$ 19,701,492	$ 2,660,713	$ 2,206,826	$ 20,792,358
158		**Depreciation & Amort. Reserve**								
159		**Intangible Plant**								
160		Customer	NONINCUS	$ —	$ (711)	$ (148)	$ (1,014)	$ (16)	$ (2)	$ (38)
161		Demand	NONINDEM	$ —	$ (11,861)	$ (9,459)	$ (8,944)	$ (1,297)	$ (1,096)	$ (4,961)
162		Commodity	COM	$ —	$ (120)	$ (134)	$ (61)	$ (27)	$ (18)	$ (25)
163		Total Intangible Plant		$ —	$ (12,691)	$ (9,740)	$ (10,018)	$ (1,340)	$ (1,116)	$ (5,024)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
164		**Transmission Plant**								
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ —	$ (291,512)	$ (232,480)	$ (219,810)	$ (31,886)	$ (26,936)	$ (121,931)
167		Commodity	COM	$ —	$ (4,333)	$ (4,837)	$ (2,217)	$ (962)	$ (645)	$ (914)
168		Total Transmission Plant		$ —	$ (295,845)	$ (237,317)	$ (222,027)	$ (32,847)	$ (27,581)	$ (122,845)
169		**Distribution Plant - Allocated**								
170		Customer	DISPLTCUS	$ —	$ (284,430)	$ (62,570)	$ (297,299)	$ (7,055)	$ (882)	$ (1,048,154)
171		Demand	DISPLTDEM	$ —	$ (2,727,445)	$ (2,175,131)	$ (2,056,589)	$ (298,328)	$ (252,016)	$ (1,787,673)
172		Commodity	COM	$ —	$ (23,957)	$ (26,741)	$ (12,256)	$ (5,317)	$ (3,566)	$ (5,053)
173		Total Distribution Plant - Allocated		$ —	$ (3,035,831)	$ (2,264,441)	$ (2,366,144)	$ (310,699)	$ (256,465)	$ (2,840,880)
174		**Distribution Plant - Dir. Assn.**								
175		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ (610,921)
176		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ (356,159)
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ (967,079)
179		**General Plant - Allocated**								
180		Customer	GENPTCUS	$ —	$ (77,477)	$ (16,689)	$ (91,873)	$ (1,856)	$ (232)	$ (181,654)
181		Demand	DISPLTDEM	$ —	$ (613,968)	$ (489,638)	$ (462,953)	$ (67,156)	$ (56,731)	$ (402,418)
182		Commodity	COM	$ —	$ (7,523)	$ (8,397)	$ (3,849)	$ (1,670)	$ (1,120)	$ (1,587)
183		Total General Plant - Allocated		$ —	$ (698,968)	$ (514,724)	$ (558,676)	$ (70,682)	$ (58,083)	$ (585,659)
184		**General Plant - Directly Assigned**								
185		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ (18,649)
186		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ (13,143)
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ (31,792)
189		**Total Depr. & Amort. Reserve**								
190		Customer		$ —	$ (362,617)	$ (79,406)	$ (390,186)	$ (8,927)	$ (1,117)	$ (1,859,416)
191		Demand		$ —	$ (3,644,785)	$ (2,906,708)	$ (2,748,296)	$ (398,666)	$ (336,779)	$ (2,686,285)
192		Commodity		$ —	$ (35,933)	$ (40,108)	$ (18,383)	$ (7,975)	$ (5,349)	$ (7,579)
193		Total Depr. & Amortization Reserve		$ —	$ (4,043,336)	$ (3,026,222)	$ (3,156,865)	$ (415,568)	$ (343,244)	$ (4,553,280)
194		**Net Plant in Service**								
195		Customer		$ —	$ 1,428,554	$ 313,667	$ 1,511,374	$ 35,323	$ 4,419	$ 4,496,938
196		Demand		$ —	$ 19,803,405	$ 15,793,168	$ 14,932,460	$ 2,166,094	$ 1,829,837	$ 11,700,584
197		Commodity		$ —	$ 197,014	$ 219,909	$ 100,793	$ 43,727	$ 29,326	$ 41,555
198		Total Net Plant in Service		$ —	$ 21,428,973	$ 16,326,744	$ 16,544,627	$ 2,245,144	$ 1,863,582	$ 16,239,077
199		**Customer Deposits**								
200		Customer	DEPCUS	$ —	$ (145,892)	$ (38,879)	$ —	$ —	$ —	$ —
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ —	$ (145,892)	$ (38,879)	$ —	$ —	$ —	$ —
204		**Customer Advances**								
205		Customer	MSCUS-ALL	$ —	$ (3,209)	$ (671)	$ (4,573)	$ (71)	$ (9)	$ (68)
206		Demand	DEM	$ —	$ (43,562)	$ (34,741)	$ (32,847)	$ (4,765)	$ (4,025)	$ (18,221)
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ —	$ (46,771)	$ (35,412)	$ (37,420)	$ (4,836)	$ (4,034)	$ (18,288)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
209		**Accum. Deferred Income Taxes**								
210		Customer	TPLTCUS	$ —	$ (129,283)	$ (28,371)	$ (137,251)	$ (3,194)	$ (400)	$ (458,788)
211		Demand	TPLTDEM	$ —	$ (1,692,440)	$ (1,349,717)	$ (1,276,159)	$ (185,119)	$ (156,382)	$ (1,038,413)
212		Commodity	COM	$ —	$ (16,814)	$ (18,767)	$ (8,602)	$ (3,732)	$ (2,503)	$ (3,546)
213		Total Accum. Deferred Inc. Taxes		$ —	$ (1,838,537)	$ (1,396,856)	$ (1,422,012)	$ (192,045)	$ (159,284)	$ (1,500,748)
214		**Excess Deferred Income Taxes**								
215		Customer	TPLTCUS	$ —	$ (19,570)	$ (4,295)	$ (20,776)	$ (483)	$ (60)	$ (69,448)
216		Demand	TPLTDEM	$ —	$ (256,191)	$ (204,312)	$ (193,177)	$ (28,022)	$ (23,672)	$ (157,188)
217		Commodity	COM	$ —	$ (2,545)	$ (2,841)	$ (1,302)	$ (565)	$ (379)	$ (537)
218		**Total Excess Deferred Income Taxes**		$ —	$ (278,306)	$ (211,447)	$ (215,255)	$ (29,070)	$ (24,111)	$ (227,174)
219		**Negative Acquisition Adjustment on OPC Assets**								
220		Customer	DISPLTCUS	$ —	$ (1,251)	$ (275)	$ (1,308)	$ (31)	$ (4)	$ (4,610)
221		Demand	DISPLTDEM	$ —	$ (24,572)	$ (19,596)	$ (18,528)	$ (2,688)	$ (2,270)	$ (16,106)
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ —	$ (25,823)	$ (19,872)	$ (19,836)	$ (2,719)	$ (2,274)	$ (20,716)
224		**Materials and Supplies**								
225		Customer	TPLTCUS	$ —	$ 18,705	$ 4,105	$ 19,857	$ 462	$ 58	$ 66,378
226		Demand	TPLTDEM	$ —	$ 244,863	$ 195,278	$ 184,635	$ 26,783	$ 22,625	$ 150,238
227		Commodity	COM	$ —	$ 2,433	$ 2,715	$ 1,245	$ 540	$ 362	$ 513
228		Total Materials and Supplies		$ —	$ 266,001	$ 202,098	$ 205,737	$ 27,785	$ 23,045	$ 217,129
229		**Prepayments**								
230		Customer	OPEXPCUS	$ —	$ 10,739	$ 2,365	$ 9,425	$ 273	$ 34	$ 20,548
231		Demand	OPEXPDEM	$ —	$ 73,858	$ 58,902	$ 55,691	$ 8,079	$ 6,824	$ 41,542
232		Commodity	COM	$ —	$ 7,189	$ 8,025	$ 3,678	$ 1,596	$ 1,070	$ 1,516
233		Total Prepayments		$ —	$ 91,787	$ 69,291	$ 68,795	$ 9,947	$ 7,929	$ 63,606
234		**Pension & FAS 106 Reg. Asset**								
235		Customer	OPEXPCUS	$ —	$ 37,035	$ 8,155	$ 32,502	$ 942	$ 118	$ 70,859
236		Demand	OPEXPDEM	$ —	$ 254,699	$ 203,122	$ 192,052	$ 27,859	$ 23,534	$ 143,257
237		Commodity	COM	$ —	$ 24,793	$ 27,674	$ 12,684	$ 5,503	$ 3,690	$ 5,229
238		Total Pen. & FAS 106 Reg. Asset		$ —	$ 316,526	$ 238,951	$ 237,238	$ 34,304	$ 27,342	$ 219,346
239		**DIMP Deferrals**								
240		Customer	TPLTCUS	$ —	$ 3,653	$ 802	$ 3,879	$ 90	$ 11	$ 12,965
241		Demand	TPLTDEM	$ —	$ 31,313	$ 24,972	$ 23,611	$ 3,425	$ 2,893	$ 19,212
242		Commodity	COM	$ —	$ 3,087	$ 3,446	$ 1,579	$ 685	$ 460	$ 651
243		Total DIMP Deferrals		$ —	$ 38,054	$ 29,220	$ 29,069	$ 4,200	$ 3,364	$ 32,829
244		**Regulatory Asset**								
245		Customer	TPLTCUS	$ —	$ 1,627	$ 357	$ 1,727	$ 40	$ 5	$ 5,772
246		Demand	TPLTDEM	$ —	$ 13,941	$ 11,118	$ 10,512	$ 1,525	$ 1,288	$ 8,554
247		Commodity	COM	$ —	$ 1,374	$ 1,534	$ 703	$ 305	$ 205	$ 290
248		**Total Regulatory Asset**		$ —	$ 16,942	$ 13,009	$ 12,942	$ 1,870	$ 1,498	$ 14,616

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
249		**Cash Working Capital**								
250		Customer	OPEXPCUS	$ —	$ (12,991)	$ (2,861)	$ (11,401)	$ (330)	$ (41)	$ (24,856)
251		Demand	OPEXPDEM	$ —	$ (89,343)	$ (71,251)	$ (67,368)	$ (9,772)	$ (8,255)	$ (50,252)
252		Commodity	COM	$ —	$ (8,697)	$ (9,707)	$ (4,449)	$ (1,930)	$ (1,295)	$ (1,834)
253		Total Cash Working Capital		$ —	$ (111,031)	$ (83,819)	$ (83,218)	$ (12,033)	$ (9,591)	$ (76,942)
254		**Total Rate Base**								
255		Customer		$ —	$ 1,188,116	$ 254,099	$ 1,403,456	$ 33,021	$ 4,130	$ 4,115,689
256		Demand		$ —	$ 18,315,970	$ 14,606,943	$ 13,810,883	$ 2,003,399	$ 1,692,398	$ 10,783,208
257		Commodity		$ —	$ 207,835	$ 231,986	$ 106,329	$ 46,129	$ 30,937	$ 43,838
258		Total Rate Base		$ —	$ 19,711,921	$ 15,093,028	$ 15,320,668	$ 2,082,548	$ 1,727,465	$ 14,942,735

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1		**Transmission and Distribution Op. Exp.**										
2	814-865	**Transmission Expenses**										
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 9,124,268	$ 6,081,874	$ 1,688,951	$ 40,180	$ 437,754	$ —	$ —	$ 276,048	$ 220,147
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 9,124,268	$ 6,081,874	$ 1,688,951	$ 40,180	$ 437,754	$ —	$ —	$ 276,048	$ 220,147
7	8650	**Odorization**										
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ 2,471	$ 1,247	$ 611	$ 24	$ 102	$ —	$ —	$ 152	$ 169
11		Total Odorization		$ 2,471	$ 1,247	$ 611	$ 24	$ 102	$ —	$ —	$ 152	$ 169
12	8700	**Operation Supervision & Engineering**										
13		Customer	871-879CUS	$ 2,296,831	$ 2,108,716	$ 157,948	$ 1,032	$ 18,937	$ 17	$ —	$ 5,190	$ 1,185
14		Demand	DEM	$ 389,559	$ 259,665	$ 72,110	$ 1,715	$ 18,690	$ —	$ —	$ 11,786	$ 9,399
15		Commodity	COM	$ 47,984	$ 24,217	$ 11,868	$ 471	$ 1,973	$ —	$ —	$ 2,946	$ 3,288
16		Total Supervision & Engineering		$ 2,734,374	$ 2,392,598	$ 241,926	$ 3,219	$ 39,599	$ 17	$ —	$ 19,922	$ 13,872
17	8710	**Distribution Load Dispatch**										
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 585,292	$ 295,390	$ 144,768	$ 5,751	$ 24,063	$ —	$ —	$ 35,930	$ 40,106
21		Total Distribution Load Dispatch		$ 585,292	$ 295,390	$ 144,768	$ 5,751	$ 24,063	$ —	$ —	$ 35,930	$ 40,106
22	8740	**Mains & Services - Allocated**										
23		Customer	MSCUS-ALL	$ 12,245,352	$ 11,530,932	$ 640,893	$ 1,904	$ 50,932	$ 19	$ —	$ 7,713	$ 1,613
24		Demand	DEM	$ 3,446,270	$ 2,297,147	$ 637,923	$ 15,176	$ 165,341	$ —	$ —	$ 104,264	$ 83,150
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 15,691,623	$ 13,828,078	$ 1,278,816	$ 17,080	$ 216,274	$ 19	$ —	$ 111,978	$ 84,764
27	8740	**Mains & Services - Dir. Assn.**										
28		Customer	MSCUS-DA	$ 50,458	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM-DA	$ 28,854	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ 79,312	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
32	8740	**Odorization**										
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ (45,825)	$ (23,127)	$ (11,334)	$ (450)	$ (1,884)	$ —	$ —	$ (2,813)	$ (3,140)
36		Total Odorization		$ (45,825)	$ (23,127)	$ (11,334)	$ (450)	$ (1,884)	$ —	$ —	$ (2,813)	$ (3,140)
37	8750	**Meas. & Reg. Station - Gen. - Allocated**										
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 1,078,584	$ 718,941	$ 199,652	$ 4,750	$ 51,747	$ —	$ —	$ 32,632	$ 26,024
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 1,078,584	$ 718,941	$ 199,652	$ 4,750	$ 51,747	$ —	$ —	$ 32,632	$ 26,024
42		**Meas. & Reg. Station - Gen. - DA**										
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ 8,173	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
46		Total Meas. & Reg. Station - Gen. - DA		$ 8,173	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	8750	**Odorization**										
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 273,994	$ 138,282	$ 67,771	$ 2,692	$ 11,264	$ —	$ —	$ 16,820	$ 18,775
51		Total Odorization		$ 273,994	$ 138,282	$ 67,771	$ 2,692	$ 11,264	$ —	$ —	$ 16,820	$ 18,775
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**										
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 89,782	$ —	$ 49,841	$ 1,186	$ 12,918	$ —	$ —	$ 8,146	$ 6,497
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 89,782	$ —	$ 49,841	$ 1,186	$ 12,918	$ —	$ —	$ 8,146	$ 6,497
57	8760	**Meas. & Reg. Stat. - Ind. - DA**										
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ 1,326	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ 1,326	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
62	8770	**Meas. & Reg. Stat.- City Gate**										
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 98,743	$ 65,818	$ 18,278	$ 435	$ 4,737	$ —	$ —	$ 2,987	$ 2,382
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 98,743	$ 65,818	$ 18,278	$ 435	$ 4,737	$ —	$ —	$ 2,987	$ 2,382
67	8780	**Meter & House Reg. Exp. - Alloc.**										
68		Customer	MTRGCUS-ALL	$ 15,692,849	$ 14,119,177	$ 1,280,279	$ 10,650	$ 179,396	$192	$ —	$ 55,415	$ 12,795
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
71		Total Meter & House Reg. Exp. - Alloc.		$ 15,692,849	$ 14,119,177	$ 1,280,279	$ 10,650	$ 179,396	$192	$ —	$ 55,415	$ 12,795
72	8780	**Meter & House Reg. Exp - Dir. Assn.**										
73		Customer	CUS-DA	$ 16,673	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ 16,673	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
77	8780	**Odorization**										
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ 81	$ 41	$ 20	$ 1	$ 3	$ —	$ —	$ 5	$ 6
81		Total Odorization		$ 81	$ 41	$ 20	$ 1	$ 3	$ —	$ —	$ 5	$ 6
82	8790	**Customer Installation Expense**										
83		Customer	METCUS-ALL	$ 10,745	$ 9,768	$ 816	$ 6	$ 100	$ 0	$ —	$ 28	$ 7
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 10,745	$ 9,768	$ 816	$ 6	$ 100	$ 0	$ —	$ 28	$ 7
87	8800	**Other Expenses**										
88		Customer	871-879CUS	$ 2,762,147	$ 2,535,922	$ 189,947	$ 1,241	$ 22,773	$ 21	$ —	$ 6,242	$ 1,425
89		Demand	DEM	$ 468,481	$ 312,270	$ 86,718	$ 2,063	$ 22,476	$ —	$ —	$ 14,174	$ 11,303
90		Commodity	COM	$ 57,705	$ 29,123	$ 14,273	$ 567	$ 2,372	$ —	$ —	$ 3,542	$ 3,954

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
91		Total Other Expenses		$ 3,288,333	$ 2,877,316	$ 290,938	$ 3,871	$ 47,622	$ 21	$ —	$ 23,958	$ 16,682
92	8800	**Odorization**										
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 1,505	$ 760	$ 372	$ 15	$ 62	$ —	$ —	$ 92	$ 103
96		Total Odorization		$ 1,505 $—	$ 760	$ 372	$ 15	$ 62	$ —	$ —	$ 92	$ 103
97	8810	**Rents**										
98		Customer	871-879CUS	$ 98,383	$ 90,325	$ 6,766	$ 44	$ 811	$ 1	$ —	$ 222	$ 51
99		Demand	DEM	$ 16,686	$ 11,123	$ 3,089	$ 73	$ 801	$ —	$ —	$ 505	$ 403
100		Commodity	COM	$ 2,055	$ 1,037	$ 508	$ 20	$ 84	$ —	$ —	$ 126	$ 141
101		Total Rents		$ 117,124	$ 102,485	$ 10,363	$ 138	$ 1,696	$ 1	$ —	$ 853	$ 594
102	8820	**Corporate & Div. Exp.**										
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**										
108		Customer		$ 33,173,437	$ 30,394,840	$ 2,276,648	$ 14,877	$ 272,949	$250	$ —	$ 74,810	$ 17,075
109		Demand		$ 14,750,728	$ 9,746,838	$ 2,756,562	$ 65,579	$ 714,465	$ —	$ —	$ 450,541	$ 359,306
110		Commodity		$ 925,262	$ 466,970	$ 228,858	$ 9,091	$ 38,039	$ —	$ —	$ 56,801	$ 63,401
111		Total Distr. & Trans. Operations Exp.		$ 48,849,427	$ 40,608,648	$ 5,262,068	$ 89,547	$ 1,025,454	$250	$ —	$ 582,152	$ 439,782
112		**Distribution Maintenance Expenses**										
113	8850	**Maintenance Supervision and Engineering**										
114		Customer	887-893CUS	$ 10,488	$ 9,882	$ 543	$ 2	$ 43	$ 0	$ —	$ 6	$ 1
115		Demand	887-893DEM	$ 8,504	$ 4,501	$ 2,222	$ 53	$ 576	$ —	$ —	$ 363	$ 290
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ 18,992	$ 14,383	$ 2,765	$ 54	$ 619	$ 0	$ —	$ 370	$ 291
118	8860	**Structures and Improvements**										
119		Customer	887-893CUS	$ 1,311,078	$ 1,235,401	$ 67,903	$ 200	$ 5,415	$ 2	$ —	$ 808	$ 169
120		Demand	887-893DEM	$ 1,063,129	$ 562,681	$ 277,818	$ 6,609	$ 72,007	$ —	$ —	$ 45,407	$ 36,212
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 2,374,207	$ 1,798,082	$ 345,721	$ 6,809	$ 77,421	$ 2	$ —	$ 46,215	$ 36,381
123	8870	**Maintenance of Mains-Allocated**										
124		Customer	CUS	$ 5,390,250	$ 5,098,272	$ 263,028	$ 700	$ 20,870	$ 8	$ —	$ 2,718	$ 564
125		Demand	DEM	$ 3,071,067	$ 2,047,051	$ 568,471	$ 13,524	$ 147,340	$ —	$ —	$ 92,913	$ 74,098
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 8,461,317	$ 7,145,323	$ 831,499	$ 14,224	$ 168,211	$ 8	$ —	$ 95,631	$ 74,662
128	8870	**Maintenance of Mains - Directly Assigned**										
129		Customer	CUS-DA	$ 32,752	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM-DA	$ 25,788	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ 58,540	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**										
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 2,784,748	$ 1,856,202	$ 515,472	$ 12,263	$ 133,604	$ —	$ —	$ 84,250	$ 67,189

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 2,784,748	$ 1,856,202	$ 515,472	$ 12,263	$ 133,604	$ —	$ —	$ 84,250	$ 67,189
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**										
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ 18,902	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 18,902	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
143	8890	**Odorization**										
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 343,209	$ 173,214	$ 84,891	$ 3,372	$ 14,110	$ —	$ —	$ 21,069	$ 23,518
147		Total Odorization		$ 343,209	$ 173,214	$ 84,891	$ 3,372	$ 14,110	$ —	$ —	$ 21,069	$ 23,518
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**										
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 1,536,947	$ —	$ 853,219	$ 20,298	$ 221,143	$ —	$ —	$ 139,453	$ 111,213
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 1,536,947	$ —	$ 853,219	$ 20,298	$ 221,143	$ —	$ —	$ 139,453	$ 111,213
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**										
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ 22,697	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ 22,697	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**										
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 69,264	$ 46,169	$ 12,821	$ 305	$ 3,323	$ —	$ —	$ 2,096	$ 1,671
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 69,264	$ 46,169	$ 12,821	$ 305	$ 3,323	$ —	$ —	$ 2,096	$ 1,671
163	8910	**Odorization**										
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ 100	$ 50	$ 25	$ 1	$ 4	$ —	$ —	$ 6	$ 7
167		**Total Odorization**		$ 100 $—	$ 50	$ 25	$ 1	$ 4	$ —	$ —	$ 6	$ 7
168	8920	**Services - Allocated**										
169		Customer	SERCUS-ALL	$ 3,825,896	$ 3,587,095	$ 213,462	$ 691	$ 16,987	$ 6	$ —	$ 2,879	$ 605
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 3,825,896	$ 3,587,095	$ 213,462	$ 691	$ 16,987	$ 6	$ —	$ 2,879	$ 605
173	8920	**Services - Directly Assigned**										
174		Customer	CUS-DA	$ 8,552	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ 8,552	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178	8930	**Meters & House Regulators - Alloc.**										
179		Customer	MTRGCUS-ALL	$ 27,992	$ 25,185	$ 2,284	$ 19	$ 320	$ 0	$ —	$ 99	$ 23
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ 27,992	$ 25,185	$ 2,284	$ 19	$ 320	$ 0	$ —	$ 99	$ 23
183	8930	**Meters & House Regulators - DA**										
184		Customer	CUS-DA	$ 30	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ 30	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188	8940	**Maintenance of Other Equipment**										
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**										
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**										
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**										
204		Customer		$ 10,607,039	$ 9,955,835	$ 547,220	$ 1,611	$ 43,635	$ 16	$ —	$ 6,510	$ 1,363
205		Demand		$ 8,601,046	$ 4,516,604	$ 2,230,023	$ 53,052	$ 577,993	$ —	$ —	$ 364,482	$ 290,674
206		Commodity		$ 343,309	$ 173,264	$ 84,915	$ 3,373	$ 14,114	$ —	$ —	$ 21,075	$ 23,524
207		Total Distr. Maintenance Expense		$ 19,551,393	$ 14,645,704	$ 2,862,158	$ 58,036	$ 635,742	$ 16	$ —	$ 392,068	$ 315,561
208		**Total Oper. & Maint. Expense**										
209		Customer		$ 43,780,476	$ 40,350,676	$ 2,823,868	$ 16,488	$ 316,584	$266	$ —	$ 81,321	$ 18,438
210		Demand		$ 23,351,773	$ 14,263,442	$ 4,986,586	$ 118,631	$ 1,292,458	$ —	$ —	$ 815,024	$ 649,979
211		Commodity		$ 1,268,571	$ 640,234	$ 313,773	$ 12,464	$ 52,154	$ —	$ —	$ 77,876	$ 86,926
212		Total Operations & Maint. Expense		$ 68,400,820	$ 55,254,351	$ 8,124,227	$ 147,584	$ 1,661,196	$266	$ —	$ 974,220	$ 755,343
213		**Customer Accounts Expense**										
214	901	**Supervision**										
215		Customer	902-904CUS	$ 645	$ 610	$ 33	$ 0	$ 1	$ 0	$ —	$ 0	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 645	$ 610	$ 33	$ 0	$ 1	$ 0	$ —	$ 0	$ 0
219	902	**Meter Reading Expense**										
220		Customer	METCUS-TOT	$ 1,423,705	$ 1,294,173	$ 108,140	$ 749	$ 13,292	$ 12	$ —	$ 3,734	$ 876
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 1,423,705	$ 1,294,173	$ 108,140	$ 749	$ 13,292	$ 12	$ —	$ 3,734	$ 876
224	903	**Customer Accounting**										
225		Customer	903CUS	$ 11,808,882	$ 11,351,886	$ 432,914	$ 936	$ 17,647	$ 6	$ —	$ 1,985	$ 412

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 11,808,882	$ 11,351,886	$ 432,914	$ 936	$ 17,647	$ 6	$ —	$ 1,985	$ 412
229	904	**Bad Debt Expense**										
230		Customer	904CUS	$ 3,374,231	$ 3,059,074	$ 306,239	$ 4,787	$ 1,752	$ —	$ —	$ 2,379	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ 3,374,231	$ 3,059,074	$ 306,239	$ 4,787	$ 1,752	$ —	$ —	$ 2,379	$ —
234	905	**Miscellaneous Customer Accounts**										
235		Customer	902-904CUS	$ 869,396	$ 822,191	$ 44,357	$ 339	$ 1,711	$ 1	$ —	$ 424	$ 67
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 869,396	$ 822,191	$ 44,357	$ 339	$ 1,711	$ 1	$ —	$ 424	$ 67
239	907-910	**Customer Information Expense**										
240		Customer	CUS	$ 2,509,218	$ 2,373,299	$ 122,442	$ 326	$ 9,715	$ 4	$ —	$ 1,265	$ 263
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 2,509,218	$ 2,373,299	$ 122,442	$ 326	$ 9,715	$ 4	$ —	$ 1,265	$ 263
244		**Sales and Advertising Expense**										
245	911	**Supervision**										
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**										
251		Customer	CUS	$ 1,630	$ 1,542	$ 80	$ 0	$ 6	$ 0	$ —	$ 1	$ 0
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ 1,630	$ 1,542	$ 80	$ 0	$ 6	$ 0	$ —	$ 1	$ 0
255	913	**Advertising**										
256		Customer	CUS	$ 191,835	$ 181,444	$ 9,361	$ 25	$ 743	$ 0	$ —	$ 97	$ 20
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 191,835	$ 181,444	$ 9,361	$ 25	$ 743	$ 0	$ —	$ 97	$ 20
260	914	**Employee Sales Referrals**										
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**										
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**										

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
271	920-940	**Administrative & General Expenses**										
272		Customer	OPEXPCUS	$ 65,695,784	$ 61,178,955	$ 3,818,816	$ 19,469	$ 354,689	$245	$ —	$ 80,107	$ 17,640
273		Demand	OPEXPDEM	$ 8,384,235	$ 5,177,014	$ 1,757,461	$ 41,810	$ 455,511	$ —	$ —	$ 287,245	$ 229,077
274		Commodity	COM	$ 455,468	$ 229,870	$ 112,657	$ 4,475	$ 18,725	$ —	$ —	$ 27,961	$ 31,210
275		Total Administrative & General Exp.		$ 74,535,487	$ 66,585,839	$ 5,688,934	$ 65,754	$ 828,925	$245	$ —	$ 395,312	$ 277,927
276		**Depreciation & Amortization Expense**										
277	301-303	**Intangible Plant - Allocated**										
278		Customer	CUS	$ 63,471	$ 60,032	$ 3,097	$ 8	$ 246	$ 0	$ —	$ 32	$ 7
279		Demand	DEM	$ 23,729	$ 15,817	$ 4,392	$ 104	$ 1,138	$ —	$ —	$ 718	$ 573
280		Commodity	COM	$ 130	$ 66	$ 32	$ 1	$ 5	$ —	$ —	$ 8	$ 9
281		Total Intangible Plant		$ 87,330	$ 75,915	$ 7,522	$ 114	$ 1,390	$ 0	$ —	$ 758	$ 588
282	301-303	**Intangible Plant - Directly Assigned**										
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**										
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**										
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 49,857	$ 33,232	$ 9,229	$ 220	$ 2,392	$ —	$ —	$ 1,508	$ 1,203
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ 49,857	$ 33,232	$ 9,229	$ 220	$ 2,392	$ —	$ —	$ 1,508	$ 1,203
297	367	**Transmission Mains**										
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 3,282,834	$ 2,188,206	$ 607,670	$ 14,456	$ 157,500	$ —	$ —	$ 99,320	$ 79,207
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 3,282,834	$ 2,188,206	$ 607,670	$ 14,456	$ 157,500	$ —	$ —	$ 99,320	$ 79,207
302	368	**Compression Station Equipment**										
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ 3,937	$ 2,624	$ 729	$ 17	$ 189	$ —	$ —	$ 119	$ 95
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ 3,937	$ 2,624	$ 729	$ 17	$ 189	$ —	$ —	$ 119	$ 95
307	369	**Meas. & Reg. Station Equipment**										
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 890,894	$ 593,834	$ 164,909	$ 3,923	$ 42,742	$ —	$ —	$ 26,953	$ 21,495
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 890,894	$ 593,834	$ 164,909	$ 3,923	$ 42,742	$ —	$ —	$ 26,953	$ 21,495
312	371	**Other Equipment**										
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ 2,818	$ 1,878	$ 522	$ 12	$ 135	$ —	$ —	$ 85	$ 68
315		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
316		Total Other Equipment		$ 2,818	$ 1,878	$ 522	$ 12	$ 135	$ —	$ —	$ 85	$ 68
317	375	**Structures and Improvements**										
318		Customer	376-379CUS	$ 11,442	$ 10,757	$ 555	$ 1	$ 44	$ 0	$ —	$ 6	$ 1
319		Demand	DEM	$ 7,784	$ 5,189	$ 1,441	$ 34	$ 373	$ —	$ —	$ 236	$ 188
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
321		Total Structures and Improvements		$ 19,226	$ 15,945	$ 1,996	$ 36	$ 417	$ 0	$ —	$ 241	$ 189
322	376	**Distribution Mains - Allocated**										
323		Customer	CUS	$ 18,434,684	$ 17,436,119	$ 899,556	$ 2,393	$ 71,376	$ 26	$ —	$ 9,296	$ 1,930
324		Demand	DEM	$ 10,503,067	$ 7,000,926	$ 1,944,174	$ 46,252	$ 503,905	$ —	$ —	$ 317,762	$ 253,415
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Distribution Mains - Allocated		$ 28,937,751	$ 24,437,045	$ 2,843,730	$ 48,645	$ 575,281	$ 26	$ —	$ 327,059	$ 255,344
327	376	**Distribution Mains - Directly Assigned**										
328		Customer	CUS-DA	$ 103,492	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
329		Demand	DEM-DA	$ 81,487	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
330		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
331		Distribution Mains - Directly Assigned		$ 184,979	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
332	377	**Compressor Station Equipment**										
333		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
336		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
337	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**										
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ 1,415,814	$ 943,725	$ 262,075	$ 6,235	$ 67,926	$ —	$ —	$ 42,834	$ 34,160
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
341		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 1,415,814	$ 943,725	$ 262,075	$ 6,235	$ 67,926	$ —	$ —	$ 42,834	$ 34,160
342	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**										
343		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM-DA	$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
345		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
346		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
347	378	**Odorization**										
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694
351		Total Odorization		$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694
352	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**										
353		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM	$ 459,933	$ 306,573	$ 85,136	$ 2,025	$ 22,066	$ —	$ —	$ 13,915	$ 11,097
355		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq.- City Gate		$ 459,933	$ 306,573	$ 85,136	$ 2,025	$ 22,066	$ —	$ —	$ 13,915	$ 11,097
357	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**										
358		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
361		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
362	379	**Odorization**										
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
366		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
367	380	**Services - Allocated**										
368		Customer	SERCUS-ALL	$ 25,906,053	$ 24,289,073	$ 1,445,400	$ 4,678	$ 115,021	$ 42	$ —	$ 19,495	$ 4,098
369		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
371		Total Services - Allocated		$ 25,906,053	$ 24,289,073	$ 1,445,400	$ 4,678	$ 115,021	$ 42	$ —	$ 19,495	$ 4,098
372	380	**Services - Directly Assigned**										
373		Customer	CUS-DA	$ 56,728	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
374		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
375		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
376		Total Services - Directly Assigned		$ 56,728	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
377	381	**Meters - Allocated**										
378		Customer	METCUS-ALL	$ 7,349,631	$ 6,681,789	$ 558,326	$ 3,865	$ 68,628	$ 62	$ —	$ 19,280	$ 4,522
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
381		Total Meters - Allocated		$ 7,349,631	$ 6,681,789	$ 558,326	$ 3,865	$ 68,628	$ 62	$ —	$ 19,280	$ 4,522
382	381	**Meters - Directly Assigned**										
383		Customer	CUS-DA	$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
386		Total Meters - Directly Assigned		$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
387	382	**Meter Installations**										
388		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
391		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
392	383	**House Regulators - Allocated**										
393		Customer	REGCUS-ALL	$ 1,510,038	$ 1,296,188	$ 160,466	$ 2,054	$ 31,472	$ 42	$ —	$ 11,122	$ 2,546
394		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
396		Total House Regulators - Allocated		$ 1,510,038	$ 1,296,188	$ 160,466	$ 2,054	$ 31,472	$ 42	$ —	$ 11,122	$ 2,546
397	383	**House Regulators - Directly Assn.**										
398		Customer	CUS-DA	$ 3,363	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
399		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
401		House Regulators - Directly Assn.		$ 3,363	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
402	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**										
403		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
404		Demand	NRDEM	$ 940,499	$ —	$ 522,107	$ 12,421	$ 135,323	$ —	$ —	$ 85,335	$ 68,054
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
406		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 940,499	$ —	$ 522,107	$ 12,421	$ 135,323	$ —	$ —	$ 85,335	$ 68,054
407	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**										
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
411		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
412	386	**Other Prop.- Customer Premises**										
413		Customer	CUS	$ 355,527	$ 336,268	$ 17,349	$ 46	$ 1,377	$ 1	$ —	$ 179	$ 37
414		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
416		Total Other Prop. - Customer Premises		$ 355,527	$ 336,268	$ 17,349	$ 46	$ 1,377	$ 1	$ —	$ 179	$ 37
417	387	**Other Equipment**										
418		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
421		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
422	389-98	**General Plant - Allocated**										
423		Customer	GENPTCUS	$ 15,397,496	$ 14,469,372	$ 802,883	$ 2,671	$ 68,426	$ 32	$ —	$ 11,338	$ 2,442
424		Demand	DISPLTDEM	$ 2,179,682	$ 1,327,267	$ 463,240	$ 11,021	$ 120,066	$ —	$ —	$ 75,713	$ 60,381
425		Commodity	COM	$ 21,678	$ 10,941	$ 5,362	$ 213	$ 891	$ —	$ —	$ 1,331	$ 1,485
426		Total General Plant - Allocated		$ 17,598,856	$ 15,807,579	$ 1,271,485	$ 13,904	$ 189,383	$ 32	$ —	$ 88,382	$ 64,309
427	389-98	**General Plant - Directly Assigned**										
428		Customer	CUS-DA	$ 2,171	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
429		Demand	DEM-DA	$ 307	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
430		Commodity	COM-DA	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
431		Total General Plant - Directly Assn.		$ 2,481	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
432	389-98	**General Plant - Odorization**										
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
435		Commodity	COM	$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694
436		Total General Plant - Odorization		$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694
437	40730	**Pension & FAS 106 Amort. Expense**										
438		Customer	CUS	$ (582,896)	$ (551,322)	$ (28,444)	$ (76)	$ (2,257)	$ (1)	$ —	$ (294)	$ (61)
439		Demand	DEM	$ (142,676)	$ (95,102)	$ (26,410)	$ (628)	$ (6,845)	$ —	$ —	$ (4,317)	$ (3,442)
440		Commodity	COM	$ (7,751)	$ (3,912)	$ (1,917)	$ (76)	$ (319)	$ —	$ —	$ (476)	$ (531)
441		Total Pension & FAS 106 Amort. Exp.		$ (733,323)	$ (650,336)	$ (56,771)	$ (780)	$ (9,421)	$ (1)	$ —	$ (5,086)	$ (4,035)
442		**Total Depreciation & Amort. Exp.**										
443		Customer		$ 68,618,412	$ 64,028,276	$ 3,859,188	$ 15,640	$ 354,333	$205	$ —	$ 70,454	$ 15,522
444		Demand		$ 19,707,177	$ 12,324,170	$ 4,039,215	$ 96,093	$ 1,046,912	$ —	$ —	$ 660,182	$ 526,494
445		Commodity		$ 34,321	$ 17,320	$ 8,488	$ 337	$ 1,411	$ —	$ —	$ 2,107	$ 2,352
446		Total Depreciation & Amort. Expense		$ 88,359,910	$ 76,369,765	$ 7,906,891	$ 112,071	$ 1,402,656	$205	$ —	$ 732,743	$ 544,368
447		**Taxes Other Than Income**										
448	4081	**Payroll and Other Taxes**										
449		Customer	OPEXPCUS	$ 5,111,189	$ 4,759,775	$ 297,107	$ 1,515	$ 27,595	$ 19	$ —	$ 6,232	$ 1,372
450		Demand	OPEXPDEM	$ 1,251,072	$ 772,499	$ 262,243	$ 6,239	$ 67,970	$ —	$ —	$ 42,862	$ 34,182

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
451		Commodity	COM	$ 67,964	$ 34,301	$ 16,810	$ 668	$ 2,794	$ —	$ —	$ 4,172	$ 4,657
452		Total Payroll and Other Taxes		$ 6,430,224	$ 5,566,575	$ 576,161	$ 8,421	$ 98,359	$ 19	$ —	$ 53,266	$ 40,212
453	4081	**Ad Valorem Taxes - Allocated**										
454		Customer	CUS	$ 14,106,095	$ 13,342,000	$ 688,334	$ 1,831	$ 54,617	$ 20	$ —	$ 7,114	$ 1,477
455		Demand	DEM	$ 5,258,969	$ 3,505,419	$ 973,464	$ 23,159	$ 252,309	$ —	$ —	$ 159,106	$ 126,887
456		Commodity	COM	$ 28,961	$ 14,616	$ 7,163	$ 285	$ 1,191	$ —	$ —	$ 1,778	$ 1,984
457		Total Ad Valorem Taxes - Allocated		$ 19,394,025	$ 16,862,035	$ 1,668,961	$ 25,274	$ 308,117	$ 20	$ —	$ 167,997	$ 130,348
458	4081	**Ad Valorem Taxes - Directly Assn.**										
459		Customer	CUS-DA	$ 44,614	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
460		Demand	DEM-DA	$ 31,442	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
461		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
462		Total Ad Valorem Taxes - Directly Assn.		$ 76,057	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
463		**Revenue Related Taxes**										
464		Customer	TOTREVCUS	$ 329,692	$ 241,745	$ 64,767	$ 2,420	$ 10,213	$ 3	$ —	$ 2,691	$ 2,762
465		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
466		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
467		Total Revenue Related Taxes		$ 329,692	$ 241,745	$ 64,767	$ 2,420	$ 10,213	$ 3	$ —	$ 2,691	$ 2,762
468		**Total Taxes Other Than Income**										
469		Customer		$ 19,591,590	$ 18,343,520	$ 1,050,208	$ 5,765	$ 92,425	$ 42	$ —	$ 16,037	$ 5,611
470		Demand		$ 6,541,483	$ 4,277,918	$ 1,235,707	$ 29,398	$ 320,279	$ —	$ —	$ 201,968	$ 161,069
471		Commodity		$ 96,925	$ 48,917	$ 23,974	$ 952	$ 3,985	$ —	$ —	$ 5,950	$ 6,642
472		Total Taxes Other Than Income		$ 26,229,998	$ 22,670,356	$ 2,309,889	$ 36,115	$ 416,689	$ 42	$ —	$ 223,955	$ 173,322
473		**Excess Def. Income Tax Amort. - Directly Assn.**										
474		Customer	CUS-DA	$ (5,769)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
475		Demand	DEM-DA	$ (4,148)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
477		**Total Excess Def. Income Tax Amort. - DA**		$ (9,917)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
478		**Excess Def. Income Tax Amort. - Alloc.**										
479		Customer	CUS	$ (1,613,973)	$ (1,526,548)	$ (78,757)	$ (209)	$ (6,249)	$ (2)	$ —	$ (814)	$ (169)
480		Demand	DEM	$ (644,598)	$ (429,664)	$ (119,319)	$ (2,839)	$ (30,926)	$ —	$ —	$ (19,502)	$ (15,553)
481		Commodity	COM	$ (3,549)	$ (1,791)	$ (878)	$ (35)	$ (146)	$ —	$ —	$ (218)	$ (243)
482		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (2,262,121)	$ (1,958,003)	$ (198,954)	$ (3,083)	$ (37,321)	$ (2)	$ —	$ (20,534)	$ (15,965)
483		**Interest on Customer Deposits**										
484		Customer	DEPCUS	$ 824,647	$ 391,766	$ 414,090	$ 5,203	$ 4,257	$ —	$ —	$ 7,368	$ 1,963
485		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
486		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
487		Total Interest on Cust. Deposits		$ 824,647	$ 391,766	$ 414,090	$ 5,203	$ 4,257	$ —	$ —	$ 7,368	$ 1,963
488		**Req. Return - Other Than Directly Assn.**										
489		Customer	CUS	$ 107,448,563	$ 101,628,316	$ 5,243,159	$ 13,946	$ 416,025	$153	$ —	$ 54,185	$ 11,247
490		Demand	DEM	$ 42,913,466	$ 28,604,407	$ 7,943,515	$ 188,976	$ 2,058,856	$ —	$ —	$ 1,298,314	$ 1,035,402
491		Commodity	COM	$ 236,298	$ 119,257	$ 58,447	$ 2,322	$ 9,715	$ —	$ —	$ 14,506	$ 16,192
492		Tot. Req. Return - Other Than Dir. Assn.		$ 150,598,327	$ 130,351,980	$ 13,245,120	$ 205,245	$ 2,484,596	$153	$ —	$ 1,367,005	$ 1,062,841
493		**Req. Return - Directly Assigned**										
494		Customer	CUS-DA	$ 384,051	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
495		Demand	DEM-DA	$ 276,140	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
496		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
497		Tot. Req. Return - Directly Assigned		$ 660,191	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
498		**Income Taxes - Other Than DA**										
499		Customer	CUS	$ 22,243,200	$ 21,038,336	$ 1,085,400	$ 2,887	$ 86,122	$ 32	$ —	$ 11,217	$ 2,328
500		Demand	DEM	$ 8,883,626	$ 5,921,471	$ 1,644,407	$ 39,121	$ 426,209	$ —	$ —	$ 268,767	$ 214,341
501		Commodity	COM	$ 48,917	$ 24,688	$ 12,099	$ 481	$ 2,011	$ —	$ —	$ 3,003	$ 3,352
502		Total Income Taxes - Other Than DA		$ 31,175,742	$ 26,984,495	$ 2,741,906	$ 42,488	$ 514,342	$ 32	$ —	$ 282,987	$ 220,021
503		**Income Taxes - Directly Assigned**										
504		Customer	CUS-DA	$ 79,503	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
505		Demand	DEM-DA	$ 57,164	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
506		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
507		Total Income Taxes - Dir. Assigned		$ 136,668	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
508		**Total Cost of Service Before Revenue Credits**										
509		Customer		$ 347,226,026	$ 324,517,516	$ 19,239,537	$ 86,351	$ 1,663,055	$962	$ —	$ 329,760	$ 74,220
510		Demand		$ 109,466,318	$ 70,138,757	$ 21,487,572	$ 511,190	$ 5,569,300	$ —	$ —	$ 3,511,998	$ 2,800,810
511		Commodity		$ 2,136,950	$ 1,078,495	$ 528,560	$ 20,996	$ 87,854	$ —	$ —	$ 131,184	$ 146,429
512		**Total Cost of Service Before Revenue Credits**		$ 458,829,294	$ 395,734,768	$ 41,255,670	$ 618,538	$ 7,320,209	$962	$ —	$ 3,972,943	$ 3,021,458

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
1		**Transmission and Distribution Op. Exp.**					
2	814-865	**Transmission Expenses**					
3		Customer	CUS	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 208,150	$ 30,194	$ 25,507	$ 115,463
5		Commodity	COM	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 208,150	$ 30,194	$ 25,507	$ 115,463
7	8650	**Odorization**					
8		Customer	CUS	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —
10		Commodity	COM	$ 78	$ 34	$ 23	$ 32
11		Total Odorization		$ 78	$ 34	$ 23	$ 32
12	8700	**Operation Supervision & Engineering**					
13		Customer	871-879CUS	$ 3,634	$ 141	$ 18	$ 13
14		Demand	DEM	$ 8,887	$ 1,289	$ 1,089	$ 4,930
15		Commodity	COM	$ 1,507	$ 654	$ 438	$ 621
16		Total Supervision & Engineering		$ 14,028	$ 2,084	$ 1,545	$ 5,564
17	8710	**Distribution Load Dispatch**					
18		Customer	CUS	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 18,382	$ 7,975	$ 5,348	$ 7,579
21		Total Distribution Load Dispatch		$ 18,382	$ 7,975	$ 5,348	$ 7,579
22	8740	**Mains & Services - Allocated**					
23		Customer	MSCUS-ALL	$ 10,991	$ 171	$ 22	$ 162
24		Demand	DEM	$ 78,619	$ 11,404	$ 9,634	$ 43,611
25		Commodity	COM	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 89,610	$ 11,575	$ 9,656	$ 43,773
27	8740	**Mains & Services - Dir. Assn.**					
28		Customer	MSCUS-DA	$ —	$ —	$ —	$ 50,458
29		Demand	DEM-DA	$ —	$ —	$ —	$ 28,854
30		Commodity	COM-DA	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ —	$ —	$ —	$ 79,312
32	8740	**Odorization**					
33		Customer	CUS	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —
35		Commodity	COM	$ (1,439)	$ (624)	$ (419)	$ (593)
36		Total Odorization		$ (1,439)	$ (624)	$ (419)	$ (593)
37	8750	**Meas. & Reg. Station - Gen. - Allocated**					
38		Customer	CUS	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 24,605	$ 3,569	$ 3,015	$ 13,649
40		Commodity	COM	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 24,605	$ 3,569	$ 3,015	$ 13,649
42		**Meas. & Reg. Station - Gen. - DA**					
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ —	$ —	$ —	$ 8,173
45		Commodity	COM-DA	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
46		Total Meas. & Reg. Station - Gen. - DA		$ —	$ —	$ —	$ 8,173
47	8750	**Odorization**					
48		Customer	CUS	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 8,605	$ 3,733	$ 2,504	$ 3,548
51		Total Odorization		$ 8,605	$ 3,733	$ 2,504	$ 3,548
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**					
53		Customer	NRCUS	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 6,143	$ 891	$ 753	$ 3,407
55		Commodity	COM	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 6,143	$ 891	$ 753	$ 3,407
57	8760	**Meas. & Reg. Stat. - Ind. - DA**					
58		Customer	CUS-DA	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ —	$ —	$ —	$ 1,326
60		Commodity	COM-DA	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ —	$ —	$ —	$ 1,326
62	8770	**Meas. & Reg. Stat.- City Gate**					
63		Customer	CUS	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 2,253	$ 327	$ 276	$ 1,250
65		Commodity	COM	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 2,253	$ 327	$ 276	$ 1,250
67	8780	**Meter & House Reg. Exp. - Alloc.**					
68		Customer	MTRGCUS-ALL	$ 33,209	$ 1,544	$ 192	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —
71		Total Meter & House Reg. Exp. - Alloc.		$ 33,209	$ 1,544	$ 192	$ —
72	8780	**Meter & House Reg. Exp - Dir. Assn.**					
73		Customer	CUS-DA	$ —	$ —	$ —	$ 16,673
74		Demand	DEM-DA	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ —	$ —	$ —	$ 16,673
77	8780	**Odorization**					
78		Customer	CUS	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —
80		Commodity	COM	$ 3	$ 1	$ 1	$ 1
81		Total Odorization		$ 3	$ 1	$ 1	$ 1
82	8790	**Customer Installation Expense**					
83		Customer	METCUS-ALL	$ 18	$ 1	$ 0	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 18	$ 1	$ 0	$ —
87	8800	**Other Expenses**					
88		Customer	871-879CUS	$ 4,370	$ 170	$ 21	$ 16
89		Demand	DEM	$ 10,687	$ 1,550	$ 1,310	$ 5,928
90		Commodity	COM	$ 1,812	$ 786	$ 527	$ 747

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
91		Total Other Expenses		$ 16,870	$ 2,506	$ 1,858	$ 6,692
92	8800	**Odorization**					
93		Customer	CUS	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 47	$ 21	$ 14	$ 19
96		Total Odorization		$ 47	$ 21	$ 14	$ 19
97	8810	**Rents**					
98		Customer	871-879CUS	$ 156	$ 6	$ 1	$ 1
99		Demand	DEM	$ 381	$ 55	$ 47	$ 211
100		Commodity	COM	$ 65	$ 28	$ 19	$ 27
101		Total Rents		$ 601	$ 89	$ 66	$ 238
102	8820	**Corporate & Div. Exp.**					
103		Customer	CUS	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**					
108		Customer		$ 52,378	$ 2,032	$ 254	$ 67,323
109		Demand		$ 339,724	$ 49,280	$ 41,630	$ 226,802
110		Commodity		$ 29,059	$ 12,607	$ 8,455	$ 11,981
111		Total Distr. & Trans. Operations Exp.		$ 421,161	$ 63,919	$ 50,339	$ 306,106
112		**Distribution Maintenance Expenses**					
113	8850	**Maintenance Supervision and Engineering**					
114		Customer	887-893CUS	$ 9	$ 0	$ 0	$ 0
115		Demand	887-893DEM	$ 274	$ 40	$ 34	$ 152
116		Commodity	COM	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ 283	$ 40	$ 34	$ 152
118	8860	**Structures and Improvements**					
119		Customer	887-893CUS	$ 1,140	$ 18	$ 2	$ 21
120		Demand	887-893DEM	$ 34,239	$ 4,967	$ 4,196	$ 18,993
121		Commodity	COM	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 35,379	$ 4,985	$ 4,198	$ 19,013
123	8870	**Maintenance of Mains-Allocated**					
124		Customer	CUS	$ 3,877	$ 61	$ 8	$ 145
125		Demand	DEM	$ 70,059	$ 10,163	$ 8,585	$ 38,863
126		Commodity	COM	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 73,936	$ 10,224	$ 8,593	$ 39,008
128	8870	**Maintenance of Mains - Directly Assigned**					
129		Customer	CUS-DA	$ —	$ —	$ —	$ 32,752
130		Demand	DEM-DA	$ —	$ —	$ —	$ 25,788
131		Commodity	COM-DA	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ —	$ —	$ —	$ 58,540
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**					
134		Customer	CUS	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 63,528	$ 9,215	$ 7,785	$ 35,240

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
136		Commodity	COM	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 63,528	$ 9,215	$ 7,785	$ 35,240
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**					
139		Customer	CUS-DA	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ —	$ —	$ —	$ 18,902
141		Commodity	COM-DA	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ 18,902
143	8890	**Odorization**					
144		Customer	CUS	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 10,779	$ 4,676	$ 3,136	$ 4,444
147		Total Odorization		$ 10,779	$ 4,676	$ 3,136	$ 4,444
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**					
149		Customer	NRCUS	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 105,152	$ 15,253	$ 12,885	$ 58,329
151		Commodity	COM	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 105,152	$ 15,253	$ 12,885	$ 58,329
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**					
154		Customer	CUS-DA	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ —	$ —	$ —	$ 22,697
156		Commodity	COM-DA	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ —	$ —	$ —	$ 22,697
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**					
159		Customer	CUS	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 1,580	$ 229	$ 194	$ 877
161		Commodity	COM	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 1,580	$ 229	$ 194	$ 877
163	8910	**Odorization**					
164		Customer	CUS	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —
166		Commodity	COM	$ 3	$ 1	$ 1	$ 1
167		**Total Odorization**		$ 3	$ 1	$ 1	$ 1
168	8920	**Services - Allocated**					
169		Customer	SERCUS-ALL	$ 4,100	$ 63	$ 8	$ —
170		Demand	DEM	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 4,100	$ 63	$ 8	$ —
173	8920	**Services - Directly Assigned**					
174		Customer	CUS-DA	$ —	$ —	$ —	$ 8,552
175		Demand	DEM-DA	$ —	$ —	$ —	$ —
176		Commodity	COM-DA	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ —	$ —	$ —	$ 8,552
178	8930	**Meters & House Regulators - Alloc.**					
179		Customer	MTRGCUS-ALL	$ 59	$ 3	$ 0	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
181		Commodity	COM	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ 59	$ 3	$ 0	$ —
183	8930	**Meters & House Regulators - DA**					
184		Customer	CUS-DA	$ —	$ —	$ —	$ 30
185		Demand	DEM-DA	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ —	$ —	$ —	$ 30
188	8940	**Maintenance of Other Equipment**					
189		Customer	CUS	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**					
194		Customer	CUS	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**					
199		Customer	CUS	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**					
204		Customer		$ 9,185	$ 145	$ 18	$ 41,500
205		Demand		$ 274,832	$ 39,867	$ 33,678	$ 219,840
206		Commodity		$ 10,782	$ 4,678	$ 3,137	$ 4,445
207		Total Distr. Maintenance Expense		$ 294,800	$ 44,690	$ 36,834	$ 265,785
208		**Total Oper. & Maint. Expense**					
209		Customer		$ 61,563	$ 2,177	$ 272	$ 108,822
210		Demand		$ 614,556	$ 89,147	$ 75,308	$ 446,642
211		Commodity		$ 39,842	$ 17,284	$ 11,592	$ 16,426
212		Total Operations & Maint. Expense		$ 715,961	$ 108,609	$ 87,173	$ 571,890
213		**Customer Accounts Expense**					
214	901	**Supervision**					
215		Customer	902-904CUS	$ 0	$ 0	$ 0	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —
218		Total Supervision		$ 0	$ 0	$ 0	$ 0
219	902	**Meter Reading Expense**					
220		Customer	METCUS-TOT	$ 2,440	$ 97	$ 12	$ 180
221		Demand	DEM	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 2,440	$ 97	$ 12	$ 180
224	903	**Customer Accounting**					
225		Customer	903CUS	$ 2,939	$ 45	$ 6	$ 106

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
226		Demand	DEM	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 2,939	$ 45	$ 6	$ 106
229	904	**Bad Debt Expense**					
230		Customer	904CUS	$ —	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ —	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**					
235		Customer	902-904CUS	$ 282	$ 7	$ 1	$ 15
236		Demand	DEM	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 282	$ 7	$ 1	$ 15
239	907-910	**Customer Information Expense**					
240		Customer	CUS	$ 1,805	$ 28	$ 4	$ 67
241		Demand	DEM	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 1,805	$ 28	$ 4	$ 67
244		**Sales and Advertising Expense**					
245	911	**Supervision**					
246		Customer	CUS	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**					
251		Customer	CUS	$ 1	$ 0	$ 0	$ 0
252		Demand	DEM	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ 1	$ 0	$ 0	$ 0
255	913	**Advertising**					
256		Customer	CUS	$ 138	$ 2	$ 0	$ 5
257		Demand	DEM	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —
259		Total Advertising		$ 138	$ 2	$ 0	$ 5
260	914	**Employee Sales Referrals**					
261		Customer	CUS	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**					
266		Customer	CUS	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**					

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
271	920-940	**Administrative & General Expenses**					
272		Customer	OPEXPCUS	$ 70,303	$ 2,037	$ 255	$ 153,268
273		Demand	OPEXPDEM	$ 216,593	$ 31,419	$ 26,541	$ 161,563
274		Commodity	COM	$ 14,305	$ 6,206	$ 4,162	$ 5,898
275		Total Administrative & General Exp.		$ 301,201	$ 39,662	$ 30,958	$ 320,729
276		**Depreciation & Amortization Expense**					
277	301-303	**Intangible Plant - Allocated**					
278		Customer	CUS	$ 46	$ 1	$ 0	$ 2
279		Demand	DEM	$ 541	$ 79	$ 66	$ 300
280		Commodity	COM	$ 4	$ 2	$ 1	$ 2
281		Total Intangible Plant		$ 591	$ 81	$ 68	$ 304
282	301-303	**Intangible Plant - Directly Assigned**					
283		Customer	CUS-DA	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**					
288		Customer	CUS	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**					
293		Customer	CUS	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 1,137	$ 165	$ 139	$ 631
295		Commodity	COM	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ 1,137	$ 165	$ 139	$ 631
297	367	**Transmission Mains**					
298		Customer	CUS	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 74,890	$ 10,864	$ 9,177	$ 41,543
300		Commodity	COM	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 74,890	$ 10,864	$ 9,177	$ 41,543
302	368	**Compression Station Equipment**					
303		Customer	CUS	$ —	$ —	$ —	$ —
304		Demand	DEM	$ 90	$ 13	$ 11	$ 50
305		Commodity	COM	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ 90	$ 13	$ 11	$ 50
307	369	**Meas. & Reg. Station Equipment**					
308		Customer	CUS	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 20,324	$ 2,948	$ 2,490	$ 11,274
310		Commodity	COM	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 20,324	$ 2,948	$ 2,490	$ 11,274
312	371	**Other Equipment**					
313		Customer	CUS	$ —	$ —	$ —	$ —
314		Demand	DEM	$ 64	$ 9	$ 8	$ 36
315		Commodity	COM	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
316		Total Other Equipment		$ 64	$ 9	$ 8	$ 36
317	375	**Structures and Improvements**					
318		Customer	376-379CUS	$ 8	$ 0	$ 0	$ 69
319		Demand	DEM	$ 178	$ 26	$ 22	$ 99
320		Commodity	COM	$ —	$ —	$ —	$ —
321		Total Structures and Improvements		$ 186	$ 26	$ 22	$ 168
322	376	**Distribution Mains - Allocated**					
323		Customer	CUS	$ 13,258	$ 209	$ 26	$ 495
324		Demand	DEM	$ 239,604	$ 34,757	$ 29,361	$ 132,911
325		Commodity	COM	$ —	$ —	$ —	$ —
326		Total Distribution Mains - Allocated		$ 252,861	$ 34,966	$ 29,387	$ 133,406
327	376	**Distribution Mains - Directly Assigned**					
328		Customer	CUS-DA	$ —	$ —	$ —	$ 103,492
329		Demand	DEM-DA	$ —	$ —	$ —	$ 81,487
330		Commodity	COM-DA	$ —	$ —	$ —	$ —
331		Distribution Mains - Directly Assigned		$ —	$ —	$ —	$ 184,979
332	377	**Compressor Station Equipment**					
333		Customer	CUS	$ —	$ —	$ —	$ —
334		Demand	DEM	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —
336		Total Compressor Station Equipment		$ —	$ —	$ —	$ —
337	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**					
338		Customer	CUS	$ —	$ —	$ —	$ —
339		Demand	DEM	$ 32,299	$ 4,685	$ 3,958	$ 17,916
340		Commodity	COM	$ —	$ —	$ —	$ —
341		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 32,299	$ 4,685	$ 3,958	$ 17,916
342	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**					
343		Customer	CUS-DA	$ —	$ —	$ —	$ —
344		Demand	DEM-DA	$ —	$ —	$ —	$ 7,213
345		Commodity	COM-DA	$ —	$ —	$ —	$ —
346		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ —	$ —	$ —	$ 7,213
347	378	**Odorization**					
348		Customer	CUS	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 318	$ 138	$ 93	$ 131
351		Total Odorization		$ 318	$ 138	$ 93	$ 131
352	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**					
353		Customer	CUS	$ —	$ —	$ —	$ —
354		Demand	DEM	$ 10,492	$ 1,522	$ 1,286	$ 5,820
355		Commodity	COM	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq.- City Gate		$ 10,492	$ 1,522	$ 1,286	$ 5,820
357	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**					
358		Customer	CUS-DA	$ —	$ —	$ —	$ —
359		Demand	DEM-DA	$ —	$ —	$ —	$ —
360		Commodity	COM-DA	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
361		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —
362	379	**Odorization**					
363		Customer	CUS	$ —	$ —	$ —	$ —
364		Demand	DEM	$ —	$ —	$ —	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —
366		Total Odorization		$ —	$ —	$ —	$ —
367	380	**Services - Allocated**					
368		Customer	SERCUS-ALL	$ 27,765	$ 427	$ 55	$ —
369		Demand	DEM	$ —	$ —	$ —	$ —
370		Commodity	COM	$ —	$ —	$ —	$ —
371		Total Services - Allocated		$ 27,765	$ 427	$ 55	$ —
372	380	**Services - Directly Assigned**					
373		Customer	CUS-DA	$ —	$ —	$ —	$ 56,728
374		Demand	DEM-DA	$ —	$ —	$ —	$ —
375		Commodity	COM-DA	$ —	$ —	$ —	$ —
376		Total Services - Directly Assigned		$ —	$ —	$ —	$ 56,728
377	381	**Meters - Allocated**					
378		Customer	METCUS-ALL	$ 12,596	$ 499	$ 62	$ —
379		Demand	DEM	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —
381		Total Meters - Allocated		$ 12,596	$ 499	$ 62	$ —
382	381	**Meters - Directly Assigned**					
383		Customer	CUS-DA	$ —	$ —	$ —	$ 7,213
384		Demand	DEM-DA	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —
386		Total Meters - Directly Assigned		$ —	$ —	$ —	$ 7,213
387	382	**Meter Installations**					
388		Customer	METCUS-TOT	$ —	$ —	$ —	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —
391		Total Meter Installations		$ —	$ —	$ —	$ —
392	383	**House Regulators - Allocated**					
393		Customer	REGCUS-ALL	$ 5,755	$ 350	$ 42	$ —
394		Demand	DEM	$ —	$ —	$ —	$ —
395		Commodity	COM	$ —	$ —	$ —	$ —
396		Total House Regulators - Allocated		$ 5,755	$ 350	$ 42	$ —
397	383	**House Regulators - Directly Assn.**					
398		Customer	CUS-DA	$ —	$ —	$ —	$ 3,363
399		Demand	DEM-DA	$ —	$ —	$ —	$ —
400		Commodity	COM-DA	$ —	$ —	$ —	$ —
401		House Regulators - Directly Assn.		$ —	$ —	$ —	$ 3,363
402	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**					
403		Customer	NRCUS	$ —	$ —	$ —	$ —
404		Demand	NRDEM	$ 64,346	$ 9,334	$ 7,885	$ 35,693
405		Commodity	COM	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
406		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 64,346	$ 9,334	$ 7,885	$ 35,693
407	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**					
408		Customer	CUS-DA	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —
411		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —
412	386	**Other Prop.- Customer Premises**					
413		Customer	CUS	$ 256	$ 4	$ 1	$ 10
414		Demand	DEM	$ —	$ —	$ —	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —
416		Total Other Prop. - Customer Premises		$ 256	$ 4	$ 1	$ 10
417	387	**Other Equipment**					
418		Customer	CUS	$ —	$ —	$ —	$ —
419		Demand	DEM	$ —	$ —	$ —	$ —
420		Commodity	COM	$ —	$ —	$ —	$ —
421		Total Other Equipment		$ —	$ —	$ —	$ —
422	389-98	**General Plant - Allocated**					
423		Customer	GENPTCUS	$ 13,444	$ 272	$ 34	$ 26,583
424		Demand	DISPLTDEM	$ 57,091	$ 8,282	$ 6,996	$ 49,626
425		Commodity	COM	$ 681	$ 295	$ 198	$ 281
426		Total General Plant - Allocated		$ 71,216	$ 8,849	$ 7,228	$ 76,489
427	389-98	**General Plant - Directly Assigned**					
428		Customer	CUS-DA	$ —	$ —	$ —	$ 2,171
429		Demand	DEM-DA	$ —	$ —	$ —	$ 307
430		Commodity	COM-DA	$ —	$ —	$ —	$ 3
431		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ 2,481
432	389-98	**General Plant - Odorization**					
433		Customer	CUS	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —
435		Commodity	COM	$ 318	$ 138	$ 93	$ 131
436		Total General Plant - Odorization		$ 318	$ 138	$ 93	$ 131
437	40730	**Pension & FAS 106 Amort. Expense**					
438		Customer	CUS	$ (419)	$ (7)	$ (1)	$ (16)
439		Demand	DEM	$ (3,255)	$ (472)	$ (399)	$ (1,805)
440		Commodity	COM	$ (243)	$ (106)	$ (71)	$ (100)
441		Total Pension & FAS 106 Amort. Exp.		$ (3,917)	$ (584)	$ (471)	$ (1,922)
442		**Total Depreciation & Amort. Exp.**					
443		Customer		$ 72,709	$ 1,755	$ 219	$ 200,110
444		Demand		$ 497,801	$ 72,211	$ 61,001	$ 383,099
445		Commodity		$ 1,078	$ 468	$ 314	$ 447
446		Total Depreciation & Amort. Expense		$ 571,587	$ 74,433	$ 61,534	$ 583,657
447		**Taxes Other Than Income**					
448	4081	**Payroll and Other Taxes**					
449		Customer	OPEXPCUS	$ 5,470	$ 159	$ 20	$ 11,924
450		Demand	OPEXPDEM	$ 32,319	$ 4,688	$ 3,960	$ 24,108

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
451		Commodity	COM	$ 2,135	$ 926	$ 621	$ 880
452		Total Payroll and Other Taxes		$ 39,924	$ 5,773	$ 4,601	$ 36,912
453	4081	**Ad Valorem Taxes - Allocated**					
454		Customer	CUS	$ 10,145	$ 160	$ 20	$ 379
455		Demand	DEM	$ 119,972	$ 17,403	$ 14,701	$ 66,550
456		Commodity	COM	$ 910	$ 395	$ 265	$ 375
457		Total Ad Valorem Taxes - Allocated		$ 131,026	$ 17,958	$ 14,986	$ 67,303
458	4081	**Ad Valorem Taxes - Directly Assn.**					
459		Customer	CUS-DA	$ —	$ —	$ —	$ 44,614
460		Demand	DEM-DA	$ —	$ —	$ —	$ 31,442
461		Commodity	COM-DA	$ —	$ —	$ —	$ —
462		Total Ad Valorem Taxes - Directly Assn.		$ —	$ —	$ —	$ 76,057
463		**Revenue Related Taxes**					
464		Customer	TOTREVCUS	$ 1,669	$ 381	$ 114	$ 2,926
465		Demand	DEM	$ —	$ —	$ —	$ —
466		Commodity	COM	$ —	$ —	$ —	$ —
467		Total Revenue Related Taxes		$ 1,669	$ 381	$ 114	$ 2,926
468		**Total Taxes Other Than Income**					
469		Customer		$ 17,284	$ 699	$ 154	$ 59,844
470		Demand		$ 152,291	$ 22,091	$ 18,662	$ 122,100
471		Commodity		$ 3,044	$ 1,321	$ 886	$ 1,255
472		Total Taxes Other Than Income		$ 172,619	$ 24,111	$ 19,702	$ 183,199
473		**Excess Def. Income Tax Amort. - Directly Assn.**					
474		Customer	CUS-DA	$ —	$ —	$ —	$ (5,769)
475		Demand	DEM-DA	$ —	$ —	$ —	$ (4,148)
476		Commodity	COM-DA	$ —	$ —	$ —	$ —
477		**Total Excess Def. Income Tax Amort. - DA**		$ —	$ —	$ —	$ (9,917)
478		**Excess Def. Income Tax Amort. - Alloc.**					
479		Customer	CUS	$ (1,161)	$ (18)	$ (2)	$ (43)
480		Demand	DEM	$ (14,705)	$ (2,133)	$ (1,802)	$ (8,157)
481		Commodity	COM	$ (111)	$ (48)	$ (32)	$ (46)
482		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (15,977)	$ (2,200)	$ (1,837)	$ (8,246)
483		**Interest on Customer Deposits**					
484		Customer	DEPCUS	$ —	$ —	$ —	$ —
485		Demand	DEM	$ —	$ —	$ —	$ —
486		Commodity	COM	$ —	$ —	$ —	$ —
487		Total Interest on Cust. Deposits		$ —	$ —	$ —	$ —
488		**Req. Return - Other Than Directly Assn.**					
489		Customer	CUS	$ 77,274	$ 1,220	$ 153	$ 2,885
490		Demand	DEM	$ 978,974	$ 142,009	$ 119,964	$ 543,049
491		Commodity	COM	$ 7,421	$ 3,220	$ 2,159	$ 3,060
492		Tot. Req. Return - Other Than Dir. Assn.		$ 1,063,669	$ 146,449	$ 122,276	$ 548,993
493		**Req. Return - Directly Assigned**					
494		Customer	CUS-DA	$ —	$ —	$ —	$ 384,051
495		Demand	DEM-DA	$ —	$ —	$ —	$ 276,140

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOC. FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
496		Commodity	COM-DA	$ —	$ —	$ —	$ —
497		Tot. Req. Return - Directly Assigned		$ —	$ —	$ —	$ 660,191
498		**Income Taxes - Other Than DA**					
499		Customer	CUS	$ 15,997	$ 253	$ 32	$ 597
500		Demand	DEM	$ 202,660	$ 29,398	$ 24,834	$ 112,418
501		Commodity	COM	$ 1,536	$ 666	$ 447	$ 633
502		Total Income Taxes - Other Than DA		$ 220,193	$ 30,317	$ 25,313	$ 113,648
503		**Income Taxes - Directly Assigned**					
504		Customer	CUS-DA	$ —	$ —	$ —	$ 79,503
505		Demand	DEM-DA	$ —	$ —	$ —	$ 57,164
506		Commodity	COM-DA	$ —	$ —	$ —	$ —
507		Total Income Taxes - Dir. Assigned		$ —	$ —	$ —	$ 136,668
508		**Total Cost of Service Before Revenue Credits**					
509		Customer		$ 321,574	$ 8,303	$ 1,105	$ 983,643
510		Demand		$ 2,648,169	$ 384,142	$ 324,509	$ 2,089,871
511		Commodity		$ 67,114	$ 29,116	$ 19,527	$ 27,673
512		**Total Cost of Service Before Revenue Credits**		$ 3,036,857	$ 421,561	$ 345,141	$ 3,101,187

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Cost Allocation Factors							
2								
3	Total Customers		704,554	666,390	34,380	91	2,728	1
4	Total Customers Factor (CUS)	CUS	1.00000	0.94583	0.04880	0.00013	0.00387	0.00000
5								
6	Customers - Directly Assigned		19	0	0	0	0	0
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8								
9	Services - Allocated Weighting			1.00000	1.15345	1.40333	1.15681	1.15677
10	Weighted Customers		710,753	666,390	39,656	128	3,156	1
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.93758	0.05579	0.00018	0.00444	0.00000
12								
13	Meters - Allocated Weighting			1.00000	1.61963	4.21548	2.50902	6.20576
14	Weighted Customers		732,995	666,390	55,683	385	6,844	6
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.90913	0.07597	0.00053	0.00934	0.00001
16								
17	Meters - Total Weighting			1.00000	1.61963	4.21548	2.50902	6.20576
18	Weighted Customers		733,088	666,390	55,683	385	6,844	6
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.90902	0.07596	0.00053	0.00934	0.00001
20								
21	Regulators - Allocated Weighting			1.00000	2.39959	11.54692	5.93139	21.82621
22	Weighted Customers		776,334	666,390	82,498	1,056	16,180	22
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.85838	0.10627	0.00136	0.02084	0.00003
24								
25	Meters and Regulators - Allocated Weighting			1.00000	1.75759	5.49667	3.10384	9.08033
26	Weighted Customers		740,663	666,390	60,426	503	8,467	9
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.89972	0.08158	0.00068	0.01143	0.00001
28								
29	Non-Residential Customers		38,164	0	34,380	91	2,728	1
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.90085	0.00240	0.07148	0.00003
31								
32	Customer Cost Allocation Factors							
33								
34	Distribution Plant Customer Costs		$ 1,572,088,582	$ 1,466,099,805	$ 88,124,439	$ 352,858	$ 8,037,523	$ 4,581
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.93258	0.05606	0.00022	0.00511	0.00000
36								
37	Account 376-379 Customer Costs		$ 669,963,070	$ 629,845,609	$ 32,494,688	$ 86,433	$ 2,578,333	$ 945
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.94012	0.04850	0.00013	0.00385	0.00000
39								
40	Total Revenue (inc. cost of gas)		$ 570,341,527	$ 418,199,958	$ 112,042,479	$ 4,185,762	$ 17,668,057	$ 4,533
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.73324	0.19645	0.00734	0.03098	0.00001
42								
43	Mains - Allocated Customer Cost Factor		0.49397	0.46721	0.02410	0.00006	0.00191	0.00000

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
44	Services - Allocated Customer Cost Factor		0.50603	0.47445	0.02823	0.00009	0.00225	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.94166	0.05234	0.00016	0.00416	0.00000
46								
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
48								
49	Total Plant Customer		$ 1,854,087,642	$ 1,731,078,328	$ 102,820,997	$ 401,683	$ 9,289,516	$ 5,175
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.93366	0.05546	0.00022	0.00501	0.00000
51								
52	Non-Intangible Plant Customer							
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 1,854,087,642	$ 1,753,655,889	$ 90,473,762	$ 240,653	$ 7,178,756	$ 2,632
54		NONINCUS	1.00000	0.94583	0.04880	0.00013	0.00387	0.00000
55								
56	Account 871-879 Customer Costs		$ 27,948,946	$ 25,659,877	$ 1,921,988	$ 12,560	$ 230,429	$ 211
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.91810	0.06877	0.00045	0.00824	0.00001
58								
59	Account 887-893 Customer Costs		$ 9,244,138	$ 8,710,552	$ 478,773	$ 1,409	$ 38,177	$ 14
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.94228	0.05179	0.00015	0.00413	0.00000
61								
62	Account 903 Customer		$ 11,808,882	$ 11,351,886	$ 432,914	$ 936	$ 17,647	$ 6
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.96130	0.03666	0.00008	0.00149	0.00000
64								
65	Customer Cost Allocation Factors							
66								
67	Account 904 Customer		$ 3,374,231	$ 3,059,074	$ 306,239	$ 4,787	$ 1,752	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.90660	0.09076	0.00142	0.00052	0.00000
69								
70	Accounts 902-904 Customer		$ 16,606,818	$ 15,705,133	$ 847,293	$ 6,472	$ 32,691	$ 18
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.94570	0.05102	0.00039	0.00197	0.00000
72								
73	Operating Expense Customer		$ 132,578,429	$ 123,463,171	$ 7,706,622	$ 39,290	$ 715,786	$ 494
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.93125	0.05813	0.00030	0.00540	0.00000
75								
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 188,188,716	$ 175,501,204	$ 10,549,040	$ 42,239	$ 962,141	$ 548

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 219,962,293	$ 208,047,431	$ 10,733,482	$ 28,550	$ 851,662	$ 312
78	Total General Plant Customer Costs		$ 408,151,009	$ 383,548,635	$ 21,282,522	$ 70,790	$ 1,813,803	$ 861
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.93972	0.05214	0.00017	0.00444	0.00000
80								
81	Customer Deposits		$ (16,329,640)	$ (7,757,745)	$ (8,199,802)	$ (103,027)	$ (84,295)	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.47507	0.50214	0.00631	0.00516	0.00000
83								
84	Demand Cost Allocation Factors							
85								
86	System Demand							
87	**System Demand Factor (DEM)**	DEM	1.00000	0.66656	0.18511	0.00440	0.04798	0.00000
88								
89	Non-Residential Demand							
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.55514	0.01321	0.14388	0.00000
91								
92	Directly Assigned Demand							
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
94								
95	Distribution Plant Demand		$ 497,032,940	$ 302,656,687	$ 105,632,702	$ 2,513,006	$ 27,378,625	$ —
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.60893	0.21253	0.00506	0.05508	0.00000
97								
98	Demand Cost Allocation Factors							
99								
100	Non-Intangible Plant Demand		$ 692,494,004	$ 461,588,917	$ 128,184,387	$ 3,049,511	$ 33,223,729	$ —
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.66656	0.18511	0.00440	0.04798	0.00000
102								
103	Total Plant Demand		$ 693,172,712	$ 430,164,848	$ 143,463,826	$ 3,413,009	$ 37,183,962	$ —
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.62057	0.20697	0.00492	0.05364	0.00000
105								
106	Operating Expense Demand		$ 43,058,951	$ 26,587,611	$ 9,025,801	$ 214,724	$ 2,339,370	$ —
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.61747	0.20961	0.00499	0.05433	0.00000
108								
109	Acct. 887-893 Demand		$ 7,462,026	$ 3,949,422	$ 1,949,983	$ 46,390	$ 505,410	$ —
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.52927	0.26132	0.00622	0.06773	0.00000
111								
112	Rate Base Demand		$ 542,387,737	$ 337,400,422	$ 112,063,199	$ 2,665,987	$ 29,045,327	$ —
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.62206	0.20661	0.00492	0.05355	0.00000
114								

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
115	Commodity Cost Allocation Factors							
116								
117	Annual Distribution Volumes (Ccf)		466,615,216	235,495,795	115,414,328	4,584,666	19,183,545	—
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.50469	0.24734	0.00983	0.04111	0.00000
119								
120	Commodity - Direct Assignment		6,041,960	0	0	0	0	0
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Customer Cost Allocation Factors								
2									
3	Total Customers		0	355	74	507	8	1	19
4	Total Customers Factor (CUS)	CUS	0.00000	0.00050	0.00010	0.00072	0.00001	0.00000	0.00003
5									
6	Customers - Directly Assigned		0	0	0	0	0	0	19
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
8									
9	Services - Allocated Weighting		0.00000	1.50534	1.52440	1.50337	1.46577	1.50398	0.00000
10	Weighted Customers		0	535	112	762	12	2	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	0.00000	0.00075	0.00016	0.00107	0.00002	0.00000	0.00000
12									
13	Meters - Allocated Weighting		0.00000	5.41191	6.11572	2.47933	6.21545	6.20576	0.00000
14	Weighted Customers		0	1,923	451	1,256	50	6	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	0.00000	0.00262	0.00062	0.00171	0.00007	0.00001	0.00000
16									
17	Meters - Total Weighting		0.00000	5.41191	6.11572	2.47933	6.21545	6.20576	4.89953
18	Weighted Customers		0	1,923	451	1,256	50	6	93
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	0.00000	0.00262	0.00062	0.00171	0.00007	0.00001	0.00013
20									
21	Regulators - Allocated Weighting		0.00000	16.09336	17.75033	5.83955	22.49194	21.82621	0.00000
22	Weighted Customers		0	5,718	1,309	2,959	180	22	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	0.00000	0.00737	0.00169	0.00381	0.00023	0.00003	0.00000
24									
25	Meters and Regulators - Allocated Weighting		0.00000	7.36119	8.18848	3.09332	9.10767	9.08033	0.00000
26	Weighted Customers		0	2,615	604	1,567	73	9	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	0.00000	0.00353	0.00082	0.00212	0.00010	0.00001	0.00000
28									
29	Non-Residential Customers		0	355	74	507	8	1	19
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	0.00000	0.00931	0.00193	0.01328	0.00021	0.00003	0.00050
31									
32	Customer Cost Allocation Factors								
33									
34	Distribution Plant Customer Costs		$ —	$ 1,583,972	$ 348,449	$ 1,655,640	$ 39,287	$ 4,915	$ 5,837,111
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	0.00000	0.00101	0.00022	0.00105	0.00002	0.00000	0.00371
36									
37	Account 376-379 Customer Costs		$ —	$ 335,816	$ 69,706	$ 478,908	$ 7,561	$ 945	$ 4,064,125
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	0.00000	0.00050	0.00010	0.00071	0.00001	0.00000	0.00607
39									
40	Total Revenue (inc. cost of gas)		$ —	$ 4,655,868	$ 4,778,368	$ 2,887,898	$ 658,287	$ 197,869	$ 5,062,449
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	0.00000	0.00816	0.00838	0.00506	0.00115	0.00035	0.00888
42									
43	Mains - Allocated Customer Cost Factor		0.00000	0.00025	0.00005	0.00036	0.00001	0.00000	0.00001

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
44	Services - Allocated Customer Cost Factor		0.00000	0.00038	0.00008	0.00054	0.00001	0.00000	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	0.00000	0.00063	0.00013	0.00090	0.00001	0.00000	0.00001
46									
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
48									
49	Total Plant Customer		$ —	$ 1,791,171	$ 393,073	$ 1,901,560	$ 44,250	$ 5,535	$ 6,356,354
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	0.00000	0.00097	0.00021	0.00103	0.00002	0.00000	0.00343
51									
52	Non-Intangible Plant Customer								
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ —	$ 935,000	$ 194,079	$ 1,333,407	$ 21,053	$ 2,632	$ 49,781
54		NONINCUS	0.00000	0.00050	0.00010	0.00072	0.00001	0.00000	0.00003
55									
56	Account 871-879 Customer Costs		$ —	$ 63,156	$ 14,415	$ 44,218	$ 1,715	$ 214	$ 162
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	0.00000	0.00226	0.00052	0.00158	0.00006	0.00001	0.00001
58									
59	Account 887-893 Customer Costs		$ —	$ 5,696	$ 1,192	$ 8,036	$ 127	$ 16	$ 145
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	0.00000	0.00062	0.00013	0.00087	0.00001	0.00000	0.00002
61									
62	Account 903 Customer		$ —	$ 1,985	$ 412	$ 2,939	$ 45	$ 6	$ 106
63	**Account 903 Customer Factor (903CUS)**	903CUS	0.00000	0.00017	0.00003	0.00025	0.00000	0.00000	0.00001
64									
65	Customer Cost Allocation Factors								
66									
67	Account 904 Customer		$ —	$ 2,379	$ —	$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	0.00000	0.00071	0.00000	0.00000	0.00000	0.00000	0.00000
69									
70	Accounts 902-904 Customer		$ —	$ 8,099	$ 1,288	$ 5,379	$ 141	$ 18	$ 286
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	0.00000	0.00049	0.00008	0.00032	0.00001	0.00000	0.00002
72									
73	Operating Expense Customer		$ —	$ 161,660	$ 35,598	$ 141,877	$ 4,112	$ 514	$ 309,306
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	0.00000	0.00122	0.00027	0.00107	0.00003	0.00000	0.00233
75									
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ —	$ 189,611	$ 41,712	$ 198,190	$ 4,703	$ 588	$ 698,738

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ —	$ 110,925	$ 23,025	$ 158,191	$ 2,498	$ 312	$ 5,906
78	Total General Plant Customer Costs		$ —	$ 300,536	$ 64,736	$ 356,381	$ 7,201	$ 901	$ 704,644
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	0.00000	0.00074	0.00016	0.00087	0.00002	0.00000	0.00173
80									
81	Customer Deposits		$ —	$ (145,892)	$ (38,879)	$ —	$ —	$ —	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	0.00000	0.00893	0.00238	0.00000	0.00000	0.00000	0.00000
83									
84	Demand Cost Allocation Factors								
85									
86	System Demand								
87	**System Demand Factor (DEM)**	DEM	0.00000	0.03025	0.02413	0.02281	0.00331	0.00280	0.01265
88									
89	Non-Residential Demand								
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	0.00000	0.09073	0.07236	0.06842	0.00992	0.00838	0.03795
91									
92	Directly Assigned Demand								
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
94									
95	Distribution Plant Demand		$ —	$ 17,264,949	$ 13,768,756	$ 13,018,376	$ 1,888,438	$ 1,595,283	$ 11,316,116
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	0.00000	0.03474	0.02770	0.02619	0.00380	0.00321	0.02277
97									
98	Demand Cost Allocation Factors								
99									
100	Non-Intangible Plant Demand		$ —	$ 20,950,869	$ 16,708,268	$ 15,797,689	$ 2,291,604	$ 1,935,863	$ 8,763,167
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	0.00000	0.03025	0.02413	0.02281	0.00331	0.00280	0.01265
102									
103	Total Plant Demand		$ —	$ 23,448,190	$ 18,699,876	$ 17,680,756	$ 2,564,760	$ 2,166,616	$ 14,386,869
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	0.00000	0.03383	0.02698	0.02551	0.00370	0.00313	0.02076
105									
106	Operating Expense Demand		$ —	$ 1,475,206	$ 1,176,473	$ 1,112,357	$ 161,358	$ 136,309	$ 829,741
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	0.00000	0.03426	0.02732	0.02583	0.00375	0.00317	0.01927
108									
109	Acct. 887-893 Demand		$ —	$ 318,712	$ 254,172	$ 240,320	$ 34,861	$ 29,449	$ 133,308
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	0.00000	0.04271	0.03406	0.03221	0.00467	0.00395	0.01786
111									
112	Rate Base Demand		$ —	$ 18,315,970	$ 14,606,943	$ 13,810,883	$ 2,003,399	$ 1,692,398	$ 10,783,208
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	0.00000	0.03377	0.02693	0.02546	0.00369	0.00312	0.01988
114									

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
115	Commodity Cost Allocation Factors								
116									
117	Annual Distribution Volumes (Ccf)		—	28,644,878	31,973,610	14,654,808	6,357,708	4,263,918	6,041,960
118	**Distribution Commodity Factor (COM)**	COM	0.00000	0.06139	0.06852	0.03141	0.01363	0.00914	0.01295
119									
120	Commodity - Direct Assignment		0	0	0	0	0	0	6,041,960
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Current Revenue-to-Cost Ratio (1)	0.9105	0.8257	1.5365	3.6100	1.3051	4.7222	0.0000	1.1838	1.5934	0.9629	1.5734	0.5852	0.8112
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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
4	Rate Design Revenue Increase	$ 41,069,909	$ 68,979,937	$ (22,135,415)	$ (1,614,410)	$ (2,233,085)	$ (3,582)	$ —	$ (730,324)	$ (1,792,984)	$ 112,741	$ (241,743)	$ 143,164	$ 585,611
5	% Increase - Non-Gas Revenue (2)	9.83%	21.11%	-34.92%	-72.30%	-23.38%	-78.82%	— %	-15.53%	-37.24%	3.86%	-36.45%	70.88%	23.28%
6	% Increase - Total Revenue (3)	7.07%	16.14%	-19.63%	-38.50%	-12.58%	-78.82%	— %	-15.53%	-37.24%	3.86%	-36.45%	70.88%	11.48%
7	% Total Revenue (for GRIP)	100.00 %	86.15 %	9.04 %	0.14 %	1.61 %	0.00 %	— %	0.88 %	0.67 %	0.67 %	0.09 %	0.08 %	0.68 %
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)													
9	Revenue-to-Cost Ratio	1.0000	0.9419	1.4292	3.0880	1.2440	3.9777	0.0000	1.1471	1.4747	1.0000	1.4588	1.0000	1.0000
10	Rate Design Revenue Increase	$ 41,069,909	$ 45,978,702	$ (4,427,083)	$ (322,882)	$ (446,617)	$ (716)	$ —	$ (146,065)	$ (358,597)	$ 112,741	$ (48,349)	$ 143,164	$ 585,611
11	% Increase - Non-Gas Revenue (2)	9.83%	14.07%	-6.98%	-14.46%	-4.68%	-15.76%	— %	-3.11%	-7.45%	3.86%	-7.29%	70.88%	23.28%
12	% Increase - Total Revenue (3)	7.07%	10.76%	-3.93%	-7.70%	-2.52%	-15.76%	— %	-3.11%	-7.45%	3.86%	-7.29%	70.88%	11.48%
13	% Total Revenue (for GRIP)	100.00 %	81.02 %	12.99 %	0.42 %	2.01 %	0.00 %	— %	1.01 %	0.99 %	0.67 %	0.14 %	0.08 %	0.68 %
14	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)													
15	Revenue-to-Cost Ratio	1.0000	0.9273	1.5365	3.6100	1.3051	4.7222	0.0000	1.1838	1.5934	1.0000	1.5734	1.0000	1.0000
16	Rate Design Revenue Increase	$ 41,069,909	$ 40,228,393	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 112,741	$ —	$ 143,164	$ 585,611
17	% Increase - Non-Gas Revenue (2)	9.83%	12.31%	0.00%	0.00%	0.00%	0.00%	— %	— %	— %	3.86 %	— %	70.88 %	23.28%
18	% Increase - Total Revenue (3)	7.07%	9.41%	0.00%	0.00%	0.00%	0.00%	— %	— %	— %	3.86 %	— %	70.88 %	11.48%
19	% Total Revenue (for GRIP)	100.00 %	79.74 %	13.97 %	0.50 %	2.11 %	0.00 %	— %	1.04 %	1.07 %	0.67 %	0.15 %	0.08 %	0.68 %

(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 decreases 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 deceases is assigned to the residential class.

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Costs	$ 140,338,908	$ 129,719,421	$ 8,676,981	$ 29,206	$ 870,937	$ —	$ —	$ 24,847	$ 12,320	$ 8,849	$ 3,898	$ —	$ 992,448
2	Demand Costs	$ 40,005,310	$ 25,618,240	$ 7,975,493	$ 233,071	$ 2,874,650	$ —	$ —	$ 574,243	$ 348,772	$ 436,058	$ 243,570	$ —	$ 1,701,213
3	Commodity Costs	$ 856,512	$ 499,809	$ 187,789	$ 4,868	$ 51,292	$ —	$ —	$ 26,008	$ 28,203	$ 14,145	$ 20,851	$ —	$ 23,548
4	Cost of Service Before Revenue Credits	$ 181,200,730	$ 155,837,470	$ 16,840,263	$ 267,145	$ 3,796,879	$ —	$ —	$ 625,098	$ 389,294	$ 459,052	$ 268,320	$ —	$ 2,717,209
5	Revenues Credited to Cost of Service (1)	$ 3,968,242	$ 3,588,417	$ 295,253	$ 2,884	$ 37,867	$ —	$ —	$ 6,143	$ 3,826	$ 4,511	$ 2,637	$ —	$ 26,703
6	Total Cost of Service	$ 177,232,489	$ 152,249,052	$ 16,545,010	$ 264,261	$ 3,759,012	$ —	$ —	$ 618,955	$ 385,469	$ 454,540	$ 265,683	$ —	$ 2,690,506
7	Revenue at Current Rates	$ 162,934,804	$ 127,095,494	$ 23,637,602	$ 687,784	$ 6,087,202	$ —	$ —	$ 755,871	$ 1,064,645	$ 556,804	$ 570,738	$ —	$ 2,478,665
8	Revenue Deficiency	$ 14,297,684	$ 25,153,559	$ (7,092,592)	$ (423,522)	$ (2,328,190)	$ —	$ —	$ (136,916)	$ (679,176)	$ (102,263)	$ (305,055)	$ —	$ 211,841
9	Revenue-to-Cost Ratios:													
10	Current Revenue	0.9211	0.8386	1.4212	2.5854	1.6132	0.0000	0.0000	1.2190	2.7446	1.2228	2.1369	0.0000	0.9220
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000

(1) Service charge revenue including Company recommended changes, special contract (other than Fort Bliss), irrigation, unmetered gas service, and other 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	$ 2,187,489
Special Contract	$ 1,389,269
Irrigation	$ 391,485
Unmetered Gas Service	$ —
Other Revenue	$ —
	$ 3,968,242

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	$ 130,422	$ 94,808	$ 35,430	$ 185
2	302	Franchises and Consents	NONINTPLT	$ 9,496	$ 6,903	$ 2,580	$ 13
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 893,065	$ 649,196	$ 242,605	$ 1,264
4		Total Intangible Plant		$ 1,032,983	$ 750,907	$ 280,614	$ 1,462
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ 190,844	$ —	$ 190,844	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ —	$ —	$ —	$ —
9	367	Transmission Mains	DEM	$ 62,816,443	$ —	$ 62,816,443	$ —
10	368	Compression Station Equipment	DEM	$ —	$ —	$ —	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 4,526,711	$ —	$ 4,526,711	$ —
12	369	Odorization	COM	$ 101,675	$ —	$ —	$ 101,675
13	371	Other Equipment	DEM	$ —	$ —	$ —	$ —
14		Total Transmission Plant		$ 67,635,672	$ —	$ 67,533,997	$ 101,675
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 1,738,852	$ 1,078,851	$ 660,001	$ —
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ 19,533	$ 10,458	$ 9,076	$ —
19	375	Structures and Improvements	DIS376-379-ALL	$ 348,933	$ 216,492	$ 132,442	$ —
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 396,167,860	$ 266,629,090	$ 129,538,770	$ —
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ 7,232,484	$ 4,046,444	$ 3,186,040	$ —
22	376	Odorization	COM	$ —	$ —	$ —	$ —
23	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
24	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 23,638,487	$ —	$ 23,638,487	$ —
25	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ 325,537	$ —	$ 325,537	$ —
26	378	Odorization	COM	$ 335,461	$ —	$ —	$ 335,461
27	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 9,936,592	$ —	$ 9,936,592	$ —
28	379	Odorization	COM	$ 802,155	$ —	$ —	$ 802,155
29	380	Services - Allocated	CUS	$ 262,000,773	$ 262,000,773	$ —	$ —
30	380	Services - Directly Assigned	CUS	$ 1,524,955	$ 1,524,955	$ —	$ —
31	381	Meters - Allocated	CUS	$ 68,367,717	$ 68,367,717	$ —	$ —
32	381	Meters - Directly Assigned	CUS	$ 152,811	$ 152,811	$ —	$ —
33	382	Meter Installations	CUS	$ —	$ —	$ —	$ —
34	383	House Regulators - Allocated	CUS	$ 17,419,944	$ 17,419,944	$ —	$ —
35	383	House Regulators - Directly Assigned	CUS	$ 75,571	$ 75,571	$ —	$ —
36	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 18,361,882	$ —	$ 18,361,882	$ —
37	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ 574,172	$ —	$ 574,172	$ —
38	385	Odorization	COM	$ 4,057	$ —	$ —	$ 4,057
39	386	Other Property - Customer Premises	CUS	$ 638,227	$ 638,227	$ —	$ —

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)
40	387	Other Equipment	DIS376-379-ALL	$ —	$ —	$ —	$ —
41		Total Distribution Plant		$ 809,666,002	$ 622,161,332	$ 186,362,998	$ 1,141,672
42							
43		**General Plant**					
44	389	Land & Land Rights	GENPLT	$ 1,916,040	$ 1,518,153	$ 395,464	$ 2,423
45	390	Structures & Improvements	GENPLT	$ 14,592,055	$ 12,092,409	$ 2,484,426	$ 15,220
46	391	Office Furniture and Equipment	GENPLT	$ 43,747,635	$ 43,156,225	$ 587,809	$ 3,601
47	392	Transportation Equipment	GENPLT	$ 20,111,772	$ 15,482,291	$ 4,601,293	$ 28,188
48	393	Stores Equipment	GENPLT	$ 22,054	$ 16,946	$ 5,076	$ 31
49	394	Tools, Shop & Garage - Allocated	GENPLT	$ 10,786,158	$ 8,317,385	$ 2,453,742	$ 15,032
50	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ 11,690	$ 6,857	$ 4,833	$ —
51	394	Odorization	COM	$ 64,149	$ —	$ —	$ 64,149
52	395	CNG Equipment	GENPLT	$ —	$ —	$ —	$ —
53	396	Major Work Equipment	GENPLT	$ 3,980,125	$ 3,058,397	$ 916,116	$ 5,612
54	397	Communication Equipment - Allocated	GENPLT	$ 25,701,649	$ 19,844,089	$ 5,821,894	$ 35,665
55	397	Communication Equipment - Dir. Assn.	GENPLT	$ 48,893	$ 28,680	$ 20,213	$ —
56	398	Miscellaneous General Plant	GENPLT	$ —	$ —	$ —	$ —
57		Total General Plant		$ 120,982,219	$ 103,521,434	$ 17,290,865	$ 169,920
58							
59		Total Plant in Service		$ 999,316,877	$ 726,433,673	$ 271,468,474	$ 1,414,730
60							
61		**Depreciation & Amortization Reserve**					
62	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (533,001)	$ (424,675)	$ (107,790)	$ (536)
63	325-371	Transmission Plant	DEM	$ (6,494,811)	$ —	$ (6,494,811)	$ —
64	369	Odorization	COM	$ (16,773)	$ —	$ —	$ (16,773)
65	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (132,994,926)	$ (105,965,232)	$ (26,895,939)	$ (133,755)
66	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ (8,660)	$ (4,636)	$ (4,023)	$ —
67	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ (697,520)	$ (390,250)	$ (307,270)	$ —
68	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ (44,709)	$ —	$ (44,709)	$ —
69	380	Services - Directly Assigned	CUS	$ (160,974)	$ (160,974)	$ —	$ —
70	381	Meters - Directly Assigned	CUS	$ (39,495)	$ (39,495)	$ —	$ —
71	383	House Regulators - Directly Assigned	CUS	$ (15,367)	$ (15,367)	$ —	$ —
72	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ (39,779)	$ —	$ (39,779)	$ —
73	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (47,839,470)	$ (41,797,844)	$ (5,993,366)	$ (48,261)
74	389-398	General Plant - Directly Assigned	GEN-DARES	$ (31,792)	$ (18,649)	$ (13,143)	$ —
75		Total Depreciation & Amortization Reserve		$ (188,917,277)	$ (148,817,123)	$ (39,900,830)	$ (199,325)
76							
77		Net Plant in Service		$ 810,399,599	$ 577,616,550	$ 231,567,644	$ 1,215,405
78							
79		Customer Deposits	CUS	$ (7,616,570)	$ (7,616,570)	$ —	$ —

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)
80							
81		Customer Advances	MAINS/SVCS	$ (599,726)	$ (480,374)	$ (119,351)	$ —
82							
83		Accumulated Deferred Income Taxes	TOTPLT	$ (73,940,261)	$ (53,749,413)	$ (20,086,171)	$ (104,677)
84							
85		Excess Deferred Income Taxes	TOTPLT	$ (10,974,235)	$ (7,977,503)	$ (2,981,195)	$ (15,536)
86							
87		Negative Acquisition Adjustment on OPC Assets	MAINS-ALLOC	$ —	$ —	$ —	$ —
88							
89		Materials and Supplies	TOTPLT	$ 9,515,969	$ 6,917,445	$ 2,585,051	$ 13,472
90							
91		Prepayments	OPEXP	$ 4,895,854	$ 4,114,966	$ 727,923	$ 52,965
92							
93		Pension & FAS 106 Regulatory Asset	OPEXP	$ 17,466,013	$ 14,680,188	$ 2,596,872	$ 188,953
94							
95		DIMP Deferrals	OPEXP	$ 2,196,298	$ 1,845,989	$ 326,549	$ 23,760
96							
97		Regulatory Assets	OPEXP	$ 1,150,763	$ 967,216	$ 171,097	$ 12,449
98							
99		Cash Working Capital	OPEXP	$ (5,943,984)	$ (4,995,920)	$ (883,760)	$ (64,304)
100							
101		Total Rate Base		$ 746,549,720	$ 531,322,574	$ 213,904,658	$ 1,322,488

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	814-865	Transmission Expenses	DEM	$ 2,085,468	$ —	$ 2,085,468	$ —
3	8650	Odorization	COM	$ 2,471	$ —	$ —	$ 2,471.13
4	8700	Operation Supervision & Engineering	DIS871-879	$ 1,165,883	$ 994,460	$ 145,979	$ 25,444
5	8710	Distribution Load Dispatch	COM	$ 258,612	$ —	$ —	$ 258,612
6	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 5,227,507	$ 4,198,645	$ 1,028,862	$ —
7	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ 69,595	$ 44,275	$ 25,319	$ —
8	8740	Odorization	COM	$ 2,897	$ —	$ —	$ 2,897
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 351,540	$ —	$ 351,540	$ —
10	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ 6,618	$ —	$ 6,618	$ —
11	8750	Odorization	COM	$ 129,001	$ —	$ —	$ 129,001
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 30,814	$ —	$ 30,814	$ —
13	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ 964	$ —	$ 964	$ —
14	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 39,598	$ —	$ 39,598	$ —
15	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 5,841,355	$ 5,841,355	$ —	$ —
16	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ 15,551	$ 15,551	$ —	$ —
17	8780	Odorization	COM	$ 81	$ —	$ —	$ 81
18	8790	Customer Installation Expenses	CUS	$ 7,768	$ 7,768	$ —	$ —
19	8800	Other Expenses	DIS871-879	$ 1,128,099	$ 962,232	$ 141,248	$ 24,620
20	8800	Odorization	COM	$ 853	$ —	$ —	$ 853
21	8810	Rents	DIS871-879	$ 69,005	$ 58,859	$ 8,640	$ 1,506
22	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
23		Total Transmission & Distribution Oper. Exp.		$ 16,433,679	$ 12,123,145	$ 3,865,049	$ 445,485
24							
25		**Distribution Maintenance Expenses**					
26	8850	Maintenance Supervision and Engineering	DIS887-893	$ 18,937	$ 11,232	$ 7,706	$ —
27	8860	Structures and Improvements	DIS887-893	$ 679,184	$ 402,826	$ 276,358	$ —
28	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 2,975,516	$ 2,002,584	$ 972,933	$ —
29	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ 54,321	$ 30,392	$ 23,930	$ —
30	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 963,593	$ —	$ 963,593	$ —
31	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ 13,824	$ —	$ 13,824	$ —
32	8890	Odorization	COM	$ 40,208	$ —	$ —	$ 40,208
33	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 503,673	$ —	$ 503,673	$ —
34	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ 15,750	$ —	$ 15,750	$ —
35	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 33,659	$ —	$ 33,659	$ —
36	8910	Odorization	COM	$ 100	$ —	$ —	$ 100
37	8920	Maintenance of Services - Allocated	CUS	$ 1,613,870	$ 1,613,870	$ —	$ —
38	8920	Maintenance of Services - Directly Assn.	CUS	$ 9,393	$ 9,393	$ —	$ —

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)
39	8930	Main. of Meters & House Reg. - Allocated	CUS	$ 27,628	$ 27,628	$ —	$ —
40	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ 74	$ 74	$ —	$ —
41	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
42	8950	Clearing - Meter Shop - Small Meters	CUS	$ —	$ —	$ —	$ —
43	8960	Clearing - Meter Shop - Large Meters	CUS	$ —	$ —	$ —	$ —
44		Total Distribution Maintenance Expenses		$ 6,949,731	$ 4,097,999	$ 2,811,424	$ 40,308
45							
46		Total Operations & Maintenance Expenses		$ 23,383,410	$ 16,221,144	$ 6,676,473	$ 485,793
47							
48		**Customer Accounting Expenses**					
49	9010	Supervision	CUS	$ 285	$ 285	$ —	$ —
50	9020	Meter Reading Expense	CUS	$ 394,235	$ 394,235	$ —	$ —
51	9030	Customer Accounting	CUS	$ 5,154,764	$ 5,154,764	$ —	$ —
52	9040	Bad Debts (includes gross up)	CUS	$ 1,393,252	$ 1,393,252	$ —	$ —
53	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 408,799	$ 408,799	$ —	$ —
54		Total Customer Accounts Expenses		$ 7,351,336	$ 7,351,336	$ —	$ —
55							
56		**Customer Information Expenses**					
57	9070	Supervision	CUS	$ —	$ —	$ —	$ —
58	9080	Customer Assistance	CUS	$ 891,531	$ 891,531	$ —	$ —
59	9090	Informational and Instructional Advertising	CUS	$ 70,912	$ 70,912	$ —	$ —
60	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —
61		Total Customer Information Expenses		$ 962,443	$ 962,443	$ —	$ —
62							
63		**Sales and Advertising Expenses**					
64	9110	Supervision	CUS	$ —	$ —	$ —	$ —
65	9120	Demonstrating and Selling	CUS	$ —	$ —	$ —	$ —
66	9130	Advertising	CUS	$ 26,690	$ 26,690	$ —	$ —
67	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —
68	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —
69		Total Sales and Advertising Expenses		$ 26,690	$ 26,690	$ —	$ —
70							
71		**Administrative & General Expenses**					
72	920-940	Administrative & General Expenses	ADMINGEN	$ 32,600,912	$ 29,503,386	$ 2,887,431	$ 210,095
73		Total Administrative & General Expenses		$ 32,600,912	$ 29,503,386	$ 2,887,431	$ 210,095
74							
75		**Depreciation and Amortization Expense**					
76	301-303	Intangible Plant - Allocated	PLT301-03	$ 16,818	$ 12,226	$ 4,569	$ 24
77	301-303	Intangible Plant - Directly Assigned	PLT301-03	$ —	$ —	$ —	$ —
78	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —

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)
79	366	Meas. and Reg. Station Structures	PLT366	$ —	$ —	$ —	$ —
80	367	Transmission Mains	PLT367	$ 1,796,551	$ —	$ 1,796,551	$ —
81	368	Compression Station Equipment	PLT368	$ —	$ —	$ —	$ —
82	369	Measuring and Reg. Station Equipment	PLT369	$ 157,828	$ —	$ 157,828	$ —
83	371	Other Equipment	PLT371	$ —	$ —	$ —	$ —
84	375	Structures and Improvements	PLT375	$ 12,095	$ 7,504	$ 4,591	$ —
85	376	Mains - Allocated	MAINS-ALLOC	$ 11,276,217	$ 7,589,125	$ 3,687,092	$ —
86	376	Mains - Directly Assigned	MAINS-DA	$ 184,988	$ 103,497	$ 81,490	$ —
87	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
88	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 621,104	$ —	$ 621,104	$ —
89	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ 7,213	$ —	$ 7,213	$ —
90	378	Odorization Tank	COM	$ 4,279	$ —	$ —	$ 4,279
91	379	Meas. & Reg. Sta. Equipment - City Gate - Alloc.	PLT379	$ 234,094	$ —	$ 234,094	$ —
92	379	Meas. & Reg. Sta. Equipment - City Gate - Dir. Assn.	PLT379	$ —	$ —	$ —	$ —
93	379	Odorization	COM	$ —	$ —	$ —	$ —
94	380	Services - Allocated	PLT380	$ 10,034,625	$ 10,034,625	$ —	$ —
95	380	Services - Directly Assigned	PLT380	$ 56,728	$ 56,728	$ —	$ —
96	381	Meters - Allocated	PLT381	$ 2,782,422	$ 2,782,422	$ —	$ —
97	381	Meters - Directly Assigned	PLT381	$ 7,213	$ 7,213	$ —	$ —
98	382	Meter Installations	PLT382	$ —	$ —	$ —	$ —
99	383	House Regulators - Allocated	PLT383	$ 771,699	$ 771,699	$ —	$ —
100	383	House Regulators - Directly Assigned	PLT383	$ 3,363	$ 3,363	$ —	$ —
101	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 450,264	$ —	$ 450,264	$ —
102	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ —	$ —	$ —	$ —
103	386	Other Property - Customer Premises	PLT386	$ 146,728	$ 146,728	$ —	$ —
104	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —
105	389-398	General Plant - Allocated	GENDEP	$ 6,797,717	$ 6,095,101	$ 694,096	$ 8,520
106	389-398	General Plant - Directly Assigned	GENDEP	$ 2,481	$ 2,225	$ 253	$ 3
107	389-398	General Plant - Odorization	COM	$ 4,279	$ —	$ —	$ 4,279
108	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ (191,109)	$ (160,627)	$ (28,414)	$ (2,067)
109		Total Depreciation and Amortization Expense		$ 35,177,598	$ 27,451,830	$ 7,710,731	$ 15,037
110							
111		**Taxes Other Than Income**					
112	4080	Payroll and Other	OPEXP	$ 2,626,528	$ 2,207,597	$ 390,516	$ 28,415
113	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 7,986,243	$ 5,816,731	$ 2,158,092	$ 11,420
114	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ 80,445	$ 47,188	$ 33,256	$ —
115	4080	Revenue Related (includes gross up)	CUS	$ 107,233	$ 107,233	$ —	$ —
116		Total Taxes Other Than Income		$ 10,800,448	$ 8,178,749	$ 2,581,864	$ 39,835
117							
118	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ (18,979)	$ (11,090)	$ (7,889)	$ —
119	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (1,703,920)	$ (1,216,915)	$ (484,420)	$ (2,584)

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)
120							
121	4310	Interest on Customer Deposits	CUS	$ 384,637	$ 384,637	$ —	$ —
122							
123		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 59,185,610	$ 42,269,526	$ 16,826,331	$ 89,753
124		Required Return - Directly Assigned	RB-DA	$ 659,250	$ 385,211	$ 274,039	$ —
125		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 12,254,794	$ 8,752,200	$ 3,484,009	$ 18,584
126		Income Taxes - Directly Assigned	RB-DA	$ 136,502	$ 79,761	$ 56,742	$ —
127		Total Cost of Service Before Revenue Credits		$ 181,200,730	$ 140,338,908	$ 40,005,310	$ 856,512

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	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			Total Transmission Plant	$ 67,635,672	$ —	$ 67,533,997	$ 101,675
8			Total Distribution Plant	$ 809,666,002	$ 622,161,332	$ 186,362,998	$ 1,141,672
9			Total General Plant	$ 120,982,219	$ 103,521,434	$ 17,290,865	$ 169,920
10			Total Non-Intangible Plant	$ 998,283,893	$ 725,682,766	$ 271,187,860	$ 1,413,267
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.72693	0.27165	0.00142
12							
13	376		Distribution Mains-Allocated	$ 396,167,860	$ 266,629,090	$ 129,538,770	$ —
14	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 23,638,487	$ —	$ 23,638,487	$ —
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 9,936,592	$ —	$ 9,936,592	$ —
17			Total Accounts 376-379	$ 429,742,939	$ 266,629,090	$ 163,113,849	$ —
18		DIS376-379-ALL	Accounts 376-379 Allocated Factor	1.00000	0.62044	0.37956	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ 7,232,484	$ 4,046,444	$ 3,186,040	$ —
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ 325,537	$ —	$ 325,537	$ —
22			Total Accounts 376-379 Directly Assigned	$ 7,558,021	$ 4,046,444	$ 3,511,576	$ —
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	1.00000	0.53538	0.46462	0.00000
24							
25	376		Mains-Allocated	$ 396,167,860	$ 266,629,090	$ 129,538,770	$ —
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.67302	0.32698	0.00000
27							
28	376		Mains-Directly Assigned	$ 7,232,484	$ 4,046,444	$ 3,186,040	$ —
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.55948	0.44052	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ 8,757,439	$ 5,571,399	$ 3,186,040	$ —
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	1.00000	0.63619	0.36381	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 658,168,633	$ 528,629,863	$ 129,538,770	$ —
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.80318	0.19682	0.00000
36							
37	376/380		Mains and Services	$ 666,926,072	$ 534,201,262	$ 132,724,810	$ —
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.80099	0.19901	0.00000
39							
40	374-387		Total Distribution Plant	$ 809,666,002	$ 622,161,332	$ 186,362,998	$ 1,141,672

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
41		DISPLT	Distribution Plant Factor	1.00000	0.76842	0.23017	0.00141
42							
43	374		Land & Land Rights - Directly Assigned	$ 19,533	$ 10,458	$ 9,076	$ —
44	376		Mains - Directly Assigned	$ 7,232,484	$ 4,046,444	$ 3,186,040	$ —
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ 325,537	$ —	$ 325,537	$ —
46	380		Service - Directly Assigned	$ 1,524,955	$ 1,524,955	$ —	$ —
47	381		Meters - Directly Assigned	$ 152,811	$ 152,811	$ —	$ —
48	383		House Regulators - Directly Assigned	$ 75,571	$ 75,571	$ —	$ —
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ 574,172	$ —	$ 574,172	$ —
50			Total Distribution Plant - Directly Assigned	$ 9,905,062	$ 5,810,239	$ 4,094,824	$ —
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	1.00000	0.58659	0.41341	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (47,006)	$ (29,164)	$ (17,842)	$ —
54	375		Structures and Improvements	$ (151,663)	$ (94,098)	$ (57,566)	$ —
55	376		Distribution Mains - Allocated	$ (62,485,106)	$ (42,053,757)	$ (20,431,349)	$ —
56	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (1,686,208)	$ —	$ (1,686,208)	$ —
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (1,073,728)	$ —	$ (1,073,728)	$ —
59	378-379		Odorization Tank	$ (133,755)	$ —	$ —	$ (133,755)
60	380		Services - Allocated	$ (39,439,278)	$ (39,439,278)	$ —	$ —
61	381		Meters - Allocated	$ (19,129,225)	$ (19,129,225)	$ —	$ —
62	382		Meter Installations	$ (78,719)	$ (78,719)	$ —	$ —
63	383		House Regulators - Allocated	$ (4,888,265)	$ (4,888,265)	$ —	$ —
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (3,474,637)	$ —	$ (3,474,637)	$ —
65	386		Other Property-Customer Premises	$ (407,335)	$ (252,727)	$ (154,609)	$ —
66	387		Other Equipment	$ —	$ —	$ —	$ —
67			Total Distribution Plant - Allocated Reserve	$ (132,994,926)	$ (105,965,232)	$ (26,895,939)	$ (133,755)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.79676	0.20223	0.00101
69							
70	376		Distribution Mains - Directly Assigned	$ (697,520)	$ (390,250)	$ (307,270)	$ —
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	1.00000	0.55948	0.44052	0.00000
72							
73			General Plant - Allocated Reserve	$ (47,839,470)	$ (41,797,844)	$ (5,993,366)	$ (48,261)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.87371	0.12528	0.00101
75							
76			General Plant - Directly Assigned Reserve	$ (31,792)	$ (18,649)	$ (13,143)	$ —
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	1.00000	0.58659	0.41341	0.00000
78							
79			Total Plant - Allocated	$ 989,351,232	$ 720,587,897	$ 267,348,605	$ 1,414,730
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.72834	0.27023	0.00143

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
81							
82			Total Plant - Directly Assigned	$ 9,965,645	$ 5,845,776	$ 4,119,869	$ —
83		TPLT-DA	Total Plant Directly Assigned Factor	$ 1.00000	$ 0.58659	$ 0.41341	$ —
84							
85			Total Plant	$ 999,316,877	$ 726,433,673	$ 271,468,474	$ 1,414,730
86		TOTPLT	Total Plant Factor	1.00000	0.72693	0.27165	0.00142
87							
88			Total Operations and Maintenance Expenses	$ 23,383,410	$ 16,221,144	$ 6,676,473	$ 485,793
89			Total Customer Accounts Expenses	$ 7,351,336	$ 7,351,336	$ —	$ —
90			Total Customer Information Expenses	$ 962,443	$ 962,443	$ —	$ —
91			Total Sales and Advertising Expenses	$ 26,690	$ 26,690	$ —	$ —
92			Administrative and General Expenses	$ 32,600,912	$ 29,503,386	$ 2,887,431	$ 210,095
93			Total Operating Expenses	$ 64,324,791	$ 54,065,000	$ 9,563,904	$ 695,888
94		OPEXP	Operating Expense Factor	1.00000	0.84050	0.14868	0.01082
95							
96	8710		Distribution Load Dispatch	$ 258,612	$ —	$ —	$ 258,612
97	8740		Mains and Services Expenses - Allocated	$ 5,227,507	$ 4,198,645	$ 1,028,862	$ —
98	8740		Mains and Services Expenses - Dir. Assn.	$ 69,595	$ 44,275	$ 25,319	$ —
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 351,540	$ —	$ 351,540	$ —
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ 6,618	$ —	$ 6,618	$ —
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 30,814	$ —	$ 30,814	$ —
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ 964	$ —	$ 964	$ —
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 39,598	$ —	$ 39,598	$ —
104	8780		Meter and House Regulator Exp.- Allocated	$ 5,841,355	$ 5,841,355	$ —	$ —
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ 15,551	$ 15,551	$ —	$ —
106	8790		Customer Installation Expenses	$ 7,768	$ 7,768	$ —	$ —
107			Total Accounts 871-879	$ 11,849,921	$ 10,107,595	$ 1,483,714	$ 258,612
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.85297	0.12521	0.02182
109							
110	8870		Maintenance of Mains-Allocated	$ 2,975,516	$ 2,002,584	$ 972,933	$ —
111	8870		Maintenance of Mains - Directly Assn.	$ 54,321	$ 30,392	$ 23,930	$ —
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 963,593	$ —	$ 963,593	$ —
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ 13,824	$ —	$ 13,824	$ —
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 503,673	$ —	$ 503,673	$ —
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ 15,750	$ —	$ 15,750	$ —
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 33,659	$ —	$ 33,659	$ —
117	8920		Maintenance of Services - Allocated	$ 1,613,870	$ 1,613,870	$ —	$ —
118	8920		Maintenance of Services - Directly Assn.	$ 9,393	$ 9,393	$ —	$ —
119	8930		Main. of Meters & House Reg. - Allocated	$ 27,628	$ 27,628	$ —	$ —
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ 74	$ 74	$ —	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
121			Total Accounts 887-893	$ 6,211,301	$ 3,683,941	$ 2,527,360	$ —
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.59310	0.40690	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 23,383,410	$ 16,221,144	$ 6,676,473	$ 485,793
125			Total Customer Accounts Expenses	$ 7,351,336	$ 7,351,336	$ —	$ —
126			Total Customer Service Expenses	$ 962,443	$ 962,443	$ —	$ —
127			Total Sales and Advertising Expenses	$ 26,690	$ 26,690	$ —	$ —
128			Total Operating Exp. Without A&G Expenses	$ 31,723,879	$ 24,561,614	$ 6,676,473	$ 485,793
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.77423	0.21046	0.01531
130							
131	920-932		Administrative and General Expenses	$ 32,600,912	$ 29,503,386	$ 2,887,431	$ 210,095
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.90499	0.08857	0.00644
133							
134	366		Meas. and Reg. Station Structures	$ —	$ —	$ —	$ —
135		PLT366	Measuring and Reg. Station Structures Factor	0.00000	0.00000	0.00000	0.00000
136							
137	367		Transmission Mains	$ 62,816,443	$ —	$ 62,816,443	$ —
138		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
139							
140	368		Compression Station Equipment	$ —	$ —	$ —	$ —
141		PLT368	Compression Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
142							
143	369		Measuring and Reg. Station Equipment	$ 4,526,711	$ —	$ 4,526,711	$ —
144		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
145							
146	371		Other Equipment	$ —	$ —	$ —	$ —
147		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
148							
149	375		Structures and Improvements	$ 348,933	$ 216,492	$ 132,442	$ —
150		PLT375	Structures and Improvements Factor	1.00000	0.62044	0.37956	0.00000
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 23,638,487	$ —	$ 23,638,487	$ —
153		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
154							
155	379		Meas. & Reg. Sta. Equip.- City Gate	$ 9,936,592	$ —	$ 9,936,592	$ —
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services - Allocated	$ 262,000,773	$ 262,000,773	$ —	$ —
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters - Allocated	$ 68,367,717	$ 68,367,717	$ —	$ —
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
163							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
164	382		Meter Installations	$ —	$ —	$ —	$ —
165		PLT382	Meter Installations Factor	—	0.00000	0.00000	0.00000
166							
167	383		House Regulators - Allocated	$ 17,419,944	$ 17,419,944	$ —	$ —
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 18,361,882	$ —	$ 18,361,882	$ —
171		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
172							
173	386		Other Property - Customer Premises	$ 638,227	$ 638,227	$ —	$ —
174		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
175							
176	387		Other Equipment	$ —	$ —	$ —	$ —
177		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
178							
179	301-303		Intangible Plant	$ 1,032,983	$ 750,907	$ 280,614	$ 1,462
180		PLT301-03	Intangible Plant	1.00000	0.72693	0.27165	0.00142
181							
182	389-398		General Plant Depreciation Expense	$ 6,804,477	$ 6,101,162	$ 694,786	$ 8,529
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.89664	0.10211	0.00125
184							
185			Net Plant Directly Assigned	$ 8,927,348	$ 5,216,405	$ 3,710,944	$ —
186		NETPLT-DA	Net Plant Directly Assigned Factor	1.00000	0.58432	0.41568	0.00000
187							
188			Net Plant Allocated	$ 801,472,251	$ 572,400,146	$ 227,856,700	$ 1,215,405
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.71419	0.28430	0.00152
190							
191			Rate Base Directly Assigned	$ 8,223,979	$ 4,805,414	$ 3,418,565	$ —
192		RB-DA	Rate Base Directly Assigned Factor	1.00000	0.58432	0.41568	0.00000
193							
194			Rate Base Allocated	$ 738,325,741	$ 527,301,802	$ 209,904,294	$ 1,119,646
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.71419	0.28430	0.00152
196							
197			Required Return	$ 59,844,860	$ 42,654,737	$ 17,100,370	$ 89,753
198		REQRET	Required Return Factor	1.00000	0.71276	0.28575	0.00150
199							
200			Non-Plant Rate Base	$ (63,849,879)	$ (46,293,976)	$ (17,662,986)	$ 107,082
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.72504	0.27663	-0.00168

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	301-303	**Intangible Plant**									
2		Customer	NONINCUS	$ 750,907	$ 705,769	$ 41,458	$ 85	$ 3,434	$ —	$ —	$ 50
3		Demand	NONINDEM	$ 280,614	$ 188,926	$ 53,002	$ 1,549	$ 19,104	$ —	$ —	$ 3,816
4		Commodity	COM	$ 1,462	$ 853	$ 321	$ 8	$ 88	$ —	$ —	$ 44
5		Total Intangible Plant		$ 1,032,983	$ 895,548	$ 94,781	$ 1,642	$ 22,625	$ —	$ —	$ 3,911
6	365-371	**Transmission Plant**									
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 67,533,997	$ 45,467,946	$ 12,755,608	$ 372,761	$ 4,597,573	$ —	$ —	$ 918,416
9		Commodity	COM	$ 101,675	$ 59,332	$ 22,292	$ 578	$ 6,089	$ —	$ —	$ 3,087
10		Total Transmission Plant		$ 67,635,672	$ 45,527,278	$ 12,777,900	$ 373,339	$ 4,603,662	$ —	$ —	$ 921,504
11		**Distribution Plant**									
12	374	**Land & Land Rights - Allocated**									
13		Customer	376-379CUS	$ 1,078,851	$ 998,841	$ 58,674	$ 120	$ 4,860	$ —	$ —	$ 71
14		Demand	DEM	$ 660,001	$ 444,352	$ 124,659	$ 3,643	$ 44,932	$ —	$ —	$ 8,976
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 1,738,852	$ 1,443,193	$ 183,333	$ 3,763	$ 49,792	$ —	$ —	$ 9,047
17	374	**Land & Land Rights - DA**									
18		Customer	CUS-DA	$ 10,458	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM-DA	$ 9,076	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ 19,533	$ —	$ —	$ —	$ —	$ —	$ —	$ —
22	375	**Structures and Improvements**									
23		Customer	376-379CUS	$ 216,492	$ 200,436	$ 11,774	$ 24	$ 975	$ —	$ —	$ 14
24		Demand	DEM	$ 132,442	$ 89,168	$ 25,015	$ 731	$ 9,016	$ —	$ —	$ 1,801
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 348,933	$ 289,604	$ 36,789	$ 755	$ 9,992	$ —	$ —	$ 1,815
27	376	**Distribution Mains-Allocated**									
28		Customer	CUS	$ 266,629,090	$ 250,601,622	$ 14,720,920	$ 30,021	$ 1,219,345	$ —	$ —	$ 17,798
29		Demand	DEM	$ 129,538,770	$ 87,213,286	$ 24,466,874	$ 715,004	$ 8,818,729	$ —	$ —	$ 1,761,639
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 396,167,860	$ 337,814,908	$ 39,187,794	$ 745,024	$ 10,038,074	$ —	$ —	$ 1,779,437
32	376	**Odorization**									
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
36		**Total Odorization**		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
37		**Distribution Mains - Directly Assn.**									
38		Customer	CUS-DA	$ 4,046,444	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM-DA	$ 3,186,040	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ 7,232,484	$ —	$ —	$ —	$ —	$ —	$ —	$ —
42	377	**Compressor Station Equipment**									
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**									
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 23,638,487	$ 15,914,850	$ 4,464,763	$ 130,475	$ 1,609,259	$ —	$ —	$ 321,467
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 23,638,487	$ 15,914,850	$ 4,464,763	$ 130,475	$ 1,609,259	$ —	$ —	$ 321,467
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**									
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ 325,537	$ —	$ —	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 325,537	$ —	$ —	$ —	$ —	$ —	$ —	$ —
57	378	**Odorization**									
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 335,461	$ 195,755	$ 73,550	$ 1,907	$ 20,089	$ —	$ —	$ 10,186
61		Total Odorization		$ 335,461	$ 195,755	$ 73,550	$ 1,907	$ 20,089	$ —	$ —	$ 10,186
62	379	**Meas. & Reg. Station - City Gate**									
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 9,936,592	$ 6,689,911	$ 1,876,792	$ 54,846	$ 676,462	$ —	$ —	$ 135,131
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 9,936,592	$ 6,689,911	$ 1,876,792	$ 54,846	$ 676,462	$ —	$ —	$ 135,131
67	379	**Odorization**									
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 802,155	$ 468,090	$ 175,872	$ 4,559	$ 48,037	$ —	$ —	$ 24,357
71		Total Odorization		$ 802,155	$ 468,090	$ 175,872	$ 4,559	$ 48,037	$ —	$ —	$ 24,357
72	380	**Services - Allocated**									
73		Customer	SERCUS-ALL	$ 262,000,773	$ 244,104,248	$ 16,436,389	$ 41,745	$ 1,361,439	$ —	$ —	$ 24,749
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 262,000,773	$ 244,104,248	$ 16,436,389	$ 41,745	$ 1,361,439	$ —	$ —	$ 24,749
77	380	**Services-Directly Assigned**									
78		Customer	CUS-DA	$ 1,524,955	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ 1,524,955	$ —	$ —	$ —	$ —	$ —	$ —	$ —
82	381	**Meters - Allocated**									
83		Customer	METCUS-ALL	$ 68,367,717	$ 61,707,844	$ 5,607,079	$ 34,436	$ 956,803	$ —	$ —	$ 27,282
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 68,367,717	$ 61,707,844	$ 5,607,079	$ 34,436	$ 956,803	$ —	$ —	$ 27,282
87	381	**Meters-Directly Assigned**									
88		Customer	CUS-DA	$ 152,811	$ —	$ —	$ —	$ —	$ —	$ —	$ —
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ 152,811	$ —	$ —	$ —	$ —	$ —	$ —	$ —
92	382	**Meter Installations**									
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**									
98		Customer	REGCUS-ALL	$ 17,419,944	$ 14,639,057	$ 2,088,527	$ 27,191	$ 610,997	$ —	$ —	$ 24,077
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 17,419,944	$ 14,639,057	$ 2,088,527	$ 27,191	$ 610,997	$ —	$ —	$ 24,077
102	383	**House Regulators - Directly Assigned**									
103		Customer	CUS-DA	$ 75,571	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ 75,571	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**									
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 18,361,882	$ —	$ 10,614,358	$ 310,187	$ 3,825,791	$ —	$ —	$ 764,244
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 18,361,882	$ —	$ 10,614,358	$ 310,187	$ 3,825,791	$ —	$ —	$ 764,244
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**									
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ 574,172	$ —	$ —	$ —	$ —	$ —	$ —	$ —
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ 574,172	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117	385	**Odorization**									

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ 4,057	$ 2,367	$ 889	$ 23	$ 243	$ —	$ —	$ 123
121		Total Odorization		$ 4,057	$ 2,367	$ 889	$ 23	$ 243	$ —	$ —	$ 123
122	386	**Other Prop.-Customer Premises**									
123		Customer	CUS	$ 638,227	$ 599,862	$ 35,237	$ 72	$ 2,919	$ —	$ —	$ 43
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 638,227	$ 599,862	$ 35,237	$ 72	$ 2,919	$ —	$ —	$ 43
127	387	**Other Equipment**									
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**									
133		Customer		$ 622,161,332	$ 572,851,910	$ 38,958,600	$ 133,609	$ 4,157,338	$ —	$ —	$ 94,033
134		Demand		$ 186,362,998	$ 110,351,567	$ 41,572,461	$ 1,214,886	$ 14,984,189	$ —	$ —	$ 2,993,258
135		Commodity		$ 1,141,672	$ 666,213	$ 250,311	$ 6,489	$ 68,369	$ —	$ —	$ 34,666
136		Total Distribution Plant		$ 809,666,002	$ 683,869,690	$ 80,781,373	$ 1,354,984	$ 19,209,895	$ —	$ —	$ 3,121,958
137		**General Plant**									
138		**General Plant - Allocated**									
139		Customer	GENPTCUS	$ 103,485,896	$ 96,305,124	$ 6,085,054	$ 16,775	$ 579,025	$ —	$ —	$ 11,140
140		Demand	DISPLTDEM	$ 17,265,820	$ 10,223,651	$ 3,851,530	$ 112,555	$ 1,388,228	$ —	$ —	$ 277,314
141		Commodity	COM	$ 169,920	$ 99,155	$ 37,255	$ 966	$ 10,176	$ —	$ —	$ 5,160
142		Total General Plant - Allocated		$ 120,921,637	$ 106,627,931	$ 9,973,839	$ 130,295	$ 1,977,429	$ —	$ —	$ 293,614
143		**Total General Plant - Directly Assigned**									
144		Customer	CUS-DA	$ 35,537	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM-DA	$ 25,045	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ 60,583	$ —	$ —	$ —	$ —	$ —	$ —	$ —
148		**Total General Plant**									
149		Customer		$ 103,521,434	$ 96,305,124	$ 6,085,054	$ 16,775	$ 579,025	$ —	$ —	$ 11,140
150		Demand		$ 17,290,865	$ 10,223,651	$ 3,851,530	$ 112,555	$ 1,388,228	$ —	$ —	$ 277,314
151		Commodity		$ 169,920	$ 99,155	$ 37,255	$ 966	$ 10,176	$ —	$ —	$ 5,160
152		Total General Plant		$ 120,982,219	$ 106,627,931	$ 9,973,839	$ 130,295	$ 1,977,429	$ —	$ —	$ 293,614
153		**Total Plant in Service**									
154		Customer		$ 726,433,673	$ 669,862,803	$ 45,085,113	$ 150,468	$ 4,739,797	$ —	$ —	$ 105,224
155		Demand		$ 271,468,474	$ 166,232,091	$ 58,232,601	$ 1,701,751	$ 20,989,094	$ —	$ —	$ 4,192,804
156		Commodity		$ 1,414,730	$ 825,553	$ 310,179	$ 8,041	$ 84,720	$ —	$ —	$ 42,958
157		Total Plant in Service		$ 999,316,877	$ 836,920,447	$ 103,627,892	$ 1,860,260	$ 25,813,612	$ —	$ —	$ 4,340,986

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
158		**Depreciation & Amort. Reserve**									
159		**Intangible Plant**									
160		Customer	NONINCUS	$ (424,675)	$ (399,147)	$ (23,447)	$ (48)	$ (1,942)	$ —	$ —	$ (28)
161		Demand	NONINDEM	$ (107,790)	$ (72,571)	$ (20,359)	$ (595)	$ (7,338)	$ —	$ —	$ (1,466)
162		Commodity	COM	$ (536)	$ (313)	$ (118)	$ (3)	$ (32)	$ —	$ —	$ (16)
163		Total Intangible Plant		$ (533,001)	$ (472,031)	$ (43,923)	$ (646)	$ (9,312)	$ —	$ —	$ (1,510)
164		**Transmission Plant**									
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (6,494,811)	$ (4,372,697)	$ (1,226,719)	$ (35,849)	$ (442,153)	$ —	$ —	$ (88,325)
167		Commodity	COM	$ (16,773)	$ (9,788)	$ (3,677)	$ (95)	$ (1,004)	$ —	$ —	$ (509)
168		Total Transmission Plant		$ (6,511,584)	$ (4,382,485)	$ (1,230,397)	$ (35,944)	$ (443,158)	$ —	$ —	$ (88,834)
169		**Distribution Plant - Allocated**									
170		Customer	DISPLTCUS	$ (105,965,232)	$ (97,566,954)	$ (6,635,348)	$ (22,756)	$ (708,069)	$ —	$ —	$ (16,016)
171		Demand	DISPLTDEM	$ (26,895,939)	$ (15,925,956)	$ (5,999,744)	$ (175,333)	$ (2,162,521)	$ —	$ —	$ (431,987)
172		Commodity	COM	$ (133,755)	$ (78,051)	$ (29,326)	$ (760)	$ (8,010)	$ —	$ —	$ (4,061)
173		Total Distribution Plant - Allocated		$ (132,994,926)	$ (113,570,961)	$ (12,664,418)	$ (198,849)	$ (2,878,600)	$ —	$ —	$ (452,064)
174		**Distribution Plant - Dir. Assn.**									
175		Customer	CUS-DA	$ (610,722)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
176		Demand	DEM-DA	$ (395,782)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ (1,006,505)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
179		**General Plant - Allocated**									
180		Customer	GENPTCUS	$ (41,797,844)	$ (38,897,538)	$ (2,457,747)	$ (6,775)	$ (233,868)	$ —	$ —	$ (4,499)
181		Demand	DISPLTDEM	$ (5,993,366)	$ (3,548,866)	$ (1,336,955)	$ (39,070)	$ (481,886)	$ —	$ —	$ (96,262)
182		Commodity	COM	$ (48,261)	$ (28,162)	$ (10,581)	$ (274)	$ (2,890)	$ —	$ —	$ (1,465)
183		Total General Plant - Allocated		$ (47,839,470)	$ (42,474,566)	$ (3,805,283)	$ (46,120)	$ (718,644)	$ —	$ —	$ (102,227)
184		**General Plant - Directly Assigned**									
185		Customer	CUS-DA	$ (18,649)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Demand	DEM-DA	$ (13,143)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ (31,792)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
189		**Total Depr. & Amort. Reserve**									
190		Customer		$ (148,817,123)	$ (136,863,638)	$ (9,116,542)	$ (29,579)	$ (943,879)	$ —	$ —	$ (20,543)
191		Demand		$ (39,900,830)	$ (23,920,090)	$ (8,583,778)	$ (250,847)	$ (3,093,898)	$ —	$ —	$ (618,040)
192		Commodity		$ (199,325)	$ (116,314)	$ (43,702)	$ (1,133)	$ (11,936)	$ —	$ —	$ (6,052)
193		Total Depr. & Amortization Reserve		$ (188,917,277)	$ (160,900,042)	$ (17,744,022)	$ (281,559)	$ (4,049,713)	$ —	$ —	$ (644,636)
194		**Net Plant in Service**									
195		Customer		$ 577,616,550	$ 532,999,165	$ 35,968,571	$ 120,889	$ 3,795,918	$ —	$ —	$ 84,680
196		Demand		$ 231,567,644	$ 142,312,001	$ 49,648,823	$ 1,450,904	$ 17,895,196	$ —	$ —	$ 3,574,764
197		Commodity		$ 1,215,405	$ 709,239	$ 266,477	$ 6,908	$ 72,784	$ —	$ —	$ 36,905

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
198		Total Net Plant in Service		$ 810,399,599	$ 676,020,405	$ 85,883,871	$ 1,578,702	$ 21,763,898	$ —	$ —	$ 3,696,349
199		**Customer Deposits**									
200		Customer	DEPCUS	$ (7,616,570)	$ (4,094,939)	$ (3,320,190)	$ (31,580)	$ (58,965)	$ —	$ —	$ (110,896)
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (7,616,570)	$ (4,094,939)	$ (3,320,190)	$ (31,580)	$ (58,965)	$ —	$ —	$ (110,896)
204		**Customer Advances**									
205		Customer	MSCUS-ALL	$ (480,374)	$ (449,547)	$ (28,313)	$ (65)	$ (2,345)	$ —	$ —	$ (39)
206		Demand	DEM	$ (119,351)	$ (80,354)	$ (22,543)	$ (659)	$ (8,125)	$ —	$ —	$ (1,623)
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (599,726)	$ (529,902)	$ (50,856)	$ (724)	$ (10,470)	$ —	$ —	$ (1,662)
209		**Accum. Deferred Income Taxes**									
210		Customer	TPLTCUS	$ (53,749,413)	$ (49,563,689)	$ (3,335,884)	$ (11,133)	$ (350,701)	$ —	$ —	$ (7,786)
211		Demand	TPLTDEM	$ (20,086,171)	$ (12,299,646)	$ (4,308,677)	$ (125,914)	$ (1,553,000)	$ —	$ —	$ (310,229)
212		Commodity	COM	$ (104,677)	$ (61,083)	$ (22,950)	$ (595)	$ (6,269)	$ —	$ —	$ (3,178)
213		Total Accum. Deferred Inc. Taxes		$ (73,940,261)	$ (61,924,418)	$ (7,667,511)	$ (137,642)	$ (1,909,970)	$ —	$ —	$ (321,193)
214		**Excess Deferred Income Taxes**									
215		Customer	TPLTCUS	$ (7,977,503)	$ (7,356,257)	$ (495,113)	$ (1,652)	$ (52,051)	$ —	$ —	$ (1,156)
216		Demand	TPLTDEM	$ (2,981,195)	$ (1,825,517)	$ (639,495)	$ (18,688)	$ (230,497)	$ —	$ —	$ (46,044)
217		Commodity	COM	$ (15,536)	$ (9,066)	$ (3,406)	$ (88)	$ (930)	$ —	$ —	$ (472)
218		**Total Excess Deferred Income Taxes**		$ (10,974,235)	$ (9,190,840)	$ (1,138,014)	$ (20,429)	$ (283,478)	$ —	$ —	$ (47,672)
219		**Negative Acquisition Adjustment on OPC Assets**									
220		Customer	DISPLTCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
221		Demand	DISPLTDEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
224		**Materials and Supplies**									
225		Customer	TPLTCUS	$ 6,917,445	$ 6,378,751	$ 429,322	$ 1,433	$ 45,135	$ —	$ —	$ 1,002
226		Demand	TPLTDEM	$ 2,585,051	$ 1,582,941	$ 554,518	$ 16,205	$ 199,868	$ —	$ —	$ 39,926
227		Commodity	COM	$ 13,472	$ 7,861	$ 2,954	$ 77	$ 807	$ —	$ —	$ 409
228		Total Materials and Supplies		$ 9,515,969	$ 7,969,553	$ 986,794	$ 17,714	$ 245,809	$ —	$ —	$ 41,337
229		**Prepayments**									
230		Customer	OPEXPCUS	$ 4,114,966	$ 3,792,109	$ 266,354	$ 1,023	$ 29,909	$ —	$ —	$ 747
231		Demand	OPEXPDEM	$ 727,923	$ 445,745	$ 157,542	$ 4,604	$ 56,784	$ —	$ —	$ 11,343
232		Commodity	COM	$ 52,965	$ 30,907	$ 11,613	$ 301	$ 3,172	$ —	$ —	$ 1,608
233		Total Prepayments		$ 4,895,854	$ 4,268,760	$ 435,509	$ 5,928	$ 89,865	$ —	$ —	$ 13,699
234		**Pension & FAS 106 Reg. Asset**									
235		Customer	OPEXPCUS	$ 14,680,188	$ 13,528,389	$ 950,219	$ 3,651	$ 106,702	$ —	$ —	$ 2,665
236		Demand	OPEXPDEM	$ 2,596,872	$ 1,590,199	$ 562,034	$ 16,425	$ 202,577	$ —	$ —	$ 40,467
237		Commodity	COM	$ 188,953	$ 110,262	$ 41,428	$ 1,074	$ 11,315	$ —	$ —	$ 5,738
238		Total Pen. & FAS 106 Reg. Asset		$ 17,466,013	$ 15,228,849	$ 1,553,682	$ 21,149	$ 320,595	$ —	$ —	$ 48,870
239		**DIMP Deferrals**									
240		Customer	TPLTCUS	$ 1,845,989	$ 1,702,233	$ 114,569	$ 382	$ 12,045	$ —	$ —	$ 267
241		Demand	TPLTDEM	$ 326,549	$ 199,960	$ 70,048	$ 2,047	$ 25,248	$ —	$ —	$ 5,044

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
242		Commodity	COM	$ 23,760	$ 13,865	$ 5,209	$ 135	$ 1,423	$ —	$ —	$ 721
243		Total DIMP Deferrals		$ 2,196,298	$ 1,916,058	$ 189,826	$ 2,564	$ 38,715	$ —	$ —	$ 6,032
244		**Regulatory Asset**									
245		Customer	TPLTCUS	$ 967,216	$ 891,894	$ 60,029	$ 200	$ 6,311	$ —	$ —	$ 140
246		Demand	TPLTDEM	$ 171,097	$ 104,770	$ 36,702	$ 1,073	$ 13,229	$ —	$ —	$ 2,643
247		Commodity	COM	$ 12,449	$ 7,265	$ 2,730	$ 71	$ 746	$ —	$ —	$ 378
248		**Total Regulatory Asset**		$ 1,150,763	$ 1,003,929	$ 99,460	$ 1,344	$ 20,285	$ —	$ —	$ 3,161
249		**Cash Working Capital**									
250		Customer	OPEXPCUS	$ (4,995,920)	$ (4,603,943)	$ (323,376)	$ (1,242)	$ (36,313)	$ —	$ —	$ (907)
251		Demand	OPEXPDEM	$ (883,760)	$ (541,172)	$ (191,270)	$ (5,590)	$ (68,940)	$ —	$ —	$ (13,772)
252		Commodity	COM	$ (64,304)	$ (37,524)	$ (14,099)	$ (366)	$ (3,851)	$ —	$ —	$ (1,953)
253		Total Cash Working Capital		$ (5,943,984)	$ (5,182,639)	$ (528,745)	$ (7,197)	$ (109,104)	$ —	$ —	$ (16,631)
254		**Total Rate Base**									
255		Customer		$ 531,322,574	$ 493,224,166	$ 30,286,188	$ 81,905	$ 3,495,645	$ —	$ —	$ (31,281)
256		Demand		$ 213,904,658	$ 131,488,925	$ 45,867,683	$ 1,340,407	$ 16,532,339	$ —	$ —	$ 3,302,518
257		Commodity		$ 1,322,488	$ 771,726	$ 289,955	$ 7,517	$ 79,197	$ —	$ —	$ 40,157
258		Total Rate Base		$ 746,549,720	$ 625,484,817	$ 76,443,826	$ 1,429,829	$ 20,107,180	$ —	$ —	$ 3,311,394

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
1	301-303	**Intangible Plant**						
2		Customer	NONINCUS	$ 31	$ 24	$ 10	$ —	$ 46
3		Demand	NONINDEM	$ 2,318	$ 2,898	$ 1,619	$ —	$ 7,383
4		Commodity	COM	$ 48	$ 24	$ 36	$ —	$ 40
5		Total Intangible Plant		$ 2,397	$ 2,946	$ 1,664	$ —	$ 7,469
6	365-371	**Transmission Plant**						
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 557,808	$ 697,409	$ 389,555	$ —	$ 1,776,920
9		Commodity	COM	$ 3,348	$ 1,679	$ 2,475	$ —	$ 2,795
10		Total Transmission Plant		$ 561,156	$ 699,088	$ 392,030	$ —	$ 1,779,715
11		**Distribution Plant**						
12	374	**Land & Land Rights - Allocated**						
13		Customer	376-379CUS	$ 44	$ 34	$ 14	$ —	$ 16,193
14		Demand	DEM	$ 5,451	$ 6,816	$ 3,807	$ —	$ 17,366
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 5,496	$ 6,850	$ 3,821	$ —	$ 33,558
17	374	**Land & Land Rights - DA**						
18		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 10,458
19		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 9,076
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ —	$ —	$ —	$ —	$ 19,533
22	375	**Structures and Improvements**						
23		Customer	376-379CUS	$ 9	$ 7	$ 3	$ —	$ 3,249
24		Demand	DEM	$ 1,094	$ 1,368	$ 764	$ —	$ 3,485
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 1,103	$ 1,375	$ 767	$ —	$ 6,734
27	376	**Distribution Mains-Allocated**						
28		Customer	CUS	$ 11,151	$ 8,577	$ 3,431	$ —	$ 16,225
29		Demand	DEM	$ 1,069,947	$ 1,337,719	$ 747,215	$ —	$ 3,408,358
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 1,081,097	$ 1,346,296	$ 750,646	$ —	$ 3,424,584
32	376	**Odorization**						
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —
36		**Total Odorization**		$ —	$ —	$ —	$ —	$ —
37		**Distribution Mains - Directly Assn.**						
38		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 4,046,444
39		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 3,186,040

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ —	$ —	$ —	$ —	$ 7,232,484
42	377	**Compressor Station Equipment**						
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**						
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 195,246	$ 244,110	$ 136,353	$ —	$ 621,964
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 195,246	$ 244,110	$ 136,353	$ —	$ 621,964
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**						
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 325,537
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ 325,537
57	378	**Odorization**						
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 11,046	$ 5,540	$ 8,167	$ —	$ 9,221
61		Total Odorization		$ 11,046	$ 5,540	$ 8,167	$ —	$ 9,221
62	379	**Meas. & Reg. Station - City Gate**						
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 82,073	$ 102,613	$ 57,317	$ —	$ 261,447
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 82,073	$ 102,613	$ 57,317	$ —	$ 261,447
67	379	**Odorization**						
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 26,413	$ 13,248	$ 19,528	$ —	$ 22,050
71		Total Odorization		$ 26,413	$ 13,248	$ 19,528	$ —	$ 22,050
72	380	**Services - Allocated**						
73		Customer	SERCUS-ALL	$ 15,505	$ 11,927	$ 4,771	$ —	$ —
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 15,505	$ 11,927	$ 4,771	$ —	$ —
77	380	**Services-Directly Assigned**						
78		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 1,524,955

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ 1,524,955
82	381	**Meters - Allocated**						
83		Customer	METCUS-ALL	$ 17,092	$ 11,922	$ 5,259	$ —	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 17,092	$ 11,922	$ 5,259	$ —	$ —
87	381	**Meters-Directly Assigned**						
88		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 152,811
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ 152,811
92	382	**Meter Installations**						
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**						
98		Customer	REGCUS-ALL	$ 15,084	$ 10,370	$ 4,641	$ —	$ —
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 15,084	$ 10,370	$ 4,641	$ —	$ —
102	383	**House Regulators - Directly Assigned**						
103		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 75,571
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ —	$ —	$ —	$ —	$ 75,571
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**						
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 464,170	$ 580,337	$ 324,161	$ —	$ 1,478,633
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 464,170	$ 580,337	$ 324,161	$ —	$ 1,478,633
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**						
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 574,172
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ —	$ —	$ —	$ —	$ 574,172
117	385	**Odorization**						

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ 134	$ 67	$ 99	$ —	$ 112
121		Total Odorization		$ 134	$ 67	$ 99	$ —	$ 112
122	386	**Other Prop.-Customer Premises**						
123		Customer	CUS	$ 27	$ 21	$ 8	$ —	$ 39
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 27	$ 21	$ 8	$ —	$ 39
127	387	**Other Equipment**						
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**						
133		Customer		$ 58,912	$ 42,857	$ 18,127	$ —	$ 5,845,945
134		Demand		$ 1,817,981	$ 2,272,962	$ 1,269,617	$ —	$ 9,886,076
135		Commodity		$ 37,593	$ 18,855	$ 27,793	$ —	$ 31,383
136		Total Distribution Plant		$ 1,914,486	$ 2,334,674	$ 1,315,537	$ —	$ 15,763,404
137		**General Plant**						
138		**General Plant - Allocated**						
139		Customer	GENPTCUS	$ 6,979	$ 5,170	$ 2,147	$ —	$ 474,480
140		Demand	DISPLTDEM	$ 168,429	$ 210,581	$ 117,625	$ —	$ 915,907
141		Commodity	COM	$ 5,595	$ 2,806	$ 4,137	$ —	$ 4,671
142		Total General Plant - Allocated		$ 181,003	$ 218,558	$ 123,909	$ —	$ 1,395,058
143		**Total General Plant - Directly Assigned**						
144		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 35,537
145		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 25,045
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ —	$ —	$ —	$ —	$ 60,583
148		**Total General Plant**						
149		Customer		$ 6,979	$ 5,170	$ 2,147	$ —	$ 510,018
150		Demand		$ 168,429	$ 210,581	$ 117,625	$ —	$ 940,952
151		Commodity		$ 5,595	$ 2,806	$ 4,137	$ —	$ 4,671
152		Total General Plant		$ 181,003	$ 218,558	$ 123,909	$ —	$ 1,455,641
153		**Total Plant in Service**						
154		Customer		$ 65,923	$ 48,052	$ 20,284	$ —	$ 6,356,009
155		Demand		$ 2,546,536	$ 3,183,850	$ 1,778,416	$ —	$ 12,611,332
156		Commodity		$ 46,584	$ 23,364	$ 34,441	$ —	$ 38,890
157		Total Plant in Service		$ 2,659,043	$ 3,255,266	$ 1,833,140	$ —	$ 19,006,230

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
158		**Depreciation & Amort. Reserve**						
159		**Intangible Plant**						
160		Customer	NONINCUS	$ (18)	$ (14)	$ (5)	$ —	$ (26)
161		Demand	NONINDEM	$ (890)	$ (1,113)	$ (622)	$ —	$ (2,836)
162		Commodity	COM	$ (18)	$ (9)	$ (13)	$ —	$ (15)
163		Total Intangible Plant		$ (926)	$ (1,136)	$ (640)	$ —	$ (2,877)
164		**Transmission Plant**						
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (53,645)	$ (67,071)	$ (37,464)	$ —	$ (170,888)
167		Commodity	COM	$ (552)	$ (277)	$ (408)	$ —	$ (461)
168		Total Transmission Plant		$ (54,197)	$ (67,348)	$ (37,872)	$ —	$ (171,349)
169		**Distribution Plant - Allocated**						
170		Customer	DISPLTCUS	$ (10,034)	$ (7,299)	$ (3,087)	$ —	$ (995,669)
171		Demand	DISPLTDEM	$ (262,371)	$ (328,034)	$ (183,231)	$ —	$ (1,426,760)
172		Commodity	COM	$ (4,404)	$ (2,209)	$ (3,256)	$ —	$ (3,677)
173		Total Distribution Plant - Allocated		$ (276,809)	$ (337,543)	$ (189,575)	$ —	$ (2,426,106)
174		**Distribution Plant - Dir. Assn.**						
175		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ (610,722)
176		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ (395,782)
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ —	$ —	$ —	$ —	$ (1,006,505)
179		**General Plant - Allocated**						
180		Customer	GENPTCUS	$ (2,819)	$ (2,088)	$ (867)	$ —	$ (191,642)
181		Demand	DISPLTDEM	$ (58,466)	$ (73,098)	$ (40,830)	$ —	$ (317,933)
182		Commodity	COM	$ (1,589)	$ (797)	$ (1,175)	$ —	$ (1,327)
183		Total General Plant - Allocated		$ (62,874)	$ (75,983)	$ (42,873)	$ —	$ (510,901)
184		**General Plant - Directly Assigned**						
185		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ (18,649)
186		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ (13,143)
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ (31,792)
189		**Total Depr. & Amort. Reserve**						
190		Customer		$ (12,871)	$ (9,401)	$ (3,960)	$ —	$ (1,816,709)
191		Demand		$ (375,372)	$ (469,315)	$ (262,147)	$ —	$ (2,327,342)
192		Commodity		$ (6,563)	$ (3,292)	$ (4,852)	$ —	$ (5,479)
193		Total Depr. & Amortization Reserve		$ (394,806)	$ (482,009)	$ (270,960)	$ —	$ (4,149,530)
194		**Net Plant in Service**						
195		Customer		$ 53,053	$ 38,651	$ 16,324	$ —	$ 4,539,300
196		Demand		$ 2,171,164	$ 2,714,534	$ 1,516,268	$ —	$ 10,283,990
197		Commodity		$ 40,020	$ 20,072	$ 29,588	$ —	$ 33,410

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
198		Total Net Plant in Service		$ 2,264,237	$ 2,773,258	$ 1,562,180	$ —	$ 14,856,700
199		**Customer Deposits**						
200		Customer	DEPCUS	$ —	$ —	$ —	$ —	$ —
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ —	$ —	$ —	$ —	$ —
204		**Customer Advances**						
205		Customer	MSCUS-ALL	$ (24)	$ (19)	$ (7)	$ —	$ (15)
206		Demand	DEM	$ (986)	$ (1,233)	$ (688)	$ —	$ (3,140)
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (1,010)	$ (1,251)	$ (696)	$ —	$ (3,155)
209		**Accum. Deferred Income Taxes**						
210		Customer	TPLTCUS	$ (4,878)	$ (3,555)	$ (1,501)	$ —	$ (470,286)
211		Demand	TPLTDEM	$ (188,420)	$ (235,576)	$ (131,586)	$ —	$ (933,123)
212		Commodity	COM	$ (3,447)	$ (1,729)	$ (2,548)	$ —	$ (2,877)
213		Total Accum. Deferred Inc. Taxes		$ (196,745)	$ (240,860)	$ (135,636)	$ —	$ (1,406,286)
214		**Excess Deferred Income Taxes**						
215		Customer	TPLTCUS	$ (724)	$ (528)	$ (223)	$ —	$ (69,800)
216		Demand	TPLTDEM	$ (27,965)	$ (34,964)	$ (19,530)	$ —	$ (138,494)
217		Commodity	COM	$ (512)	$ (257)	$ (378)	$ —	$ (427)
218		**Total Excess Deferred Income Taxes**		$ (29,201)	$ (35,748)	$ (20,131)	$ —	$ (208,721)
219		**Negative Acquisition Adjustment on OPC Assets**						
220		Customer	DISPLTCUS	$ —	$ —	$ —	$ —	$ —
221		Demand	DISPLTDEM	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ —	$ —	$ —	$ —	$ —
224		**Materials and Supplies**						
225		Customer	TPLTCUS	$ 628	$ 458	$ 193	$ —	$ 60,525
226		Demand	TPLTDEM	$ 24,249	$ 30,318	$ 16,935	$ —	$ 120,091
227		Commodity	COM	$ 444	$ 222	$ 328	$ —	$ 370
228		Total Materials and Supplies		$ 25,321	$ 30,998	$ 17,456	$ —	$ 180,986
229		**Prepayments**						
230		Customer	OPEXPCUS	$ 468	$ 335	$ 144	$ —	$ 23,877
231		Demand	OPEXPDEM	$ 6,889	$ 8,614	$ 4,811	$ —	$ 31,590
232		Commodity	COM	$ 1,744	$ 875	$ 1,289	$ —	$ 1,456
233		Total Prepayments		$ 9,101	$ 9,823	$ 6,245	$ —	$ 56,924
234		**Pension & FAS 106 Reg. Asset**						
235		Customer	OPEXPCUS	$ 1,670	$ 1,195	$ 514	$ —	$ 85,183
236		Demand	OPEXPDEM	$ 24,578	$ 30,729	$ 17,164	$ —	$ 112,699
237		Commodity	COM	$ 6,222	$ 3,121	$ 4,600	$ —	$ 5,194
238		Total Pen. & FAS 106 Reg. Asset		$ 32,470	$ 35,044	$ 22,278	$ —	$ 203,076
239		**DIMP Deferrals**						
240		Customer	TPLTCUS	$ 168	$ 122	$ 52	$ —	$ 16,152
241		Demand	TPLTDEM	$ 3,063	$ 3,830	$ 2,139	$ —	$ 15,170

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
242		Commodity	COM	$ 782	$ 392	$ 578	$ —	$ 653
243		Total DIMP Deferrals		$ 4,013	$ 4,344	$ 2,769	$ —	$ 31,975
244		**Regulatory Asset**						
245		Customer	TPLTCUS	$ 88	$ 64	$ 27	$ —	$ 8,463
246		Demand	TPLTDEM	$ 1,605	$ 2,007	$ 1,121	$ —	$ 7,948
247		Commodity	COM	$ 410	$ 206	$ 303	$ —	$ 342
248		**Total Regulatory Asset**		$ 2,103	$ 2,276	$ 1,451	$ —	$ 16,753
249		**Cash Working Capital**						
250		Customer	OPEXPCUS	$ (568)	$ (407)	$ (175)	$ —	$ (28,989)
251		Demand	OPEXPDEM	$ (8,364)	$ (10,458)	$ (5,841)	$ —	$ (38,353)
252		Commodity	COM	$ (2,117)	$ (1,062)	$ (1,565)	$ —	$ (1,768)
253		Total Cash Working Capital		$ (11,050)	$ (11,926)	$ (7,582)	$ —	$ (69,110)
254		**Total Rate Base**						
255		Customer		$ 49,879	$ 36,316	$ 15,347	$ —	$ 4,164,410
256		Demand		$ 2,005,813	$ 2,507,802	$ 1,400,793	$ —	$ 9,458,378
257		Commodity		$ 43,546	$ 21,841	$ 32,195	$ —	$ 36,354
258		Total Rate Base		$ 2,099,239	$ 2,565,958	$ 1,448,335	$ —	$ 13,659,142

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1		**Transmission and Distribution Op. Exp.**									
2	814-865	**Transmission Expenses**									
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 2,085,468	$ 1,404,063	$ 393,897	$ 11,511	$ 141,974	$ —	$ —	$ 28,361
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 2,085,468	$ 1,404,063	$ 393,897	$ 11,511	$ 141,974	$ —	$ —	$ 28,361
7	8650	**Odorization**									
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ 2,471	$ 1,442	$ 542	$ 14	$ 148	$ —	$ —	$ 75
11		Total Odorization		$ 2,471	$ 1,442	$ 542	$ 14	$ 148	$ —	$ —	$ 75
12	8700	**Operation Supervision & Engineering**									
13		Customer	871-879CUS	$ 994,460	$ 904,843	$ 75,962	$ 459	$ 12,352	$ —	$ —	$ 368
14		Demand	DEM	$ 145,979	$ 98,282	$ 27,572	$ 806	$ 9,938	$ —	$ —	$ 1,985
15		Commodity	COM	$ 25,444	$ 14,848	$ 5,579	$ 145	$ 1,524	$ —	$ —	$ 773
16		Total Supervision & Engineering		$ 1,165,883	$ 1,017,972	$ 109,113	$ 1,410	$ 23,813	$ —	$ —	$ 3,126
17	8710	**Distribution Load Dispatch**									
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 258,612	$ 150,911	$ 56,701	$ 1,470	$ 15,487	$ —	$ —	$ 7,853
21		Total Distribution Load Dispatch		$ 258,612	$ 150,911	$ 56,701	$ 1,470	$ 15,487	$ —	$ —	$ 7,853
22	8740	**Mains & Services - Allocated**									
23		Customer	MSCUS-ALL	$ 4,198,645	$ 3,929,203	$ 247,467	$ 570	$ 20,498	$ —	$ —	$ 338
24		Demand	DEM	$ 1,028,862	$ 692,692	$ 194,328	$ 5,679	$ 70,043	$ —	$ —	$ 13,992
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 5,227,507	$ 4,621,895	$ 441,795	$ 6,249	$ 90,541	$ —	$ —	$ 14,330
27	8740	**Mains & Services - Dir. Assn.**									
28		Customer	MSCUS-DA	$ 44,275	$ —	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM-DA	$ 25,319	$ —	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ 69,595	$ —	$ —	$ —	$ —	$ —	$ —	$ —
32	8740	**Odorization**									
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ 2,897	$ 1,690	$ 635	$ 16	$ 173	$ —	$ —	$ 88

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
36		Total Odorization		$ 2,897	$ 1,690	$ 635	$ 16	$ 173	$ —	$ —	$ 88
37	8750	**Meas. & Reg. Station - Gen. - Allocated**									
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 351,540	$ 236,678	$ 66,398	$ 1,940	$ 23,932	$ —	$ —	$ 4,781
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 351,540	$ 236,678	$ 66,398	$ 1,940	$ 23,932	$ —	$ —	$ 4,781
42		**Meas. & Reg. Station - Gen. - DA**									
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ 6,618	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ 6,618	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	8750	**Odorization**									
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 129,001	$ 75,277	$ 28,283	$ 733	$ 7,725	$ —	$ —	$ 3,917
51		Total Odorization		$ 129,001	$ 75,277	$ 28,283	$ 733	$ 7,725	$ —	$ —	$ 3,917
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**									
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 30,814	$ —	$ 17,812	$ 521	$ 6,420	$ —	$ —	$ 1,283
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 30,814	$ —	$ 17,812	$ 521	$ 6,420	$ —	$ —	$ 1,283
57	8760	**Meas. & Reg. Stat. - Ind. - DA**									
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ 964	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ 964	$ —	$ —	$ —	$ —	$ —	$ —	$ —
62	8770	**Meas. & Reg. Stat.- City Gate**									
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 39,598	$ 26,660	$ 7,479	$ 219	$ 2,696	$ —	$ —	$ 539
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 39,598	$ 26,660	$ 7,479	$ 219	$ 2,696	$ —	$ —	$ 539
67	8780	**Meter & House Reg. Exp. - Alloc.**									
68		Customer	MTRGCUS-ALL	$ 5,841,355	$ 5,206,087	$ 519,397	$ 4,068	$ 104,191	$ —	$ —	$ 3,378
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
71		Total Meter & House Reg. Exp. - Alloc.		$ 5,841,355	$ 5,206,087	$ 519,397	$ 4,068	$ 104,191	$ —	$ —	$ 3,378
72	8780	**Meter & House Reg. Exp - Dir. Assn.**									
73		Customer	CUS-DA	$ 15,551	$ —	$ —	$ —	$ —	$ —	$ —	$ —
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ 15,551	$ —	$ —	$ —	$ —	$ —	$ —	$ —
77	8780	**Odorization**									
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ 81	$ 47	$ 18	$ 0	$ 5	$ —	$ —	$ 2
81		Total Odorization		$ 81	$ 47	$ 18	$ 0	$ 5	$ —	$ —	$ 2
82	8790	**Customer Installation Expense**									
83		Customer	METCUS-ALL	$ 7,768	$ 7,012	$ 637	$ 4	$ 109	$ —	$ —	$ 3
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 7,768	$ 7,012	$ 637	$ 4	$ 109	$ —	$ —	$ 3
87	8800	**Other Expenses**									
88		Customer	871-879CUS	$ 962,232	$ 875,519	$ 73,500	$ 445	$ 11,951	$ —	$ —	$ 356
89		Demand	DEM	$ 141,248	$ 95,097	$ 26,678	$ 780	$ 9,616	$ —	$ —	$ 1,921
90		Commodity	COM	$ 24,620	$ 14,367	$ 5,398	$ 140	$ 1,474	$ —	$ —	$ 748
91		Total Other Expenses		$ 1,128,099	$ 984,982	$ 105,577	$ 1,364	$ 23,042	$ —	$ —	$ 3,025
92	8800	**Odorization**									
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 853	$ 498	$ 187	$ 5	$ 51	$ —	$ —	$ 26
96		Total Odorization		$ 853	$ 498	$ 187	$ 5	$ 51	$ —	$ —	$ 26
97	8810	**Rents**									
98		Customer	871-879CUS	$ 58,859	$ 53,555	$ 4,496	$ 27	$ 731	$ —	$ —	$ 22
99		Demand	DEM	$ 8,640	$ 5,817	$ 1,632	$ 48	$ 588	$ —	$ —	$ 117
100		Commodity	COM	$ 1,506	$ 879	$ 330	$ 9	$ 90	$ —	$ —	$ 46
101		Total Rents		$ 69,005	$ 60,250	$ 6,458	$ 83	$ 1,409	$ —	$ —	$ 185
102	8820	**Corporate & Div. Exp.**									
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**									
108		Customer		$ 12,123,145	$ 10,976,219	$ 921,460	$ 5,573	$ 149,832	$ —	$ —	$ 4,465
109		Demand		$ 3,865,049	$ 2,559,287	$ 735,796	$ 21,502	$ 265,207	$ —	$ —	$ 52,978
110		Commodity		$ 445,485	$ 259,959	$ 97,672	$ 2,532	$ 26,678	$ —	$ —	$ 13,527
111		Total Distr. & Trans. Operations Exp.		$ 16,433,679	$ 13,795,465	$ 1,754,929	$ 29,607	$ 441,717	$ —	$ —	$ 70,970
112		**Distribution Maintenance Expenses**									
113	8850	**Maintenance Supervision and Engineering**									
114		Customer	887-893CUS	$ 11,232	$ 10,512	$ 660	$ 2	$ 56	$ —	$ —	$ 1
115		Demand	887-893DEM	$ 7,706	$ 4,132	$ 2,066	$ 60	$ 745	$ —	$ —	$ 149
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ 18,937	$ 14,643	$ 2,726	$ 62	$ 800	$ —	$ —	$ 150
118	8860	**Structures and Improvements**									
119		Customer	887-893CUS	$ 402,826	$ 377,001	$ 23,686	$ 55	$ 1,994	$ —	$ —	$ 33
120		Demand	887-893DEM	$ 276,358	$ 148,179	$ 74,096	$ 2,165	$ 26,707	$ —	$ —	$ 5,335
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 679,184	$ 525,180	$ 97,781	$ 2,221	$ 28,701	$ —	$ —	$ 5,368
123	8870	**Maintenance of Mains-Allocated**									
124		Customer	CUS	$ 2,002,584	$ 1,882,205	$ 110,565	$ 225	$ 9,158	$ —	$ —	$ 134
125		Demand	DEM	$ 972,933	$ 655,037	$ 183,764	$ 5,370	$ 66,235	$ —	$ —	$ 13,231
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 2,975,516	$ 2,537,242	$ 294,330	$ 5,596	$ 75,393	$ —	$ —	$ 13,365
128	8870	**Maintenance of Mains - Directly Assigned**									
129		Customer	CUS-DA	$ 30,392	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM-DA	$ 23,930	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ 54,321	$ —	$ —	$ —	$ —	$ —	$ —	$ —
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**									
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 963,593	$ 648,749	$ 182,000	$ 5,319	$ 65,599	$ —	$ —	$ 13,104
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 963,593	$ 648,749	$ 182,000	$ 5,319	$ 65,599	$ —	$ —	$ 13,104
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**									
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ 13,824	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 13,824	$ —	$ —	$ —	$ —	$ —	$ —	$ —
143	8890	**Odorization**									
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 40,208	$ 23,463	$ 8,816	$ 229	$ 2,408	$ —	$ —	$ 1,221
147		Total Odorization		$ 40,208	$ 23,463	$ 8,816	$ 229	$ 2,408	$ —	$ —	$ 1,221
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**									
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 503,673	$ —	$ 291,155	$ 8,509	$ 104,943	$ —	$ —	$ 20,963
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 503,673	$ —	$ 291,155	$ 8,509	$ 104,943	$ —	$ —	$ 20,963
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**									
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ 15,750	$ —	$ —	$ —	$ —	$ —	$ —	$ —
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ 15,750	$ —	$ —	$ —	$ —	$ —	$ —	$ —
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**									
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 33,659	$ 22,661	$ 6,357	$ 186	$ 2,291	$ —	$ —	$ 458
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 33,659	$ 22,661	$ 6,357	$ 186	$ 2,291	$ —	$ —	$ 458
163	8910	**Odorization**									
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ 100	$ 58	$ 22	$ 1	$ 6	$ —	$ —	$ 3
167		Total Odorization		$ 100	$ 58	$ 22	$ 1	$ 6	$ —	$ —	$ 3
168	8920	**Services - Allocated**									
169		Customer	SERCUS-ALL	$ 1,613,870	$ 1,503,632	$ 101,245	$ 257	$ 8,386	$ —	$ —	$ 152
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 1,613,870	$ 1,503,632	$ 101,245	$ 257	$ 8,386	$ —	$ —	$ 152
173	8920	**Services - Directly Assigned**									
174		Customer	CUS-DA	$ 9,393	$ —	$ —	$ —	$ —	$ —	$ —	$ —
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ 9,393	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178	8930	**Meters & House Regulators - Alloc.**									
179		Customer	MTRGCUS-ALL	$ 27,628	$ 24,624	$ 2,457	$ 19	$ 493	$ —	$ —	$ 16
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ 27,628	$ 24,624	$ 2,457	$ 19	$ 493	$ —	$ —	$ 16
183	8930	**Meters & House Regulators - DA**									
184		Customer	CUS-DA	$ 74	$ —	$ —	$ —	$ —	$ —	$ —	$ —
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ 74	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188	8940	**Maintenance of Other Equipment**									
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**									
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**									
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**									
204		Customer		$ 4,097,999	$ 3,797,973	$ 238,612	$ 559	$ 20,087	$ —	$ —	$ 336
205		Demand		$ 2,811,424	$ 1,478,758	$ 739,439	$ 21,609	$ 266,520	$ —	$ —	$ 53,240
206		Commodity		$ 40,308	$ 23,521	$ 8,838	$ 229	$ 2,414	$ —	$ —	$ 1,224
207		Total Distr. Maintenance Expense		$ 6,949,731	$ 5,300,252	$ 986,889	$ 22,397	$ 289,021	$ —	$ —	$ 54,801
208		**Total Oper. & Maint. Expense**									
209		Customer		$ 16,221,144	$ 14,774,192	$ 1,160,072	$ 6,132	$ 169,919	$ —	$ —	$ 4,801
210		Demand		$ 6,676,473	$ 4,038,045	$ 1,475,236	$ 43,111	$ 531,727	$ —	$ —	$ 106,218

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
211		Commodity		$ 485,793	$ 283,480	$ 106,510	$ 2,761	$ 29,091	$ —	$ —	$ 14,751
212		Total Operations & Maint. Expense		$ 23,383,410	$ 19,095,717	$ 2,741,818	$ 52,004	$ 730,737	$ —	$ —	$ 125,770
213		**Customer Accounts Expense**									
214	901	**Supervision**									
215		Customer	902-904CUS	$ 285	$ 268	$ 16	$ 0	$ 1	$ —	$ —	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 285	$ 268	$ 16	$ 0	$ 1	$ —	$ —	$ 0
219	902	**Meter Reading Expense**									
220		Customer	METCUS-TOT	$ 394,235	$ 355,730	$ 32,323	$ 199	$ 5,516	$ —	$ —	$ 157
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 394,235	$ 355,730	$ 32,323	$ 199	$ 5,516	$ —	$ —	$ 157
224	903	**Customer Accounting**									
225		Customer	903CUS	$ 5,154,764	$ 4,921,047	$ 224,357	$ 410	$ 8,582	$ —	$ —	$ 115
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 5,154,764	$ 4,921,047	$ 224,357	$ 410	$ 8,582	$ —	$ —	$ 115
229	904	**Bad Debt Expense**									
230		Customer	904CUS	$ 1,393,252	$ 1,247,831	$ 143,815	$ —	$ 1,607	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ 1,393,252	$ 1,247,831	$ 143,815	$ —	$ 1,607	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**									
235		Customer	902-904CUS	$ 408,799	$ 384,206	$ 23,583	$ 36	$ 925	$ —	$ —	$ 16
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 408,799	$ 384,206	$ 23,583	$ 36	$ 925	$ —	$ —	$ 16
239	907-910	**Customer Information Expense**									
240		Customer	CUS	$ 962,443	$ 904,589	$ 53,138	$ 108	$ 4,401	$ —	$ —	$ 64
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 962,443	$ 904,589	$ 53,138	$ 108	$ 4,401	$ —	$ —	$ 64
244		**Sales and Advertising Expense**		$ 962,443							
245	911	**Supervision**									

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**									
251		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
255	913	**Advertising**									
256		Customer	CUS	$ 26,690	$ 25,086	$ 1,474	$ 3	$ 122	$ —	$ —	$ 2
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 26,690	$ 25,086	$ 1,474	$ 3	$ 122	$ —	$ —	$ 2
260	914	**Employee Sales Referrals**									
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**									
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**									
271	920-940	**Administrative & General Expenses**									
272		Customer	OPEXPCUS	$ 29,503,386	$ 27,188,567	$ 1,909,696	$ 7,337	$ 214,444	$ —	$ —	$ 5,356
273		Demand	OPEXPDEM	$ 2,887,431	$ 1,768,123	$ 624,919	$ 18,262	$ 225,243	$ —	$ —	$ 44,995
274		Commodity	COM	$ 210,095	$ 122,599	$ 46,063	$ 1,194	$ 12,581	$ —	$ —	$ 6,379
275		Total Administrative & General Exp.		$ 32,600,912	$ 29,079,289	$ 2,580,678	$ 26,794	$ 452,269	$ —	$ —	$ 56,731
276		**Depreciation & Amortization Expense**		$ 32,600,912							
277	301-303	**Intangible Plant - Allocated**									
278		Customer	CUS	$ 12,226	$ 11,491	$ 675	$ 1	$ 56	$ —	$ —	$ 1
279		Demand	DEM	$ 4,569	$ 3,076	$ 863	$ 25	$ 311	$ —	$ —	$ 62
280		Commodity	COM	$ 24	$ 14	$ 5	$ 0	$ 1	$ —	$ —	$ 1

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
281		Total Intangible Plant		$ 16,818	$ 14,581	$ 1,543	$ 27	$ 368	$ —	$ —	$ 64
282	301-303	**Intangible Plant - Directly Assigned**									
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**									
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**									
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
297	367	**Transmission Mains**									
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 1,796,551	$ 1,209,546	$ 339,327	$ 9,916	$ 122,305	$ —	$ —	$ 24,432
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 1,796,551	$ 1,209,546	$ 339,327	$ 9,916	$ 122,305	$ —	$ —	$ 24,432
302	368	**Compression Station Equipment**									
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
307	369	**Meas. & Reg. Station Equipment**									
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 157,828	$ 106,259	$ 29,810	$ 871	$ 10,745	$ —	$ —	$ 2,146
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 157,828	$ 106,259	$ 29,810	$ 871	$ 10,745	$ —	$ —	$ 2,146
312	371	**Other Equipment**									
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
316		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
317	375	**Structures and Improvements**									
318		Customer	376-379CUS	$ 7,504	$ 6,948	$ 408	$ 1	$ 34	$ —	$ —	$ 0
319		Demand	DEM	$ 4,591	$ 3,091	$ 867	$ 25	$ 313	$ —	$ —	$ 62
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
321		Total Structures and Improvements		$ 12,095	$ 10,039	$ 1,275	$ 26	$ 346	$ —	$ —	$ 63
322	376	**Distribution Mains - Allocated**									
323		Customer	CUS	$ 7,589,125	$ 7,132,932	$ 419,005	$ 854	$ 34,707	$ —	$ —	$ 507
324		Demand	DEM	$ 3,687,092	$ 2,482,372	$ 696,406	$ 20,351	$ 251,010	$ —	$ —	$ 50,142
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Distribution Mains - Allocated		$ 11,276,217	$ 9,615,304	$ 1,115,411	$ 21,206	$ 285,716	$ —	$ —	$ 50,649
327	376	**Distribution Mains - Directly Assigned**									
328		Customer	CUS-DA	$ 103,497	$ —	$ —	$ —	$ —	$ —	$ —	$ —
329		Demand	DEM-DA	$ 81,490	$ —	$ —	$ —	$ —	$ —	$ —	$ —
330		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
331		Distribution Mains - Directly Assigned		$ 184,988	$ —	$ —	$ —	$ —	$ —	$ —	$ —
332	377	**Compressor Station Equipment**									
333		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
336		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
337	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**									
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ 621,104	$ 418,165	$ 117,312	$ 3,428	$ 42,283	$ —	$ —	$ 8,447
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
341		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 621,104	$ 418,165	$ 117,312	$ 3,428	$ 42,283	$ —	$ —	$ 8,447
342	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**									
343		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM-DA	$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —
345		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
346		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —
347	378	**Odorization**									
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 4,279	$ 2,497	$ 938	$ 24	$ 256	$ —	$ —	$ 130

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
351		Total Odorization		$ 4,279	$ 2,497	$ 938	$ 24	$ 256	$ —	$ —	$ 130
352	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**									
353		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM	$ 234,094	$ 157,606	$ 44,215	$ 1,292	$ 15,937	$ —	$ —	$ 3,184
355		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq.- City Gate		$ 234,094	$ 157,606	$ 44,215	$ 1,292	$ 15,937	$ —	$ —	$ 3,184
357	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**									
358		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
361		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
362	379	**Odorization**									
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
366		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
367	380	**Services - Allocated**									
368		Customer	SERCUS-ALL	$ 10,034,625	$ 9,349,189	$ 629,513	$ 1,599	$ 52,143	$ —	$ —	$ 948
369		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
371		Total Services - Allocated		$ 10,034,625	$ 9,349,189	$ 629,513	$ 1,599	$ 52,143	$ —	$ —	$ 948
372	380	**Services - Directly Assigned**									
373		Customer	CUS-DA	$ 56,728	$ —	$ —	$ —	$ —	$ —	$ —	$ —
374		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
375		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
376		Total Services - Directly Assigned		$ 56,728	$ —	$ —	$ —	$ —	$ —	$ —	$ —
377	381	**Meters - Allocated**									
378		Customer	METCUS-ALL	$ 2,782,422	$ 2,511,379	$ 228,196	$ 1,401	$ 38,940	$ —	$ —	$ 1,110
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
381		Total Meters - Allocated		$ 2,782,422	$ 2,511,379	$ 228,196	$ 1,401	$ 38,940	$ —	$ —	$ 1,110
382	381	**Meters - Directly Assigned**									
383		Customer	CUS-DA	$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
386		Total Meters - Directly Assigned		$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —
387	382	**Meter Installations**									
388		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
391		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
392	383	**House Regulators - Allocated**									
393		Customer	REGCUS-ALL	$ 771,699	$ 648,507	$ 92,521	$ 1,205	$ 27,067	$ —	$ —	$ 1,067
394		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
396		Total House Regulators - Allocated		$ 771,699	$ 648,507	$ 92,521	$ 1,205	$ 27,067	$ —	$ —	$ 1,067
397	383	**House Regulators - Directly Assn.**									
398		Customer	CUS-DA	$ 3,363	$ —	$ —	$ —	$ —	$ —	$ —	$ —
399		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
401		House Regulators - Directly Assn.		$ 3,363	$ —	$ —	$ —	$ —	$ —	$ —	$ —
402	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**									
403		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
404		Demand	NRDEM	$ 450,264	$ —	$ 260,282	$ 7,606	$ 93,815	$ —	$ —	$ 18,741
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
406		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 450,264	$ —	$ 260,282	$ 7,606	$ 93,815	$ —	$ —	$ 18,741
407	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**									
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
411		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
412	386	**Other Prop.- Customer Premises**									
413		Customer	CUS	$ 146,728	$ 137,908	$ 8,101	$ 17	$ 671	$ —	$ —	$ 10
414		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
416		Total Other Prop. - Customer Premises		$ 146,728	$ 137,908	$ 8,101	$ 17	$ 671	$ —	$ —	$ 10
417	387	**Other Equipment**									
418		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
421		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
422	389-98	**General Plant - Allocated**									
423		Customer	GENPTCUS	$ 6,095,101	$ 5,672,169	$ 358,397	$ 988	$ 34,103	$ —	$ —	$ 656
424		Demand	DISPLTDEM	$ 694,096	$ 410,997	$ 154,834	$ 4,525	$ 55,808	$ —	$ —	$ 11,148
425		Commodity	COM	$ 8,520	$ 4,972	$ 1,868	$ 48	$ 510	$ —	$ —	$ 259
426		Total General Plant - Allocated		$ 6,797,717	$ 6,088,137	$ 515,099	$ 5,561	$ 90,421	$ —	$ —	$ 12,063
427	389-98	**General Plant - Directly Assigned**									
428		Customer	CUS-DA	$ 2,225	$ —	$ —	$ —	$ —	$ —	$ —	$ —
429		Demand	DEM-DA	$ 253	$ —	$ —	$ —	$ —	$ —	$ —	$ —
430		Commodity	COM-DA	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —
431		Total General Plant - Directly Assn.		$ 2,481	$ —	$ —	$ —	$ —	$ —	$ —	$ —
432	389-98	**General Plant - Odorization**									
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
435		Commodity	COM	$ 4,279	$ 2,497	$ 938	$ 24	$ 256	$ —	$ —	$ 130
436		Total General Plant - Odorization		$ 4,279	$ 2,497	$ 938	$ 24	$ 256	$ —	$ —	$ 130
437	40730	**Pension & FAS 106 Amort. Expense**									
438		Customer	CUS	$ (160,627)	$ (150,972)	$ (8,868)	$ (18)	$ (735)	$ —	$ —	$ (11)
439		Demand	DEM	$ (28,414)	$ (19,130)	$ (5,367)	$ (157)	$ (1,934)	$ —	$ —	$ (386)
440		Commodity	COM	$ (2,067)	$ (1,206)	$ (453)	$ (12)	$ (124)	$ —	$ —	$ (63)
441		Total Pension & FAS 106 Amort. Exp.		$ (191,109)	$ (171,309)	$ (14,689)	$ (187)	$ (2,793)	$ —	$ —	$ (460)
442		**Total Depreciation & Amort. Exp.**									
443		Customer		$ 27,451,830	$ 25,319,550	$ 1,727,948	$ 6,048	$ 186,986	$ —	$ —	$ 4,288
444		Demand		$ 7,710,731	$ 4,771,981	$ 1,638,549	$ 47,884	$ 590,591	$ —	$ —	$ 117,977
445		Commodity		$ 15,037	$ 8,773	$ 3,296	$ 85	$ 900	$ —	$ —	$ 457
446		Total Depreciation & Amort. Expense		$ 35,177,598	$ 30,100,304	$ 3,369,794	$ 54,017	$ 778,477	$ —	$ —	$ 122,722
447		**Taxes Other Than Income**									
448	4081	**Payroll and Other Taxes**									
449		Customer	OPEXPCUS	$ 2,207,597	$ 2,034,390	$ 142,893	$ 549	$ 16,046	$ —	$ —	$ 401
450		Demand	OPEXPDEM	$ 390,516	$ 239,133	$ 84,518	$ 2,470	$ 30,463	$ —	$ —	$ 6,085
451		Commodity	COM	$ 28,415	$ 16,581	$ 6,230	$ 162	$ 1,702	$ —	$ —	$ 863
452		Total Payroll and Other Taxes		$ 2,626,528	$ 2,290,104	$ 233,642	$ 3,180	$ 48,211	$ —	$ —	$ 7,349
453	4081	**Ad Valorem Taxes - Allocated**									
454		Customer	CUS	$ 5,816,731	$ 5,467,079	$ 321,149	$ 655	$ 26,601	$ —	$ —	$ 388
455		Demand	DEM	$ 2,158,092	$ 1,452,957	$ 407,614	$ 11,912	$ 146,918	$ —	$ —	$ 29,349
456		Commodity	COM	$ 11,420	$ 6,664	$ 2,504	$ 65	$ 684	$ —	$ —	$ 347
457		Total Ad Valorem Taxes - Allocated		$ 7,986,243	$ 6,926,700	$ 731,266	$ 12,632	$ 174,203	$ —	$ —	$ 30,084
458	4081	**Ad Valorem Taxes - Directly Assn.**									
459		Customer	CUS-DA	$ 47,188	$ —	$ —	$ —	$ —	$ —	$ —	$ —
460		Demand	DEM-DA	$ 33,256	$ —	$ —	$ —	$ —	$ —	$ —	$ —
461		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
462		Total Ad Valorem Taxes - Directly Assn.		$ 80,445	$ —	$ —	$ —	$ —	$ —	$ —	$ —
463		**Revenue Related Taxes**									
464		Customer	TOTREVCUS	$ 107,233	$ 79,121	$ 19,062	$ 527	$ 5,043	$ —	$ —	$ 334
465		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
466		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
467		Total Revenue Related Taxes		$ 107,233	$ 79,121	$ 19,062	$ 527	$ 5,043	$ —	$ —	$ 334
468		**Total Taxes Other Than Income**									
469		Customer		$ 8,178,749	$ 7,580,590	$ 483,104	$ 1,731	$ 47,690	$ —	$ —	$ 1,123
470		Demand		$ 2,581,864	$ 1,692,090	$ 492,132	$ 14,382	$ 177,382	$ —	$ —	$ 35,434
471		Commodity		$ 39,835	$ 23,245	$ 8,734	$ 226	$ 2,385	$ —	$ —	$ 1,210
472		Total Taxes Other Than Income		$ 10,800,448	$ 9,295,926	$ 983,969	$ 16,339	$ 227,457	$ —	$ —	$ 37,767
473		**Excess Def. Income Tax Amort. - Directly Assn.**									
474		Customer	CUS-DA	$ (11,090)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
475		Demand	DEM-DA	$ (7,889)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
477		**Total Excess Def. Income Tax Amort. - DA**		$ (18,979)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
478		**Excess Def. Income Tax Amort. - Alloc.**									
479		Customer	CUS	$ (1,216,915)	$ (1,143,765)	$ (67,187)	$ (137)	$ (5,565)	$ —	$ —	$ (81)
480		Demand	DEM	$ (484,420)	$ (326,141)	$ (91,496)	$ (2,674)	$ (32,978)	$ —	$ —	$ (6,588)
481		Commodity	COM	$ (2,584)	$ (1,508)	$ (567)	$ (15)	$ (155)	$ —	$ —	$ (78)
482		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (1,703,920)	$ (1,471,414)	$ (159,250)	$ (2,826)	$ (38,698)	$ —	$ —	$ (6,747)
483		**Interest on Customer Deposits**									
484		Customer	DEPCUS	$ 384,637	$ 206,794	$ 167,670	$ 1,595	$ 2,978	$ —	$ —	$ 5,600
485		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
486		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
487		Total Interest on Cust. Deposits		$ 384,637	$ 206,794	$ 167,670	$ 1,595	$ 2,978	$ —	$ —	$ 5,600
488		**Req. Return - Other Than Directly Assn.**									
489		Customer	CUS	$ 42,269,526	$ 39,728,642	$ 2,333,753	$ 4,759	$ 193,307	$ —	$ —	$ 2,822
490		Demand	DEM	$ 16,826,331	$ 11,328,498	$ 3,178,104	$ 92,875	$ 1,145,501	$ —	$ —	$ 228,827
491		Commodity	COM	$ 89,753	$ 52,375	$ 19,678	$ 510	$ 5,375	$ —	$ —	$ 2,725
492		Tot. Req. Return - Other Than Dir. Assn.		$ 59,185,610	$ 51,109,514	$ 5,531,535	$ 98,144	$ 1,344,183	$ —	$ —	$ 234,374
493		**Req. Return - Directly Assigned**									
494		Customer	CUS-DA	$ 385,211	$ —	$ —	$ —	$ —	$ —	$ —	$ —
495		Demand	DEM-DA	$ 274,039	$ —	$ —	$ —	$ —	$ —	$ —	$ —
496		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
497		Tot. Req. Return - Directly Assigned		$ 659,250	$ —	$ —	$ —	$ —	$ —	$ —	$ —
498		**Income Taxes - Other Than DA**									
499		Customer	CUS	$ 8,752,200	$ 8,226,093	$ 483,220	$ 985	$ 40,025	$ —	$ —	$ 584
500		Demand	DEM	$ 3,484,009	$ 2,345,645	$ 658,049	$ 19,230	$ 237,184	$ —	$ —	$ 47,380
501		Commodity	COM	$ 18,584	$ 10,845	$ 4,075	$ 106	$ 1,113	$ —	$ —	$ 564
502		Total Income Taxes - Other Than DA		$ 12,254,794	$ 10,582,582	$ 1,145,343	$ 20,321	$ 278,322	$ —	$ —	$ 48,529
503		**Income Taxes - Directly Assigned**									
504		Customer	CUS-DA	$ 79,761	$ —	$ —	$ —	$ —	$ —	$ —	$ —
505		Demand	DEM-DA	$ 56,742	$ —	$ —	$ —	$ —	$ —	$ —	$ —
506		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
507		Total Income Taxes - Dir. Assigned		$ 136,502	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRICAL COGENERATON	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
508		**Total Cost of Service Before Revenue Credits**									
509		Customer		$ 140,338,908	$ 129,719,421	$ 8,676,981	$ 29,206	$ 870,937	$ —	$ —	$ 24,847
510		Demand		$ 40,005,310	$ 25,618,240	$ 7,975,493	$ 233,071	$ 2,874,650	$ —	$ —	$ 574,243
511		Commodity		$ 856,512	$ 499,809	$ 187,789	$ 4,868	$ 51,292	$ —	$ —	$ 26,008
512		**Total Cost of Service Before Revenue Credits**		$ 181,200,730	$ 155,837,470	$ 16,840,263	$ 267,145	$ 3,796,879	$ —	$ —	$ 625,098

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
1		**Transmission and Distribution Op. Exp.**						
2	814-865	**Transmission Expenses**						
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 17,225	$ 21,536	$ 12,030	$ —	$ 54,872
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 17,225	$ 21,536	$ 12,030	$ —	$ 54,872
7	8650	**Odorization**						
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ 81	$ 41	$ 60	$ —	$ 68
11		Total Odorization		$ 81	$ 41	$ 60	$ —	$ 68
12	8700	**Operation Supervision & Engineering**						
13		Customer	871-879CUS	$ 231	$ 161	$ 71	$ —	$ 13
14		Demand	DEM	$ 1,206	$ 1,507	$ 842	$ —	$ 3,841
15		Commodity	COM	$ 838	$ 420	$ 619	$ —	$ 699
16		Total Supervision & Engineering		$ 2,274	$ 2,089	$ 1,532	$ —	$ 4,553
17	8710	**Distribution Load Dispatch**						
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 8,515	$ 4,271	$ 6,296	$ —	$ 7,109
21		Total Distribution Load Dispatch		$ 8,515	$ 4,271	$ 6,296	$ —	$ 7,109
22	8740	**Mains & Services - Allocated**						
23		Customer	MSCUS-ALL	$ 212	$ 163	$ 65	$ —	$ 129
24		Demand	DEM	$ 8,498	$ 10,625	$ 5,935	$ —	$ 27,071
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 8,710	$ 10,788	$ 6,000	$ —	$ 27,200
27	8740	**Mains & Services - Dir. Assn.**						
28		Customer	MSCUS-DA	$ —	$ —	$ —	$ —	$ 44,275
29		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 25,319
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ —	$ —	$ —	$ —	$ 69,595
32	8740	**Odorization**						
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ 95	$ 48	$ 71	$ —	$ 80

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
36		Total Odorization		$ 95	$ 48	$ 71	$ —	$ 80
37	8750	**Meas. & Reg. Station - Gen. - Allocated**						
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 2,904	$ 3,630	$ 2,028	$ —	$ 9,250
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 2,904	$ 3,630	$ 2,028	$ —	$ 9,250
42		**Meas. & Reg. Station - Gen. - DA**						
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 6,618
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ —	$ —	$ —	$ —	$ 6,618
47	8750	**Odorization**						
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 4,248	$ 2,130	$ 3,140	$ —	$ 3,546
51		Total Odorization		$ 4,248	$ 2,130	$ 3,140	$ —	$ 3,546
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**						
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 779	$ 974	$ 544	$ —	$ 2,481
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 779	$ 974	$ 544	$ —	$ 2,481
57	8760	**Meas. & Reg. Stat. - Ind. - DA**						
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 964
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ —	$ —	$ —	$ —	$ 964
62	8770	**Meas. & Reg. Stat.- City Gate**						
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 327	$ 409	$ 228	$ —	$ 1,042
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 327	$ 409	$ 228	$ —	$ 1,042
67	8780	**Meter & House Reg. Exp. - Alloc.**						
68		Customer	MTRGCUS-ALL	$ 2,116	$ 1,467	$ 651	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
71		Total Meter & House Reg. Exp. - Alloc.		$ 2,116	$ 1,467	$ 651	$ —	$ —
72	8780	**Meter & House Reg. Exp - Dir. Assn.**						
73		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 15,551
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ —	$ —	$ —	$ —	$ 15,551
77	8780	**Odorization**						
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ 3	$ 1	$ 2	$ —	$ 2
81		Total Odorization		$ 3	$ 1	$ 2	$ —	$ 2
82	8790	**Customer Installation Expense**						
83		Customer	METCUS-ALL	$ 2	$ 1	$ 1	$ —	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 2	$ 1	$ 1	$ —	$ —
87	8800	**Other Expenses**						
88		Customer	871-879CUS	$ 223	$ 156	$ 69	$ —	$ 12
89		Demand	DEM	$ 1,167	$ 1,459	$ 815	$ —	$ 3,716
90		Commodity	COM	$ 811	$ 407	$ 599	$ —	$ 677
91		Total Other Expenses		$ 2,200	$ 2,021	$ 1,483	$ —	$ 4,406
92	8800	**Odorization**						
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 28	$ 14	$ 21	$ —	$ 23
96		Total Odorization		$ 28	$ 14	$ 21	$ —	$ 23
97	8810	**Rents**						
98		Customer	871-879CUS	$ 14	$ 10	$ 4	$ —	$ 1
99		Demand	DEM	$ 71	$ 89	$ 50	$ —	$ 227
100		Commodity	COM	$ 50	$ 25	$ 37	$ —	$ 41
101		Total Rents		$ 135	$ 124	$ 91	$ —	$ 269
102	8820	**Corporate & Div. Exp.**						
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**						
108		Customer		$ 2,797	$ 1,958	$ 861	$ —	$ 59,981
109		Demand		$ 32,177	$ 40,229	$ 22,471	$ —	$ 135,401
110		Commodity		$ 14,669	$ 7,357	$ 10,845	$ —	$ 12,246
111		Total Distr. & Trans. Operations Exp.		$ 49,643	$ 49,545	$ 34,177	$ —	$ 207,628
112		**Distribution Maintenance Expenses**						
113	8850	**Maintenance Supervision and Engineering**						
114		Customer	887-893CUS	$ 1	$ 0	$ 0	$ —	$ 0
115		Demand	887-893DEM	$ 90	$ 113	$ 63	$ —	$ 288
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ 91	$ 113	$ 63	$ —	$ 288
118	8860	**Structures and Improvements**						
119		Customer	887-893CUS	$ 21	$ 16	$ 6	$ —	$ 13
120		Demand	887-893DEM	$ 3,240	$ 4,051	$ 2,263	$ —	$ 10,322
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 3,261	$ 4,067	$ 2,269	$ —	$ 10,335
123	8870	**Maintenance of Mains-Allocated**						
124		Customer	CUS	$ 84	$ 64	$ 26	$ —	$ 122
125		Demand	DEM	$ 8,036	$ 10,047	$ 5,612	$ —	$ 25,599
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 8,120	$ 10,112	$ 5,638	$ —	$ 25,721
128	8870	**Maintenance of Mains - Directly Assigned**						
129		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 30,392
130		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 23,930
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ 54,321
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**						
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 7,959	$ 9,951	$ 5,558	$ —	$ 25,354
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 7,959	$ 9,951	$ 5,558	$ —	$ 25,354
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**						
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 13,824

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ 13,824
143	8890	**Odorization**						
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 1,324	$ 664	$ 979	$ —	$ 1,105
147		Total Odorization		$ 1,324	$ 664	$ 979	$ —	$ 1,105
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**						
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 12,732	$ 15,919	$ 8,892	$ —	$ 40,559
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 12,732	$ 15,919	$ 8,892	$ —	$ 40,559
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**						
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 15,750
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ —	$ —	$ —	$ —	$ 15,750
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**						
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 278	$ 348	$ 194	$ —	$ 886
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 278	$ 348	$ 194	$ —	$ 886
163	8910	**Odorization**						
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ 3	$ 2	$ 2	$ —	$ 3
167		Total Odorization		$ 3	$ 2	$ 2	$ —	$ 3
168	8920	**Services - Allocated**						
169		Customer	SERCUS-ALL	$ 96	$ 73	$ 29	$ —	$ —
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 96	$ 73	$ 29	$ —	$ —
173	8920	**Services - Directly Assigned**						
174		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 9,393
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ 9,393
178	8930	**Meters & House Regulators - Alloc.**						
179		Customer	MTRGCUS-ALL	$ 10	$ 7	$ 3	$ —	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ 10	$ 7	$ 3	$ —	$ —
183	8930	**Meters & House Regulators - DA**						
184		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 74
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ —	$ —	$ —	$ —	$ 74
188	8940	**Maintenance of Other Equipment**						
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**						
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**						
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**						
204		Customer		$ 211	$ 161	$ 65	$ —	$ 39,994
205		Demand		$ 32,336	$ 40,429	$ 22,582	$ —	$ 156,511
206		Commodity		$ 1,327	$ 666	$ 981	$ —	$ 1,108
207		Total Distr. Maintenance Expense		$ 33,874	$ 41,256	$ 23,629	$ —	$ 197,613
208		**Total Oper. & Maint. Expense**						
209		Customer		$ 3,008	$ 2,119	$ 925	$ —	$ 99,976
210		Demand		$ 64,513	$ 80,658	$ 45,054	$ —	$ 291,911

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
211		Commodity		$ 15,996	$ 8,023	$ 11,826	$ —	$ 13,354
212		Total Operations & Maint. Expense		$ 83,517	$ 90,800	$ 57,805	$ —	$ 405,241
213		**Customer Accounts Expense**						
214	901	**Supervision**						
215		Customer	902-904CUS	$ 0	$ 0	$ 0	$ —	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 0	$ 0	$ 0	$ —	$ 0
219	902	**Meter Reading Expense**						
220		Customer	METCUS-TOT	$ 99	$ 69	$ 30	$ —	$ 113
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 99	$ 69	$ 30	$ —	$ 113
224	903	**Customer Accounting**						
225		Customer	903CUS	$ 72	$ 55	$ 22	$ —	$ 105
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 72	$ 55	$ 22	$ —	$ 105
229	904	**Bad Debt Expense**						
230		Customer	904CUS	$ —	$ —	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ —	$ —	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**						
235		Customer	902-904CUS	$ 10	$ 7	$ 3	$ —	$ 13
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 10	$ 7	$ 3	$ —	$ 13
239	907-910	**Customer Information Expense**						
240		Customer	CUS	$ 40	$ 31	$ 12	$ —	$ 59
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 40	$ 31	$ 12	$ —	$ 59
244		**Sales and Advertising Expense**						
245	911	**Supervision**						

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**						
251		Customer	CUS	$ —	$ —	$ —	$ —	$ —
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ —	$ —	$ —	$ —	$ —
255	913	**Advertising**						
256		Customer	CUS	$ 1	$ 1	$ 0	$ —	$ 2
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 1	$ 1	$ 0	$ —	$ 2
260	914	**Employee Sales Referrals**						
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**						
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**						
271	920-940	**Administrative & General Expenses**						
272		Customer	OPEXPCUS	$ 3,356	$ 2,401	$ 1,033	$ —	$ 171,196
273		Demand	OPEXPDEM	$ 27,328	$ 34,167	$ 19,085	$ —	$ 125,309
274		Commodity	COM	$ 6,918	$ 3,470	$ 5,115	$ —	$ 5,775
275		Total Administrative & General Exp.		$ 37,602	$ 40,038	$ 25,232	$ —	$ 302,280
276		**Depreciation & Amortization Expense**						
277	301-303	**Intangible Plant - Allocated**						
278		Customer	CUS	$ 1	$ 0	$ 0	$ —	$ 1
279		Demand	DEM	$ 38	$ 47	$ 26	$ —	$ 120
280		Commodity	COM	$ 1	$ 0	$ 1	$ —	$ 1

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
281		Total Intangible Plant		$ 39	$ 48	$ 27	$ —	$ 122
282	301-303	**Intangible Plant - Directly Assigned**						
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**						
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**						
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ —	$ —	$ —	$ —	$ —
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ —	$ —	$ —	$ —	$ —
297	367	**Transmission Mains**						
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 14,839	$ 18,553	$ 10,363	$ —	$ 47,270
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 14,839	$ 18,553	$ 10,363	$ —	$ 47,270
302	368	**Compression Station Equipment**						
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ —	$ —	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ —	$ —	$ —	$ —	$ —
307	369	**Meas. & Reg. Station Equipment**						
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 1,304	$ 1,630	$ 910	$ —	$ 4,153
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 1,304	$ 1,630	$ 910	$ —	$ 4,153
312	371	**Other Equipment**						
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
316		Total Other Equipment		$ —	$ —	$ —	$ —	$ —
317	375	**Structures and Improvements**						
318		Customer	376-379CUS	$ 0	$ 0	$ 0	$ —	$ 113
319		Demand	DEM	$ 38	$ 47	$ 26	$ —	$ 121
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —
321		Total Structures and Improvements		$ 38	$ 48	$ 27	$ —	$ 233
322	376	**Distribution Mains - Allocated**						
323		Customer	CUS	$ 317	$ 244	$ 98	$ —	$ 462
324		Demand	DEM	$ 30,454	$ 38,076	$ 21,268	$ —	$ 97,013
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —
326		Total Distribution Mains - Allocated		$ 30,772	$ 38,320	$ 21,366	$ —	$ 97,475
327	376	**Distribution Mains - Directly Assigned**						
328		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 103,497
329		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 81,490
330		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
331		Distribution Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ 184,988
332	377	**Compressor Station Equipment**						
333		Customer	CUS	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —	$ —
336		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —
337	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**						
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ 5,130	$ 6,414	$ 3,583	$ —	$ 16,342
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —
341		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 5,130	$ 6,414	$ 3,583	$ —	$ 16,342
342	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**						
343		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 7,213
345		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
346		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ —	$ —	$ —	$ —	$ 7,213
347	378	**Odorization**						
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 141	$ 71	$ 104	$ —	$ 118

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
351		Total Odorization		$ 141	$ 71	$ 104	$ —	$ 118
352	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**						
353		Customer	CUS	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM	$ 1,934	$ 2,417	$ 1,350	$ —	$ 6,159
355		Commodity	COM	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq.- City Gate		$ 1,934	$ 2,417	$ 1,350	$ —	$ 6,159
357	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**						
358		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
361		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —
362	379	**Odorization**						
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ —	$ —	$ —	$ —	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —
366		Total Odorization		$ —	$ —	$ —	$ —	$ —
367	380	**Services - Allocated**						
368		Customer	SERCUS-ALL	$ 594	$ 457	$ 183	$ —	$ —
369		Demand	DEM	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM	$ —	$ —	$ —	$ —	$ —
371		Total Services - Allocated		$ 594	$ 457	$ 183	$ —	$ —
372	380	**Services - Directly Assigned**						
373		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 56,728
374		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
375		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
376		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ 56,728
377	381	**Meters - Allocated**						
378		Customer	METCUS-ALL	$ 696	$ 485	$ 214	$ —	$ —
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —
381		Total Meters - Allocated		$ 696	$ 485	$ 214	$ —	$ —
382	381	**Meters - Directly Assigned**						
383		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 7,213
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
386		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ 7,213
387	382	**Meter Installations**						
388		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —
391		Total Meter Installations		$ —	$ —	$ —	$ —	$ —
392	383	**House Regulators - Allocated**						
393		Customer	REGCUS-ALL	$ 668	$ 459	$ 206	$ —	$ —
394		Demand	DEM	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM	$ —	$ —	$ —	$ —	$ —
396		Total House Regulators - Allocated		$ 668	$ 459	$ 206	$ —	$ —
397	383	**House Regulators - Directly Assn.**						
398		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 3,363
399		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
401		House Regulators - Directly Assn.		$ —	$ —	$ —	$ —	$ 3,363
402	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**						
403		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
404		Demand	NRDEM	$ 11,382	$ 14,231	$ 7,949	$ —	$ 36,259
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —
406		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 11,382	$ 14,231	$ 7,949	$ —	$ 36,259
407	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**						
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
411		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —
412	386	**Other Prop.- Customer Premises**						
413		Customer	CUS	$ 6	$ 5	$ 2	$ —	$ 9
414		Demand	DEM	$ —	$ —	$ —	$ —	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —
416		Total Other Prop. - Customer Premises		$ 6	$ 5	$ 2	$ —	$ 9
417	387	**Other Equipment**						
418		Customer	CUS	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
421		Total Other Equipment		$ —	$ —	$ —	$ —	$ —
422	389-98	**General Plant - Allocated**						
423		Customer	GENPTCUS	$ 411	$ 305	$ 126	$ —	$ 27,946
424		Demand	DISPLTDEM	$ 6,771	$ 8,465	$ 4,729	$ —	$ 36,820
425		Commodity	COM	$ 281	$ 141	$ 207	$ —	$ 234
426		Total General Plant - Allocated		$ 7,463	$ 8,911	$ 5,063	$ —	$ 65,000
427	389-98	**General Plant - Directly Assigned**						
428		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 2,225
429		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 253
430		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ 3
431		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ 2,481
432	389-98	**General Plant - Odorization**						
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —
435		Commodity	COM	$ 141	$ 71	$ 104	$ —	$ 118
436		Total General Plant - Odorization		$ 141	$ 71	$ 104	$ —	$ 118
437	40730	**Pension & FAS 106 Amort. Expense**						
438		Customer	CUS	$ (7)	$ (5)	$ (2)	$ —	$ (10)
439		Demand	DEM	$ (235)	$ (293)	$ (164)	$ —	$ (748)
440		Commodity	COM	$ (68)	$ (34)	$ (50)	$ —	$ (57)
441		Total Pension & FAS 106 Amort. Exp.		$ (309)	$ (333)	$ (216)	$ —	$ (814)
442		**Total Depreciation & Amort. Exp.**						
443		Customer		$ 2,686	$ 1,950	$ 827	$ —	$ 201,546
444		Demand		$ 71,654	$ 89,587	$ 50,041	$ —	$ 332,466
445		Commodity		$ 495	$ 248	$ 366	$ —	$ 416
446		Total Depreciation & Amort. Expense		$ 74,836	$ 91,786	$ 51,234	$ —	$ 534,428
447		**Taxes Other Than Income**						
448	4081	**Payroll and Other Taxes**						
449		Customer	OPEXPCUS	$ 251	$ 180	$ 77	$ —	$ 12,810
450		Demand	OPEXPDEM	$ 3,696	$ 4,621	$ 2,581	$ —	$ 16,948
451		Commodity	COM	$ 936	$ 469	$ 692	$ —	$ 781
452		Total Payroll and Other Taxes		$ 4,883	$ 5,270	$ 3,350	$ —	$ 30,538
453	4081	**Ad Valorem Taxes - Allocated**						
454		Customer	CUS	$ 243	$ 187	$ 75	$ —	$ 354
455		Demand	DEM	$ 17,825	$ 22,286	$ 12,448	$ —	$ 56,783
456		Commodity	COM	$ 376	$ 189	$ 278	$ —	$ 314
457		Total Ad Valorem Taxes - Allocated		$ 18,444	$ 22,662	$ 12,801	$ —	$ 57,451
458	4081	**Ad Valorem Taxes - Directly Assn.**						
459		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 47,188
460		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 33,256
461		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
462		Total Ad Valorem Taxes - Directly Assn.		$ —	$ —	$ —	$ —	$ 80,445
463		**Revenue Related Taxes**						
464		Customer	TOTREVCUS	$ 471	$ 246	$ 252	$ —	$ 2,175
465		Demand	DEM	$ —	$ —	$ —	$ —	$ —
466		Commodity	COM	$ —	$ —	$ —	$ —	$ —
467		Total Revenue Related Taxes		$ 471	$ 246	$ 252	$ —	$ 2,175
468		**Total Taxes Other Than Income**						
469		Customer		$ 965	$ 613	$ 405	$ —	$ 62,527
470		Demand		$ 21,521	$ 26,907	$ 15,030	$ —	$ 106,987
471		Commodity		$ 1,312	$ 658	$ 970	$ —	$ 1,095
472		Total Taxes Other Than Income		$ 23,798	$ 28,178	$ 16,404	$ —	$ 170,609
473		**Excess Def. Income Tax Amort. - Directly Assn.**						
474		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ (11,090)
475		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ (7,889)
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
477		**Total Excess Def. Income Tax Amort. - DA**		$ —	$ —	$ —	$ —	$ (18,979)
478		**Excess Def. Income Tax Amort. - Alloc.**						
479		Customer	CUS	$ (51)	$ (39)	$ (16)	$ —	$ (74)
480		Demand	DEM	$ (4,001)	$ (5,003)	$ (2,794)	$ —	$ (12,746)
481		Commodity	COM	$ (85)	$ (43)	$ (63)	$ —	$ (71)
482		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (4,137)	$ (5,084)	$ (2,873)	$ —	$ (12,891)
483		**Interest on Customer Deposits**						
484		Customer	DEPCUS	$ —	$ —	$ —	$ —	$ —
485		Demand	DEM	$ —	$ —	$ —	$ —	$ —
486		Commodity	COM	$ —	$ —	$ —	$ —	$ —
487		Total Interest on Cust. Deposits		$ —	$ —	$ —	$ —	$ —
488		**Req. Return - Other Than Directly Assn.**						
489		Customer	CUS	$ 1,768	$ 1,360	$ 544	$ —	$ 2,572
490		Demand	DEM	$ 138,980	$ 173,762	$ 97,059	$ —	$ 442,726
491		Commodity	COM	$ 2,955	$ 1,482	$ 2,185	$ —	$ 2,467
492		Tot. Req. Return - Other Than Dir. Assn.		$ 143,703	$ 176,604	$ 99,788	$ —	$ 447,765
493		**Req. Return - Directly Assigned**						
494		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 385,211
495		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 274,039
496		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
497		Tot. Req. Return - Directly Assigned		$ —	$ —	$ —	$ —	$ 659,250
498		**Income Taxes - Other Than DA**						
499		Customer	CUS	$ 366	$ 282	$ 113	$ —	$ 533
500		Demand	DEM	$ 28,777	$ 35,979	$ 20,097	$ —	$ 91,669
501		Commodity	COM	$ 612	$ 307	$ 452	$ —	$ 511
502		Total Income Taxes - Other Than DA		$ 29,755	$ 36,567	$ 20,662	$ —	$ 92,713
503		**Income Taxes - Directly Assigned**						
504		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ 79,761
505		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ 56,742
506		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
507		Total Income Taxes - Dir. Assigned		$ —	$ —	$ —	$ —	$ 136,502

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
508		**Total Cost of Service Before Revenue Credits**						
509		Customer		$ 12,320	$ 8,849	$ 3,898	$ —	$ 992,448
510		Demand		$ 348,772	$ 436,058	$ 243,570	$ —	$ 1,701,213
511		Commodity		$ 28,203	$ 14,145	$ 20,851	$ —	$ 23,548
512		**Total Cost of Service Before Revenue Credits**		$ 389,294	$ 459,052	$ 268,320	$ —	$ 2,717,209

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Customer Cost Allocation Factors										
2											
3	Total Customers		310,852	292,167	17,163	35	1,422	0	0	21	13
4	Total Customers Factor (CUS)	CUS	1.00000	0.93989	0.05521	0.00011	0.00457	0.00000	0.00000	0.00007	0.00004
5											
6	Customers - Directly Assigned		19	0	0	0	0	0	0	0	0
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8											
9	Services - Allocated Weighting			1.00000	1.14625	1.42755	1.14625	0.00000	0.00000	1.42755	1.42755
10	Weighted Customers		313,587	292,167	19,673	50	1,629	0	0	30	19
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.93169	0.06273	0.00016	0.00520	0.00000	0.00000	0.00009	0.00006
12											
13	Meters - Allocated Weighting			1.00000	1.54684	4.65843	3.18669	0.00000	0.00000	6.22515	6.22515
14	Weighted Customers		323,699	292,167	26,548	163	4,530	0	0	129	81
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.90259	0.08201	0.00050	0.01399	0.00000	0.00000	0.00040	0.00025
16											
17	Meters - Total Weighting			1.00000	1.54684	4.65843	3.18669	0.00000	0.00000	6.22515	6.22515
18	Weighted Customers		323,792	292,167	26,548	163	4,530	0	0	129	81
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.90233	0.08199	0.00050	0.01399	0.00000	0.00000	0.00040	0.00025
20											
21	Regulators - Allocated Weighting			1.00000	2.42871	15.50500	8.57795	0.00000	0.00000	23.15767	23.15767
22	Weighted Customers		347,668	292,167	41,683	543	12,194	0	0	481	301
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.84036	0.11989	0.00156	0.03507	0.00000	0.00000	0.00138	0.00087
24											
25	Meters and Regulators - Allocated Weighting			1.00000	1.69839	6.52242	4.11317	0.00000	0.00000	9.13500	9.13500
26	Weighted Customers		327,818	292,167	29,149	228	5,847	0	0	190	119
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.89125	0.08892	0.00070	0.01784	0.00000	0.00000	0.00058	0.00036
28											
29	Non-Residential Customers		18,686	0	17,163	35	1,422	0	0	21	13
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.91848	0.00187	0.07608	0.00000	0.00000	0.00111	0.00070
31											
32	Customer Cost Allocation Factors										
33											
34	Distribution Plant Customer Costs		$ 622,161,332	$ 572,851,910	$ 38,958,600	$ 133,609	$ 4,157,338	$ —	$ —	$ 94,033	$ 58,912
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.92074	0.06262	0.00021	0.00668	0.00000	0.00000	0.00015	0.00009
36											
37	Account 376-379 Customer Costs		$ 270,675,535	$ 250,601,622	$ 14,720,920	$ 30,021	$ 1,219,345	$ —	$ —	$ 17,798	$ 11,151
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.92584	0.05439	0.00011	0.00450	0.00000	0.00000	0.00007	0.00004
39											
40	Total Revenue (inc. cost of gas)		$ 242,442,357	$ 178,885,429	$ 43,096,254	$ 1,192,245	$ 11,402,023	$ —	$ —	$ 755,871	$ 1,064,645

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.73785	0.17776	0.00492	0.04703	0.00000	0.00000	0.00312	0.00439
42											
43	Mains - Allocated Customer Cost Factor		0.50438	0.47406	0.02785	0.00006	0.00231	0.00000	0.00000	0.00003	0.00002
44	Services - Allocated Customer Cost Factor		0.49562	0.46177	0.03109	0.00008	0.00258	0.00000	0.00000	0.00005	0.00003
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.93583	0.05894	0.00014	0.00488	0.00000	0.00000	0.00008	0.00005
46											
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
48											
49	Total Plant Customer		$ 726,433,673	$ 669,862,803	$ 45,085,113	$ 150,468	$ 4,739,797	$ —	$ —	$ 105,224	$ 65,923
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.92213	0.06206	0.00021	0.00652	0.00000	0.00000	0.00014	0.00009
51											
52	Non-Intangible Plant Customer										
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 726,433,673	$ 682,766,672	$ 40,107,297	$ 81,792	$ 3,322,118	$ —	$ —	$ 48,491	$ 30,380
54		NONINCUS	1.00000	0.93989	0.05521	0.00011	0.00457	0.00000	0.00000	0.00007	0.00004
55											
56	Account 871-879 Customer Costs		$ 10,047,769	$ 9,142,303	$ 767,501	$ 4,642	$ 124,798	$ —	$ —	$ 3,719	$ 2,330
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.90988	0.07639	0.00046	0.01242	0.00000	0.00000	0.00037	0.00023
58											
59	Account 887-893 Customer Costs		$ 3,644,082	$ 3,410,461	$ 214,266	$ 502	$ 18,037	$ —	$ —	$ 302	$ 189
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.93589	0.05880	0.00014	0.00495	0.00000	0.00000	0.00008	0.00005
61											
62	Account 903 Customer		$ 5,154,764	$ 4,921,047	$ 224,357	$ 410	$ 8,582	$ —	$ —	$ 115	$ 72
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.95466	0.04352	0.00008	0.00166	0.00000	0.00000	0.00002	0.00001
64											
65	Customer Cost Allocation Factors										
66											
67	Account 904 Customer		$ 1,393,252	$ 1,247,831	$ 143,815	$ —	$ 1,607	$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.89562	0.10322	0.00000	0.00115	0.00000	0.00000	0.00000	0.00000
69											
70	Accounts 902-904 Customer		$ 6,942,252	$ 6,524,608	$ 400,495	$ 608	$ 15,704	$ —	$ —	$ 272	$ 170
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.93984	0.05769	0.00009	0.00226	0.00000	0.00000	0.00004	0.00002
72											
73	Operating Expense Customer		$ 52,013,444	$ 47,932,499	$ 3,366,727	$ 12,935	$ 378,058	$ —	$ —	$ 9,443	$ 5,916
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.92154	0.06473	0.00025	0.00727	0.00000	0.00000	0.00018	0.00011
75											
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 76,158,602	$ 70,122,649	$ 4,768,912	$ 16,355	$ 508,899	$ —	$ —	$ 11,511	$ 7,211
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 80,991,465	$ 76,122,949	$ 4,471,638	$ 9,119	$ 370,389	$ —	$ —	$ 5,406	$ 3,387
78	Total General Plant Customer Costs		$ 157,150,068	$ 146,245,598	$ 9,240,550	$ 25,474	$ 879,288	$ —	$ —	$ 16,917	$ 10,599
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.93061	0.05880	0.00016	0.00560	0.00000	0.00000	0.00011	0.00007
80											

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
81	Customer Deposits		$ (7,616,570)	$ (4,094,939)	$ (3,320,190)	$ (31,580)	$ (58,965)	$ —	$ —	$ (110,896)	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.53764	0.43592	0.00415	0.00774	0.00000	0.00000	0.01456	0.00000
83											
84	Demand Cost Allocation Factors										
85											
86	System Demand										
87	**System Demand Factor (DEM)**	DEM	1.00000	0.67326	0.18888	0.00552	0.06808	0.00000	0.00000	0.01360	0.00826
88											
89	Non-Residential Demand										
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.57806	0.01689	0.20836	0.00000	0.00000	0.04162	0.02528
91											
92	Directly Assigned Demand										
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
94											
95	Distribution Plant Demand		$ 186,362,998	$ 110,351,567	$ 41,572,461	$ 1,214,886	$ 14,984,189	$ —	$ —	$ 2,993,258	$ 1,817,981
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.59213	0.22307	0.00652	0.08040	0.00000	0.00000	0.01606	0.00976
97											
98	Demand Cost Allocation Factors										
99											
100	Non-Intangible Plant Demand		$ 271,187,860	$ 182,579,967	$ 51,221,107	$ 1,496,852	$ 18,461,903	$ —	$ —	$ 3,687,970	$ 2,239,921
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.67326	0.18888	0.00552	0.06808	0.00000	0.00000	0.01360	0.00826
102											
103	Total Plant Demand		$ 271,468,474	$ 166,232,091	$ 58,232,601	$ 1,701,751	$ 20,989,094	$ —	$ —	$ 4,192,804	$ 2,546,536
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.61234	0.21451	0.00627	0.07732	0.00000	0.00000	0.01544	0.00938
105											
106	Operating Expense Demand		$ 14,387,204	$ 8,810,026	$ 3,113,785	$ 90,995	$ 1,122,318	$ —	$ —	$ 224,196	$ 136,167
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.61235	0.21643	0.00632	0.07801	0.00000	0.00000	0.01558	0.00946
108											
109	Acct. 887-893 Demand		$ 2,473,857	$ 1,326,447	$ 663,278	$ 19,383	$ 239,069	$ —	$ —	$ 47,757	$ 29,005
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.53619	0.26811	0.00784	0.09664	0.00000	0.00000	0.01930	0.01172
111											
112	Rate Base Demand		$ 213,904,658	$ 131,488,925	$ 45,867,683	$ 1,340,407	$ 16,532,339	$ —	$ —	$ 3,302,518	$ 2,005,813
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.61471	0.21443	0.00627	0.07729	0.00000	0.00000	0.01544	0.00938
114											
115	Commodity Cost Allocation Factors										
116											
117	Annual Distribution Volumes (Ccf)		219,795,229	128,259,579	48,190,030	1,249,315	13,162,340	—	—	6,674,007	7,237,332
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.58354	0.21925	0.00568	0.05988	0.00000	0.00000	0.03036	0.03293
119											
120	Commodity - Direct Assignment		6,041,960	0	0	0	0	0	0	0	0
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(l)	(m)	(n)	(o)
1	Customer Cost Allocation Factors					
2						
3	Total Customers		10	4	0	19
4	Total Customers Factor (CUS)	CUS	0.00003	0.00001	0.00000	0.00006
5						
6	Customers - Directly Assigned		0	0	0	19
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	0.00000	0.00000	0.00000	1.00000
8						
9	Services - Allocated Weighting		1.42755	1.42755	0.00000	0.00000
10	Weighted Customers		14	6	0	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	0.00005	0.00002	0.00000	0.00000
12						
13	Meters - Allocated Weighting		5.64458	6.22515	0.00000	0.00000
14	Weighted Customers		56	25	0	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	0.00017	0.00008	0.00000	0.00000
16						
17	Meters - Total Weighting		5.64458	6.22515	0.00000	4.89953
18	Weighted Customers		56	25	0	93
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	0.00017	0.00008	0.00000	0.00029
20						
21	Regulators - Allocated Weighting		20.69571	23.15767	0.00000	0.00000
22	Weighted Customers		207	93	0	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	0.00060	0.00027	0.00000	0.00000
24						
25	Meters and Regulators - Allocated Weighting		8.23111	9.13500	0.00000	0.00000
26	Weighted Customers		82	37	0	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	0.00025	0.00011	0.00000	0.00000
28						
29	Non-Residential Customers		10	4	0	19
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	0.00054	0.00021	0.00000	0.00101
31						
32	Customer Cost Allocation Factors					
33						
34	Distribution Plant Customer Costs		$ 42,857	$ 18,127	$ —	$ 5,845,945
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	0.00007	0.00003	0.00000	0.00940
36						
37	Account 376-379 Customer Costs		$ 8,577	$ 3,431	$ —	$ 4,062,670
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	0.00003	0.00001	0.00000	0.01501
39						
40	Total Revenue (inc. cost of gas)		$ 556,804	$ 570,738	$ —	$ 4,918,348

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(l)	(m)	(n)	(o)
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	0.00230	0.00235	0.00000	0.02029
42						
43	Mains - Allocated Customer Cost Factor		0.00002	0.00001	0.00000	0.00003
44	Services - Allocated Customer Cost Factor		0.00002	0.00001	0.00000	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	0.00004	0.00002	0.00000	0.00003
46						
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	0.00000	0.00000	0.00000	1.00000
48						
49	Total Plant Customer		$ 48,052	$ 20,284	$ —	$ 6,356,009
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	0.00007	0.00003	0.00000	0.00875
51						
52	Non-Intangible Plant Customer					
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 23,369	$ 9,348	$ —	$ 44,207
54		NONINCUS	0.00003	0.00001	0.00000	0.00006
55						
56	Account 871-879 Customer Costs		$ 1,631	$ 717	$ —	$ 129
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	0.00016	0.00007	0.00000	0.00001
58						
59	Account 887-893 Customer Costs		$ 145	$ 58	$ —	$ 122
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	0.00004	0.00002	0.00000	0.00003
61						
62	Account 903 Customer		$ 55	$ 22	$ —	$ 105
63	**Account 903 Customer Factor (903CUS)**	903CUS	0.00001	0.00000	0.00000	0.00002
64						
65	Customer Cost Allocation Factors					
66						
67	Account 904 Customer		$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	0.00000	0.00000	0.00000	0.00000
69						
70	Accounts 902-904 Customer		$ 124	$ 52	$ —	$ 217
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	0.00002	0.00001	0.00000	0.00003
72						
73	Operating Expense Customer		$ 4,233	$ 1,820	$ —	$ 301,812
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	0.00008	0.00003	0.00000	0.00580
75						
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 5,246	$ 2,219	$ —	$ 715,601
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 2,605	$ 1,042	$ —	$ 4,929
78	Total General Plant Customer Costs		$ 7,852	$ 3,261	$ —	$ 720,529
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	0.00005	0.00002	0.00000	0.00458
80						

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(l)	(m)	(n)	(o)
81	Customer Deposits		$ —	$ —	$ —	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	0.00000	0.00000	0.00000	0.00000
83						
84	Demand Cost Allocation Factors					
85						
86	System Demand					
87	**System Demand Factor (DEM)**	DEM	0.01033	0.00577	0.00000	0.02631
88						
89	Non-Residential Demand					
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	0.03161	0.01765	0.00000	0.08053
91						
92	Directly Assigned Demand					
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	0.00000	0.00000	0.00000	1.00000
94						
95	Distribution Plant Demand		$ 2,272,962	$ 1,269,617	$ —	$ 9,886,076
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	0.01220	0.00681	0.00000	0.05305
97						
98	Demand Cost Allocation Factors					
99						
100	Non-Intangible Plant Demand		$ 2,800,499	$ 1,564,286	$ —	$ 7,135,357
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	0.01033	0.00577	0.00000	0.02631
102						
103	Total Plant Demand		$ 3,183,850	$ 1,778,416	$ —	$ 12,611,332
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	0.01173	0.00655	0.00000	0.04646
105						
106	Operating Expense Demand		$ 170,245	$ 95,095	$ —	$ 624,377
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	0.01183	0.00661	0.00000	0.04340
108						
109	Acct. 887-893 Demand		$ 36,265	$ 20,256	$ —	$ 92,398
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	0.01466	0.00819	0.00000	0.03735
111						
112	Rate Base Demand		$ 2,507,802	$ 1,400,793	$ —	$ 9,458,378
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	0.01172	0.00655	0.00000	0.04422
114						
115	Commodity Cost Allocation Factors					
116						
117	Annual Distribution Volumes (Ccf)		3,629,913	5,350,754	—	6,041,960
118	**Distribution Commodity Factor (COM)**	COM	0.01651	0.02434	0.00000	0.02749
119						
120	Commodity - Direct Assignment		0	0	0	6,041,960
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	0.00000	0.00000	0.00000	1.00000

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Current Revenue-to-Cost Ratio (1)	0.9211	0.8386	1.4212	2.5854	1.6132	0.0000	0.0000	1.2190	2.7446	1.2228	2.1369	0.0000	0.9220
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	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000
4	Rate Design Revenue Increase	$ 14,297,684	$ 25,153,559	$ (7,092,592)	$ (423,522)	$ (2,328,190)	$ —	$ —	$ (136,916)	$ (679,176)	$ (102,263)	$ (305,055)	$ —	$ 211,841
5	% Increase - Non-Gas Revenue (2)	8.57%	19.25%	-29.64%	-61.32%	-38.01%	— %	— %	-17.97%	-63.57%	-18.22%	-53.20%	— %	8.46%
6	% Increase - Total Revenue (3)	5.80%	13.78%	-16.35%	-35.44%	-20.35%	— %	— %	-17.97%	-63.57%	-18.22%	-53.20%	— %	4.28%
7	% Total Revenue (for GRIP)	100.00 %	85.90 %	9.34 %	0.15 %	2.12 %	— %	— %	0.35 %	0.22 %	0.26 %	0.15 %	— %	1.52 %
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)													
9	Revenue-to-Cost Ratio	1.0000	0.9432	1.3369	2.2683	1.4905	0.0000	0.0000	1.1752	2.3957	1.1782	1.9095	0.0000	1.0000
10	Rate Design Revenue Increase	$ 14,297,684	$ 16,299,387	$ (1,418,518)	$ (84,704)	$ (465,638)	$ —	$ —	$ (27,383)	$ (135,835)	$ (20,453)	$ (61,011)	$ —	$ 211,841
11	% Increase - Non-Gas Revenue (2)	8.57%	12.47%	-5.93%	-12.26%	-7.60%	— %	— %	-3.59%	-12.71%	-3.64%	-10.64%	— %	8.46%
12	% Increase - Total Revenue (3)	5.80%	8.93%	-3.27%	-7.09%	-4.07%	— %	— %	-3.59%	-12.71%	-3.64%	-10.64%	— %	4.28%
13	% Total Revenue (for GRIP)	100.00 %	80.91 %	12.54 %	0.34 %	3.17 %	— %	— %	0.41 %	0.52 %	0.30 %	0.29 %	— %	1.52 %
14	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)													
15	Revenue-to-Cost Ratio	1.0000	0.9290	1.4212	2.5854	1.6132	0.0000	0.0000	1.2190	2.7446	1.2228	2.1369	0.0000	1.0000
16	Rate Design Revenue Increase	$ 14,297,684	$ 14,085,844	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 211,841
17	% Increase - Non-Gas Revenue (2)	8.57%	10.78%	0.00%	0.00%	0.00%	— %	— %	0.00%	0.00%	0.00%	0.00%	— %	8.46%
18	% Increase - Total Revenue (3)	5.80%	7.72%	0.00%	0.00%	0.00%	— %	— %	0.00%	0.00%	0.00%	0.00%	— %	4.28%
19	% Total Revenue (for GRIP)	100.00 %	79.66 %	13.34 %	0.39 %	3.43 %	— %	— %	0.43 %	0.60 %	0.31 %	0.32 %	— %	1.52 %

(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 decreases 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 deceases is assigned to the residential class.

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Costs	$ 173,765,358	$ 164,760,299	$ 7,840,555	$ 21,040	$ 483,972	$ 1,013	$ —	$ 295,313	$ 30,579	$ 327,200	$ 4,222	$ 1,166	$ —
2	Demand Costs	$ 44,012,904	$ 30,202,279	$ 6,854,086	$ 93,444	$ 1,114,762	$ —	$ —	$ 2,194,287	$ 1,550,490	$ 1,650,390	$ 56,727	$ 296,439	$ —
3	Commodity Costs	$ 997,532	$ 495,745	$ 229,188	$ 4,343	$ 22,127	$ —	$ —	$ 85,526	$ 84,273	$ 50,121	$ 5,007	$ 21,203	$ —
4	Cost of Service Before Revenue Credits	$ 218,775,795	$ 195,458,322	$ 14,923,828	$ 118,828	$ 1,620,861	$ 1,013	$ —	$ 2,575,126	$ 1,665,341	$ 2,027,711	$ 65,957	$ 318,808	$ —
5	Revenues Credited to Cost of Service (1)	$ 5,033,330	$ 4,668,665	$ 255,644	$ 1,530	$ 21,632	$ 13	$ —	$ 33,267	$ 21,444	$ 26,180	$ 849	$ 4,105	$ —
6	Total Cost of Service	$ 213,742,464	$ 190,789,657	$ 14,668,184	$ 117,297	$ 1,599,229	$ 1,000	$ —	$ 2,541,859	$ 1,643,897	$ 2,001,531	$ 65,107	$ 314,702	$ —
7	Revenue at Current Rates	$ 194,049,576	$ 160,704,198	$ 23,226,443	$ 306,132	$ 1,671,002	$ 4,533	$ —	$ 3,219,163	$ 2,492,159	$ 2,140,528	$ 87,549	$ 197,869	$ —
8	Revenue Deficiency	$ 19,692,888	$ 30,085,459	$ (8,558,259)	$ (188,835)	$ (71,773)	$ (3,533)	$ —	$ (677,304)	$ (848,261)	$ (138,997)	$ (22,441)	$ 116,833	$ —
9	Revenue-to-Cost Ratios:													
10	Current Revenue	0.9100	0.8461	1.5735	2.5891	1.0443	4.4879	0.0000	1.2630	1.5094	1.0685	1.3402	0.6335	0.0000
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000

(1) Service charge revenue including Company recommended changes, special contract (other than Fort Bliss), irrigation and other 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	$ 2,216,214
Special Contract	$ 2,781,387
Irrigation	$ 33,749
Unmetered Gas Service	$ 1,980
Other Revenue	$ —
	$ 5,033,330

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	$ 42,705	$ 13,462	$ 89
2	302	Franchises and Consents	NONINTPLT	$ 393,474	$ 298,693	$ 94,157	$ 624
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 1,015,106	$ 770,584	$ 242,912	$ 1,611
4		Total Intangible Plant		$ 1,464,837	$ 1,111,982	$ 350,531	$ 2,325
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ —	$ —	$ —	$ —
9	367	Transmission Mains	DEM	$ 15,177,328	$ —	$ 15,177,328	$ —
10	368	Compression Station Equipment	DEM	$ —	$ —	$ —	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 7,047,208	$ —	$ 7,047,208	$ —
12	369	Odorization	COM	$ 419,683	$ —	$ —	$ 419,683
13	371	Other Equipment	DEM	$ —	$ —	$ —	$ —
14		Total Transmission Plant		$ 22,644,220	$ —	$ 22,224,536	$ 419,683
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 239,657	$ 146,204	$ 93,453	$ —
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ —	$ —	$ —	$ —
19	375	Structures and Improvements	DIS376-379-ALL	$ 51,281	$ 31,284	$ 19,997	$ —
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 565,025,835	$ 364,252,631	$ 200,773,204	$ —
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ —	$ —	$ —	$ —
22	376	Odorization	COM	$ 144,153	$ —	$ —	$ 144,153
23	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
24	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 25,444,508	$ —	$ 25,444,508	$ —
25	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
26	378	Odorization	COM	$ 688,208	$ —	$ —	$ 688,208
27	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 6,612,251	$ —	$ 6,612,251	$ —
28	379	Odorization	COM	$ 517,861	$ —	$ —	$ 517,861
29	380	Services - Allocated	CUS	$ 345,609,791	$ 345,609,791	$ —	$ —
30	380	Services - Directly Assigned	CUS	$ —	$ —	$ —	$ —
31	381	Meters - Allocated	CUS	$ 88,936,245	$ 88,936,245	$ —	$ —
32	381	Meters - Directly Assigned	CUS	$ —	$ —	$ —	$ —
33	382	Meter Installations	CUS	$ —	$ —	$ —	$ —
34	383	House Regulators - Allocated	CUS	$ 13,143,929	$ 13,143,929	$ —	$ —
35	383	House Regulators - Directly Assigned	CUS	$ —	$ —	$ —	$ —
36	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 17,195,275	$ —	$ 17,195,275	$ —
37	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
38	385	Odorization	COM	$ 47,784	$ —	$ —	$ 47,784
39	386	Other Property - Customer Premises	CUS	$ 1,063,249	$ 1,063,249	$ —	$ —

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)
40	387	Other Equipment	DIS376-379-ALL	$ —	$ —	$ —	$ —
41		Total Distribution Plant		$ 1,064,720,028	$ 813,183,333	$ 250,138,689	$ 1,398,006
42							
43		**General Plant**					
44	389	Land & Land Rights	GENPLT	$ 8,556,742	$ 6,584,688	$ 1,961,094	$ 10,960
45	390	Structures & Improvements	GENPLT	$ 37,720,751	$ 29,758,319	$ 7,918,178	$ 44,254
46	391	Office Furniture and Equipment	GENPLT	$ 47,588,016	$ 46,637,432	$ 945,301	$ 5,283
47	392	Transportation Equipment	GENPLT	$ 26,077,684	$ 19,947,186	$ 6,096,426	$ 34,072
48	393	Stores Equipment	GENPLT	$ 68,516	$ 52,329	$ 16,097	$ 90
49	394	Tools, Shop & Garage - Allocated	GENPLT	$ 16,417,830	$ 12,570,580	$ 3,825,867	$ 21,382
50	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ —	$ —	$ —	$ —
51	394	Odorization	COM	$ 19,654	$ —	$ —	$ 19,654
52	395	CNG Equipment	GENPLT	$ —	$ —	$ —	$ —
53	396	Major Work Equipment	GENPLT	$ 4,143,841	$ 3,164,872	$ 973,528	$ 5,441
54	397	Communication Equipment - Allocated	GENPLT	$ 34,877,483	$ 26,739,739	$ 8,092,516	$ 45,228
55	397	Communication Equipment - Dir. Assn.	GENPLT	$ —	$ —	$ —	$ —
56	398	Miscellaneous General Plant	GENPLT	$ 6,349	$ 4,849	$ 1,492	$ 8
57		Total General Plant		$ 175,476,866	$ 145,459,994	$ 29,830,498	$ 186,375
58							
59		Total Plant in Service		$ 1,264,305,951	$ 959,755,309	$ 302,544,253	$ 2,006,389
60							
61		**Depreciation & Amortization Reserve**					
62	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (1,270,477)	$ (994,160)	$ (274,685)	$ (1,632)
63	325-371	Transmission Plant	DEM	$ (421,851)	$ —	$ (421,851)	$ —
64	369	Odorization	COM	$ (17,195)	$ —	$ —	$ (17,195)
65	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (199,145,352)	$ (155,833,134)	$ (43,056,426)	$ (255,792)
66	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ —	$ —	$ —	$ —
67	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ —	$ —	$ —	$ —
68	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
69	380	Services - Directly Assigned	CUS	$ —	$ —	$ —	$ —
70	381	Meters - Directly Assigned	CUS	$ —	$ —	$ —	$ —
71	383	House Regulators - Directly Assigned	CUS	$ —	$ —	$ —	$ —
72	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
73	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (61,870,623)	$ (52,693,554)	$ (9,120,572)	$ (56,498)
74	389-398	General Plant - Directly Assigned	GEN-DARES	$ —	$ —	$ —	$ —
75		Total Depreciation & Amortization Reserve		$ (262,725,499)	$ (209,520,847)	$ (52,873,534)	$ (331,117)
76							
77		Net Plant in Service		$ 1,001,580,453	$ 750,234,461	$ 249,670,719	$ 1,675,272
78							
79		Customer Deposits	CUS	$ (6,199,032)	$ (6,199,032)	$ —	$ —

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)
80							
81		Customer Advances	MAINS/SVCS	$ (5,796,693)	$ (4,518,662)	$ (1,278,031)	$ —
82							
83		Accumulated Deferred Income Taxes	TOTPLT	$ (87,756,882)	$ (66,617,683)	$ (20,999,933)	$ (139,266)
84							
85		Excess Deferred Income Taxes	TOTPLT	$ (14,202,202)	$ (10,781,124)	$ (3,398,540)	$ (22,538)
86							
87		Negative Acquisition Adjustment on OPC Assets	MAINS-ALLOC	$ (1,949,023)	$ (1,256,467)	$ (692,555)	$ —
88							
89		Materials and Supplies	TOTPLT	$ 14,063,346	$ 10,675,716	$ 3,365,312	$ 22,318
90							
91		Prepayments	OPEXP	$ 5,177,582	$ 4,368,047	$ 757,263	$ 52,272
92							
93		Pension & FAS 106 Regulatory Asset	OPEXP	$ 16,643,110	$ 14,040,896	$ 2,434,190	$ 168,025
94							
95		DIMP Deferrals	OPEXP	$ 2,242,418	$ 1,891,808	$ 327,972	$ 22,639
96							
97		Regulatory Assets	OPEXP	$ 866,314	$ 730,862	$ 126,705	$ 8,746
98							
99		Cash Working Capital	OPEXP	$ (6,231,654)	$ (5,257,311)	$ (911,430)	$ (62,913)
100							
101		Total Rate Base		$ 918,437,737	$ 687,311,510	$ 229,401,673	$ 1,724,554

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	814-865	Transmission Expenses	DEM	$ 1,559,538	$ —	$ 1,559,538	$ —
3	8650	Odorization	COM	$ —	$ —	$ —	$ —
4	8700	Operation Supervision & Engineering	DIS871-879	$ 1,135,475	$ 962,146	$ 154,591	$ 18,738
5	8710	Distribution Load Dispatch	COM	$ 273,494	$ —	$ —	$ 273,494
6	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 7,663,580	$ 5,973,945	$ 1,689,635	$ —
7	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ —	$ —	$ —	$ —
8	8740	Odorization	COM	$ (48,721)	$ —	$ —	$ (48,721)
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 517,003	$ —	$ 517,003	$ —
10	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ —	$ —	$ —	$ —
11	8750	Odorization	COM	$ 49,290	$ —	$ —	$ 49,290
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 34,456	$ —	$ 34,456	$ —
13	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ —	$ —	$ —	$ —
14	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 15,221	$ —	$ 15,221	$ —
15	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 8,068,256	$ 8,068,256	$ —	$ —
16	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ —	$ —	$ —	$ —
17	8780	Odorization	COM	$ —	$ —	$ —	$ —
18	8790	Customer Installation Expenses	CUS	$ 656	$ 656	$ —	$ —
19	8800	Other Expenses	DIS871-879	$ 1,806,512	$ 1,530,749	$ 245,951	$ 29,812
20	8800	Odorization	COM	$ —	$ —	$ —	$ —
21	8810	Rents	DIS871-879	$ 32,665	$ 27,679	$ 4,447	$ 539
22	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
23		Total Transmission & Distribution Oper. Exp.		$ 21,107,425	$ 16,563,431	$ 4,220,842	$ 323,152
24							
25		**Distribution Maintenance Expenses**					
26	8850	Maintenance Supervision and Engineering	DIS887-893	$ —	$ —	$ —	$ —
27	8860	Structures and Improvements	DIS887-893	$ 1,257,960	$ 731,547	$ 526,414	$ —
28	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 4,161,695	$ 2,682,901	$ 1,478,794	$ —
29	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ —	$ —	$ —	$ —
30	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 975,090	$ —	$ 975,090	$ —
31	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
32	8890	Odorization	COM	$ 222,980	$ —	$ —	$ 222,980
33	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 692,596	$ —	$ 692,596	$ —
34	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
35	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 18,138	$ —	$ 18,138	$ —
36	8910	Odorization	COM	$ —	$ —	$ —	$ —
37	8920	Maintenance of Services - Allocated	CUS	$ 1,714,903	$ 1,714,903	$ —	$ —
38	8920	Maintenance of Services - Directly Assn.	CUS	$ —	$ —	$ —	$ —

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)
39	8930	Main. of Meters & House Reg. - Allocated	CUS	$ —	$ —	$ —	$ —
40	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ —	$ —	$ —	$ —
41	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
42	8950	Clearing - Meter Shop - Small Meters	CUS	$ —	$ —	$ —	$ —
43	8960	Clearing - Meter Shop - Large Meters	CUS	$ —	$ —	$ —	$ —
44		Total Distribution Maintenance Expenses		$ 9,043,361	$ 5,129,350	$ 3,691,031	$ 222,980
45							
46		Total Operations & Maintenance Expenses		$ 30,150,786	$ 21,692,781	$ 7,911,873	$ 546,132
47							
48		**Customer Accounting Expenses**					
49	9010	Supervision	CUS	$ 301	$ 301	$ —	$ —
50	9020	Meter Reading Expense	CUS	$ 622,858	$ 622,858	$ —	$ —
51	9030	Customer Accounting	CUS	$ 5,594,291	$ 5,594,291	$ —	$ —
52	9040	Bad Debts (includes gross up)	CUS	$ 1,380,038	$ 1,380,038	$ —	$ —
53	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 380,873	$ 380,873	$ —	$ —
54		Total Customer Accounts Expenses		$ 7,978,362	$ 7,978,362	$ —	$ —
55							
56		**Customer Information Expenses**					
57	9070	Supervision	CUS	$ —	$ —	$ —	$ —
58	9080	Customer Assistance	CUS	$ 1,232,263	$ 1,232,263	$ —	$ —
59	9090	Informational and Instructional Advertising	CUS	$ 74,992	$ 74,992	$ —	$ —
60	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —
61		Total Customer Information Expenses		$ 1,307,255	$ 1,307,255	$ —	$ —
62							
63		**Sales and Advertising Expenses**					
64	9110	Supervision	CUS	$ —	$ —	$ —	$ —
65	9120	Demonstrating and Selling	CUS	$ 1,630	$ 1,630	$ —	$ —
66	9130	Advertising	CUS	$ 157,433	$ 157,433	$ —	$ —
67	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —
68	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —
69		Total Sales and Advertising Expenses		$ 159,063	$ 159,063	$ —	$ —
70							
71		**Administrative & General Expenses**					
72	920-940	Administrative & General Expenses	ADMINGEN	$ 34,898,477	$ 31,709,066	$ 2,983,471	$ 205,940
73		Total Administrative & General Expenses		$ 34,898,477	$ 31,709,066	$ 2,983,471	$ 205,940
74							
75		**Depreciation and Amortization Expense**					
76	301-303	Intangible Plant - Allocated	PLT301-03	$ 42,882	$ 32,552	$ 10,261	$ 68
77	301-303	Intangible Plant - Directly Assigned	PLT301-03	$ —	$ —	$ —	$ —
78	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —

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)
79	366	Meas. and Reg. Station Structures	PLT366	$ —	$ —	$ —	$ —
80	367	Transmission Mains	PLT367	$ 458,355	$ —	$ 458,355	$ —
81	368	Compression Station Equipment	PLT368	$ —	$ —	$ —	$ —
82	369	Measuring and Reg. Station Equipment	PLT369	$ 241,719	$ —	$ 241,719	$ —
83	369	Odorization	COM	$ 14,395	$ —	$ —	$ 14,395
84	371	Other Equipment	PLT371	$ —	$ —	$ —	$ —
85	375	Structures and Improvements	PLT375	$ 1,810	$ 1,104	$ 706	$ —
86	376	Mains - Allocated	MAINS-ALLOC	$ 15,147,317	$ 9,764,952	$ 5,382,365	$ —
87	376	Mains - Directly Assigned	MAINS-DA	$ —	$ —	$ —	$ —
88	376	Odorization	COM	$ 3,532	$ —	$ —	$ 3,532
89	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
90	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 648,978	$ —	$ 648,978	$ —
91	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ —	$ —	$ —	$ —
92	378	Odorization	COM	$ 17,549	$ —	$ —	$ 17,549
93	379	Meas. & Reg. Sta. Equipment - City Gate - Alloc.	PLT379	$ 143,560	$ —	$ 143,560	$ —
94	379	Meas. & Reg. Sta. Equipment - City Gate - Dir. Assn.	PLT379	$ —	$ —	$ —	$ —
95	379	Odorization	COM	$ 11,238	$ —	$ —	$ 11,238
96	380	Services - Allocated	PLT380	$ 13,087,353	$ 13,087,353	$ —	$ —
97	380	Services - Directly Assigned	PLT380	$ —	$ —	$ —	$ —
98	381	Meters - Allocated	PLT381	$ 3,601,852	$ 3,601,852	$ —	$ —
99	381	Meters - Directly Assigned	PLT381	$ —	$ —	$ —	$ —
100	382	Meter Installations	PLT382	$ —	$ —	$ —	$ —
101	383	House Regulators - Allocated	PLT383	$ 528,397	$ 528,397	$ —	$ —
102	383	House Regulators - Directly Assigned	PLT383	$ —	$ —	$ —	$ —
103	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 413,565	$ —	$ 413,565	$ —
104	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ —	$ —	$ —	$ —
105	385	Odorization	COM	$ 1,147	$ —	$ —	$ 1,147
106	386	Other Property - Customer Premises	PLT386	$ 207,440	$ 207,440	$ —	$ —
107	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —
108	389-398	General Plant - Allocated	GENDEP	$ 8,655,924	$ 7,543,497	$ 1,104,941	$ 7,486
109	389-398	General Plant - Directly Assigned	GENDEP	$ —	$ —	$ —	$ —
110	389-398	General Plant - Odorization	COM	$ 1,311	$ —	$ —	$ 1,311
111	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ (565,213)	$ (476,840)	$ (82,667)	$ (5,706)
112		Total Depreciation and Amortization Expense		$ 42,663,112	$ 34,290,308	$ 8,321,784	$ 51,020
113							
114		**Taxes Other Than Income**					
115	4080	Payroll and Other	OPEXP	$ 3,098,749	$ 2,614,247	$ 453,217	$ 31,284
116	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 9,612,094	$ 7,296,698	$ 2,300,142	$ 15,254
117	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ —	$ —	$ —	$ —
118	4080	Revenue Related (includes gross up)	CUS	$ 169,364	$ 169,364	$ —	$ —

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)
119		Total Taxes Other Than Income		$ 12,880,207	$ 10,080,309	$ 2,753,360	$ 46,538
120							
121	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ —	$ —	$ —	$ —
122	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (438,167)	$ (328,209)	$ (109,225)	$ (733)
123							
124	4310	Interest on Customer Deposits	CUS	$ 313,051	$ 313,051	$ —	$ —
125							
126		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 73,623,733	$ 55,147,903	$ 18,352,685	$ 123,145
127		Required Return - Directly Assigned	RB-DA	$ —	$ —	$ —	$ —
128		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 15,239,916	$ 11,415,469	$ 3,798,957	$ 25,491
129		Income Taxes - Directly Assigned	RB-DA	$ —	$ —	$ —	$ —
130		Total Cost of Service Before Revenue Credits		$ 218,775,795	$ 173,765,358	$ 44,012,904	$ 997,532

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	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			Total Transmission Plant	$ 22,644,220	$ —	$ 22,224,536	$ 419,683
8			Total Distribution Plant	$ 1,064,720,028	$ 813,183,333	$ 250,138,689	$ 1,398,006
9			Total General Plant	$ 175,476,866	$ 145,459,994	$ 29,830,498	$ 186,375
10			Total Non-Intangible Plant	$ 1,262,841,114	$ 958,643,327	$ 302,193,723	$ 2,004,065
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.75912	0.23930	0.00159
12							
13	376		Distribution Mains-Allocated	$ 565,025,835	$ 364,252,631	$ 200,773,204	$ —
14	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 25,444,508	$ —	$ 25,444,508	$ —
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 6,612,251	$ —	$ 6,612,251	$ —
17			Total Accounts 376-379	$ 597,082,594	$ 364,252,631	$ 232,829,963	$ —
18		DIS376-379-ALL	Accounts 376-379 Allocated Factor	1.00000	0.61005	0.38995	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ —	$ —	$ —	$ —
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ —	$ —	$ —	$ —
22			Total Accounts 376-379 Directly Assigned	$ —	$ —	$ —	$ —
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
24							
25	376		Mains-Allocated	$ 565,025,835	$ 364,252,631	$ 200,773,204	$ —
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.64467	0.35533	0.00000
27							
28	376		Mains-Directly Assigned	$ —	$ —	$ —	$ —
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.55948	0.44052	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ —	$ —	$ —	$ —
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 910,635,626	$ 709,862,422	$ 200,773,204	$ —
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.77952	0.22048	0.00000
36							
37	376/380		Mains and Services	$ 910,635,626	$ 709,862,422	$ 200,773,204	$ —
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.77952	0.22048	0.00000
39							
40	374-387		Total Distribution Plant	$ 1,064,720,028	$ 813,183,333	$ 250,138,689	$ 1,398,006

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
41		DISPLT	Distribution Plant Factor	1.00000	0.76375	0.23493	0.00131
42							
43	374		Land & Land Rights - Directly Assigned	$ —	$ —	$ —	$ —
44	376		Mains - Directly Assigned	$ —	$ —	$ —	$ —
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ —	$ —	$ —	$ —
46	380		Service - Directly Assigned	$ —	$ —	$ —	$ —
47	381		Meters - Directly Assigned	$ —	$ —	$ —	$ —
48	383		House Regulators - Directly Assigned	$ —	$ —	$ —	$ —
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ —	$ —	$ —	$ —
50			Total Distribution Plant - Directly Assigned	$ —	$ —	$ —	$ —
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	0.00000	0.00000	0.00000	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (12,240)	$ (7,467)	$ (4,773)	$ —
54	375		Structures and Improvements	$ (145,657)	$ (88,859)	$ (56,798)	$ —
55	376		Distribution Mains - Allocated	$ (97,112,224)	$ (62,604,895)	$ (34,507,329)	$ —
56	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (3,199,103)	$ —	$ (3,199,103)	$ —
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (930,038)	$ —	$ (930,038)	$ —
59	378-379		Odorization	$ (255,769)	$ —	$ —	$ (255,769)
60	380		Services - Allocated	$ (64,032,459)	$ (64,032,459)	$ —	$ —
61	381		Meters - Allocated	$ (24,104,336)	$ (24,104,336)	$ —	$ —
62	382		Meter Installations	$ (25,858)	$ (25,858)	$ —	$ —
63	383		House Regulators - Allocated	$ (4,511,187)	$ (4,511,187)	$ —	$ —
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (4,070,833)	$ —	$ (4,070,833)	$ —
65	386		Other Property-Customer Premises	$ (727,168)	$ (443,612)	$ (283,556)	$ —
66	387		Other Equipment	$ —	$ —	$ —	$ —
67			Total Distribution Plant - Allocated Reserve	$ (199,126,872)	$ (155,818,673)	$ (43,052,431)	$ (255,769)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.78251	0.21621	0.00128
69							
70	376		Distribution Mains - Directly Assigned	$ —	$ —	$ —	$ —
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	0.00000	0.00000	0.00000	0.00000
72							
73			General Plant - Allocated Reserve	$ (61,870,623)	$ (52,693,554)	$ (9,120,572)	$ (56,498)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.85167	0.14741	0.00091
75							
76			General Plant - Directly Assigned Reserve	$ —	$ —	$ —	$ —
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	0.00000	0.00000	0.00000	0.00000
78							
79			Total Plant - Allocated	$ 1,264,305,951	$ 959,755,309	$ 302,544,253	$ 2,006,389
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.75912	0.23930	0.00159

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
81							
82			Total Plant - Directly Assigned	$ —	$ —	$ —	$ —
83		TPLT-DA	Total Plant Directly Assigned Factor	$ —	$ —	$ —	$ —
84							
85			Total Plant	$ 1,264,305,951	$ 959,755,309	$ 302,544,253	$ 2,006,389
86		TOTPLT	Total Plant Factor	1.00000	0.75912	0.23930	0.00159
87							
88			Total Operations and Maintenance Expenses	$ 30,150,786	$ 21,692,781	$ 7,911,873	$ 546,132
89			Total Customer Accounts Expenses	$ 7,978,362	$ 7,978,362	$ —	$ —
90			Total Customer Information Expenses	$ 1,307,255	$ 1,307,255	$ —	$ —
91			Total Sales and Advertising Expenses	$ 159,063	$ 159,063	$ —	$ —
92			Administrative and General Expenses	$ 34,898,477	$ 31,709,066	$ 2,983,471	$ 205,940
93			Total Operating Expenses	$ 74,493,943	$ 62,846,528	$ 10,895,344	$ 752,072
94		OPEXP	Operating Expense Factor	1.00000	0.84365	0.14626	0.01010
95							
96	8710		Distribution Load Dispatch	$ 273,494	$ —	$ —	$ 273,494
97	8740		Mains and Services Expenses - Allocated	$ 7,663,580	$ 5,973,945	$ 1,689,635	$ —
98	8740		Mains and Services Expenses - Dir. Assn.	$ —	$ —	$ —	$ —
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 517,003	$ —	$ 517,003	$ —
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ —	$ —	$ —	$ —
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 34,456	$ —	$ 34,456	$ —
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ —	$ —	$ —	$ —
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 15,221	$ —	$ 15,221	$ —
104	8780		Meter and House Regulator Exp.- Allocated	$ 8,068,256	$ 8,068,256	$ —	$ —
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ —	$ —	$ —	$ —
106	8790		Customer Installation Expenses	$ 656	$ 656	$ —	$ —
107			Total Accounts 871-879	$ 16,572,666	$ 14,042,857	$ 2,256,315	$ 273,494
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.84735	0.13615	0.01650
109							
110	8870		Maintenance of Mains-Allocated	$ 4,161,695	$ 2,682,901	$ 1,478,794	$ —
111	8870		Maintenance of Mains - Directly Assn.	$ —	$ —	$ —	$ —
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 975,090	$ —	$ 975,090	$ —
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ —	$ —	$ —	$ —
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 692,596	$ —	$ 692,596	$ —
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ —	$ —	$ —	$ —
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 18,138	$ —	$ 18,138	$ —
117	8920		Maintenance of Services - Allocated	$ 1,714,903	$ 1,714,903	$ —	$ —
118	8920		Maintenance of Services - Directly Assn.	$ —	$ —	$ —	$ —
119	8930		Main. of Meters & House Reg. - Allocated	$ —	$ —	$ —	$ —
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
121			Total Accounts 887-893	$ 7,562,421	$ 4,397,804	$ 3,164,617	$ —
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.58153	0.41847	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 30,150,786	$ 21,692,781	$ 7,911,873	$ 546,132
125			Total Customer Accounts Expenses	$ 7,978,362	$ 7,978,362	$ —	$ —
126			Total Customer Service Expenses	$ 1,307,255	$ 1,307,255	$ —	$ —
127			Total Sales and Advertising Expenses	$ 159,063	$ 159,063	$ —	$ —
128			Total Operating Exp. Without A&G Expenses	$ 39,595,466	$ 31,137,461	$ 7,911,873	$ 546,132
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.78639	0.19982	0.01379
130							
131	920-932		Administrative and General Expenses	$ 34,898,477	$ 31,709,066	$ 2,983,471	$ 205,940
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.90861	0.08549	0.00590
133							
134	366		Meas. and Reg. Station Structures	$ —	$ —	$ —	$ —
135		PLT366	Measuring and Reg. Station Structures Factor	0.00000	0.00000	0.00000	0.00000
136							
137	367		Transmission Mains	$ 15,177,328	$ —	$ 15,177,328	$ —
138		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
139							
140	368		Compression Station Equipment	$ —	$ —	$ —	$ —
141		PLT368	Compression Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
142							
143	369		Measuring and Reg. Station Equipment	$ 7,047,208	$ —	$ 7,047,208	$ —
144		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
145							
146	371		Other Equipment	$ —	$ —	$ —	$ —
147		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
148							
149	375		Structures and Improvements	$ 51,281	$ 31,284	$ 19,997	$ —
150		PLT375	Structures and Improvements Factor	1.00000	0.61005	0.38995	0.00000
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 25,444,508	$ —	$ 25,444,508	$ —
153		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
154							
155	379		Meas. & Reg. Sta. Equip.- City Gate	$ 6,612,251	$ —	$ 6,612,251	$ —
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services - Allocated	$ 345,609,791	$ 345,609,791	$ —	$ —
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters - Allocated	$ 88,936,245	$ 88,936,245	$ —	$ —
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
163							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
164	382		Meter Installations	$ —	$ —	$ —	$ —
165		PLT382	Meter Installations Factor	—	0.00000	0.00000	0.00000
166							
167	383		House Regulators - Allocated	$ 13,143,929	$ 13,143,929	$ —	$ —
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 17,195,275	$ —	$ 17,195,275	$ —
171		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
172							
173	386		Other Property - Customer Premises	$ 1,063,249	$ 1,063,249	$ —	$ —
174		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
175							
176	387		Other Equipment	$ —	$ —	$ —	$ —
177		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
178							
179	301-303		Intangible Plant	$ 1,464,837	$ 1,111,982	$ 350,531	$ 2,325
180		PLT301-03	Intangible Plant	1.00000	0.75912	0.23930	0.00159
181							
182	389-398		General Plant Depreciation Expense	$ 8,657,235	$ 7,544,640	$ 1,105,108	$ 7,487
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.87148	0.12765	0.00086
184							
185			Net Plant Directly Assigned	$ —	$ —	$ —	$ —
186		NETPLT-DA	Net Plant Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
187							
188			Net Plant Allocated	$ 1,001,580,453	$ 750,234,461	$ 249,670,719	$ 1,675,272
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.74905	0.24928	0.00167
190							
191			Rate Base Directly Assigned	$ —	$ —	$ —	$ —
192		RB-DA	Rate Base Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
193							
194			Rate Base Allocated	$ 918,437,737	$ 687,956,358	$ 228,945,173	$ 1,536,205
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.74905	0.24928	0.00167
196							
197			Required Return	$ 73,623,733	$ 55,147,903	$ 18,352,685	$ 123,145
198		REQRET	Required Return Factor	1.00000	0.74905	0.24928	0.00167
199							
200			Non-Plant Rate Base	$ (83,142,716)	$ (62,922,951)	$ (20,269,046)	$ 49,282
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.75681	0.24379	-0.00059

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	301-303	**Intangible Plant**									
2		Customer	NONINCUS	$ 1,111,982	$ 1,062,028	$ 44,347	$ 67	$ 2,736	$ 3	$ —	$ 1,036
3		Demand	NONINDEM	$ 350,531	$ 249,694	$ 50,044	$ 682	$ 8,139	$ —	$ —	$ 16,021
4		Commodity	COM	$ 2,325	$ 1,155	$ 534	$ 10	$ 52	$ —	$ —	$ 199
5		Total Intangible Plant		$ 1,464,837	$ 1,312,877	$ 94,925	$ 760	$ 10,927	$ 3	$ —	$ 17,257
6	365-371	**Transmission Plant**									
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 22,224,536	$ 15,831,241	$ 3,172,934	$ 43,258	$ 516,052	$ —	$ —	$ 1,015,792
9		Commodity	COM	$ 419,683	$ 208,571	$ 96,424	$ 1,827	$ 9,309	$ —	$ —	$ 35,982
10		Total Transmission Plant		$ 22,644,220	$ 16,039,811	$ 3,269,358	$ 45,085	$ 525,361	$ —	$ —	$ 1,051,775
11		**Distribution Plant**									
12	374	**Land & Land Rights - Allocated**									
13		Customer	376-379CUS	$ 146,204	$ 139,636	$ 5,831	$ 9	$ 360	$ 0	$ —	$ 136
14		Demand	DEM	$ 93,453	$ 66,570	$ 13,342	$ 182	$ 2,170	$ —	$ —	$ 4,271
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 239,657	$ 206,206	$ 19,173	$ 191	$ 2,530	$ 0	$ —	$ 4,408
17	374	**Land & Land Rights - DA**									
18		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
22	375	**Structures and Improvements**									
23		Customer	376-379CUS	$ 31,284	$ 29,879	$ 1,248	$ 2	$ 77	$ 0	$ —	$ 29
24		Demand	DEM	$ 19,997	$ 14,244	$ 2,855	$ 39	$ 464	$ —	$ —	$ 914
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 51,281	$ 44,123	$ 4,103	$ 41	$ 541	$ 0	$ —	$ 943
27	376	**Distribution Mains-Allocated**									
28		Customer	CUS	$ 364,252,631	$ 347,889,029	$ 14,526,663	$ 21,993	$ 896,204	$ 1,104	$ —	$ 339,433
29		Demand	DEM	$ 200,773,204	$ 143,017,111	$ 28,663,818	$ 390,784	$ 4,661,940	$ —	$ —	$ 9,176,517
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 565,025,835	$ 490,906,140	$ 43,190,481	$ 412,777	$ 5,558,143	$ 1,104	$ —	$ 9,515,950
32	376	**Odorization**									
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ 144,153	$ 71,640	$ 33,120	$ 628	$ 3,198	$ —	$ —	$ 12,359
36		Total Odorization		$ 144,153	$ 71,640	$ 33,120	$ 628	$ 3,198	$ —	$ —	$ 12,359
37		**Distribution Mains - Directly Assn.**									
38		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
42	377	**Compressor Station Equipment**									
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**									
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 25,444,508	$ 18,124,929	$ 3,632,640	$ 49,525	$ 590,820	$ —	$ —	$ 1,162,964
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 25,444,508	$ 18,124,929	$ 3,632,640	$ 49,525	$ 590,820	$ —	$ —	$ 1,162,964
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**									
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
57	378	**Odorization**									
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 688,208	$ 342,020	$ 158,119	$ 2,996	$ 15,266	$ —	$ —	$ 59,005
61		Total Odorization		$ 688,208	$ 342,020	$ 158,119	$ 2,996	$ 15,266	$ —	$ —	$ 59,005
62	379	**Meas. & Reg. Station - City Gate**									
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 6,612,251	$ 4,710,116	$ 944,012	$ 12,870	$ 153,536	$ —	$ —	$ 302,219
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 6,612,251	$ 4,710,116	$ 944,012	$ 12,870	$ 153,536	$ —	$ —	$ 302,219
67	379	**Odorization**									
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 517,861	$ 257,362	$ 118,981	$ 2,255	$ 11,487	$ —	$ —	$ 44,400
71		Total Odorization		$ 517,861	$ 257,362	$ 118,981	$ 2,255	$ 11,487	$ —	$ —	$ 44,400
72	380	**Services - Allocated**									
73		Customer	SERCUS-ALL	$ 345,609,791	$ 327,484,052	$ 15,818,347	$ 31,137	$ 975,892	$ 1,202	$ —	$ 480,557
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 345,609,791	$ 327,484,052	$ 15,818,347	$ 31,137	$ 975,892	$ 1,202	$ —	$ 480,557
77	380	**Services-Directly Assigned**									
78		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
82	381	**Meters - Allocated**									
83		Customer	METCUS-ALL	$ 88,936,245	$ 82,065,911	$ 5,659,268	$ 17,342	$ 407,635	$ 1,617	$ —	$ 428,536
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 88,936,245	$ 82,065,911	$ 5,659,268	$ 17,342	$ 407,635	$ 1,617	$ —	$ 428,536
87	381	**Meters-Directly Assigned**									
88		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
92	382	**Meter Installations**									
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**									
98		Customer	REGCUS-ALL	$ 13,143,929	$ 11,517,553	$ 1,203,799	$ 7,552	$ 110,524	$ 798	$ —	$ 180,435
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 13,143,929	$ 11,517,553	$ 1,203,799	$ 7,552	$ 110,524	$ 798	$ —	$ 180,435
102	383	**House Regulators - Directly Assigned**									
103		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**									
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 17,195,275	$ —	$ 8,533,857	$ 116,345	$ 1,387,963	$ —	$ —	$ 2,732,054
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 17,195,275	$ —	$ 8,533,857	$ 116,345	$ 1,387,963	$ —	$ —	$ 2,732,054
112	385	**Odorization**									
113		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
115		Commodity	COM	$ 47,784	$ 23,747	$ 10,979	$ 208	$ 1,060	$ —	$ —	$ 4,097
116		Total Odorization		$ 47,784	$ 23,747	$ 10,979	$ 208	$ 1,060	$ —	$ —	$ 4,097
117	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**									

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
118		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
121		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
122	386	**Other Prop.-Customer Premises**									
123		Customer	CUS	$ 1,063,249	$ 1,015,484	$ 42,403	$ 64	$ 2,616	$ 3	$ —	$ 991
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 1,063,249	$ 1,015,484	$ 42,403	$ 64	$ 2,616	$ 3	$ —	$ 991
127	387	**Other Equipment**									
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —		$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —		$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —		$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —		$ —
132		**Total Distribution Plant**									
133		Customer		$ 813,183,333	$ 770,141,544	$ 37,257,558	$ 78,099	$ 2,393,307	$ 4,725	$ —	$ 1,430,117
134		Demand		$ 250,138,689	$ 165,932,969	$ 41,790,524	$ 569,745	$ 6,796,893	$ —	$ —	$ 13,378,939
135		Commodity		$ 1,398,006	$ 694,769	$ 321,199	$ 6,087	$ 31,010	$ —	$ —	$ 119,861
136		Total Distribution Plant		$ 1,064,720,028	$ 936,769,282	$ 79,369,281	$ 653,931	$ 9,221,210	$ 4,725	$ —	$ 14,928,917
137		**General Plant**									
138		**General Plant - Allocated**									
139		Customer	GENPTCUS	$ 145,459,994	$ 138,416,643	$ 6,178,254	$ 11,049	$ 388,563	$ 618	$ —	$ 188,086
140		Demand	DISPLTDEM	$ 29,830,498	$ 19,788,475	$ 4,983,764	$ 67,945	$ 810,569	$ —	$ —	$ 1,595,516
141		Commodity	COM	$ 186,375	$ 92,623	$ 42,821	$ 811	$ 4,134	$ —	$ —	$ 15,979
142		Total General Plant - Allocated		$ 175,476,866	$ 158,297,740	$ 11,204,839	$ 79,806	$ 1,203,267	$ 618	$ —	$ 1,799,582
143		**Total General Plant - Directly Assigned**									
144		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
148		**Total General Plant**									
149		Customer		$ 145,459,994	$ 138,416,643	$ 6,178,254	$ 11,049	$ 388,563	$ 618	$ —	$ 188,086
150		Demand		$ 29,830,498	$ 19,788,475	$ 4,983,764	$ 67,945	$ 810,569	$ —	$ —	$ 1,595,516
151		Commodity		$ 186,375	$ 92,623	$ 42,821	$ 811	$ 4,134	$ —	$ —	$ 15,979
152		Total General Plant		$ 175,476,866	$ 158,297,740	$ 11,204,839	$ 79,806	$ 1,203,267	$ 618	$ —	$ 1,799,582
153		**Total Plant in Service**									
154		Customer		$ 959,755,309	$ 909,620,214	$ 43,480,159	$ 89,215	$ 2,784,607	$ 5,346	$ —	$ 1,619,239
155		Demand		$ 302,544,253	$ 201,802,379	$ 49,997,265	$ 681,631	$ 8,131,653	$ —	$ —	$ 16,006,269
156		Commodity		$ 2,006,389	$ 997,117	$ 460,978	$ 8,736	$ 44,505	$ —	$ —	$ 172,022
157		Total Plant in Service		$ 1,264,305,951	$ 1,112,419,711	$ 93,938,402	$ 779,581	$ 10,960,765	$ 5,346	$ —	$ 17,797,530

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
158		**Depreciation & Amort. Reserve**									
159		**Intangible Plant**									
160		Customer	NONINCUS	$ (994,160)	$ (949,499)	$ (39,648)	$ (60)	$ (2,446)	$ (3)	$ —	$ (926)
161		Demand	NONINDEM	$ (274,685)	$ (195,667)	$ (39,216)	$ (535)	$ (6,378)	$ —	$ —	$ (12,555)
162		Commodity	COM	$ (1,632)	$ (811)	$ (375)	$ (7)	$ (36)	$ —	$ —	$ (140)
163		Total Intangible Plant		$ (1,270,477)	$ (1,145,977)	$ (79,239)	$ (602)	$ (8,860)	$ (3)	$ —	$ (13,621)
164		**Transmission Plant**									
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (421,851)	$ (300,498)	$ (60,226)	$ (821)	$ (9,795)	$ —	$ —	$ (19,281)
167		Commodity	COM	$ (17,195)	$ (8,546)	$ (3,951)	$ (75)	$ (381)	$ —	$ —	$ (1,474)
168		Total Transmission Plant		$ (439,047)	$ (309,044)	$ (64,177)	$ (896)	$ (10,177)	$ —	$ —	$ (20,755)
169		**Distribution Plant - Allocated**									
170		Customer	DISPLTCUS	$ (155,833,134)	$ (147,584,887)	$ (7,139,795)	$ (14,966)	$ (458,638)	$ (905)	$ —	$ (274,058)
171		Demand	DISPLTDEM	$ (43,056,426)	$ (28,562,078)	$ (7,193,412)	$ (98,070)	$ (1,169,951)	$ —	$ —	$ (2,302,920)
172		Commodity	COM	$ (255,792)	$ (127,121)	$ (58,770)	$ (1,114)	$ (5,674)	$ —	$ —	$ (21,931)
173		Total Distribution Plant - Allocated		$ (199,145,352)	$ (176,274,086)	$ (14,391,976)	$ (114,150)	$ (1,634,262)	$ (905)	$ —	$ (2,598,909)
174		**Distribution Plant - Dir. Assn.**									
175		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
176		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
179		**General Plant - Allocated**									
180		Customer	GENPTCUS	$ (52,693,554)	$ (50,142,067)	$ (2,238,101)	$ (4,002)	$ (140,759)	$ (224)	$ —	$ (68,135)
181		Demand	DISPLTDEM	$ (9,120,572)	$ (6,050,258)	$ (1,523,769)	$ (20,774)	$ (247,829)	$ —	$ —	$ (487,824)
182		Commodity	COM	$ (56,498)	$ (28,078)	$ (12,981)	$ (246)	$ (1,253)	$ —	$ —	$ (4,844)
183		Total General Plant - Allocated		$ (61,870,623)	$ (56,220,403)	$ (3,774,850)	$ (25,023)	$ (389,841)	$ (224)	$ —	$ (560,803)
184		**General Plant - Directly Assigned**									
185		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
189		**Total Depr. & Amort. Reserve**									
190		Customer		$ (209,520,847)	$ (198,676,453)	$ (9,417,544)	$ (19,029)	$ (601,843)	$ (1,132)	$ —	$ (343,120)
191		Demand		$ (52,873,534)	$ (35,108,500)	$ (8,816,623)	$ (120,200)	$ (1,433,953)	$ —	$ —	$ (2,822,579)
192		Commodity		$ (331,117)	$ (164,556)	$ (76,076)	$ (1,442)	$ (7,345)	$ —	$ —	$ (28,389)
193		Total Depr. & Amortization Reserve		$ (262,725,499)	$ (233,949,509)	$ (18,310,242)	$ (140,671)	$ (2,043,140)	$ (1,132)	$ —	$ (3,194,088)
194		**Net Plant in Service**									
195		Customer		$ 750,234,461	$ 710,943,761	$ 34,062,616	$ 70,186	$ 2,182,764	$ 4,214	$ —	$ 1,276,119
196		Demand		$ 249,670,719	$ 166,693,879	$ 41,180,642	$ 561,430	$ 6,697,701	$ —	$ —	$ 13,183,690
197		Commodity		$ 1,675,272	$ 832,562	$ 384,902	$ 7,294	$ 37,160	$ —	$ —	$ 143,633

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
198		Total Net Plant in Service		$ 1,001,580,453	$ 878,470,202	$ 75,628,160	$ 638,911	$ 8,917,625	$ 4,214	$ —	$ 14,603,442
199		**Customer Deposits**									
200		Customer	DEPCUS	$ (6,199,032)	$ (2,891,777)	$ (3,230,612)	$ (31,898)	$ (9,601)	$ —	$ —	$ (31,145)
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (6,199,032)	$ (2,891,777)	$ (3,230,612)	$ (31,898)	$ (9,601)	$ —	$ —	$ (31,145)
204		**Customer Advances**									
205		Customer	MSCUS-ALL	$ (4,518,662)	$ (4,299,118)	$ (193,163)	$ (338)	$ (11,917)	$ (15)	$ —	$ (5,220)
206		Demand	DEM	$ (1,278,031)	$ (910,382)	$ (182,461)	$ (2,488)	$ (29,676)	$ —	$ —	$ (58,414)
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (5,796,693)	$ (5,209,500)	$ (375,623)	$ (2,826)	$ (41,593)	$ (15)	$ —	$ (63,633)
209		**Accum. Deferred Income Taxes**									
210		Customer	TPLTCUS	$ (66,617,683)	$ (63,137,751)	$ (3,018,006)	$ (6,193)	$ (193,283)	$ (371)	$ —	$ (112,393)
211		Demand	TPLTDEM	$ (20,999,933)	$ (14,007,328)	$ (3,470,366)	$ (47,313)	$ (564,427)	$ —	$ —	$ (1,111,013)
212		Commodity	COM	$ (139,266)	$ (69,211)	$ (31,997)	$ (606)	$ (3,089)	$ —	$ —	$ (11,940)
213		Total Accum. Deferred Inc. Taxes		$ (87,756,882)	$ (77,214,289)	$ (6,520,369)	$ (54,112)	$ (760,799)	$ (371)	$ —	$ (1,235,346)
214		**Excess Deferred Income Taxes**									
215		Customer	TPLTCUS	$ (10,781,124)	$ (10,217,946)	$ (488,421)	$ (1,002)	$ (31,280)	$ (60)	$ —	$ (18,189)
216		Demand	TPLTDEM	$ (3,398,540)	$ (2,266,887)	$ (561,629)	$ (7,657)	$ (91,344)	$ —	$ —	$ (179,802)
217		Commodity	COM	$ (22,538)	$ (11,201)	$ (5,178)	$ (98)	$ (500)	$ —	$ —	$ (1,932)
218		**Total Excess Deferred Income Taxes**		$ (14,202,202)	$ (12,496,034)	$ (1,055,229)	$ (8,757)	$ (123,124)	$ (60)	$ —	$ (199,923)
219		**Negative Acquisition Adjustment on OPC Assets**									
220		Customer	DISPLTCUS	$ (1,256,467)	$ (1,189,963)	$ (57,567)	$ (121)	$ (3,698)	$ (7)	$ —	$ (2,210)
221		Demand	DISPLTDEM	$ (692,555)	$ (459,416)	$ (115,705)	$ (1,577)	$ (18,818)	$ —	$ —	$ (37,042)
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ (1,949,023)	$ (1,649,379)	$ (173,272)	$ (1,698)	$ (22,516)	$ (7)	$ —	$ (39,252)
224		**Materials and Supplies**									
225		Customer	TPLTCUS	$ 10,675,716	$ 10,118,044	$ 483,646	$ 992	$ 30,974	$ 59	$ —	$ 18,011
226		Demand	TPLTDEM	$ 3,365,312	$ 2,244,723	$ 556,138	$ 7,582	$ 90,451	$ —	$ —	$ 178,044
227		Commodity	COM	$ 22,318	$ 11,091	$ 5,128	$ 97	$ 495	$ —	$ —	$ 1,913
228		Total Materials and Supplies		$ 14,063,346	$ 12,373,859	$ 1,044,912	$ 8,672	$ 121,921	$ 59	$ —	$ 197,969
229		**Prepayments**									
230		Customer	OPEXPCUS	$ 4,368,047	$ 4,127,308	$ 206,505	$ 636	$ 13,142	$ 34	$ —	$ 9,774
231		Demand	OPEXPDEM	$ 757,263	$ 495,169	$ 130,075	$ 1,773	$ 21,156	$ —	$ —	$ 41,643
232		Commodity	COM	$ 52,272	$ 25,977	$ 12,010	$ 228	$ 1,159	$ —	$ —	$ 4,482
233		Total Prepayments		$ 5,177,582	$ 4,648,455	$ 348,590	$ 2,637	$ 35,457	$ 34	$ —	$ 55,898
234		**Pension & FAS 106 Reg. Asset**									
235		Customer	OPEXPCUS	$ 14,040,896	$ 13,267,051	$ 663,802	$ 2,044	$ 42,246	$ 111	$ —	$ 31,417
236		Demand	OPEXPDEM	$ 2,434,190	$ 1,591,700	$ 418,120	$ 5,700	$ 68,004	$ —	$ —	$ 133,858
237		Commodity	COM	$ 168,025	$ 83,503	$ 38,604	$ 732	$ 3,727	$ —	$ —	$ 14,406
238		Total Pen. & FAS 106 Reg. Asset		$ 16,643,110	$ 14,942,255	$ 1,120,526	$ 8,476	$ 113,976	$ 111	$ —	$ 179,681
239		**DIMP Deferrals**									
240		Customer	TPLTCUS	$ 1,891,808	$ 1,792,984	$ 85,705	$ 176	$ 5,489	$ 11	$ —	$ 3,192
241		Demand	TPLTDEM	$ 327,972	$ 218,763	$ 54,199	$ 739	$ 8,815	$ —	$ —	$ 17,352

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
242		Commodity	COM	$ 22,639	$ 11,251	$ 5,201	$ 99	$ 502	$ —	$ —	$ 1,941
243		Total DIMP Deferrals		$ 2,242,418	$ 2,022,998	$ 145,106	$ 1,013	$ 14,806	$ 11	$ —	$ 22,484
244		**Regulatory Asset**									
245		Customer	TPLTCUS	$ 730,862	$ 692,684	$ 33,111	$ 68	$ 2,121	$ 4	$ —	$ 1,233
246		Demand	TPLTDEM	$ 126,705	$ 84,515	$ 20,939	$ 285	$ 3,406	$ —	$ —	$ 6,703
247		Commodity	COM	$ 8,746	$ 4,347	$ 2,009	$ 38	$ 194	$ —	$ —	$ 750
248		**Total Regulatory Asset**		$ 866,314	$ 781,545	$ 56,059	$ 391	$ 5,720	$ 4	$ —	$ 8,686
249		**Cash Working Capital**									
250		Customer	OPEXPCUS	$ (5,257,311)	$ (4,967,562)	$ (248,546)	$ (765)	$ (15,818)	$ (41)	$ —	$ (11,763)
251		Demand	OPEXPDEM	$ (911,430)	$ (595,978)	$ (156,556)	$ (2,134)	$ (25,463)	$ —	$ —	$ (50,120)
252		Commodity	COM	$ (62,913)	$ (31,266)	$ (14,455)	$ (274)	$ (1,396)	$ —	$ —	$ (5,394)
253		Total Cash Working Capital		$ (6,231,654)	$ (5,594,806)	$ (419,557)	$ (3,174)	$ (42,676)	$ (41)	$ —	$ (67,278)
254		**Total Rate Base**									
255		Customer		$ 687,311,510	$ 654,237,717	$ 28,299,069	$ 33,786	$ 2,011,139	$ 3,938	$ —	$ 1,158,826
256		Demand		$ 229,401,673	$ 153,088,759	$ 37,873,397	$ 516,342	$ 6,159,804	$ —	$ —	$ 12,124,898
257		Commodity		$ 1,724,554	$ 857,053	$ 396,225	$ 7,508	$ 38,253	$ —	$ —	$ 147,858
258		Total Rate Base		$ 918,437,737	$ 808,183,529	$ 66,568,690	$ 557,636	$ 8,209,196	$ 3,938	$ —	$ 13,431,583

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
1	301-303	**Intangible Plant**						
2		Customer	NONINCUS	$ 94	$ 1,654	$ 13	$ 3	$ —
3		Demand	NONINDEM	$ 11,321	$ 12,050	$ 414	$ 2,164	$ —
4		Commodity	COM	$ 196	$ 117	$ 12	$ 49	$ —
5		Total Intangible Plant		$ 11,611	$ 13,821	$ 439	$ 2,217	$ —
6	365-371	**Transmission Plant**						
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 717,762	$ 764,008	$ 26,261	$ 137,229	$ —
9		Commodity	COM	$ 35,455	$ 21,087	$ 2,107	$ 8,920	$ —
10		Total Transmission Plant		$ 753,217	$ 785,095	$ 28,367	$ 146,150	$ —
11		**Distribution Plant**						
12	374	**Land & Land Rights - Allocated**						
13		Customer	376-379CUS	$ 12	$ 217	$ 2	$ 0	$ —
14		Demand	DEM	$ 3,018	$ 3,213	$ 110	$ 577	$ —
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 3,031	$ 3,430	$ 112	$ 577	$ —
17	374	**Land & Land Rights - DA**						
18		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ —	$ —	$ —	$ —	$ —
22	375	**Structures and Improvements**						
23		Customer	376-379CUS	$ 3	$ 47	$ 0	$ 0	$ —
24		Demand	DEM	$ 646	$ 687	$ 24	$ 123	$ —
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 648	$ 734	$ 24	$ 124	$ —
27	376	**Distribution Mains-Allocated**						
28		Customer	CUS	$ 30,827	$ 541,857	$ 4,417	$ 1,104	$ —
29		Demand	DEM	$ 6,484,155	$ 6,901,937	$ 237,235	$ 1,239,708	$ —
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 6,514,982	$ 7,443,794	$ 241,652	$ 1,240,812	$ —
32	376	**Odorization**						
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ 12,178	$ 7,243	$ 724	$ 3,064	$ —
36		Total Odorization		$ 12,178	$ 7,243	$ 724	$ 3,064	$ —
37		**Distribution Mains - Directly Assn.**						
38		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ —	$ —	$ —	$ —	$ —
42	377	**Compressor Station Equipment**						
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**						
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 821,754	$ 874,700	$ 30,065	$ 157,111	$ —
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 821,754	$ 874,700	$ 30,065	$ 157,111	$ —
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**						
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —
57	378	**Odorization**						
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 58,141	$ 34,579	$ 3,454	$ 14,628	$ —
61		Total Odorization		$ 58,141	$ 34,579	$ 3,454	$ 14,628	$ —
62	379	**Meas. & Reg. Station - City Gate**						
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 213,549	$ 227,308	$ 7,813	$ 40,828	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 213,549	$ 227,308	$ 7,813	$ 40,828	$ —
67	379	**Odorization**						
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 43,750	$ 26,020	$ 2,599	$ 11,007	$ —
71		Total Odorization		$ 43,750	$ 26,020	$ 2,599	$ 11,007	$ —
72	380	**Services - Allocated**						
73		Customer	SERCUS-ALL	$ 43,644	$ 767,142	$ 6,254	$ 1,563	$ —
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 43,644	$ 767,142	$ 6,254	$ 1,563	$ —
77	380	**Services-Directly Assigned**						
78		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —
82	381	**Meters - Allocated**						
83		Customer	METCUS-ALL	$ 44,876	$ 302,977	$ 6,466	$ 1,617	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 44,876	$ 302,977	$ 6,466	$ 1,617	$ —
87	381	**Meters-Directly Assigned**						
88		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —
92	382	**Meter Installations**						
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**						
98		Customer	REGCUS-ALL	$ 21,490	$ 97,788	$ 3,192	$ 798	$ —
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 21,490	$ 97,788	$ 3,192	$ 798	$ —
102	383	**House Regulators - Directly Assigned**						
103		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ —	$ —	$ —	$ —	$ —
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**						
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 1,930,477	$ 2,054,860	$ 70,630	$ 369,089	$ —
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 1,930,477	$ 2,054,860	$ 70,630	$ 369,089	$ —
112	385	**Odorization**						
113		Customer	CUS	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM	$ —	$ —	$ —	$ —	$ —
115		Commodity	COM	$ 4,037	$ 2,401	$ 240	$ 1,016	$ —
116		Total Odorization		$ 4,037	$ 2,401	$ 240	$ 1,016	$ —
117	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**						

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
118		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
121		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ —	$ —	$ —	$ —	$ —
122	386	**Other Prop.-Customer Premises**						
123		Customer	CUS	$ 90	$ 1,582	$ 13	$ 3	$ —
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 90	$ 1,582	$ 13	$ 3	$ —
127	387	**Other Equipment**						
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**						
133		Customer		$ 140,943	$ 1,711,610	$ 20,344	$ 5,086	$ —
134		Demand		$ 9,453,599	$ 10,062,706	$ 345,877	$ 1,807,437	$ —
135		Commodity		$ 118,105	$ 70,244	$ 7,017	$ 29,715	$ —
136		Total Distribution Plant		$ 9,712,647	$ 11,844,560	$ 373,238	$ 1,842,238	$ —
137		**General Plant**						
138		**General Plant - Allocated**						
139		Customer	GENPTCUS	$ 17,946	$ 255,605	$ 2,583	$ 646	$ —
140		Demand	DISPLTDEM	$ 1,127,397	$ 1,200,036	$ 41,248	$ 215,547	$ —
141		Commodity	COM	$ 15,745	$ 9,364	$ 936	$ 3,961	$ —
142		Total General Plant - Allocated		$ 1,161,088	$ 1,465,006	$ 44,766	$ 220,155	$ —
143		**Total General Plant - Directly Assigned**						
144		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ —	$ —	$ —	$ —	$ —
148		**Total General Plant**						
149		Customer		$ 17,946	$ 255,605	$ 2,583	$ 646	$ —
150		Demand		$ 1,127,397	$ 1,200,036	$ 41,248	$ 215,547	$ —
151		Commodity		$ 15,745	$ 9,364	$ 936	$ 3,961	$ —
152		Total General Plant		$ 1,161,088	$ 1,465,006	$ 44,766	$ 220,155	$ —
153		**Total Plant in Service**						
154		Customer		$ 158,983	$ 1,968,870	$ 22,940	$ 5,735	$ —
155		Demand		$ 11,310,078	$ 12,038,801	$ 413,800	$ 2,162,378	$ —
156		Commodity		$ 169,502	$ 100,812	$ 10,071	$ 42,646	$ —
157		Total Plant in Service		$ 11,638,564	$ 14,108,482	$ 446,811	$ 2,210,759	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
158		**Depreciation & Amort. Reserve**						
159		**Intangible Plant**						
160		Customer	NONINCUS	$ (84)	$ (1,479)	$ (12)	$ (3)	$ —
161		Demand	NONINDEM	$ (8,871)	$ (9,443)	$ (325)	$ (1,696)	$ —
162		Commodity	COM	$ (138)	$ (82)	$ (8)	$ (35)	$ —
163		Total Intangible Plant		$ (9,093)	$ (11,004)	$ (345)	$ (1,734)	$ —
164		**Transmission Plant**						
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (13,624)	$ (14,502)	$ (498)	$ (2,605)	$ —
167		Commodity	COM	$ (1,453)	$ (864)	$ (86)	$ (365)	$ —
168		Total Transmission Plant		$ (15,077)	$ (15,366)	$ (585)	$ (2,970)	$ —
169		**Distribution Plant - Allocated**						
170		Customer	DISPLTCUS	$ (27,009)	$ (328,002)	$ (3,899)	$ (975)	$ —
171		Demand	DISPLTDEM	$ (1,627,250)	$ (1,732,096)	$ (59,536)	$ (311,115)	$ —
172		Commodity	COM	$ (21,610)	$ (12,852)	$ (1,284)	$ (5,437)	$ —
173		Total Distribution Plant - Allocated		$ (1,675,869)	$ (2,072,950)	$ (64,718)	$ (317,526)	$ —
174		**Distribution Plant - Dir. Assn.**						
175		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
176		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ —	$ —	$ —	$ —	$ —
179		**General Plant - Allocated**						
180		Customer	GENPTCUS	$ (6,501)	$ (92,594)	$ (936)	$ (234)	$ —
181		Demand	DISPLTDEM	$ (344,698)	$ (366,907)	$ (12,611)	$ (65,903)	$ —
182		Commodity	COM	$ (4,773)	$ (2,839)	$ (284)	$ (1,201)	$ —
183		Total General Plant - Allocated		$ (355,972)	$ (462,340)	$ (13,831)	$ (67,338)	$ —
184		**General Plant - Directly Assigned**						
185		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
186		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —
189		**Total Depr. & Amort. Reserve**						
190		Customer		$ (33,595)	$ (422,075)	$ (4,846)	$ (1,212)	$ —
191		Demand		$ (1,994,443)	$ (2,122,947)	$ (72,970)	$ (381,318)	$ —
192		Commodity		$ (27,973)	$ (16,637)	$ (1,662)	$ (7,038)	$ —
193		Total Depr. & Amortization Reserve		$ (2,056,011)	$ (2,561,660)	$ (79,479)	$ (389,568)	$ —
194		**Net Plant in Service**						
195		Customer		$ 125,389	$ 1,546,795	$ 18,094	$ 4,523	$ —
196		Demand		$ 9,315,635	$ 9,915,853	$ 340,829	$ 1,781,060	$ —
197		Commodity		$ 141,529	$ 84,175	$ 8,409	$ 35,608	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
198		Total Net Plant in Service		$ 9,582,553	$ 11,546,823	$ 367,332	$ 1,821,192	$ —
199		**Customer Deposits**						
200		Customer	DEPCUS	$ (4,000)	$ —	$ —	$ —	$ —
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (4,000)	$ —	$ —	$ —	$ —
204		**Customer Advances**						
205		Customer	MSCUS-ALL	$ (474)	$ (8,332)	$ (68)	$ (17)	$ —
206		Demand	DEM	$ (41,275)	$ (43,935)	$ (1,510)	$ (7,891)	$ —
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (41,749)	$ (52,267)	$ (1,578)	$ (7,908)	$ —
209		**Accum. Deferred Income Taxes**						
210		Customer	TPLTCUS	$ (11,035)	$ (136,661)	$ (1,592)	$ (398)	$ —
211		Demand	TPLTDEM	$ (785,045)	$ (835,627)	$ (28,722)	$ (150,093)	$ —
212		Commodity	COM	$ (11,765)	$ (6,997)	$ (699)	$ (2,960)	$ —
213		Total Accum. Deferred Inc. Taxes		$ (807,846)	$ (979,285)	$ (31,014)	$ (153,451)	$ —
214		**Excess Deferred Income Taxes**						
215		Customer	TPLTCUS	$ (1,786)	$ (22,117)	$ (258)	$ (64)	$ —
216		Demand	TPLTDEM	$ (127,048)	$ (135,234)	$ (4,648)	$ (24,290)	$ —
217		Commodity	COM	$ (1,904)	$ (1,132)	$ (113)	$ (479)	$ —
218		**Total Excess Deferred Income Taxes**		$ (130,738)	$ (158,483)	$ (5,019)	$ (24,834)	$ —
219		**Negative Acquisition Adjustment on OPC Assets**						
220		Customer	DISPLTCUS	$ (218)	$ (2,645)	$ (31)	$ (8)	$ —
221		Demand	DISPLTDEM	$ (26,174)	$ (27,860)	$ (958)	$ (5,004)	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ (26,392)	$ (30,505)	$ (989)	$ (5,012)	$ —
224		**Materials and Supplies**						
225		Customer	TPLTCUS	$ 1,768	$ 21,900	$ 255	$ 64	$ —
226		Demand	TPLTDEM	$ 125,806	$ 133,912	$ 4,603	$ 24,053	$ —
227		Commodity	COM	$ 1,885	$ 1,121	$ 112	$ 474	$ —
228		Total Materials and Supplies		$ 129,460	$ 156,934	$ 4,970	$ 24,591	$ —
229		**Prepayments**						
230		Customer	OPEXPCUS	$ 989	$ 9,479	$ 143	$ 36	$ —
231		Demand	OPEXPDEM	$ 29,425	$ 31,321	$ 1,077	$ 5,626	$ —
232		Commodity	COM	$ 4,416	$ 2,626	$ 262	$ 1,111	$ —
233		Total Prepayments		$ 34,830	$ 43,426	$ 1,482	$ 6,773	$ —
234		**Pension & FAS 106 Reg. Asset**						
235		Customer	OPEXPCUS	$ 3,179	$ 30,470	$ 461	$ 115	$ —
236		Demand	OPEXPDEM	$ 94,585	$ 100,679	$ 3,461	$ 18,084	$ —
237		Commodity	COM	$ 14,195	$ 8,442	$ 843	$ 3,571	$ —
238		Total Pen. & FAS 106 Reg. Asset		$ 111,959	$ 139,591	$ 4,765	$ 21,770	$ —
239		**DIMP Deferrals**						
240		Customer	TPLTCUS	$ 313	$ 3,881	$ 45	$ 11	$ —
241		Demand	TPLTDEM	$ 12,261	$ 13,051	$ 449	$ 2,344	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
242		Commodity	COM	$ 1,913	$ 1,138	$ 114	$ 481	$ —
243		Total DIMP Deferrals		$ 14,487	$ 18,069	$ 607	$ 2,837	$ —
244		**Regulatory Asset**						
245		Customer	TPLTCUS	$ 121	$ 1,499	$ 17	$ 4	$ —
246		Demand	TPLTDEM	$ 4,737	$ 5,042	$ 173	$ 906	$ —
247		Commodity	COM	$ 739	$ 439	$ 44	$ 186	$ —
248		**Total Regulatory Asset**		$ 5,597	$ 6,981	$ 235	$ 1,096	$ —
249		**Cash Working Capital**						
250		Customer	OPEXPCUS	$ (1,190)	$ (11,409)	$ (173)	$ (43)	$ —
251		Demand	OPEXPDEM	$ (35,415)	$ (37,697)	$ (1,296)	$ (6,771)	$ —
252		Commodity	COM	$ (5,315)	$ (3,161)	$ (316)	$ (1,337)	$ —
253		Total Cash Working Capital		$ (41,921)	$ (52,267)	$ (1,784)	$ (8,151)	$ —
254		**Total Rate Base**						
255		Customer		$ 113,056	$ 1,432,861	$ 16,894	$ 4,224	$ —
256		Demand		$ 8,567,490	$ 9,119,504	$ 313,457	$ 1,638,022	$ —
257		Commodity		$ 145,693	$ 86,651	$ 8,656	$ 36,656	$ —
258		Total Rate Base		$ 8,826,239	$ 10,639,016	$ 339,008	$ 1,678,901	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1		**Transmission and Distribution Op. Exp.**										
2	814-865	**Transmission Expenses**										
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 1,559,538	$ 1,110,908	$ 222,651	$ 3,035	$ 36,212	$ —	$ —	$ 71,280	$ 50,367
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 1,559,538	$ 1,110,908	$ 222,651	$ 3,035	$ 36,212	$ —	$ —	$ 71,280	$ 50,367
7	8650	**Odorization**										
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
11		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
12	8700	**Operation Supervision & Engineering**										
13		Customer	871-879CUS	$ 962,146	$ 894,621	$ 55,641	$ 179	$ 4,019	$ 16	$ —	$ 4,082	$ 442
14		Demand	DEM	$ 154,591	$ 110,120	$ 22,071	$ 301	$ 3,590	$ —	$ —	$ 7,066	$ 4,993
15		Commodity	COM	$ 18,738	$ 9,312	$ 4,305	$ 82	$ 416	$ —	$ —	$ 1,607	$ 1,583
16		Total Supervision & Engineering		$ 1,135,475	$ 1,014,053	$ 82,017	$ 561	$ 8,024	$ 16	$ —	$ 12,754	$ 7,018
17	8710	**Distribution Load Dispatch**										
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 273,494	$ 135,919	$ 62,837	$ 1,191	$ 6,067	$ —	$ —	$ 23,449	$ 23,105
21		Total Distribution Load Dispatch		$ 273,494	$ 135,919	$ 62,837	$ 1,191	$ 6,067	$ —	$ —	$ 23,449	$ 23,105
22	8740	**Mains & Services - Allocated**										
23		Customer	MSCUS-ALL	$ 5,973,945	$ 5,683,695	$ 255,373	$ 447	$ 15,755	$ 19	$ —	$ 6,901	$ 627
24		Demand	DEM	$ 1,689,635	$ 1,203,580	$ 241,224	$ 3,289	$ 39,233	$ —	$ —	$ 77,226	$ 54,568
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 7,663,580	$ 6,887,276	$ 496,597	$ 3,736	$ 54,988	$ 19	$ —	$ 84,127	$ 55,195
27	8740	**Mains & Services - Dir. Assn.**										
28		Customer	MSCUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
32	8740	**Odorization**										
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ (48,721)	$ (24,213)	$ (11,194)	$ (212)	$ (1,081)	$ —	$ —	$ (4,177)	$ (4,116)

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
36		Total Odorization		$ (48,721)	$ (24,213)	$ (11,194)	$ (212)	$ (1,081)	$ —	$ —	$ (4,177)	$ (4,116)
37	8750	**Meas. & Reg. Station - Gen. - Allocated**										
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 517,003	$ 368,277	$ 73,811	$ 1,006	$ 12,005	$ —	$ —	$ 23,630	$ 16,697
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 517,003	$ 368,277	$ 73,811	$ 1,006	$ 12,005	$ —	$ —	$ 23,630	$ 16,697
42		**Meas. & Reg. Station - Gen. - DA**										
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	8750	**Odorization**										
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 49,290	$ 24,496	$ 11,325	$ 215	$ 1,093	$ —	$ —	$ 4,226	$ 4,164
51		Total Odorization		$ 49,290	$ 24,496	$ 11,325	$ 215	$ 1,093	$ —	$ —	$ 4,226	$ 4,164
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**										
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 34,456	$ —	$ 17,100	$ 233	$ 2,781	$ —	$ —	$ 5,475	$ 3,868
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 34,456	$ —	$ 17,100	$ 233	$ 2,781	$ —	$ —	$ 5,475	$ 3,868
57	8760	**Meas. & Reg. Stat. - Ind. - DA**										
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
62	8770	**Meas. & Reg. Stat.- City Gate**										
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 15,221	$ 10,842	$ 2,173	$ 30	$ 353	$ —	$ —	$ 696	$ 492
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 15,221	$ 10,842	$ 2,173	$ 30	$ 353	$ —	$ —	$ 696	$ 492
67	8780	**Meter & House Reg. Exp. - Alloc.**										
68		Customer	MTRGCUS-ALL	$ 8,068,256	$ 7,373,003	$ 556,689	$ 2,161	$ 42,904	$ 213	$ —	$ 52,672	$ 5,821
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
71		Total Meter & House Reg. Exp. - Alloc.		$ 8,068,256	$ 7,373,003	$ 556,689	$ 2,161	$ 42,904	$ 213	$ —	$ 52,672	$ 5,821
72	8780	**Meter & House Reg. Exp - Dir. Assn.**										
73		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
77	8780	**Odorization**										
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
82	8790	**Customer Installation Expense**										
83		Customer	METCUS-ALL	$ 656	$ 606	$ 42	$ 0	$ 3	$ 0	$ —	$ 3	$ 0
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 656	$ 606	$ 42	$ 0	$ 3	$ 0	$ —	$ 3	$ 0
87	8800	**Other Expenses**										
88		Customer	871-879CUS	$ 1,530,749	$ 1,423,318	$ 88,524	$ 284	$ 6,394	$ 25	$ —	$ 6,494	$ 703
89		Demand	DEM	$ 245,951	$ 175,199	$ 35,114	$ 479	$ 5,711	$ —	$ —	$ 11,241	$ 7,943
90		Commodity	COM	$ 29,812	$ 14,816	$ 6,850	$ 130	$ 661	$ —	$ —	$ 2,556	$ 2,519
91		Total Other Expenses		$ 1,806,512	$ 1,613,333	$ 130,487	$ 893	$ 12,767	$ 25	$ —	$ 20,292	$ 11,165
92	8800	**Odorization**										
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
96		**Total Odorization**		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
97	8810	**Rents**										
98		Customer	871-879CUS	$ 27,679	$ 25,736	$ 1,601	$ 5	$ 116	$ 0	$ —	$ 117	$ 13
99		Demand	DEM	$ 4,447	$ 3,168	$ 635	$ 9	$ 103	$ —	$ —	$ 203	$ 144
100		Commodity	COM	$ 539	$ 268	$ 124	$ 2	$ 12	$ —	$ —	$ 46	$ 46
101		Total Rents		$ 32,665	$ 29,172	$ 2,359	$ 16	$ 231	$ 0	$ —	$ 367	$ 202
102	8820	**Corporate & Div. Exp.**										
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**										
108		Customer		$ 16,563,431	$ 15,400,979	$ 957,869	$ 3,076	$ 69,191	$ 274	$ —	$ 70,269	$ 7,606
109		Demand		$ 4,220,842	$ 2,982,095	$ 614,779	$ 8,381	$ 99,989	$ —	$ —	$ 196,817	$ 139,072
110		Commodity		$ 323,152	$ 160,597	$ 74,246	$ 1,407	$ 7,168	$ —	$ —	$ 27,706	$ 27,300
111		Total Distr. & Trans. Operations Exp.		$ 21,107,425	$ 18,543,671	$ 1,646,894	$ 12,865	$ 176,348	$ 274	$ —	$ 294,792	$ 173,978
112		**Distribution Maintenance Expenses**										
113	8850	**Maintenance Supervision and Engineering**										
114		Customer	887-893CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
115		Demand	887-893DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
118	8860	**Structures and Improvements**										
119		Customer	887-893CUS	$ 731,547	$ 696,537	$ 30,854	$ 53	$ 1,904	$ 2	$ —	$ 813	$ 74
120		Demand	887-893DEM	$ 526,414	$ 292,914	$ 115,884	$ 1,580	$ 18,848	$ —	$ —	$ 37,099	$ 26,214
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 1,257,960	$ 989,451	$ 146,738	$ 1,633	$ 20,751	$ 2	$ —	$ 37,912	$ 26,288
123	8870	**Maintenance of Mains-Allocated**										
124		Customer	CUS	$ 2,682,901	$ 2,562,375	$ 106,996	$ 162	$ 6,601	$ 8	$ —	$ 2,500	$ 227
125		Demand	DEM	$ 1,478,794	$ 1,053,392	$ 211,123	$ 2,878	$ 34,337	$ —	$ —	$ 67,590	$ 47,759
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 4,161,695	$ 3,615,767	$ 318,119	$ 3,040	$ 40,938	$ 8	$ —	$ 70,090	$ 47,986
128	8870	**Maintenance of Mains - Directly Assigned**										
129		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**										
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 975,090	$ 694,587	$ 139,211	$ 1,898	$ 22,642	$ —	$ —	$ 44,567	$ 31,491
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 975,090	$ 694,587	$ 139,211	$ 1,898	$ 22,642	$ —	$ —	$ 44,567	$ 31,491
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**										
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
143	8890	**Odorization**										
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 222,980	$ 110,814	$ 51,231	$ 971	$ 4,946	$ —	$ —	$ 19,118	$ 18,838
147		Total Odorization		$ 222,980	$ 110,814	$ 51,231	$ 971	$ 4,946	$ —	$ —	$ 19,118	$ 18,838
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**										
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 692,596	$ —	$ 343,729	$ 4,686	$ 55,905	$ —	$ —	$ 110,042	$ 77,756
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 692,596	$ —	$ 343,729	$ 4,686	$ 55,905	$ —	$ —	$ 110,042	$ 77,756
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**										
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**										
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 18,138	$ 12,920	$ 2,589	$ 35	$ 421	$ —	$ —	$ 829	$ 586
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 18,138	$ 12,920	$ 2,589	$ 35	$ 421	$ —	$ —	$ 829	$ 586
163	8910	**Odorization**										
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
167		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
168	8920	**Services - Allocated**										
169		Customer	SERCUS-ALL	$ 1,714,903	$ 1,624,963	$ 78,490	$ 155	$ 4,842	$ 6	$ —	$ 2,385	$ 217
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 1,714,903	$ 1,624,963	$ 78,490	$ 155	$ 4,842	$ 6	$ —	$ 2,385	$ 217
173	8920	**Services - Directly Assigned**										
174		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178	8930	**Meters & House Regulators - Alloc.**										
179		Customer	MTRGCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
183	8930	**Meters & House Regulators - DA**										
184		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188	8940	**Maintenance of Other Equipment**										
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**										
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**										
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**										
204		Customer		$ 5,129,350	$ 4,883,876	$ 216,341	$ 369	$ 13,347	$ 16	$ —	$ 5,697	$ 517
205		Demand		$ 3,691,031	$ 2,053,814	$ 812,536	$ 11,078	$ 132,152	$ —	$ —	$ 260,128	$ 183,807
206		Commodity		$ 222,980	$ 110,814	$ 51,231	$ 971	$ 4,946	$ —	$ —	$ 19,118	$ 18,838
207		Total Distr. Maintenance Expense		$ 9,043,361	$ 7,048,504	$ 1,080,107	$ 12,418	$ 150,445	$ 16	$ —	$ 284,942	$ 203,162
208		**Total Oper. & Maint. Expense**										
209		Customer		$ 21,692,781	$ 20,284,854	$ 1,174,210	$ 3,446	$ 82,538	$ 290	$ —	$ 75,966	$ 8,123
210		Demand		$ 7,911,873	$ 5,035,908	$ 1,427,315	$ 19,459	$ 232,141	$ —	$ —	$ 456,945	$ 322,878

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
211		Commodity		$ 546,132	$ 271,412	$ 125,476	$ 2,378	$ 12,114	$ —	$ —	$ 46,824	$ 46,138
212		Total Operations & Maint. Expense		$ 30,150,786	$ 25,592,174	$ 2,727,001	$ 25,282	$ 326,793	$ 290	$ —	$ 579,735	$ 377,140
213		**Customer Accounts Expense**										
214	901	**Supervision**										
215		Customer	902-904CUS	$ 301	$ 290	$ 11	$ 0	$ 0	$ 0	$ —	$ 0	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 301	$ 290	$ 11	$ 0	$ 0	$ 0	$ —	$ 0	$ 0
219	902	**Meter Reading Expense**										
220		Customer	METCUS-TOT	$ 622,858	$ 574,742	$ 39,634	$ 121	$ 2,855	$ 11	$ —	$ 3,001	$ 314
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 622,858	$ 574,742	$ 39,634	$ 121	$ 2,855	$ 11	$ —	$ 3,001	$ 314
224	903	**Customer Accounting**										
225		Customer	903CUS	$ 5,594,291	$ 5,433,968	$ 149,497	$ 113	$ 5,913	$ 6	$ —	$ 1,738	$ 158
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 5,594,291	$ 5,433,968	$ 149,497	$ 113	$ 5,913	$ 6	$ —	$ 1,738	$ 158
229	904	**Bad Debt Expense**										
230		Customer	904CUS	$ 1,380,038	$ 1,294,423	$ 80,797	$ 2,298	$ —	$ —	$ —	$ 2,520	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ 1,380,038	$ 1,294,423	$ 80,797	$ 2,298	$ —	$ —	$ —	$ 2,520	$ —
234	905	**Miscellaneous Customer Accounts**										
235		Customer	902-904CUS	$ 380,873	$ 366,131	$ 13,532	$ 127	$ 440	$ 1	$ —	$ 364	$ 24
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 380,873	$ 366,131	$ 13,532	$ 127	$ 440	$ 1	$ —	$ 364	$ 24
239	907-910	**Customer Information Expense**										
240		Customer	CUS	$ 1,307,255	$ 1,248,528	$ 52,134	$ 79	$ 3,216	$ 4	$ —	$ 1,218	$ 111
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 1,307,255	$ 1,248,528	$ 52,134	$ 79	$ 3,216	$ 4	$ —	$ 1,218	$ 111
244		**Sales and Advertising Expense**										
245	911	**Supervision**										

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**										
251		Customer	CUS	$ 1,630	$ 1,557	$ 65	$ 0	$ 4	$ 0	$ —	$ 2	$ 0
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ 1,630	$ 1,557	$ 65	$ 0	$ 4	$ 0	$ —	$ 2	$ 0
255	913	**Advertising**										
256		Customer	CUS	$ 157,433	$ 150,361	$ 6,279	$ 10	$ 387	$ 0	$ —	$ 147	$ 13
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 157,433	$ 150,361	$ 6,279	$ 10	$ 387	$ 0	$ —	$ 147	$ 13
260	914	**Employee Sales Referrals**										
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**										
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**										
271	920-940	**Administrative & General Expenses**										
272		Customer	OPEXPCUS	$ 31,709,066	$ 29,961,465	$ 1,499,088	$ 4,617	$ 95,405	$ 250	$ —	$ 70,950	$ 7,180
273		Demand	OPEXPDEM	$ 2,983,471	$ 1,950,871	$ 512,470	$ 6,987	$ 83,349	$ —	$ —	$ 164,064	$ 115,928
274		Commodity	COM	$ 205,940	$ 102,346	$ 47,316	$ 897	$ 4,568	$ —	$ —	$ 17,657	$ 17,398
275		Total Administrative & General Exp.		$ 34,898,477	$ 32,014,682	$ 2,058,873	$ 12,500	$ 183,322	$ 250	$ —	$ 252,670	$ 140,506
276		**Depreciation & Amortization Expense**										
277	301-303	**Intangible Plant - Allocated**										
278		Customer	CUS	$ 32,552	$ 31,090	$ 1,298	$ 2	$ 80	$ 0	$ —	$ 30	$ 3
279		Demand	DEM	$ 10,261	$ 7,310	$ 1,465	$ 20	$ 238	$ —	$ —	$ 469	$ 331
280		Commodity	COM	$ 68	$ 34	$ 16	$ 0	$ 2	$ —	$ —	$ 6	$ 6

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
281		Total Intangible Plant		$ 42,882	$ 38,433	$ 2,779	$ 22	$ 320	$ 0	$ —	$ 505	$ 340
282	301-303	**Intangible Plant - Directly Assigned**										
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**										
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**										
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
297	367	**Transmission Mains**										
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 458,355	$ 326,501	$ 65,438	$ 892	$ 10,643	$ —	$ —	$ 20,950	$ 14,803
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 458,355	$ 326,501	$ 65,438	$ 892	$ 10,643	$ —	$ —	$ 20,950	$ 14,803
302	368	**Compression Station Equipment**										
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
307	369	**Meas. & Reg. Station Equipment**										
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 241,719	$ 172,184	$ 34,510	$ 470	$ 5,613	$ —	$ —	$ 11,048	$ 7,807
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 241,719	$ 172,184	$ 34,510	$ 470	$ 5,613	$ —	$ —	$ 11,048	$ 7,807
312	369	**Odorization**										
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ 14,395	$ 7,154	$ 3,307	$ 63	$ 319	$ —	$ —	$ 1,234	$ 1,216

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
316		Total Odorization		$ 14,395	$ 7,154	$ 3,307	$ 63	$ 319	$ —	$ —	$ 1,234	$ 1,216
317	371	**Other Equipment**										
318		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
319		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
321		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
322	375	**Structures and Improvements**										
323		Customer	376-379CUS	$ 1,104	$ 1,055	$ 44	$ 0	$ 3	$ 0	$ —	$ 1	$ 0
324		Demand	DEM	$ 706	$ 503	$ 101	$ 1	$ 16	$ —	$ —	$ 32	$ 23
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Structures and Improvements		$ 1,810	$ 1,558	$ 145	$ 1	$ 19	$ 0	$ —	$ 33	$ 23
327	376	**Distribution Mains - Allocated**										
328		Customer	CUS	$ 9,764,952	$ 9,326,273	$ 389,433	$ 590	$ 24,026	$ 30	$ —	$ 9,100	$ 826
329		Demand	DEM	$ 5,382,365	$ 3,834,029	$ 768,425	$ 10,476	$ 124,978	$ —	$ —	$ 246,006	$ 173,828
330		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
331		Total Distribution Mains - Allocated		$ 15,147,317	$ 13,160,303	$ 1,157,858	$ 11,066	$ 149,004	$ 30	$ —	$ 255,105	$ 174,655
332	376	**Distribution Mains - Directly Assigned**										
333		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
336		Distribution Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
337	376	**Odorization**										
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
340		Commodity	COM	$ 3,532	$ 1,755	$ 811	$ 15	$ 78	$ —	$ —	$ 303	$ 298
341		Total Odorization		$ 3,532	$ 1,755	$ 811	$ 15	$ 78	$ —	$ —	$ 303	$ 298
342	377	**Compressor Station Equipment**										
343		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
345		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
346		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
347	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**										
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ 648,978	$ 462,288	$ 92,653	$ 1,263	$ 15,069	$ —	$ —	$ 29,662	$ 20,959
350		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
351		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 648,978	$ 462,288	$ 92,653	$ 1,263	$ 15,069	$ —	$ —	$ 29,662	$ 20,959
352	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**										
353		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
355		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
357	378	**Odorization**										
358		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM	$ 17,549	$ 8,721	$ 4,032	$ 76	$ 389	$ —	$ —	$ 1,505	$ 1,483
361		Total Odorization		$ 17,549	$ 8,721	$ 4,032	$ 76	$ 389	$ —	$ —	$ 1,505	$ 1,483
362	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**										
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ 143,560	$ 102,263	$ 20,496	$ 279	$ 3,333	$ —	$ —	$ 6,562	$ 4,636
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
366		Total Meas. & Reg. Sta. Eq.- City Gate		$ 143,560	$ 102,263	$ 20,496	$ 279	$ 3,333	$ —	$ —	$ 6,562	$ 4,636
367	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**										
368		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
369		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
371		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
372	379	**Odorization**										
373		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
374		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
375		Commodity	COM	$ 11,238	$ 5,585	$ 2,582	$ 49	$ 249	$ —	$ —	$ 963	$ 949
376		Total Odorization		$ 11,238	$ 5,585	$ 2,582	$ 49	$ 249	$ —	$ —	$ 963	$ 949
377	380	**Services - Allocated**										
378		Customer	SERCUS-ALL	$ 13,087,353	$ 12,400,978	$ 599,000	$ 1,179	$ 36,955	$ 46	$ —	$ 18,197	$ 1,653
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
381		Total Services - Allocated		$ 13,087,353	$ 12,400,978	$ 599,000	$ 1,179	$ 36,955	$ 46	$ —	$ 18,197	$ 1,653
382	380	**Services - Directly Assigned**										
383		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
386		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
387	381	**Meters - Allocated**										
388		Customer	METCUS-ALL	$ 3,601,852	$ 3,323,608	$ 229,196	$ 702	$ 16,509	$ 65	$ —	$ 17,355	$ 1,817
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
391		Total Meters - Allocated		$ 3,601,852	$ 3,323,608	$ 229,196	$ 702	$ 16,509	$ 65	$ —	$ 17,355	$ 1,817
392	381	**Meters - Directly Assigned**										
393		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
394		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
396		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
397	382	**Meter Installations**										
398		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
399		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
401		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
402	383	**House Regulators - Allocated**										
403		Customer	REGCUS-ALL	$ 528,397	$ 463,016	$ 48,394	$ 304	$ 4,443	$ 32	$ —	$ 7,254	$ 864
404		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
406		Total House Regulators - Allocated		$ 528,397	$ 463,016	$ 48,394	$ 304	$ 4,443	$ 32	$ —	$ 7,254	$ 864
407	383	**House Regulators - Directly Assn.**										
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
411		House Regulators - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
412	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**										
413		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
414		Demand	NRDEM	$ 413,565	$ —	$ 205,249	$ 2,798	$ 33,382	$ —	$ —	$ 65,709	$ 46,430
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
416		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 413,565	$ —	$ 205,249	$ 2,798	$ 33,382	$ —	$ —	$ 65,709	$ 46,430
417	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**										
418		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
421		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
422	385	**Odorization**										
423		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
424		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
425		Commodity	COM	$ 1,147	$ 570	$ 263	$ 5	$ 25	$ —	$ —	$ 98	$ 97
426		Total Odorization		$ 1,147	$ 570	$ 263	$ 5	$ 25	$ —	$ —	$ 98	$ 97
427	386	**Other Prop.- Customer Premises**										
428		Customer	CUS	$ 207,440	$ 198,121	$ 8,273	$ 13	$ 510	$ 1	$ —	$ 193	$ 18
429		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
430		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
431		Total Other Prop. - Customer Premises		$ 207,440	$ 198,121	$ 8,273	$ 13	$ 510	$ 1	$ —	$ 193	$ 18
432	387	**Other Equipment**										
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
435		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
436		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
437	389-98	**General Plant - Allocated**										
438		Customer	GENPTCUS	$ 7,543,497	$ 7,178,232	$ 320,402	$ 573	$ 20,151	$ 32	$ —	$ 9,754	$ 931
439		Demand	DISPLTDEM	$ 1,104,941	$ 732,978	$ 184,602	$ 2,517	$ 30,024	$ —	$ —	$ 59,099	$ 41,759
440		Commodity	COM	$ 7,486	$ 3,720	$ 1,720	$ 33	$ 166	$ —	$ —	$ 642	$ 632
441		Total General Plant - Allocated		$ 8,655,924	$ 7,914,930	$ 506,724	$ 3,122	$ 50,341	$ 32	$ —	$ 69,495	$ 43,323
442	389-98	**General Plant - Directly Assigned**										
443		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
444		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
445		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
446		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
447	389-98	**General Plant - Odorization**										
448		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
449		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
450		Commodity	COM	$ 1,311	$ 652	$ 301	$ 6	$ 29	$ —	$ —	$ 112	$ 111
451		Total General Plant - Odorization		$ 1,311	$ 652	$ 301	$ 6	$ 29	$ —	$ —	$ 112	$ 111
452	40730	**Pension & FAS 106 Amort. Expense**										
453		Customer	CUS	$ (476,840)	$ (455,418)	$ (19,017)	$ (29)	$ (1,173)	$ (1)	$ —	$ (444)	$ (40)
454		Demand	DEM	$ (82,667)	$ (58,886)	$ (11,802)	$ (161)	$ (1,920)	$ —	$ —	$ (3,778)	$ (2,670)
455		Commodity	COM	$ (5,706)	$ (2,836)	$ (1,311)	$ (25)	$ (127)	$ —	$ —	$ (489)	$ (482)
456		Total Pension & FAS 106 Amort. Exp.		$ (565,213)	$ (517,140)	$ (32,130)	$ (215)	$ (3,219)	$ (1)	$ —	$ (4,712)	$ (3,192)
457		**Total Depreciation & Amort. Exp.**										

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
458		Customer		$ 34,290,308	$ 32,466,954	$ 1,577,024	$ 3,333	$ 101,503	$ 204	$ —	$ 61,440	$ 6,071
459		Demand		$ 8,321,784	$ 5,579,168	$ 1,361,135	$ 18,557	$ 221,378	$ —	$ —	$ 435,758	$ 307,908
460		Commodity		$ 51,020	$ 25,355	$ 11,722	$ 222	$ 1,132	$ —	$ —	$ 4,374	$ 4,310
461		Total Depreciation & Amort. Expense		$ 42,663,112	$ 38,071,478	$ 2,949,881	$ 22,112	$ 324,012	$ 204	$ —	$ 501,572	$ 318,289
462		**Taxes Other Than Income**										
463	4081	**Payroll and Other Taxes**										
464		Customer	OPEXPCUS	$ 2,614,247	$ 2,470,167	$ 123,592	$ 381	$ 7,866	$ 21	$ —	$ 5,849	$ 592
465		Demand	OPEXPDEM	$ 453,217	$ 296,356	$ 77,849	$ 1,061	$ 12,662	$ —	$ —	$ 24,923	$ 17,611
466		Commodity	COM	$ 31,284	$ 15,547	$ 7,188	$ 136	$ 694	$ —	$ —	$ 2,682	$ 2,643
467		Total Payroll and Other Taxes		$ 3,098,749	$ 2,782,070	$ 208,629	$ 1,578	$ 21,221	$ 21	$ —	$ 33,454	$ 20,845
468	4081	**Ad Valorem Taxes - Allocated**										
469		Customer	CUS	$ 7,296,698	$ 6,968,902	$ 290,998	$ 441	$ 17,953	$ 22	$ —	$ 6,800	$ 618
470		Demand	DEM	$ 2,300,142	$ 1,638,464	$ 328,385	$ 4,477	$ 53,409	$ —	$ —	$ 105,130	$ 74,285
471		Commodity	COM	$ 15,254	$ 7,581	$ 3,505	$ 66	$ 338	$ —	$ —	$ 1,308	$ 1,289
472		Total Ad Valorem Taxes - Allocated		$ 9,612,094	$ 8,614,948	$ 622,887	$ 4,984	$ 71,700	$ 22	$ —	$ 113,237	$ 76,191
473	4081	**Ad Valorem Taxes - Directly Assn.**										
474		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
475		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
477		Total Ad Valorem Taxes - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
478		**Revenue Related Taxes**										
479		Customer	TOTREVCUS	$ 169,364	$ 132,292	$ 29,041	$ 466	$ 2,444	$ 3	$ —	$ 2,025	$ 1,567
480		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
481		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
482		Total Revenue Related Taxes		$ 169,364	$ 132,292	$ 29,041	$ 466	$ 2,444	$ 3	$ —	$ 2,025	$ 1,567
483		**Total Taxes Other Than Income**										
484		Customer		$ 10,080,309	$ 9,571,361	$ 443,631	$ 1,287	$ 28,263	$ 46	$ —	$ 14,674	$ 2,777
485		Demand		$ 2,753,360	$ 1,934,820	$ 406,234	$ 5,538	$ 66,071	$ —	$ —	$ 130,053	$ 91,896
486		Commodity		$ 46,538	$ 23,128	$ 10,692	$ 203	$ 1,032	$ —	$ —	$ 3,990	$ 3,932
487		Total Taxes Other Than Income		$ 12,880,207	$ 11,529,309	$ 860,557	$ 7,028	$ 95,366	$ 46	$ —	$ 148,716	$ 98,604
488		**Excess Def. Income Tax Amort. - Directly Assn.**										
489		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
490		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
491		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
492		**Total Excess Def. Income Tax Amort. - DA**		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
493		**Excess Def. Income Tax Amort. - Alloc.**										
494		Customer	CUS	$ (328,209)	$ (313,465)	$ (13,089)	$ (20)	$ (808)	$ (1)	$ —	$ (306)	$ (28)
495		Demand	DEM	$ (109,225)	$ (77,804)	$ (15,594)	$ (213)	$ (2,536)	$ —	$ —	$ (4,992)	$ (3,528)
496		Commodity	COM	$ (733)	$ (364)	$ (168)	$ (3)	$ (16)	$ —	$ —	$ (63)	$ (62)
497		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (438,167)	$ (391,634)	$ (28,851)	$ (236)	$ (3,360)	$ (1)	$ —	$ (5,361)	$ (3,617)
498		**Interest on Customer Deposits**										
499		Customer	DEPCUS	$ 313,051	$ 146,035	$ 163,146	$ 1,611	$ 485	$ —	$ —	$ 1,573	$ 202
500		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
501		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
502		Total Interest on Cust. Deposits		$ 313,051	$ 146,035	$ 163,146	$ 1,611	$ 485	$ —	$ —	$ 1,573	$ 202
503		**Req. Return - Other Than Directly Assn.**										

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
504		Customer	CUS	$ 55,147,903	$ 52,670,451	$ 2,199,339	$ 3,330	$ 135,685	$ 167	$ —	$ 51,390	$ 4,667
505		Demand	DEM	$ 18,352,685	$ 13,073,199	$ 2,620,160	$ 35,722	$ 426,148	$ —	$ —	$ 838,826	$ 592,717
506		Commodity	COM	$ 123,145	$ 61,200	$ 28,293	$ 536	$ 2,732	$ —	$ —	$ 10,558	$ 10,403
507		Tot. Req. Return - Other Than Dir. Assn.		$ 73,623,733	$ 65,804,849	$ 4,847,793	$ 39,588	$ 564,565	$ 167	$ —	$ 900,774	$ 607,788
508		**Req. Return - Directly Assigned**										
509		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
510		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
511		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
512		Tot. Req. Return - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
513		**Income Taxes - Other Than DA**										
514		Customer	CUS	$ 11,415,469	$ 10,902,643	$ 455,257	$ 689	$ 28,087	$ 35	$ —	$ 10,638	$ 966
515		Demand	DEM	$ 3,798,957	$ 2,706,117	$ 542,366	$ 7,394	$ 88,212	$ —	$ —	$ 173,635	$ 122,691
516		Commodity	COM	$ 25,491	$ 12,668	$ 5,857	$ 111	$ 565	$ —	$ —	$ 2,186	$ 2,153
517		Total Income Taxes - Other Than DA		$ 15,239,916	$ 13,621,428	$ 1,003,480	$ 8,195	$ 116,863	$ 35	$ —	$ 186,458	$ 125,810
518		**Income Taxes - Directly Assigned**										
519		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
520		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
521		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
522		Total Income Taxes - Dir. Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
523		**Total Cost of Service Before Revenue Credits**										
524		Customer		$ 173,765,358	$ 164,760,299	$ 7,840,555	$ 21,040	$ 483,972	$ 1,013	$ —	$ 295,313	$ 30,579
525		Demand		$ 44,012,904	$ 30,202,279	$ 6,854,086	$ 93,444	$ 1,114,762	$ —	$ —	$ 2,194,287	$ 1,550,490
526		Commodity		$ 997,532	$ 495,745	$ 229,188	$ 4,343	$ 22,127	$ —	$ —	$ 85,526	$ 84,273
527		**Total Cost of Service Before Revenue Credits**		$ 218,775,795	$ 195,458,322	$ 14,923,828	$ 118,828	$ 1,620,861	$ 1,013	$ —	$ 2,575,126	$ 1,665,341

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
1		**Transmission and Distribution Op. Exp.**					
2	814-865	**Transmission Expenses**					
3		Customer	CUS	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 53,612	$ 1,843	$ 9,630	$ —
5		Commodity	COM	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 53,612	$ 1,843	$ 9,630	$ —
7	8650	**Odorization**					
8		Customer	CUS	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —
10		Commodity	COM	$ —	$ —	$ —	$ —
11		Total Odorization		$ —	$ —	$ —	$ —
12	8700	**Operation Supervision & Engineering**					
13		Customer	871-879CUS	$ 3,066	$ 64	$ 16	$ —
14		Demand	DEM	$ 5,314	$ 183	$ 955	$ —
15		Commodity	COM	$ 942	$ 94	$ 398	$ —
16		Total Supervision & Engineering		$ 9,322	$ 341	$ 1,369	$ —
17	8710	**Distribution Load Dispatch**					
18		Customer	CUS	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 13,742	$ 1,373	$ 5,813	$ —
21		Total Distribution Load Dispatch		$ 13,742	$ 1,373	$ 5,813	$ —
22	8740	**Mains & Services - Allocated**					
23		Customer	MSCUS-ALL	$ 11,016	$ 90	$ 22	$ —
24		Demand	DEM	$ 58,084	$ 1,996	$ 10,433	$ —
25		Commodity	COM	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 69,100	$ 2,086	$ 10,455	$ —
27	8740	**Mains & Services - Dir. Assn.**					
28		Customer	MSCUS-DA	$ —	$ —	$ —	$ —
29		Demand	DEM-DA	$ —	$ —	$ —	$ —
30		Commodity	COM-DA	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ —	$ —	$ —	$ —
32	8740	**Odorization**					
33		Customer	CUS	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —
35		Commodity	COM	$ (2,448)	$ (245)	$ (1,036)	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
36		Total Odorization		$ (2,448)	$ (245)	$ (1,036)	$ —
37	8750	**Meas. & Reg. Station - Gen. - Allocated**					
38		Customer	CUS	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 17,773	$ 611	$ 3,192	$ —
40		Commodity	COM	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 17,773	$ 611	$ 3,192	$ —
42		**Meas. & Reg. Station - Gen. - DA**					
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ —	$ —	$ —	$ —
45		Commodity	COM-DA	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ —	$ —	$ —	$ —
47	8750	**Odorization**					
48		Customer	CUS	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 2,477	$ 247	$ 1,048	$ —
51		Total Odorization		$ 2,477	$ 247	$ 1,048	$ —
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**					
53		Customer	NRCUS	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 4,118	$ 142	$ 740	$ —
55		Commodity	COM	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 4,118	$ 142	$ 740	$ —
57	8760	**Meas. & Reg. Stat. - Ind. - DA**					
58		Customer	CUS-DA	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ —	$ —	$ —	$ —
60		Commodity	COM-DA	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ —	$ —	$ —	$ —
62	8770	**Meas. & Reg. Stat.- City Gate**					
63		Customer	CUS	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 523	$ 18	$ 94	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 523	$ 18	$ 94	$ —
67	8780	**Meter & House Reg. Exp. - Alloc.**					
68		Customer	MTRGCUS-ALL	$ 33,731	$ 850	$ 213	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
71		Total Meter & House Reg. Exp. - Alloc.		$ 33,731	$ 850	$ 213	$ —
72	8780	**Meter & House Reg. Exp - Dir. Assn.**					
73		Customer	CUS-DA	$ —	$ —	$ —	$ —
74		Demand	DEM-DA	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ —	$ —	$ —	$ —
77	8780	**Odorization**					
78		Customer	CUS	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —
80		Commodity	COM	$ —	$ —	$ —	$ —
81		Total Odorization		$ —	$ —	$ —	$ —
82	8790	**Customer Installation Expense**					
83		Customer	METCUS-ALL	$ 2	$ 0	$ 0	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 2	$ 0	$ 0	$ —
87	8800	**Other Expenses**					
88		Customer	871-879CUS	$ 4,878	$ 102	$ 26	$ —
89		Demand	DEM	$ 8,455	$ 291	$ 1,519	$ —
90		Commodity	COM	$ 1,498	$ 150	$ 634	$ —
91		Total Other Expenses		$ 14,831	$ 543	$ 2,178	$ —
92	8800	**Odorization**					
93		Customer	CUS	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —
96		**Total Odorization**		$ —	$ —	$ —	$ —
97	8810	**Rents**					
98		Customer	871-879CUS	$ 88	$ 2	$ 0	$ —
99		Demand	DEM	$ 153	$ 5	$ 27	$ —
100		Commodity	COM	$ 27	$ 3	$ 11	$ —
101		Total Rents		$ 268	$ 10	$ 39	$ —
102	8820	**Corporate & Div. Exp.**					
103		Customer	CUS	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**					
108		Customer		$ 52,781	$ 1,109	$ 277	$ —
109		Demand		$ 148,032	$ 5,088	$ 26,589	$ —
110		Commodity		$ 16,237	$ 1,622	$ 6,869	$ —
111		Total Distr. & Trans. Operations Exp.		$ 217,050	$ 7,819	$ 33,735	$ —
112		**Distribution Maintenance Expenses**					
113	8850	**Maintenance Supervision and Engineering**					
114		Customer	887-893CUS	$ —	$ —	$ —	$ —
115		Demand	887-893DEM	$ —	$ —	$ —	$ —
116		Commodity	COM	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ —	$ —	$ —	$ —
118	8860	**Structures and Improvements**					
119		Customer	887-893CUS	$ 1,297	$ 11	$ 3	$ —
120		Demand	887-893DEM	$ 27,904	$ 959	$ 5,012	$ —
121		Commodity	COM	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 29,201	$ 970	$ 5,015	$ —
123	8870	**Maintenance of Mains-Allocated**					
124		Customer	CUS	$ 3,991	$ 33	$ 8	$ —
125		Demand	DEM	$ 50,836	$ 1,747	$ 9,131	$ —
126		Commodity	COM	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 54,827	$ 1,780	$ 9,139	$ —
128	8870	**Maintenance of Mains - Directly Assigned**					
129		Customer	CUS-DA	$ —	$ —	$ —	$ —
130		Demand	DEM-DA	$ —	$ —	$ —	$ —
131		Commodity	COM-DA	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ —	$ —	$ —	$ —
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**					
134		Customer	CUS	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 33,520	$ 1,152	$ 6,021	$ —
136		Commodity	COM	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 33,520	$ 1,152	$ 6,021	$ —
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**					
139		Customer	CUS-DA	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
141		Commodity	COM-DA	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —
143	8890	**Odorization**					
144		Customer	CUS	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 11,204	$ 1,119	$ 4,739	$ —
147		Total Odorization		$ 11,204	$ 1,119	$ 4,739	$ —
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**					
149		Customer	NRCUS	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 82,766	$ 2,845	$ 14,866	$ —
151		Commodity	COM	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 82,766	$ 2,845	$ 14,866	$ —
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**					
154		Customer	CUS-DA	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ —	$ —	$ —	$ —
156		Commodity	COM-DA	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ —	$ —	$ —	$ —
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**					
159		Customer	CUS	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 624	$ 21	$ 112	$ —
161		Commodity	COM	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 624	$ 21	$ 112	$ —
163	8910	**Odorization**					
164		Customer	CUS	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —
166		Commodity	COM	$ —	$ —	$ —	$ —
167		Total Odorization		$ —	$ —	$ —	$ —
168	8920	**Services - Allocated**					
169		Customer	SERCUS-ALL	$ 3,807	$ 31	$ 8	$ —
170		Demand	DEM	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 3,807	$ 31	$ 8	$ —
173	8920	**Services - Directly Assigned**					
174		Customer	CUS-DA	$ —	$ —	$ —	$ —
175		Demand	DEM-DA	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
176		Commodity	COM-DA	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ —	$ —	$ —	$ —
178	8930	**Meters & House Regulators - Alloc.**					
179		Customer	MTRGCUS-ALL	$ —	$ —	$ —	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ —	$ —	$ —	$ —
183	8930	**Meters & House Regulators - DA**					
184		Customer	CUS-DA	$ —	$ —	$ —	$ —
185		Demand	DEM-DA	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ —	$ —	$ —	$ —
188	8940	**Maintenance of Other Equipment**					
189		Customer	CUS	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**					
194		Customer	CUS	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**					
199		Customer	CUS	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**					
204		Customer		$ 9,095	$ 74	$ 19	$ —
205		Demand		$ 195,650	$ 6,725	$ 35,142	$ —
206		Commodity		$ 11,204	$ 1,119	$ 4,739	$ —
207		Total Distr. Maintenance Expense		$ 215,948	$ 7,918	$ 39,900	$ —
208		**Total Oper. & Maint. Expense**					
209		Customer		$ 61,876	$ 1,183	$ 296	$ —
210		Demand		$ 343,682	$ 11,813	$ 61,731	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
211		Commodity		$ 27,441	$ 2,741	$ 11,608	$ —
212		Total Operations & Maint. Expense		$ 432,999	$ 15,737	$ 73,635	$ —
213		**Customer Accounts Expense**					
214	901	**Supervision**					
215		Customer	902-904CUS	$ 0	$ 0	$ 0	$ —
216		Demand	DEM	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —
218		Total Supervision		$ 0	$ 0	$ 0	$ —
219	902	**Meter Reading Expense**					
220		Customer	METCUS-TOT	$ 2,122	$ 45	$ 11	$ —
221		Demand	DEM	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 2,122	$ 45	$ 11	$ —
224	903	**Customer Accounting**					
225		Customer	903CUS	$ 2,872	$ 23	$ 6	$ —
226		Demand	DEM	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 2,872	$ 23	$ 6	$ —
229	904	**Bad Debt Expense**					
230		Customer	904CUS	$ —	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ —	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**					
235		Customer	902-904CUS	$ 250	$ 3	$ 1	$ —
236		Demand	DEM	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 250	$ 3	$ 1	$ —
239	907-910	**Customer Information Expense**					
240		Customer	CUS	$ 1,945	$ 16	$ 4	$ —
241		Demand	DEM	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 1,945	$ 16	$ 4	$ —
244		**Sales and Advertising Expense**					
245	911	**Supervision**					

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
246		Customer	CUS	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**					
251		Customer	CUS	$ 2	$ 0	$ 0	$ —
252		Demand	DEM	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ 2	$ 0	$ 0	$ —
255	913	**Advertising**					
256		Customer	CUS	$ 234	$ 2	$ 0	$ —
257		Demand	DEM	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —
259		Total Advertising		$ 234	$ 2	$ 0	$ —
260	914	**Employee Sales Referrals**					
261		Customer	CUS	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**					
266		Customer	CUS	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**					
271	920-940	**Administrative & General Expenses**					
272		Customer	OPEXPCUS	$ 68,811	$ 1,041	$ 260	$ —
273		Demand	OPEXPDEM	$ 123,397	$ 4,241	$ 22,164	$ —
274		Commodity	COM	$ 10,348	$ 1,034	$ 4,377	$ —
275		Total Administrative & General Exp.		$ 202,556	$ 6,316	$ 26,802	$ —
276		**Depreciation & Amortization Expense**					
277	301-303	**Intangible Plant - Allocated**					
278		Customer	CUS	$ 48	$ 0	$ 0	$ —
279		Demand	DEM	$ 353	$ 12	$ 63	$ —
280		Commodity	COM	$ 3	$ 0	$ 1	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
281		Total Intangible Plant		$ 405	$ 13	$ 65	$ —
282	301-303	**Intangible Plant - Directly Assigned**					
283		Customer	CUS-DA	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**					
288		Customer	CUS	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**					
293		Customer	CUS	$ —	$ —	$ —	$ —
294		Demand	DEM	$ —	$ —	$ —	$ —
295		Commodity	COM	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ —	$ —	$ —	$ —
297	367	**Transmission Mains**					
298		Customer	CUS	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 15,757	$ 542	$ 2,830	$ —
300		Commodity	COM	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 15,757	$ 542	$ 2,830	$ —
302	368	**Compression Station Equipment**					
303		Customer	CUS	$ —	$ —	$ —	$ —
304		Demand	DEM	$ —	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ —	$ —	$ —	$ —
307	369	**Meas. & Reg. Station Equipment**					
308		Customer	CUS	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 8,310	$ 286	$ 1,493	$ —
310		Commodity	COM	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 8,310	$ 286	$ 1,493	$ —
312	369	**Odorization**					
313		Customer	CUS	$ —	$ —	$ —	$ —
314		Demand	DEM	$ —	$ —	$ —	$ —
315		Commodity	COM	$ 723	$ 72	$ 306	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
316		Total Odorization		$ 723	$ 72	$ 306	$ —
317	371	**Other Equipment**					
318		Customer	CUS	$ —	$ —	$ —	$ —
319		Demand	DEM	$ —	$ —	$ —	$ —
320		Commodity	COM	$ —	$ —	$ —	$ —
321		Total Other Equipment		$ —	$ —	$ —	$ —
322	375	**Structures and Improvements**					
323		Customer	376-379CUS	$ 2	$ 0	$ 0	$ —
324		Demand	DEM	$ 24	$ 1	$ 4	$ —
325		Commodity	COM	$ —	$ —	$ —	$ —
326		Total Structures and Improvements		$ 26	$ 1	$ 4	$ —
327	376	**Distribution Mains - Allocated**					
328		Customer	CUS	$ 14,526	$ 118	$ 30	$ —
329		Demand	DEM	$ 185,028	$ 6,360	$ 33,234	$ —
330		Commodity	COM	$ —	$ —	$ —	$ —
331		Total Distribution Mains - Allocated		$ 199,555	$ 6,478	$ 33,264	$ —
332	376	**Distribution Mains - Directly Assigned**					
333		Customer	CUS-DA	$ —	$ —	$ —	$ —
334		Demand	DEM-DA	$ —	$ —	$ —	$ —
335		Commodity	COM-DA	$ —	$ —	$ —	$ —
336		Distribution Mains - Directly Assigned		$ —	$ —	$ —	$ —
337	376	**Odorization**					
338		Customer	CUS	$ —	$ —	$ —	$ —
339		Demand	DEM	$ —	$ —	$ —	$ —
340		Commodity	COM	$ 177	$ 18	$ 75	$ —
341		Total Odorization		$ 177	$ 18	$ 75	$ —
342	377	**Compressor Station Equipment**					
343		Customer	CUS	$ —	$ —	$ —	$ —
344		Demand	DEM	$ —	$ —	$ —	$ —
345		Commodity	COM	$ —	$ —	$ —	$ —
346		Total Compressor Station Equipment		$ —	$ —	$ —	$ —
347	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**					
348		Customer	CUS	$ —	$ —	$ —	$ —
349		Demand	DEM	$ 22,310	$ 767	$ 4,007	$ —
350		Commodity	COM	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
351		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 22,310	$ 767	$ 4,007	$ —
352	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**					
353		Customer	CUS-DA	$ —	$ —	$ —	$ —
354		Demand	DEM-DA	$ —	$ —	$ —	$ —
355		Commodity	COM-DA	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ —	$ —	$ —	$ —
357	378	**Odorization**					
358		Customer	CUS	$ —	$ —	$ —	$ —
359		Demand	DEM	$ —	$ —	$ —	$ —
360		Commodity	COM	$ 882	$ 88	$ 373	$ —
361		Total Odorization		$ 882	$ 88	$ 373	$ —
362	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**					
363		Customer	CUS	$ —	$ —	$ —	$ —
364		Demand	DEM	$ 4,935	$ 170	$ 886	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —
366		Total Meas. & Reg. Sta. Eq.- City Gate		$ 4,935	$ 170	$ 886	$ —
367	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**					
368		Customer	CUS-DA	$ —	$ —	$ —	$ —
369		Demand	DEM-DA	$ —	$ —	$ —	$ —
370		Commodity	COM-DA	$ —	$ —	$ —	$ —
371		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —
372	379	**Odorization**					
373		Customer	CUS	$ —	$ —	$ —	$ —
374		Demand	DEM	$ —	$ —	$ —	$ —
375		Commodity	COM	$ 565	$ 56	$ 239	$ —
376		Total Odorization		$ 565	$ 56	$ 239	$ —
377	380	**Services - Allocated**					
378		Customer	SERCUS-ALL	$ 29,050	$ 237	$ 59	$ —
379		Demand	DEM	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —
381		Total Services - Allocated		$ 29,050	$ 237	$ 59	$ —
382	380	**Services - Directly Assigned**					
383		Customer	CUS-DA	$ —	$ —	$ —	$ —
384		Demand	DEM-DA	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
386		Total Services - Directly Assigned		$ —	$ —	$ —	$ —
387	381	**Meters - Allocated**					
388		Customer	METCUS-ALL	$ 12,270	$ 262	$ 65	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —
391		Total Meters - Allocated		$ 12,270	$ 262	$ 65	$ —
392	381	**Meters - Directly Assigned**					
393		Customer	CUS-DA	$ —	$ —	$ —	$ —
394		Demand	DEM-DA	$ —	$ —	$ —	$ —
395		Commodity	COM-DA	$ —	$ —	$ —	$ —
396		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —
397	382	**Meter Installations**					
398		Customer	METCUS-TOT	$ —	$ —	$ —	$ —
399		Demand	DEM	$ —	$ —	$ —	$ —
400		Commodity	COM	$ —	$ —	$ —	$ —
401		Total Meter Installations		$ —	$ —	$ —	$ —
402	383	**House Regulators - Allocated**					
403		Customer	REGCUS-ALL	$ 3,931	$ 128	$ 32	$ —
404		Demand	DEM	$ —	$ —	$ —	$ —
405		Commodity	COM	$ —	$ —	$ —	$ —
406		Total House Regulators - Allocated		$ 3,931	$ 128	$ 32	$ —
407	383	**House Regulators - Directly Assn.**					
408		Customer	CUS-DA	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —
411		House Regulators - Directly Assn.		$ —	$ —	$ —	$ —
412	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**					
413		Customer	NRCUS	$ —	$ —	$ —	$ —
414		Demand	NRDEM	$ 49,422	$ 1,699	$ 8,877	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —
416		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 49,422	$ 1,699	$ 8,877	$ —
417	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**					
418		Customer	CUS-DA	$ —	$ —	$ —	$ —
419		Demand	DEM-DA	$ —	$ —	$ —	$ —
420		Commodity	COM-DA	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
421		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —
422	385	**Odorization**					
423		Customer	CUS	$ —	$ —	$ —	$ —
424		Demand	DEM	$ —	$ —	$ —	$ —
425		Commodity	COM	$ 58	$ 6	$ 24	$ —
426		Total Odorization		$ 58	$ 6	$ 24	$ —
427	386	**Other Prop.- Customer Premises**					
428		Customer	CUS	$ 309	$ 3	$ 1	$ —
429		Demand	DEM	$ —	$ —	$ —	$ —
430		Commodity	COM	$ —	$ —	$ —	$ —
431		Total Other Prop. - Customer Premises		$ 309	$ 3	$ 1	$ —
432	387	**Other Equipment**					
433		Customer	CUS	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —
435		Commodity	COM	$ —	$ —	$ —	$ —
436		Total Other Equipment		$ —	$ —	$ —	$ —
437	389-98	**General Plant - Allocated**					
438		Customer	GENPTCUS	$ 13,256	$ 134	$ 33	$ —
439		Demand	DISPLTDEM	$ 44,450	$ 1,528	$ 7,984	$ —
440		Commodity	COM	$ 376	$ 38	$ 159	$ —
441		Total General Plant - Allocated		$ 58,082	$ 1,699	$ 8,177	$ —
442	389-98	**General Plant - Directly Assigned**					
443		Customer	CUS-DA	$ —	$ —	$ —	$ —
444		Demand	DEM-DA	$ —	$ —	$ —	$ —
445		Commodity	COM-DA	$ —	$ —	$ —	$ —
446		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —
447	389-98	**General Plant - Odorization**					
448		Customer	CUS	$ —	$ —	$ —	$ —
449		Demand	DEM	$ —	$ —	$ —	$ —
450		Commodity	COM	$ 66	$ 7	$ 28	$ —
451		Total General Plant - Odorization		$ 66	$ 7	$ 28	$ —
452	40730	**Pension & FAS 106 Amort. Expense**					
453		Customer	CUS	$ (709)	$ (6)	$ (1)	$ —
454		Demand	DEM	$ (2,842)	$ (98)	$ (510)	$ —
455		Commodity	COM	$ (287)	$ (29)	$ (121)	$ —
456		Total Pension & FAS 106 Amort. Exp.		$ (3,838)	$ (132)	$ (633)	$ —
457		**Total Depreciation & Amort. Exp.**					

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
458		Customer		$ 72,682	$ 877	$ 219	$ —
459		Demand		$ 327,747	$ 11,265	$ 58,869	$ —
460		Commodity		$ 2,564	$ 256	$ 1,084	$ —
461		Total Depreciation & Amort. Expense		$ 402,992	$ 12,398	$ 60,173	$ —
462		**Taxes Other Than Income**					
463	4081	**Payroll and Other Taxes**					
464		Customer	OPEXPCUS	$ 5,673	$ 86	$ 21	$ —
465		Demand	OPEXPDEM	$ 18,745	$ 644	$ 3,367	$ —
466		Commodity	COM	$ 1,572	$ 157	$ 665	$ —
467		Total Payroll and Other Taxes		$ 25,990	$ 887	$ 4,053	$ —
468	4081	**Ad Valorem Taxes - Allocated**					
469		Customer	CUS	$ 10,854	$ 88	$ 22	$ —
470		Demand	DEM	$ 79,072	$ 2,718	$ 14,203	$ —
471		Commodity	COM	$ 766	$ 77	$ 324	$ —
472		Total Ad Valorem Taxes - Allocated		$ 90,692	$ 2,883	$ 14,549	$ —
473	4081	**Ad Valorem Taxes - Directly Assn.**					
474		Customer	CUS-DA	$ —	$ —	$ —	$ —
475		Demand	DEM-DA	$ —	$ —	$ —	$ —
476		Commodity	COM-DA	$ —	$ —	$ —	$ —
477		Total Ad Valorem Taxes - Directly Assn.		$ —	$ —	$ —	$ —
478		**Revenue Related Taxes**					
479		Customer	TOTREVCUS	$ 1,346	$ 55	$ 124	$ —
480		Demand	DEM	$ —	$ —	$ —	$ —
481		Commodity	COM	$ —	$ —	$ —	$ —
482		Total Revenue Related Taxes		$ 1,346	$ 55	$ 124	$ —
483		**Total Taxes Other Than Income**					
484		Customer		$ 17,874	$ 229	$ 168	$ —
485		Demand		$ 97,817	$ 3,362	$ 17,570	$ —
486		Commodity		$ 2,338	$ 234	$ 989	$ —
487		Total Taxes Other Than Income		$ 118,029	$ 3,825	$ 18,727	$ —
488		**Excess Def. Income Tax Amort. - Directly Assn.**					
489		Customer	CUS-DA	$ —	$ —	$ —	$ —
490		Demand	DEM-DA	$ —	$ —	$ —	$ —
491		Commodity	COM-DA	$ —	$ —	$ —	$ —
492		**Total Excess Def. Income Tax Amort. - DA**		$ —	$ —	$ —	$ —
493		**Excess Def. Income Tax Amort. - Alloc.**					
494		Customer	CUS	$ (488)	$ (4)	$ (1)	$ —
495		Demand	DEM	$ (3,755)	$ (129)	$ (674)	$ —
496		Commodity	COM	$ (37)	$ (4)	$ (16)	$ —
497		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (4,280)	$ (137)	$ (691)	$ —
498		**Interest on Customer Deposits**					
499		Customer	DEPCUS	$ —	$ —	$ —	$ —
500		Demand	DEM	$ —	$ —	$ —	$ —
501		Commodity	COM	$ —	$ —	$ —	$ —
502		Total Interest on Cust. Deposits		$ —	$ —	$ —	$ —
503		**Req. Return - Other Than Directly Assn.**					

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(m)	(n)	(o)	(p)
504		Customer	CUS	$ 82,037	$ 669	$ 167	$ —
505		Demand	DEM	$ 630,906	$ 21,686	$ 113,322	$ —
506		Commodity	COM	$ 6,187	$ 618	$ 2,617	$ —
507		Tot. Req. Return - Other Than Dir. Assn.		$ 719,131	$ 22,972	$ 116,106	$ —
508		**Req. Return - Directly Assigned**					
509		Customer	CUS-DA	$ —	$ —	$ —	$ —
510		Demand	DEM-DA	$ —	$ —	$ —	$ —
511		Commodity	COM-DA	$ —	$ —	$ —	$ —
512		Tot. Req. Return - Directly Assigned		$ —	$ —	$ —	$ —
513		**Income Taxes - Other Than DA**					
514		Customer	CUS	$ 16,981	$ 138	$ 35	$ —
515		Demand	DEM	$ 130,596	$ 4,489	$ 23,457	$ —
516		Commodity	COM	$ 1,281	$ 128	$ 542	$ —
517		Total Income Taxes - Other Than DA		$ 148,858	$ 4,755	$ 24,034	$ —
518		**Income Taxes - Directly Assigned**					
519		Customer	CUS-DA	$ —	$ —	$ —	$ —
520		Demand	DEM-DA	$ —	$ —	$ —	$ —
521		Commodity	COM-DA	$ —	$ —	$ —	$ —
522		Total Income Taxes - Dir. Assigned		$ —	$ —	$ —	$ —
523		**Total Cost of Service Before Revenue Credits**					
524		Customer		$ 327,200	$ 4,222	$ 1,166	$ —
525		Demand		$ 1,650,390	$ 56,727	$ 296,439	$ —
526		Commodity		$ 50,121	$ 5,007	$ 21,203	$ —
527		**Total Cost of Service Before Revenue Credits**		$ 2,027,711	$ 65,957	$ 318,808	$ —

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Customer Cost Allocation Factors									
2										
3	Total Customers		329,860	315,042	13,155	20	812	1	0	307
4	Total Customers Factor (CUS)	CUS	1.00000	0.95508	0.03988	0.00006	0.00246	0.00000	0.00000	0.00093
5										
6	Customers - Directly Assigned		—	0	0	0	0	0	0	0
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8										
9	Services - Allocated Weighting			1.00000	1.15677	1.50398	1.15677	1.15677	0.00000	1.50398
10	Weighted Customers		332,479	315,042	15,217	30	939	1	0	462
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.94755	0.04577	0.00009	0.00282	0.00000	0.00000	0.00139
12										
13	Meters - Allocated Weighting			1.00000	1.65148	3.34259	1.92816	6.20576	0.00000	5.35195
14	Weighted Customers		341,416	315,042	21,725	67	1,565	6	0	1,645
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.92275	0.06363	0.00019	0.00458	0.00002	0.00000	0.00482
16										
17	Meters - Total Weighting			1.00000	1.65148	3.34259	1.92816	6.20576	0.00000	5.35195
18	Weighted Customers		341,416	315,042	21,725	67	1,565	6	0	1,645
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.92275	0.06363	0.00019	0.00458	0.00002	0.00000	0.00482
20										
21	Regulators - Allocated Weighting			1.00000	2.50304	10.37179	3.72504	21.82621	0.00000	16.05640
22	Weighted Customers		359,528	315,042	32,928	207	3,023	22	0	4,935
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.87626	0.09159	0.00057	0.00841	0.00006	0.00000	0.01373
24										
25	Meters and Regulators - Allocated Weighting			1.00000	1.80819	4.63615	2.25883	9.08033	0.00000	7.32185
26	Weighted Customers		344,749	315,042	23,787	92	1,833	9	0	2,251
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.91383	0.06900	0.00027	0.00532	0.00003	0.00000	0.00653
28										
29	Non-Residential Customers		14,819	0	13,155	20	812	1	0	307
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.88774	0.00134	0.05477	0.00007	0.00000	0.02074
31										
32	Customer Cost Allocation Factors									
33										
34	Distribution Plant Customer Costs		$ 813,183,333	$ 770,141,544	$ 37,257,558	$ 78,099	$ 2,393,307	$ 4,725	$ —	$ 1,430,117
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.94707	0.04582	0.00010	0.00294	0.00001	0.00000	0.00176
36										
37	Account 376-379 Customer Costs		$ 364,252,631	$ 347,889,029	$ 14,526,663	$ 21,993	$ 896,204	$ 1,104	$ —	$ 339,433
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.95508	0.03988	0.00006	0.00246	0.00000	0.00000	0.00093
39										
40	Total Revenue (inc. cost of gas)		$ 269,288,296	$ 210,343,638	$ 46,175,261	$ 741,014	$ 3,886,583	$ 4,533	$ —	$ 3,219,163

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.78111	0.17147	0.00275	0.01443	0.00002	0.00000	0.01195
42										
43	Mains - Allocated Customer Cost Factor		0.51313	0.49008	0.02046	0.00003	0.00126	0.00000	0.00000	0.00048
44	Services - Allocated Customer Cost Factor		0.48687	0.46133	0.02228	0.00004	0.00137	0.00000	0.00000	0.00068
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.95141	0.04275	0.00007	0.00264	0.00000	0.00000	0.00116
46										
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
48										
49	Total Plant Customer		$ 959,755,309	$ 909,620,214	$ 43,480,159	$ 89,215	$ 2,784,607	$ 5,346	$ —	$ 1,619,239
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.94776	0.04530	0.00009	0.00290	0.00001	0.00000	0.00169
51										
52	Non-Intangible Plant Customer									
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 959,755,309	$ 916,639,480	$ 38,275,748	$ 57,949	$ 2,361,373	$ 2,910	$ —	$ 894,358
54		NONINCUS	1.00000	0.95508	0.03988	0.00006	0.00246	0.00000	0.00000	0.00093
55										
56	Account 871-879 Customer Costs		$ 14,042,857	$ 13,057,304	$ 812,104	$ 2,608	$ 58,661	$ 232	$ —	$ 59,576
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.92982	0.05783	0.00019	0.00418	0.00002	0.00000	0.00424
58										
59	Account 887-893 Customer Costs		$ 4,397,804	$ 4,187,339	$ 185,486	$ 316	$ 11,443	$ 14	$ —	$ 4,885
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.95214	0.04218	0.00007	0.00260	0.00000	0.00000	0.00111
61										
62	Account 903 Customer		$ 5,594,291	$ 5,433,968	$ 149,497	$ 113	$ 5,913	$ 6	$ —	$ 1,738
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.97134	0.02672	0.00002	0.00106	0.00000	0.00000	0.00031
64										
65	Customer Cost Allocation Factors									
66										
67	Account 904 Customer		$ 1,380,038	$ 1,294,423	$ 80,797	$ 2,298	$ —	$ —	$ —	$ 2,520
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.93796	0.05855	0.00166	0.00000	0.00000	0.00000	0.00183
69										
70	Accounts 902-904 Customer		$ 7,597,187	$ 7,303,133	$ 269,929	$ 2,532	$ 8,768	$ 17	$ —	$ 7,258
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.96129	0.03553	0.00033	0.00115	0.00000	0.00000	0.00096
72										
73	Operating Expense Customer		$ 65,427,769	$ 61,821,808	$ 3,093,183	$ 9,526	$ 196,856	$ 516	$ —	$ 146,396
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.94489	0.04728	0.00015	0.00301	0.00001	0.00000	0.00224
75										
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 89,967,150	$ 85,205,189	$ 4,122,018	$ 8,641	$ 264,785	$ 523	$ —	$ 158,222
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 115,982,071	$ 110,771,719	$ 4,625,450	$ 7,003	$ 285,361	$ 352	$ —	$ 108,079
78	Total General Plant Customer Costs		$ 205,949,221	$ 195,976,908	$ 8,747,468	$ 15,643	$ 550,147	$ 874	$ —	$ 266,301
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.95158	0.04247	0.00008	0.00267	0.00000	0.00000	0.00129
80										

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
81	Customer Deposits		$ (6,199,032)	$ (2,891,777)	$ (3,230,612)	$ (31,898)	$ (9,601)	$ —	$ —	$ (31,145)
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.46649	0.52115	0.00515	0.00155	0.00000	0.00000	0.00502
83										
84	Demand Cost Allocation Factors									
85										
86	System Demand									
87	**System Demand Factor (DEM)**	DEM	1.00000	0.71233	0.14277	0.00195	0.02322	0.00000	0.00000	0.04571
88										
89	Non-Residential Demand									
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.49629	0.00677	0.08072	0.00000	0.00000	0.15888
91										
92	Directly Assigned Demand									
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
94										
95	Distribution Plant Demand		$ 250,138,689	$ 165,932,969	$ 41,790,524	$ 569,745	$ 6,796,893	$ —	$ —	$ 13,378,939
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.66336	0.16707	0.00228	0.02717	0.00000	0.00000	0.05349
97										
98	Demand Cost Allocation Factors									
99										
100	Non-Intangible Plant Demand		$ 302,193,723	$ 215,262,157	$ 43,143,336	$ 588,188	$ 7,016,917	$ —	$ —	$ 13,812,032
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.71233	0.14277	0.00195	0.02322	0.00000	0.00000	0.04571
102										
103	Total Plant Demand		$ 302,544,253	$ 201,802,379	$ 49,997,265	$ 681,631	$ 8,131,653	$ —	$ —	$ 16,006,269
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.66702	0.16526	0.00225	0.02688	0.00000	0.00000	0.05291
105										
106	Operating Expense Demand		$ 16,233,657	$ 10,615,077	$ 2,788,450	$ 38,016	$ 453,519	$ —	$ —	$ 892,702
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.65389	0.17177	0.00234	0.02794	0.00000	0.00000	0.05499
108										
109	Acct. 887-893 Demand		$ 3,164,617	$ 1,760,899	$ 696,652	$ 9,498	$ 113,305	$ —	$ —	$ 223,028
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.55643	0.22014	0.00300	0.03580	0.00000	0.00000	0.07048
111										
112	Rate Base Demand		$ 229,401,673	$ 153,088,759	$ 37,873,397	$ 516,342	$ 6,159,804	$ —	$ —	$ 12,124,898
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.66734	0.16510	0.00225	0.02685	0.00000	0.00000	0.05285
114										
115	Commodity Cost Allocation Factors									
116										
117	Annual Distribution Volumes (Ccf)		200,606,451	99,695,608	46,090,293	873,414	4,449,761	—	—	17,199,439
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.49697	0.22975	0.00435	0.02218	0.00000	0.00000	0.08574
119										
120	Commodity - Direct Assignment		0	0	0	0	0	0	0	0
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(k)	(l)	(m)	(n)	(o)
1	Customer Cost Allocation Factors						
2							
3	Total Customers		28	491	4	1	0
4	Total Customers Factor (CUS)	CUS	0.00008	0.00149	0.00001	0.00000	0.00000
5							
6	Customers - Directly Assigned		0	0	0	0	0
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	0.00000	0.00000	0.00000	0.00000	0.00000
8							
9	Services - Allocated Weighting		1.50398	1.50398	1.50398	1.50398	0.00000
10	Weighted Customers		42	738	6	2	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	0.00013	0.00222	0.00002	0.00000	0.00000
12							
13	Meters - Allocated Weighting		6.17100	2.37030	6.20576	6.20576	0.00000
14	Weighted Customers		172	1,163	25	6	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	0.00050	0.00341	0.00007	0.00002	0.00000
16							
17	Meters - Total Weighting		6.17100	2.37030	6.20576	6.20576	0.00000
18	Weighted Customers		172	1,163	25	6	0
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	0.00050	0.00341	0.00007	0.00002	0.00000
20							
21	Regulators - Allocated Weighting		21.05645	5.45109	21.82621	21.82621	0.00000
22	Weighted Customers		588	2,675	87	22	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	0.00163	0.00744	0.00024	0.00006	0.00000
24							
25	Meters and Regulators - Allocated Weighting		8.91031	2.93725	9.08033	9.08033	0.00000
26	Weighted Customers		249	1,441	36	9	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	0.00072	0.00418	0.00011	0.00003	0.00000
28							
29	Non-Residential Customers		28	491	4	1	0
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	0.00188	0.03311	0.00027	0.00007	0.00000
31							
32	Customer Cost Allocation Factors						
33							
34	Distribution Plant Customer Costs		$ 140,943	$ 1,711,610	$ 20,344	$ 5,086	$ —
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	0.00017	0.00210	0.00003	0.00001	0.00000
36							
37	Account 376-379 Customer Costs		$ 30,827	$ 541,857	$ 4,417	$ 1,104	$ —
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	0.00008	0.00149	0.00001	0.00000	0.00000
39							
40	Total Revenue (inc. cost of gas)		$ 2,492,159	$ 2,140,528	$ 87,549	$ 197,869	$ —

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(k)	(l)	(m)	(n)	(o)
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	0.00925	0.00795	0.00033	0.00073	0.00000
42							
43	Mains - Allocated Customer Cost Factor		0.00004	0.00076	0.00001	0.00000	0.00000
44	Services - Allocated Customer Cost Factor		0.00006	0.00108	0.00001	0.00000	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	0.00010	0.00184	0.00002	0.00000	0.00000
46							
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	0.00000	0.00000	0.00000	0.00000	1.00000
48							
49	Total Plant Customer		$ 158,983	$ 1,968,870	$ 22,940	$ 5,735	$ —
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	0.00017	0.00205	0.00002	0.00001	0.00000
51							
52	Non-Intangible Plant Customer						
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 81,226	$ 1,427,718	$ 11,638	$ 2,910	$ —
54		NONINCUS	0.00008	0.00149	0.00001	0.00000	0.00000
55							
56	Account 871-879 Customer Costs		$ 6,449	$ 44,749	$ 940	$ 235	$ —
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	0.00046	0.00319	0.00007	0.00002	0.00000
58							
59	Account 887-893 Customer Costs		$ 444	$ 7,798	$ 64	$ 16	$ —
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	0.00010	0.00177	0.00001	0.00000	0.00000
61							
62	Account 903 Customer		$ 158	$ 2,872	$ 23	$ 6	$ —
63	**Account 903 Customer Factor (903CUS)**	903CUS	0.00003	0.00051	0.00000	0.00000	0.00000
64							
65	Customer Cost Allocation Factors						
66							
67	Account 904 Customer		$ —	$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	0.00000	0.00000	0.00000	0.00000	0.00000
69							
70	Accounts 902-904 Customer		$ 472	$ 4,994	$ 68	$ 17	$ —
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	0.00006	0.00066	0.00001	0.00000	0.00000
72							
73	Operating Expense Customer		$ 14,815	$ 141,984	$ 2,148	$ 537	$ —
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	0.00023	0.00217	0.00003	0.00001	0.00000
75							
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 15,593	$ 189,365	$ 2,251	$ 563	$ —
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 9,816	$ 172,533	$ 1,406	$ 352	$ —
78	Total General Plant Customer Costs		$ 25,409	$ 361,898	$ 3,657	$ 914	$ —
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	0.00012	0.00176	0.00002	0.00000	0.00000
80							

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(k)	(l)	(m)	(n)	(o)
81	Customer Deposits		$ (4,000)	$ —	$ —	$ —	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	0.00065	0.00000	0.00000	0.00000	0.00000
83							
84	Demand Cost Allocation Factors						
85							
86	System Demand						
87	**System Demand Factor (DEM)**	DEM	0.03230	0.03438	0.00118	0.00617	0.00000
88							
89	Non-Residential Demand						
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	0.11227	0.11950	0.00411	0.02146	0.00000
91							
92	Directly Assigned Demand						
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	0.00000	0.00000	0.00000	0.00000	1.00000
94							
95	Distribution Plant Demand		$ 9,453,599	$ 10,062,706	$ 345,877	$ 1,807,437	$ —
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	0.03779	0.04023	0.00138	0.00723	0.00000
97							
98	Demand Cost Allocation Factors						
99							
100	Non-Intangible Plant Demand		$ 9,759,624	$ 10,388,449	$ 357,073	$ 1,865,946	$ —
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	0.03230	0.03438	0.00118	0.00617	0.00000
102							
103	Total Plant Demand		$ 11,310,078	$ 12,038,801	$ 413,800	$ 2,162,378	$ —
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	0.03738	0.03979	0.00137	0.00715	0.00000
105							
106	Operating Expense Demand		$ 630,786	$ 671,429	$ 23,078	$ 120,600	$ —
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	0.03886	0.04136	0.00142	0.00743	0.00000
108							
109	Acct. 887-893 Demand		$ 157,592	$ 167,746	$ 5,766	$ 30,130	$ —
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	0.04980	0.05301	0.00182	0.00952	0.00000
111							
112	Rate Base Demand		$ 8,567,490	$ 9,119,504	$ 313,457	$ 1,638,022	$ —
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	0.03735	0.03975	0.00137	0.00714	0.00000
114							
115	Commodity Cost Allocation Factors						
116							
117	Annual Distribution Volumes (Ccf)		16,947,496	10,079,568	1,006,954	4,263,918	—
118	**Distribution Commodity Factor (COM)**	COM	0.08448	0.05025	0.00502	0.02126	0.00000
119							
120	Commodity - Direct Assignment		0	0	0	0	0
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	0.00000	0.00000	0.00000	0.00000	0.00000

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Current Revenue-to-Cost Ratio (1)	0.9104	0.8461	1.5735	2.5891	1.0443	4.4879	0.0000	1.2630	1.5094	1.0685	1.3402	0.6335	0.0000
2	Revenue Allocation One - Cost of Service Study Required Revenue Changes													
3	Revenue-to-Cost Ratio	1.0005	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000
4	Rate Design Revenue Increase	$ 19,692,888	$ 30,085,459	$ (8,558,259)	$ (188,835)	$ (71,773)	$ (3,533)	$ —	$ (677,304)	$ (848,261)	$ (138,997)	$ (22,441)	$ 116,833	$ —
5	% Increase - Non-Gas Revenue (2)	9.90%	18.19%	-36.45%	-61.38%	-4.24%	-77.72%	— %	-20.82%	-33.75%	-6.42%	-25.39%	57.85%	— %
6	% Increase - Total Revenue (3)	7.18%	13.99%	-18.43%	-25.43%	-1.84%	-77.72%	— %	-20.82%	-33.75%	-6.42%	-25.39%	57.85%	— %
7	% Total Revenue (for GRIP)	100.00 %	89.35 %	6.87 %	0.05 %	0.75 %	0.00 %	— %	1.19 %	0.77 %	0.94 %	0.03 %	0.15 %	— %
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)													
9	Revenue-to-Cost Ratio	1.0005	0.9570	1.4588	2.2713	1.0354	3.7903	0.0000	1.2104	1.4075	1.0548	1.2722	1.0000	0.0000
10	Rate Design Revenue Increase	$ 19,692,888	$ 21,677,936	$ (1,711,652)	$ (37,767)	$ (14,355)	$ (707)	$ —	$ (135,461)	$ (169,652)	$ (27,799)	$ (4,488)	$ 116,833	$ —
11	% Increase - Non-Gas Revenue (2)	9.90%	13.11%	-7.29%	-12.28%	-0.85%	-15.54%	— %	-4.16%	-6.75%	-1.28%	-5.08%	57.85%	— %
12	% Increase - Total Revenue (3)	7.18%	10.08%	-3.69%	-5.09%	-0.37%	-15.54%	— %	-4.16%	-6.75%	-1.28%	-5.08%	57.85%	— %
13	% Total Revenue (for GRIP)	100.00 %	85.41 %	10.08 %	0.13 %	0.78 %	0.00 %	— %	1.44 %	1.09 %	0.99 %	0.04 %	0.15 %	— %
14	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)													
15	Revenue-to-Cost Ratio	1.0005	0.9462	1.5735	2.5891	1.0443	4.4879	0.0000	1.2630	1.5094	1.0685	1.3402	1.0000	0.0000
16	Rate Design Revenue Increase	$ 19,692,888	$ 19,576,055	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 116,833	$ —
17	% Increase - Non-Gas Revenue (2)	9.90%	11.84%	0.00%	0.00%	0.00%	0.00%	— %	— %	— %	— %	— %	57.85 %	— %
18	% Increase - Total Revenue (3)	7.18%	9.10%	0.00%	0.00%	0.00%	0.00%	— %	— %	— %	— %	— %	57.85 %	— %
19	% Total Revenue (for GRIP)	100.00 %	84.42 %	10.88 %	0.14 %	0.78 %	0.00 %	— %	1.51 %	1.17 %	1.00 %	0.04 %	0.15 %	— %

(1) Revenue-to-cost ratios are the ratios of each class' non-gas revenue (including revenue credits) to the

(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 decreases 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 deceases is assigned to the residential class.

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Costs	$ 35,726,640	$ 32,591,790	$ 2,728,156	$ 39,058	$ 295,268	$ —	$ —	$ 28,140	$ 37,529	$ 6,699	$ —	$ —	$ —
2	Demand Costs	$ 22,766,964	$ 6,769,598	$ 10,291,496	$ 301,425	$ 1,640,277	$ —	$ —	$ 1,049,299	$ 1,922,072	$ 792,799	$ —	$ —	$ —
3	Commodity Costs	$ 354,768	$ 57,887	$ 162,240	$ 18,900	$ 12,064	$ —	$ —	$ 36,629	$ 59,792	$ 7,257	$ —	$ —	$ —
4	Cost of Service Before Revenue Credits	$ 58,848,372	$ 39,419,275	$ 13,181,892	$ 359,382	$ 1,947,609	$ —	$ —	$ 1,114,068	$ 2,019,393	$ 806,755	$ —	$ —	$ —
5	Revenues Credited to Cost of Service (1)	$ 1,227,513	$ 918,440	$ 216,759	$ 5,430	$ 28,986	$ —	$ —	$ 16,340	$ 29,725	$ 11,833	$ —	$ —	$ —
6	Total Cost of Service	$ 57,620,859	$ 38,500,835	$ 12,965,133	$ 353,952	$ 1,918,623	$ —	$ —	$ 1,097,728	$ 1,989,668	$ 794,922	$ —	$ —	$ —
7	Revenue at Current Rates	$ 50,545,919	$ 29,692,845	$ 15,822,650	$ 1,231,259	$ 1,706,201	$ —	$ —	$ 680,834	$ 1,221,564	$ 190,566	$ —	$ —	$ —
8	Revenue Deficiency	$ 7,074,940	$ 8,807,990	$ (2,857,518)	$ (877,307)	$ 212,422	$ —	$ —	$ 416,894	$ 768,103	$ 604,356	$ —	$ —	$ —
9	Revenue-to-Cost Ratios:													
10	Current Revenue	0.8798	0.7766	1.2168	3.4412	0.8909	0.0000	0.0000	0.6258	0.6196	0.2509	0.0000	0.0000	0.0000
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000

(1) Service charge revenue including Company recommended changes, special contract, irrigation, unmetered gas service, and other 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	$ 364,382
Special Contract	$ 779,884
Irrigation	$ 83,246
Unmetered Gas Service	$ —
Other Revenue	$ —
	$ 1,227,513

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	$ —	$ —	$ —	$ —
2	302	Franchises and Consents	NONINTPLT	$ —	$ —	$ —	$ —
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ —	$ —	$ —	$ —
4		Total Intangible Plant		$ —	$ —	$ —	$ —
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ 60,932	$ —	$ 60,932	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ 1,812,971	$ —	$ 1,812,971	$ —
9	367	Transmission Mains	DEM	$ 34,430,900	$ —	$ 34,430,900	$ —
10	368	Compression Station Equipment	DEM	$ 157,464	$ —	$ 157,464	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 13,393,102	$ —	$ 13,393,102	$ —
12	369	Odorization	COM	$ 185,791	$ —	$ —	$ 185,791
13	371	Other Equipment	DEM	$ 53,986	$ —	$ 53,986	$ —
14		Total Transmission Plant		$ 50,095,148	$ —	$ 49,909,356	$ 185,791
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 40,448	$ 20,708	$ 19,740	$ —
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ —	$ —	$ —	$ —
19	375	Structures and Improvements	DIS376-379-ALL	$ 114,218	$ 58,475	$ 55,743	$ —
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 84,125,463	$ 47,163,394	$ 36,962,068	$ —
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ —	$ —	$ —	$ —
22	376	Odorization	COM	$ —	$ —	$ —	$ —
23	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
24	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 4,788,437	$ —	$ 4,788,437	$ —
25	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
26	378	Odorization	COM	$ 79,345	$ —	$ —	$ 79,345
27	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 3,208,903	$ —	$ 3,208,903	$ —
28	379	Odorization	COM	$ 17,080	$ —	$ —	$ 17,080
29	380	Services - Allocated	CUS	$ 74,573,291	$ 74,573,291	$ —	$ —
30	380	Services - Directly Assigned	CUS	$ —	$ —	$ —	$ —
31	381	Meters - Allocated	CUS	$ 21,960,475	$ 21,960,475	$ —	$ —
32	381	Meters - Directly Assigned	CUS	$ —	$ —	$ —	$ —
33	382	Meter Installations	CUS	$ —	$ —	$ —	$ —
34	383	House Regulators - Allocated	CUS	$ 5,134,243	$ 5,134,243	$ —	$ —
35	383	House Regulators - Directly Assigned	CUS	$ —	$ —	$ —	$ —
36	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 3,323,547	$ —	$ 3,323,547	$ —
37	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
38	385	Odorization	COM	$ —	$ —	$ —	$ —
39	386	Other Property - Customer Premises	CUS	$ 6,144	$ 6,144	$ —	$ —

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)
40	387	Other Equipment	DIS376-379-ALL	$ —	$ —	$ —	$ —
41		Total Distribution Plant		$ 197,371,595	$ 148,916,731	$ 48,358,439	$ 96,426
42							
43		**General Plant**					
44	389	Land & Land Rights	GENPLT	$ 168,071	$ 136,803	$ 31,207	$ 62
45	390	Structures & Improvements	GENPLT	$ 4,940,842	$ 3,919,635	$ 1,019,175	$ 2,032
46	391	Office Furniture and Equipment	GENPLT	$ 9,414,874	$ 9,183,351	$ 231,062	$ 461
47	392	Transportation Equipment	GENPLT	$ 7,633,484	$ 5,765,576	$ 1,864,191	$ 3,717
48	393	Stores Equipment	GENPLT	$ 7,313	$ 5,518	$ 1,792	$ 4
49	394	Tools, Shop & Garage - Allocated	GENPLT	$ 6,203,522	$ 4,686,901	$ 1,513,603	$ 3,018
50	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ —	$ —	$ —	$ —
51	394	Odorization	COM	$ 68,075	$ —	$ —	$ 68,075
52	395	CNG Equipment	GENPLT	$ —	$ —	$ —	$ —
53	396	Major Work Equipment	GENPLT	$ 502,270	$ 378,962	$ 123,062	$ 245
54	397	Communication Equipment - Allocated	GENPLT	$ 11,026,954	$ 8,340,432	$ 2,681,177	$ 5,346
55	397	Communication Equipment - Dir. Assn.	GENPLT	$ —	$ —	$ —	$ —
56	398	Miscellaneous General Plant	GENPLT	$ —	$ —	$ —	$ —
57		Total General Plant		$ 39,965,408	$ 32,417,177	$ 7,465,270	$ 82,961
58							
59		Total Plant in Service		$ 287,432,151	$ 181,333,908	$ 105,733,065	$ 365,178
60							
61		**Depreciation & Amortization Reserve**					
62	301-303	Intangible Plant	DISPLTRES-ALLOC	$ —	$ —	$ —	$ —
63	325-371	Transmission Plant	DEM	$ (2,718,743)	$ —	$ (2,718,743)	$ —
64	369	Odorization	COM	$ (36,621)	$ —	$ —	$ (36,621)
65	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (29,006,792)	$ (22,513,367)	$ (6,492,746)	$ (678)
66	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ —	$ —	$ —	$ —
67	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ —	$ —	$ —	$ —
68	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
69	380	Services - Directly Assigned	CUS	$ —	$ —	$ —	$ —
70	381	Meters - Directly Assigned	CUS	$ —	$ —	$ —	$ —
71	383	House Regulators - Directly Assigned	CUS	$ —	$ —	$ —	$ —
72	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
73	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (13,310,563)	$ (11,134,077)	$ (2,160,441)	$ (16,045)
74	389-398	General Plant - Directly Assigned	GEN-DARES	$ —	$ —	$ —	$ —
75		Total Depreciation & Amortization Reserve		$ (45,072,719)	$ (33,647,444)	$ (11,371,930)	$ (53,345)
76							
77		Net Plant in Service		$ 242,359,432	$ 147,686,464	$ 94,361,135	$ 311,833
78							
79		Customer Deposits	CUS	$ (2,514,038)	$ (2,514,038)	$ —	$ —

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)
80							
81		Customer Advances	MAINS/SVCS	$ (137,981)	$ (105,844)	$ (32,137)	$ —
82							
83		Accumulated Deferred Income Taxes	TOTPLT	$ (22,456,816)	$ (14,167,455)	$ (8,260,829)	$ (28,531)
84							
85		Excess Deferred Income Taxes	TOTPLT	$ (2,695,939)	$ (1,700,802)	$ (991,712)	$ (3,425)
86							
87		Negative Acquisition Adjustment on OPC Assets	MAINS-ALLOC	$ —	$ —	$ —	$ —
88							
89		Materials and Supplies	TOTPLT	$ 3,060,677	$ 1,930,906	$ 1,125,882	$ 3,889
90							
91		Prepayments	OPEXP	$ 1,006,867	$ 571,297	$ 423,349	$ 12,221
92							
93		Pension & FAS 106 Regulatory Asset	OPEXP	$ 4,101,307	$ 2,327,083	$ 1,724,444	$ 49,780
94							
95		DIMP Deferrals	OPEXP	$ 319,029	$ 181,017	$ 134,139	$ 3,872
96							
97		Regulatory Assets	OPEXP	$ 101,180	$ 57,409	$ 42,542	$ 1,228
98							
99		Cash Working Capital	OPEXP	$ (1,227,199)	$ (696,313)	$ (515,990)	$ (14,895)
100							
101		Total Rate Base		$ 221,916,520	$ 133,569,724	$ 88,010,824	$ 335,972

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	814-865	Transmission Expenses	DEM	$ 5,488,388	$ —	$ 5,488,388	$ —
3	8650	Odorization	COM	$ —	$ —	$ —	$ —
4	8700	Operation Supervision & Engineering	DIS871-879	$ 431,618	$ 344,706	$ 82,252	$ 4,660
5	8710	Distribution Load Dispatch	COM	$ 53,185	$ —	$ —	$ 53,185
6	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 2,816,762	$ 2,160,718	$ 656,044	$ —
7	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ —	$ —	$ —	$ —
8	8740	Odorization	COM	$ —	$ —	$ —	$ —
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 213,445	$ —	$ 213,445	$ —
10	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ —	$ —	$ —	$ —
11	8750	Odorization	COM	$ 95,703	$ —	$ —	$ 95,703
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 25,374	$ —	$ 25,374	$ —
13	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ —	$ —	$ —	$ —
14	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 43,956	$ —	$ 43,956	$ —
15	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 1,771,500	$ 1,771,500	$ —	$ —
16	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ —	$ —	$ —	$ —
17	8780	Odorization	COM	$ —	$ —	$ —	$ —
18	8790	Customer Installation Expenses	CUS	$ 2,227	$ 2,227	$ —	$ —
19	8800	Other Expenses	DIS871-879	$ 351,827	$ 280,982	$ 67,047	$ 3,798
20	8800	Odorization	COM	$ 652	$ —	$ —	$ 652
21	8810	Rents	DIS871-879	$ 15,455	$ 12,343	$ 2,945	$ 167
22	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
23		Total Transmission & Distribution Oper. Exp.		$ 11,310,094	$ 4,572,476	$ 6,579,452	$ 158,165
24							
25		**Distribution Maintenance Expenses**					
26	8850	Maintenance Supervision and Engineering	DIS887-893	$ —	$ —	$ —	$ —
27	8860	Structures and Improvements	DIS887-893	$ 437,039	$ 173,851	$ 252,023	$ 11,165
28	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 1,325,262	$ 742,984	$ 582,278	$ —
29	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ —	$ —	$ —	$ —
30	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 854,498	$ —	$ 854,498	$ —
31	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
32	8890	Odorization	COM	$ 80,021	$ —	$ —	$ 80,021
33	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 351,993	$ —	$ 351,993	$ —
34	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
35	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 17,564	$ —	$ 17,564	$ —
36	8910	Odorization	COM	$ —	$ —	$ —	$ —
37	8920	Maintenance of Services - Allocated	CUS	$ 503,061	$ 503,061	$ —	$ —
38	8920	Maintenance of Services - Directly Assn.	CUS	$ —	$ —	$ —	$ —
39	8930	Main. of Meters & House Reg. - Allocated	CUS	$ —	$ —	$ —	$ —
40	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ —	$ —	$ —	$ —

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)
41	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
42	8950	Clearing - Meter Shop - Small Meters	CUS	$ —	$ —	$ —	$ —
43	8960	Clearing - Meter Shop - Large Meters	CUS	$ —	$ —	$ —	$ —
44		Total Distribution Maintenance Expenses		$ 3,569,438	$ 1,419,895	$ 2,058,356	$ 91,186
45							
46		Total Operations & Maintenance Expenses		$ 14,879,531	$ 5,992,371	$ 8,637,809	$ 249,351
47							
48		**Customer Accounting Expenses**					
49	9010	Supervision	CUS	$ 59	$ 59	$ —	$ —
50	9020	Meter Reading Expense	CUS	$ 403,018	$ 403,018	$ —	$ —
51	9030	Customer Accounting	CUS	$ 1,059,614	$ 1,059,614	$ —	$ —
52	9040	Bad Debts (includes gross up)	CUS	$ 593,604	$ 593,604	$ —	$ —
53	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 79,908	$ 79,908	$ —	$ —
54		Total Customer Accounts Expenses		$ 2,136,202	$ 2,136,202	$ —	$ —
55							
56		**Customer Information Expenses**					
57	9070	Supervision	CUS	$ —	$ —	$ —	$ —
58	9080	Customer Assistance	CUS	$ 223,102	$ 223,102	$ —	$ —
59	9090	Informational and Instructional Advertising	CUS	$ 14,583	$ 14,583	$ —	$ —
60	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —
61		Total Customer Information Expenses		$ 237,686	$ 237,686	$ —	$ —
62							
63		**Sales and Advertising Expenses**					
64	9110	Supervision	CUS	$ —	$ —	$ —	$ —
65	9120	Demonstrating and Selling	CUS	$ —	$ —	$ —	$ —
66	9130	Advertising	CUS	$ 7,711	$ 7,711	$ —	$ —
67	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —
68	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —
69		Total Sales and Advertising Expenses		$ 7,711	$ 7,711	$ —	$ —
70							
71		**Administrative & General Expenses**					
72	920-940	Administrative & General Expenses	ADMINGEN	$ 7,040,937	$ 5,415,032	$ 1,580,286	$ 45,619
73		Total Administrative & General Expenses		$ 7,040,937	$ 5,415,032	$ 1,580,286	$ 45,619
74							
75		**Depreciation and Amortization Expense**					
76	301-303	Intangible Plant - Allocated	PLT301-03	$ —	$ —	$ —	$ —
77	301-303	Intangible Plant - Directly Assigned	PLT301-03	$ —	$ —	$ —	$ —
78	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —
79	366	Meas. and Reg. Station Structures	PLT366	$ 49,857	$ —	$ 49,857	$ —
80	367	Transmission Mains	PLT367	$ 1,022,631	$ —	$ 1,022,631	$ —

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)
81	368	Compression Station Equipment	PLT368	$ 3,937	$ —	$ 3,937	$ —
82	369	Measuring and Reg. Station Equipment	PLT369	$ 471,437	$ —	$ 471,437	$ —
83	369	Odorization	COM	$ 6,540	$ —	$ —	$ 6,540
84	371	Other Equipment	PLT371	$ 2,818	$ —	$ 2,818	$ —
85	375	Structures and Improvements	PLT375	$ 5,334	$ 2,731	$ 2,603	$ —
86	376	Mains - Allocated	MAINS-ALLOC	$ 2,521,204	$ 1,413,467	$ 1,107,737	$ —
87	376	Mains - Directly Assigned	MAINS-DA	$ —	$ —	$ —	$ —
88	376	Odorization	COM	$ —	$ —	$ —	$ —
89	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
90	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 127,761	$ —	$ 127,761	$ —
91	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ —	$ —	$ —	$ —
92	378	Odorization	COM	$ 4,541	$ —	$ —	$ 4,541
93	379	Meas. & Reg. Sta. Equipment - City Gate - Alloc.	PLT379	$ 70,918	$ —	$ 70,918	$ —
94	379	Meas. & Reg. Sta. Equipment - City Gate - Dir. Assn.	PLT379	$ —	$ —	$ —	$ —
95	379	Odorization	COM	$ 377	$ —	$ —	$ 377
96	380	Services - Allocated	PLT380	$ 2,798,442	$ 2,798,442	$ —	$ —
97	380	Services - Directly Assigned	PLT380	$ —	$ —	$ —	$ —
98	381	Meters - Allocated	PLT381	$ 959,674	$ 959,674	$ —	$ —
99	381	Meters - Directly Assigned	PLT381	$ —	$ —	$ —	$ —
100	382	Meter Installations	PLT382	$ —	$ —	$ —	$ —
101	383	House Regulators - Allocated	PLT383	$ 213,071	$ 213,071	$ —	$ —
102	383	House Regulators - Directly Assigned	PLT383	$ —	$ —	$ —	$ —
103	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 74,665	$ —	$ 74,665	$ —
104	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ —	$ —	$ —	$ —
105	385	Odorization	COM	$ —	$ —	$ —	$ —
106	386	Other Property - Customer Premises	PLT386	$ 1,371	$ 1,371	$ —	$ —
107	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —
108	389-398	General Plant - Allocated	GENDEP	$ 2,147,289	$ 1,809,244	$ 332,850	$ 5,195
109	389-398	General Plant - Directly Assigned	GENDEP	$ —	$ —	$ —	$ —
110	389-398	General Plant - Odorization	COM	$ 4,541	$ —	$ —	$ 4,541
111	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ 22,999	$ 13,050	$ 9,670	$ 279
112		Total Depreciation and Amortization Expense		$ 10,509,406	$ 7,211,049	$ 3,276,884	$ 21,472
113							
114		**Taxes Other Than Income**					
115	4080	Payroll and Other	OPEXP	$ 705,785	$ 400,463	$ 296,756	$ 8,567
116	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 1,791,750	$ 1,130,371	$ 659,102	$ 2,276
117	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ —	$ —	$ —	$ —
118	4080	Revenue Related (includes gross up)	CUS	$ 53,062	$ 53,062	$ —	$ —
119		Total Taxes Other Than Income		$ 2,550,597	$ 1,583,896	$ 955,858	$ 10,843
120							
121	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ —	$ —	$ —	$ —

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)
122	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (110,971)	$ (67,623)	$ (43,206)	$ (143)
123							
124	4310	Interest on Customer Deposits	CUS	$ 126,959	$ 126,959	$ —	$ —
125							
126		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 17,789,255	$ 10,840,231	$ 6,926,136	$ 22,889
127		Required Return - Directly Assigned	RB-DA	$ —	$ —	$ —	$ —
128		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 3,681,060	$ 2,243,126	$ 1,433,198	$ 4,736
129		Income Taxes - Directly Assigned	RB-DA	$ —	$ —	$ —	$ —
130		Total Cost of Service Before Revenue Credits		$ 58,848,372	$ 35,726,640	$ 22,766,964	$ 354,768

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	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			Total Transmission Plant	$ 50,095,148	$ —	$ 49,909,356	$ 185,791
8			Total Distribution Plant	$ 197,371,595	$ 148,916,731	$ 48,358,439	$ 96,426
9			Total General Plant	$ 39,965,408	$ 32,417,177	$ 7,465,270	$ 82,961
10			Total Non-Intangible Plant	$ 287,432,151	$ 181,333,908	$ 105,733,065	$ 365,178
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.63088	0.36785	0.00127
12							
13	376		Distribution Mains-Allocated	$ 84,125,463	$ 47,163,394	$ 36,962,068	$ —
14	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 4,788,437	$ —	$ 4,788,437	$ —
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 3,208,903	$ —	$ 3,208,903	$ —
17			Total Accounts 376-379	$ 92,122,803	$ 47,163,394	$ 44,959,408	$ —
18		DIS376-379-ALL	Accounts 376-379 Allocated Factor	1.00000	0.51196	0.48804	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ —	$ —	$ —	$ —
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ —	$ —	$ —	$ —
22			Total Accounts 376-379 Directly Assigned	$ —	$ —	$ —	$ —
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
24							
25	376		Mains-Allocated	$ 84,125,463	$ 47,163,394	$ 36,962,068	$ —
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.56063	0.43937	0.00000
27							
28	376		Mains-Directly Assigned	$ —	$ —	$ —	$ —
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.55948	0.44052	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ —	$ —	$ —	$ —
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 158,698,753	$ 121,736,685	$ 36,962,068	$ —
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.76709	0.23291	0.00000
36							
37	376/380		Mains and Services	$ 158,698,753	$ 121,736,685	$ 36,962,068	$ —
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.76709	0.23291	0.00000
39							
40	374-387		Total Distribution Plant	$ 197,371,595	$ 148,916,731	$ 48,358,439	$ 96,426

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
41		DISPLT	Distribution Plant Factor	1.00000	0.75450	0.24501	0.00049
42							
43	374		Land & Land Rights - Directly Assigned	$ —	$ —	$ —	$ —
44	376		Mains - Directly Assigned	$ —	$ —	$ —	$ —
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ —	$ —	$ —	$ —
46	380		Service - Directly Assigned	$ —	$ —	$ —	$ —
47	381		Meters - Directly Assigned	$ —	$ —	$ —	$ —
48	383		House Regulators - Directly Assigned	$ —	$ —	$ —	$ —
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ —	$ —	$ —	$ —
50			Total Distribution Plant - Directly Assigned	$ —	$ —	$ —	$ —
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	0.00000	0.00000	0.00000	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (35,457)	$ (18,153)	$ (17,304)	$ —
54	375		Structures and Improvements	$ (38,287)	$ (19,602)	$ (18,686)	$ —
55	376		Distribution Mains - Allocated	$ (12,542,556)	$ (7,031,754)	$ (5,510,803)	$ —
56	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (656,731)	$ —	$ (656,731)	$ —
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (81,353)	$ —	$ (81,353)	$ —
59	378-379		Odorization Tank	$ (678)	$ —	$ —	$ (678)
60	380		Services - Allocated	$ (9,175,101)	$ (9,175,101)	$ —	$ —
61	381		Meters - Allocated	$ (4,060,571)	$ (4,060,571)	$ —	$ —
62	382		Meter Installations	$ (22,173)	$ (22,173)	$ —	$ —
63	383		House Regulators - Allocated	$ (2,184,498)	$ (2,184,498)	$ —	$ —
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (206,424)	$ —	$ (206,424)	$ —
65	386		Other Property-Customer Premises	$ (2,962)	$ (1,516)	$ (1,446)	$ —
66	387		Other Equipment	$ —	$ —	$ —	$ —
67			Total Distribution Plant - Allocated Reserve	$ (29,006,792)	$ (22,513,367)	$ (6,492,746)	$ (678)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.77614	0.22384	0.00002
69							
70	376		Distribution Mains - Directly Assigned	$ —	$ —	$ —	$ —
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	0.00000	0.00000	0.00000	0.00000
72							
73			General Plant - Allocated Reserve	$ (13,310,563)	$ (11,134,077)	$ (2,160,441)	$ (16,045)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.83648	0.16231	0.00121
75							
76			General Plant - Directly Assigned Reserve	$ —	$ —	$ —	$ —
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	0.00000	0.00000	0.00000	0.00000
78							
79			Total Plant - Allocated	$ 287,432,151	$ 181,333,908	$ 105,733,065	$ 365,178
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.63088	0.36785	0.00127

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
81							
82			Total Plant - Directly Assigned	$ —	$ —	$ —	$ —
83		TPLT-DA	Total Plant Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
84							
85			Total Plant	$ 287,432,151	$ 181,333,908	$ 105,733,065	$ 365,178
86		TOTPLT	Total Plant Factor	1.00000	0.63088	0.36785	0.00127
87							
88			Total Operations and Maintenance Expenses	$ 14,879,531	$ 5,992,371	$ 8,637,809	$ 249,351
89			Total Customer Accounts Expenses	$ 2,136,202	$ 2,136,202	$ —	$ —
90			Total Customer Information Expenses	$ 237,686	$ 237,686	$ —	$ —
91			Total Sales and Advertising Expenses	$ 7,711	$ 7,711	$ —	$ —
92			Administrative and General Expenses	$ 7,040,937	$ 5,415,032	$ 1,580,286	$ 45,619
93			Total Operating Expenses	$ 24,302,067	$ 13,789,002	$ 10,218,095	$ 294,970
94		OPEXP	Operating Expense Factor	1.00000	0.56740	0.42046	0.01214
95							
96	8710		Distribution Load Dispatch	$ 53,185	$ —	$ —	$ 53,185
97	8740		Mains and Services Expenses - Allocated	$ 2,816,762	$ 2,160,718	$ 656,044	$ —
98	8740		Mains and Services Expenses - Dir. Assn.	$ —	$ —	$ —	$ —
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 213,445	$ —	$ 213,445	$ —
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ —	$ —	$ —	$ —
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 25,374	$ —	$ 25,374	$ —
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ —	$ —	$ —	$ —
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 43,956	$ —	$ 43,956	$ —
104	8780		Meter and House Regulator Exp.- Allocated	$ 1,771,500	$ 1,771,500	$ —	$ —
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ —	$ —	$ —	$ —
106	8790		Customer Installation Expenses	$ 2,227	$ 2,227	$ —	$ —
107			Total Accounts 871-879	$ 4,926,450	$ 3,934,445	$ 938,820	$ 53,185
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.79864	0.19057	0.01080
109							
110	8870		Maintenance of Mains-Allocated	$ 1,325,262	$ 742,984	$ 582,278	$ —
111	8870		Maintenance of Mains - Directly Assn.	$ —	$ —	$ —	$ —
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 934,519	$ —	$ 854,498	$ 80,021
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ —	$ —	$ —	$ —
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 351,993	$ —	$ 351,993	$ —
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ —	$ —	$ —	$ —
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 17,564	$ —	$ 17,564	$ —
117	8920		Maintenance of Services - Allocated	$ 503,061	$ 503,061	$ —	$ —
118	8920		Maintenance of Services - Directly Assn.	$ —	$ —	$ —	$ —
119	8930		Main. of Meters & House Reg. - Allocated	$ —	$ —	$ —	$ —
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
121			Total Accounts 887-893	$ 3,132,399	$ 1,246,044	$ 1,806,333	$ 80,021
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.39779	0.57666	0.02555
123							
124			Total Operations and Maintenance Expenses	$ 14,879,531	$ 5,992,371	$ 8,637,809	$ 249,351
125			Total Customer Accounts Expenses	$ 2,136,202	$ 2,136,202	$ —	$ —
126			Total Customer Service Expenses	$ 237,686	$ 237,686	$ —	$ —
127			Total Sales and Advertising Expenses	$ 7,711	$ 7,711	$ —	$ —
128			Total Operating Exp. Without A&G Expenses	$ 17,261,130	$ 8,373,970	$ 8,637,809	$ 249,351
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.48513	0.50042	0.01445
130							
131	920-932		Administrative and General Expenses	$ 7,040,937	$ 5,415,032	$ 1,580,286	$ 45,619
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.76908	0.22444	0.00648
133							
134	366		Meas. and Reg. Station Structures	$ 1,812,971	$ —	$ 1,812,971	$ —
135		PLT366	Measuring and Reg. Station Structures Factor	1.00000	0.00000	1.00000	0.00000
136							
137	367		Transmission Mains	$ 34,430,900	$ —	$ 34,430,900	$ —
138		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
139							
140	368		Compression Station Equipment	$ 157,464	$ —	$ 157,464	$ —
141		PLT368	Compression Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
142							
143	369		Measuring and Reg. Station Equipment	$ 13,393,102	$ —	$ 13,393,102	$ —
144		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
145							
146	371		Other Equipment	$ 53,986	$ —	$ 53,986	$ —
147		PLT371	Other Equipment Factor	1.00000	0.00000	1.00000	0.00000
148							
149	375		Structures and Improvements	$ 114,218	$ 58,475	$ 55,743	$ —
150		PLT375	Structures and Improvements Factor	1.00000	0.51196	0.48804	0.00000
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 4,788,437	$ —	$ 4,788,437	$ —
153		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
154							
155	379		Meas. & Reg. Sta. Equip.- City Gate	$ 3,208,903	$ —	$ 3,208,903	$ —
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services - Allocated	$ 74,573,291	$ 74,573,291	$ —	$ —
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters - Allocated	$ 21,960,475	$ 21,960,475	$ —	$ —
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
163							
164	382		Meter Installations	$ —	$ —	$ —	$ —
165		PLT382	Meter Installations Factor	—	0.00000	0.00000	0.00000
166							
167	383		House Regulators - Allocated	$ 5,134,243	$ 5,134,243	$ —	$ —
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 3,323,547	$ —	$ 3,323,547	$ —
171		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
172							
173	386		Other Property - Customer Premises	$ 6,144	$ 6,144	$ —	$ —
174		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
175							
176	387		Other Equipment	$ —	$ —	$ —	$ —
177		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
178							
179	301-303		Intangible Plant	$ —	$ —	$ —	$ —
180		PLT301-03	Intangible Plant	0.00000	0.00000	0.00000	0.00000
181							
182	389-398		General Plant Depreciation Expense	$ 2,151,829	$ 1,813,070	$ 333,554	$ 5,206
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.84257	0.15501	0.00242
184							
185			Net Plant Directly Assigned	$ —	$ —	$ —	$ —
186		NETPLT-DA	Net Plant Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
187							
188			Net Plant Allocated	$ 242,359,432	$ 147,686,464	$ 94,361,135	$ 311,833
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.60937	0.38934	0.00129
190							
191			Rate Base Directly Assigned	$ —	$ —	$ —	$ —
192		RB-DA	Rate Base Directly Assigned Factor	0.00000	0.00000	0.00000	0.00000
193							
194			Rate Base Allocated	$ 221,916,520	$ 135,229,175	$ 86,401,815	$ 285,530
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.60937	0.38934	0.00129
196							
197			Required Return	$ 17,789,255	$ 10,840,231	$ 6,926,136	$ 22,889
198		REQRET	Required Return Factor	1.00000	0.60937	0.38934	0.00129
199							
200			Non-Plant Rate Base	$ (20,442,912)	$ (14,116,739)	$ (6,350,311)	$ 24,139
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.69054	0.31064	-0.00118

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	301-303	**Intangible Plant**									
2		Customer	NONINCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
3		Demand	NONINDEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
4		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
5		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
6	365-371	**Transmission Plant**									
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 49,909,356	$ 15,246,403	$ 22,299,523	$ 653,125	$ 3,554,137	$ —	$ —	$ 2,273,611
9		Commodity	COM	$ 185,791	$ 30,315	$ 84,965	$ 9,898	$ 6,318	$ —	$ —	$ 19,182
10		Total Transmission Plant		$ 50,095,148	$ 15,276,719	$ 22,384,488	$ 663,022	$ 3,560,455	$ —	$ —	$ 2,292,793
11		**Distribution Plant**									
12	374	**Land & Land Rights - Allocated**									
13		Customer	376-379CUS	$ 20,708	$ 19,196	$ 1,318	$ 12	$ 160	$ —	$ —	$ 9
14		Demand	DEM	$ 19,740	$ 6,030	$ 8,820	$ 258	$ 1,406	$ —	$ —	$ 899
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 40,448	$ 25,227	$ 10,138	$ 270	$ 1,566	$ —	$ —	$ 908
17	374	**Land & Land Rights - DA**									
18		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
22	375	**Structures and Improvements**									
23		Customer	376-379CUS	$ 58,475	$ 54,207	$ 3,721	$ 33	$ 453	$ —	$ —	$ 25
24		Demand	DEM	$ 55,743	$ 17,028	$ 24,906	$ 729	$ 3,970	$ —	$ —	$ 2,539
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 114,218	$ 71,236	$ 28,627	$ 763	$ 4,423	$ —	$ —	$ 2,564
27	376	**Distribution Mains-Allocated**									
28		Customer	CUS	$ 47,163,394	$ 43,720,969	$ 3,001,172	$ 26,988	$ 365,507	$ —	$ —	$ 20,070
29		Demand	DEM	$ 36,962,068	$ 11,291,242	$ 16,514,669	$ 483,694	$ 2,632,137	$ —	$ —	$ 1,683,800
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 84,125,463	$ 55,012,210	$ 19,515,841	$ 510,682	$ 2,997,644	$ —	$ —	$ 1,703,869
32	376	**Odorization**									
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
36		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
37		**Distribution Mains - Directly Assn.**									
38		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
39		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
42	377	**Compressor Station Equipment**									
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**									
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 4,788,437	$ 1,462,781	$ 2,139,476	$ 62,663	$ 340,993	$ —	$ —	$ 218,136
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 4,788,437	$ 1,462,781	$ 2,139,476	$ 62,663	$ 340,993	$ —	$ —	$ 218,136
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**									
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
57	378	**Odorization**									
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 79,345	$ 12,947	$ 36,286	$ 4,227	$ 2,698	$ —	$ —	$ 8,192
61		Total Odorization		$ 79,345	$ 12,947	$ 36,286	$ 4,227	$ 2,698	$ —	$ —	$ 8,192
62	379	**Meas. & Reg. Station - City Gate**									
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 3,208,903	$ 980,262	$ 1,433,739	$ 41,992	$ 228,512	$ —	$ —	$ 146,181
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 3,208,903	$ 980,262	$ 1,433,739	$ 41,992	$ 228,512	$ —	$ —	$ 146,181
67	379	**Odorization**									
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 17,080	$ 2,787	$ 7,811	$ 910	$ 581	$ —	$ —	$ 1,764
71		Total Odorization		$ 17,080	$ 2,787	$ 7,811	$ 910	$ 581	$ —	$ —	$ 1,764
72	380	**Services - Allocated**									
73		Customer	SERCUS-ALL	$ 74,573,291	$ 68,209,245	$ 5,492,801	$ 55,795	$ 695,254	$ —	$ —	$ 49,474
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 74,573,291	$ 68,209,245	$ 5,492,801	$ 55,795	$ 695,254	$ —	$ —	$ 49,474

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
77	380	**Services-Directly Assigned**									
78		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
82	381	**Meters - Allocated**									
83		Customer	METCUS-ALL	$ 21,960,475	$ 19,126,778	$ 2,418,727	$ 49,988	$ 240,498	$ —	$ —	$ 48,188
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 21,960,475	$ 19,126,778	$ 2,418,727	$ 49,988	$ 240,498	$ —	$ —	$ 48,188
87	381	**Meters-Directly Assigned**									
88		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
92	382	**Meter Installations**									
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**									
98		Customer	REGCUS-ALL	$ 5,134,243	$ 4,400,863	$ 581,353	$ 21,228	$ 70,012	$ —	$ —	$ 23,136
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 5,134,243	$ 4,400,863	$ 581,353	$ 21,228	$ 70,012	$ —	$ —	$ 23,136
102	383	**House Regulators - Directly Assigned**									
103		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**									
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 3,323,547	$ —	$ 2,138,119	$ 62,623	$ 340,777	$ —	$ —	$ 217,998
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 3,323,547	$ —	$ 2,138,119	$ 62,623	$ 340,777	$ —	$ —	$ 217,998
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**									
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117	385	**Odorization**									
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
121		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
122	386	**Other Prop.-Customer Premises**									
123		Customer	CUS	$ 6,144	$ 5,696	$ 391	$ 4	$ 48	$ —	$ —	$ 3
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 6,144	$ 5,696	$ 391	$ 4	$ 48	$ —	$ —	$ 3
127	387	**Other Equipment**									
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**									
133		Customer		$ 148,916,731	$ 135,536,955	$ 11,499,483	$ 154,048	$ 1,371,933	$ —	$ —	$ 140,905
134		Demand		$ 48,358,439	$ 13,757,343	$ 22,259,729	$ 651,959	$ 3,547,795	$ —	$ —	$ 2,269,553
135		Commodity		$ 96,426	$ 15,734	$ 44,097	$ 5,137	$ 3,279	$ —	$ —	$ 9,956
136		Total Distribution Plant		$ 197,371,595	$ 149,310,031	$ 33,803,308	$ 811,144	$ 4,923,007	$ —	$ —	$ 2,420,414
137		**General Plant**									
138		**General Plant - Allocated**									
139		Customer	GENPTCUS	$ 32,417,177	$ 29,784,538	$ 2,277,639	$ 25,858	$ 274,356	$ —	$ —	$ 22,026
140		Demand	DISPLTDEM	$ 7,465,270	$ 2,123,771	$ 3,436,316	$ 100,645	$ 547,686	$ —	$ —	$ 350,359
141		Commodity	COM	$ 82,961	$ 13,537	$ 37,939	$ 4,420	$ 2,821	$ —	$ —	$ 8,566
142		Total General Plant - Allocated		$ 39,965,408	$ 31,921,846	$ 5,751,894	$ 130,923	$ 824,864	$ —	$ —	$ 380,951
143		**Total General Plant - Directly Assigned**									
144		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
148		**Total General Plant**									
149		Customer		$ 32,417,177	$ 29,784,538	$ 2,277,639	$ 25,858	$ 274,356	$ —	$ —	$ 22,026
150		Demand		$ 7,465,270	$ 2,123,771	$ 3,436,316	$ 100,645	$ 547,686	$ —	$ —	$ 350,359
151		Commodity		$ 82,961	$ 13,537	$ 37,939	$ 4,420	$ 2,821	$ —	$ —	$ 8,566
152		Total General Plant		$ 39,965,408	$ 31,921,846	$ 5,751,894	$ 130,923	$ 824,864	$ —	$ —	$ 380,951
153		**Total Plant in Service**									

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
154		Customer		$ 181,333,908	$ 165,321,493	$ 13,777,122	$ 179,906	$ 1,646,289	$ —	$ —	$ 162,931
155		Demand		$ 105,733,065	$ 31,127,517	$ 47,995,568	$ 1,405,729	$ 7,649,619	$ —	$ —	$ 4,893,524
156		Commodity		$ 365,178	$ 59,586	$ 167,000	$ 19,454	$ 12,418	$ —	$ —	$ 37,704
157		Total Plant in Service		$ 287,432,151	$ 196,508,596	$ 61,939,690	$ 1,605,090	$ 9,308,325	$ —	$ —	$ 5,094,159
158		**Depreciation & Amort. Reserve**									
159		**Intangible Plant**									
160		Customer	NONINCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
161		Demand	NONINDEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
162		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
163		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
164		**Transmission Plant**									
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (2,718,743)	$ (830,527)	$ (1,214,735)	$ (35,578)	$ (193,607)	$ —	$ —	$ (123,852)
167		Commodity	COM	$ (36,621)	$ (5,975)	$ (16,747)	$ (1,951)	$ (1,245)	$ —	$ —	$ (3,781)
168		Total Transmission Plant		$ (2,755,364)	$ (836,502)	$ (1,231,483)	$ (37,529)	$ (194,852)	$ —	$ —	$ (127,633)
169		**Distribution Plant - Allocated**									
170		Customer	DISPLTCUS	$ (22,513,367)	$ (20,490,600)	$ (1,738,502)	$ (23,289)	$ (207,410)	$ —	$ —	$ (21,302)
171		Demand	DISPLTDEM	$ (6,492,746)	$ (1,847,101)	$ (2,988,657)	$ (87,534)	$ (476,337)	$ —	$ —	$ (304,717)
172		Commodity	COM	$ (678)	$ (111)	$ (310)	$ (36)	$ (23)	$ —	$ —	$ (70)
173		Total Distribution Plant - Allocated		$ (29,006,792)	$ (22,337,812)	$ (4,727,469)	$ (110,859)	$ (683,770)	$ —	$ —	$ (326,089)
174		**Distribution Plant - Dir. Assn.**									
175		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
176		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
179		**General Plant - Allocated**									
180		Customer	GENPTCUS	$ (11,134,077)	$ (10,229,865)	$ (782,283)	$ (8,881)	$ (94,231)	$ —	$ —	$ (7,565)
181		Demand	DISPLTDEM	$ (2,160,441)	$ (614,617)	$ (994,466)	$ (29,127)	$ (158,500)	$ —	$ —	$ (101,394)
182		Commodity	COM	$ (16,045)	$ (2,618)	$ (7,338)	$ (855)	$ (546)	$ —	$ —	$ (1,657)
183		Total General Plant - Allocated		$ (13,310,563)	$ (10,847,100)	$ (1,784,087)	$ (38,863)	$ (253,276)	$ —	$ —	$ (110,616)
184		**General Plant - Directly Assigned**									
185		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
189		**Total Depr. & Amort. Reserve**									
190		Customer		$ (33,647,444)	$ (30,720,465)	$ (2,520,785)	$ (32,170)	$ (301,641)	$ —	$ —	$ (28,867)
191		Demand		$ (11,371,930)	$ (3,292,245)	$ (5,197,858)	$ (152,239)	$ (828,444)	$ —	$ —	$ (529,962)
192		Commodity		$ (53,345)	$ (8,704)	$ (24,395)	$ (2,842)	$ (1,814)	$ —	$ —	$ (5,508)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
193		Total Depr. & Amortization Reserve		$ (45,072,719)	$ (34,021,414)	$ (7,743,039)	$ (187,251)	$ (1,131,899)	$ —	$ —	$ (564,337)
194		**Net Plant in Service**									
195		Customer		$ 147,686,464	$ 134,601,028	$ 11,256,336	$ 147,736	$ 1,344,648	$ —	$ —	$ 134,064
196		Demand		$ 94,361,135	$ 27,835,272	$ 42,797,710	$ 1,253,490	$ 6,821,175	$ —	$ —	$ 4,363,561
197		Commodity		$ 311,833	$ 50,881	$ 142,605	$ 16,612	$ 10,604	$ —	$ —	$ 32,196
198		Total Net Plant in Service		$ 242,359,432	$ 162,487,181	$ 54,196,651	$ 1,417,839	$ 8,176,426	$ —	$ —	$ 4,529,821
199		**Customer Deposits**									
200		Customer	DEPCUS	$ (2,514,038)	$ (783,706)	$ (1,635,587)	$ (39,110)	$ (16,250)	$ —	$ —	$ (4,990)
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (2,514,038)	$ (783,706)	$ (1,635,587)	$ (39,110)	$ (16,250)	$ —	$ —	$ (4,990)
204		**Customer Advances**									
205		Customer	MSCUS-ALL	$ (105,844)	$ (97,318)	$ (7,385)	$ (72)	$ (922)	$ —	$ —	$ (60)
206		Demand	DEM	$ (32,137)	$ (9,817)	$ (14,359)	$ (421)	$ (2,289)	$ —	$ —	$ (1,464)
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (137,981)	$ (107,135)	$ (21,744)	$ (493)	$ (3,211)	$ —	$ —	$ (1,524)
209		**Accum. Deferred Income Taxes**									
210		Customer	TPLTCUS	$ (14,167,455)	$ (12,916,420)	$ (1,076,394)	$ (14,056)	$ (128,623)	$ —	$ —	$ (12,730)
211		Demand	TPLTDEM	$ (8,260,829)	$ (2,431,965)	$ (3,749,851)	$ (109,828)	$ (597,658)	$ —	$ —	$ (382,327)
212		Commodity	COM	$ (28,531)	$ (4,655)	$ (13,048)	$ (1,520)	$ (970)	$ —	$ —	$ (2,946)
213		Total Accum. Deferred Inc. Taxes		$ (22,456,816)	$ (15,353,040)	$ (4,839,292)	$ (125,404)	$ (727,251)	$ —	$ —	$ (398,002)
214		**Excess Deferred Income Taxes**									
215		Customer	TPLTCUS	$ (1,700,802)	$ (1,550,615)	$ (129,221)	$ (1,687)	$ (15,441)	$ —	$ —	$ (1,528)
216		Demand	TPLTDEM	$ (991,712)	$ (291,957)	$ (450,169)	$ (13,185)	$ (71,749)	$ —	$ —	$ (45,898)
217		Commodity	COM	$ (3,425)	$ (559)	$ (1,566)	$ (182)	$ (116)	$ —	$ —	$ (354)
218		**Total Excess Deferred Income Taxes**		$ (2,695,939)	$ (1,843,131)	$ (580,957)	$ (15,055)	$ (87,306)	$ —	$ —	$ (47,780)
219		**Negative Acquisition Adjustment on OPC Assets**									
220		Customer	DISPLTCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
221		Demand	DISPLTDEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
224		**Materials and Supplies**									
225		Customer	TPLTCUS	$ 1,930,906	$ 1,760,401	$ 146,704	$ 1,916	$ 17,530	$ —	$ —	$ 1,735
226		Demand	TPLTDEM	$ 1,125,882	$ 331,457	$ 511,073	$ 14,969	$ 81,456	$ —	$ —	$ 52,108
227		Commodity	COM	$ 3,889	$ 634	$ 1,778	$ 207	$ 132	$ —	$ —	$ 401
228		Total Materials and Supplies		$ 3,060,677	$ 2,092,492	$ 659,555	$ 17,092	$ 99,118	$ —	$ —	$ 54,244
229		**Prepayments**									
230		Customer	OPEXPCUS	$ 571,297	$ 518,161	$ 46,086	$ 729	$ 4,883	$ —	$ —	$ 567
231		Demand	OPEXPDEM	$ 423,349	$ 123,638	$ 192,812	$ 5,647	$ 30,731	$ —	$ —	$ 19,659
232		Commodity	COM	$ 12,221	$ 1,994	$ 5,589	$ 651	$ 416	$ —	$ —	$ 1,262
233		Total Prepayments		$ 1,006,867	$ 643,792	$ 244,486	$ 7,028	$ 36,029	$ —	$ —	$ 21,488
234		**Pension & FAS 106 Reg. Asset**									

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
235		Customer	OPEXPCUS	$ 2,327,083	$ 2,110,642	$ 187,723	$ 2,971	$ 19,891	$ —	$ —	$ 2,311
236		Demand	OPEXPDEM	$ 1,724,444	$ 503,618	$ 785,387	$ 23,003	$ 125,176	$ —	$ —	$ 80,076
237		Commodity	COM	$ 49,780	$ 8,123	$ 22,765	$ 2,652	$ 1,693	$ —	$ —	$ 5,140
238		Total Pen. & FAS 106 Reg. Asset		$ 4,101,307	$ 2,622,382	$ 995,875	$ 28,626	$ 146,760	$ —	$ —	$ 87,527
239		**DIMP Deferrals**									
240		Customer	TPLTCUS	$ 181,017	$ 165,033	$ 13,753	$ 180	$ 1,643	$ —	$ —	$ 163
241		Demand	TPLTDEM	$ 134,139	$ 39,490	$ 60,890	$ 1,783	$ 9,705	$ —	$ —	$ 6,208
242		Commodity	COM	$ 3,872	$ 632	$ 1,771	$ 206	$ 132	$ —	$ —	$ 400
243		Total DIMP Deferrals		$ 319,029	$ 205,155	$ 76,414	$ 2,169	$ 11,480	$ —	$ —	$ 6,771
244		**Regulatory Asset**									
245		Customer	TPLTCUS	$ 57,409	$ 52,340	$ 4,362	$ 57	$ 521	$ —	$ —	$ 52
246		Demand	TPLTDEM	$ 42,542	$ 12,524	$ 19,311	$ 566	$ 3,078	$ —	$ —	$ 1,969
247		Commodity	COM	$ 1,228	$ 200	$ 562	$ 65	$ 42	$ —	$ —	$ 127
248		**Total Regulatory Asset**		$ 101,180	$ 65,065	$ 24,235	$ 688	$ 3,641	$ —	$ —	$ 2,147
249		**Cash Working Capital**									
250		Customer	OPEXPCUS	$ (696,313)	$ (631,549)	$ (56,171)	$ (889)	$ (5,952)	$ —	$ —	$ (691)
251		Demand	OPEXPDEM	$ (515,990)	$ (150,693)	$ (235,005)	$ (6,883)	$ (37,455)	$ —	$ —	$ (23,961)
252		Commodity	COM	$ (14,895)	$ (2,430)	$ (6,812)	$ (794)	$ (507)	$ —	$ —	$ (1,538)
253		Total Cash Working Capital		$ (1,227,199)	$ (784,673)	$ (297,987)	$ (8,566)	$ (43,914)	$ —	$ —	$ (26,190)
254		**Total Rate Base**									
255		Customer		$ 133,569,724	$ 123,227,995	$ 8,750,205	$ 97,774	$ 1,221,929	$ —	$ —	$ 118,892
256		Demand		$ 88,010,824	$ 25,961,566	$ 39,917,800	$ 1,169,141	$ 6,362,170	$ —	$ —	$ 4,069,932
257		Commodity		$ 335,972	$ 54,820	$ 153,644	$ 17,898	$ 11,424	$ —	$ —	$ 34,688
258		Total Rate Base		$ 221,916,520	$ 149,244,382	$ 48,821,650	$ 1,284,814	$ 7,595,523	$ —	$ —	$ 4,223,512

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
1	301-303	**Intangible Plant**						
2		Customer	NONINCUS	$ —	$ —	$ —	$ —	$ —
3		Demand	NONINDEM	$ —	$ —	$ —	$ —	$ —
4		Commodity	COM	$ —	$ —	$ —	$ —	$ —
5		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —
6	365-371	**Transmission Plant**						
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 4,164,728	$ 1,717,829	$ —	$ —	$ —
9		Commodity	COM	$ 31,313	$ 3,800	$ —	$ —	$ —
10		Total Transmission Plant		$ 4,196,041	$ 1,721,630	$ —	$ —	$ —
11		**Distribution Plant**						
12	374	**Land & Land Rights - Allocated**						
13		Customer	376-379CUS	$ 11	$ 2	$ —	$ —	$ —
14		Demand	DEM	$ 1,647	$ 679	$ —	$ —	$ —
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 1,658	$ 681	$ —	$ —	$ —
17	374	**Land & Land Rights - DA**						
18		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ —	$ —	$ —	$ —	$ —
22	375	**Structures and Improvements**						
23		Customer	376-379CUS	$ 30	$ 5	$ —	$ —	$ —
24		Demand	DEM	$ 4,651	$ 1,919	$ —	$ —	$ —
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 4,682	$ 1,924	$ —	$ —	$ —
27	376	**Distribution Mains-Allocated**						
28		Customer	CUS	$ 24,256	$ 4,433	$ —	$ —	$ —
29		Demand	DEM	$ 3,084,331	$ 1,272,197	$ —	$ —	$ —
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 3,108,586	$ 1,276,630	$ —	$ —	$ —
32	376	**Odorization**						
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —
36		Total Odorization		$ —	$ —	$ —	$ —	$ —
37		**Distribution Mains - Directly Assn.**						
38		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
39		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ —	$ —	$ —	$ —	$ —
42	377	**Compressor Station Equipment**						
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**						
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 399,575	$ 164,813	$ —	$ —	$ —
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 399,575	$ 164,813	$ —	$ —	$ —
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**						
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —
57	378	**Odorization**						
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 13,373	$ 1,623	$ —	$ —	$ —
61		Total Odorization		$ 13,373	$ 1,623	$ —	$ —	$ —
62	379	**Meas. & Reg. Station - City Gate**						
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 267,770	$ 110,447	$ —	$ —	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 267,770	$ 110,447	$ —	$ —	$ —
67	379	**Odorization**						
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 2,879	$ 349	$ —	$ —	$ —
71		Total Odorization		$ 2,879	$ 349	$ —	$ —	$ —
72	380	**Services - Allocated**						
73		Customer	SERCUS-ALL	$ 59,794	$ 10,927	$ —	$ —	$ —
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 59,794	$ 10,927	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
77	380	**Services-Directly Assigned**						
78		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —
82	381	**Meters - Allocated**						
83		Customer	METCUS-ALL	$ 63,959	$ 12,338	$ —	$ —	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 63,959	$ 12,338	$ —	$ —	$ —
87	381	**Meters-Directly Assigned**						
88		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —
92	382	**Meter Installations**						
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**						
98		Customer	REGCUS-ALL	$ 31,533	$ 6,117	$ —	$ —	$ —
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 31,533	$ 6,117	$ —	$ —	$ —
102	383	**House Regulators - Directly Assigned**						
103		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ —	$ —	$ —	$ —	$ —
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**						
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 399,322	$ 164,709	$ —	$ —	$ —
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 399,322	$ 164,709	$ —	$ —	$ —
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**						
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ —	$ —	$ —	$ —	$ —
117	385	**Odorization**						
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ —	$ —	$ —	$ —	$ —
121		Total Odorization		$ —	$ —	$ —	$ —	$ —
122	386	**Other Prop.-Customer Premises**						
123		Customer	CUS	$ 3	$ 1	$ —	$ —	$ —
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 3	$ 1	$ —	$ —	$ —
127	387	**Other Equipment**						
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**						
133		Customer		$ 179,586	$ 33,822	$ —	$ —	$ —
134		Demand		$ 4,157,296	$ 1,714,764	$ —	$ —	$ —
135		Commodity		$ 16,252	$ 1,972	$ —	$ —	$ —
136		Total Distribution Plant		$ 4,353,133	$ 1,750,558	$ —	$ —	$ —
137		**General Plant**						
138		**General Plant - Allocated**						
139		Customer	GENPTCUS	$ 27,607	$ 5,152	$ —	$ —	$ —
140		Demand	DISPLTDEM	$ 641,777	$ 264,714	$ —	$ —	$ —
141		Commodity	COM	$ 13,982	$ 1,697	$ —	$ —	$ —
142		Total General Plant - Allocated		$ 683,366	$ 271,563	$ —	$ —	$ —
143		**Total General Plant - Directly Assigned**						
144		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ —	$ —	$ —	$ —	$ —
148		**Total General Plant**						
149		Customer		$ 27,607	$ 5,152	$ —	$ —	$ —
150		Demand		$ 641,777	$ 264,714	$ —	$ —	$ —
151		Commodity		$ 13,982	$ 1,697	$ —	$ —	$ —
152		Total General Plant		$ 683,366	$ 271,563	$ —	$ —	$ —
153		**Total Plant in Service**						

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
154		Customer		$ 207,193	$ 38,974	$ —	$ —	$ —
155		Demand		$ 8,963,801	$ 3,697,308	$ —	$ —	$ —
156		Commodity		$ 61,547	$ 7,470	$ —	$ —	$ —
157		Total Plant in Service		$ 9,232,540	$ 3,743,751	$ —	$ —	$ —
158		**Depreciation & Amort. Reserve**						
159		**Intangible Plant**						
160		Customer	NONINCUS	$ —	$ —	$ —	$ —	$ —
161		Demand	NONINDEM	$ —	$ —	$ —	$ —	$ —
162		Commodity	COM	$ —	$ —	$ —	$ —	$ —
163		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —
164		**Transmission Plant**						
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (226,868)	$ (93,576)	$ —	$ —	$ —
167		Commodity	COM	$ (6,172)	$ (749)	$ —	$ —	$ —
168		Total Transmission Plant		$ (233,040)	$ (94,325)	$ —	$ —	$ —
169		**Distribution Plant - Allocated**						
170		Customer	DISPLTCUS	$ (27,150)	$ (5,113)	$ —	$ —	$ —
171		Demand	DISPLTDEM	$ (558,171)	$ (230,229)	$ —	$ —	$ —
172		Commodity	COM	$ (114)	$ (14)	$ —	$ —	$ —
173		Total Distribution Plant - Allocated		$ (585,435)	$ (235,356)	$ —	$ —	$ —
174		**Distribution Plant - Dir. Assn.**						
175		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
176		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ —	$ —	$ —	$ —	$ —
179		**General Plant - Allocated**						
180		Customer	GENPTCUS	$ (9,482)	$ (1,769)	$ —	$ —	$ —
181		Demand	DISPLTDEM	$ (185,730)	$ (76,608)	$ —	$ —	$ —
182		Commodity	COM	$ (2,704)	$ (328)	$ —	$ —	$ —
183		Total General Plant - Allocated		$ (197,916)	$ (78,706)	$ —	$ —	$ —
184		**General Plant - Directly Assigned**						
185		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
186		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —
189		**Total Depr. & Amort. Reserve**						
190		Customer		$ (36,632)	$ (6,883)	$ —	$ —	$ —
191		Demand		$ (970,768)	$ (400,414)	$ —	$ —	$ —
192		Commodity		$ (8,991)	$ (1,091)	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
193		Total Depr. & Amortization Reserve		$ (1,016,391)	$ (408,388)	$ —	$ —	$ —
194		**Net Plant in Service**						
195		Customer		$ 170,561	$ 32,091	$ —	$ —	$ —
196		Demand		$ 7,993,032	$ 3,296,894	$ —	$ —	$ —
197		Commodity		$ 52,556	$ 6,379	$ —	$ —	$ —
198		Total Net Plant in Service		$ 8,216,149	$ 3,335,364	$ —	$ —	$ —
199		**Customer Deposits**						
200		Customer	DEPCUS	$ (34,395)	$ —	$ —	$ —	$ —
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (34,395)	$ —	$ —	$ —	$ —
204		**Customer Advances**						
205		Customer	MSCUS-ALL	$ (73)	$ (13)	$ —	$ —	$ —
206		Demand	DEM	$ (2,682)	$ (1,106)	$ —	$ —	$ —
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (2,755)	$ (1,119)	$ —	$ —	$ —
209		**Accum. Deferred Income Taxes**						
210		Customer	TPLTCUS	$ (16,188)	$ (3,045)	$ —	$ —	$ —
211		Demand	TPLTDEM	$ (700,334)	$ (288,867)	$ —	$ —	$ —
212		Commodity	COM	$ (4,809)	$ (584)	$ —	$ —	$ —
213		Total Accum. Deferred Inc. Taxes		$ (721,330)	$ (292,496)	$ —	$ —	$ —
214		**Excess Deferred Income Taxes**						
215		Customer	TPLTCUS	$ (1,943)	$ (366)	$ —	$ —	$ —
216		Demand	TPLTDEM	$ (84,075)	$ (34,678)	$ —	$ —	$ —
217		Commodity	COM	$ (577)	$ (70)	$ —	$ —	$ —
218		**Total Excess Deferred Income Taxes**		$ (86,596)	$ (35,114)	$ —	$ —	$ —
219		**Negative Acquisition Adjustment on OPC Assets**						
220		Customer	DISPLTCUS	$ —	$ —	$ —	$ —	$ —
221		Demand	DISPLTDEM	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ —	$ —	$ —	$ —	$ —
224		**Materials and Supplies**						
225		Customer	TPLTCUS	$ 2,206	$ 415	$ —	$ —	$ —
226		Demand	TPLTDEM	$ 95,450	$ 39,370	$ —	$ —	$ —
227		Commodity	COM	$ 655	$ 80	$ —	$ —	$ —
228		Total Materials and Supplies		$ 98,311	$ 39,865	$ —	$ —	$ —
229		**Prepayments**						
230		Customer	OPEXPCUS	$ 732	$ 139	$ —	$ —	$ —
231		Demand	OPEXPDEM	$ 36,010	$ 14,853	$ —	$ —	$ —
232		Commodity	COM	$ 2,060	$ 250	$ —	$ —	$ —
233		Total Prepayments		$ 38,802	$ 15,242	$ —	$ —	$ —
234		**Pension & FAS 106 Reg. Asset**						

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(m)
235		Customer	OPEXPCUS	$ 2,981	$ 565	$ —	$ —	$ —
236		Demand	OPEXPDEM	$ 146,681	$ 60,502	$ —	$ —	$ —
237		Commodity	COM	$ 8,390	$ 1,018	$ —	$ —	$ —
238		Total Pen. & FAS 106 Reg. Asset		$ 158,052	$ 62,085	$ —	$ —	$ —
239		**DIMP Deferrals**						
240		Customer	TPLTCUS	$ 207	$ 39	$ —	$ —	$ —
241		Demand	TPLTDEM	$ 11,372	$ 4,691	$ —	$ —	$ —
242		Commodity	COM	$ 653	$ 79	$ —	$ —	$ —
243		Total DIMP Deferrals		$ 12,231	$ 4,809	$ —	$ —	$ —
244		**Regulatory Asset**						
245		Customer	TPLTCUS	$ 66	$ 12	$ —	$ —	$ —
246		Demand	TPLTDEM	$ 3,607	$ 1,488	$ —	$ —	$ —
247		Commodity	COM	$ 207	$ 25	$ —	$ —	$ —
248		**Total Regulatory Asset**		$ 3,879	$ 1,525	$ —	$ —	$ —
249		**Cash Working Capital**						
250		Customer	OPEXPCUS	$ (892)	$ (169)	$ —	$ —	$ —
251		Demand	OPEXPDEM	$ (43,890)	$ (18,103)	$ —	$ —	$ —
252		Commodity	COM	$ (2,510)	$ (305)	$ —	$ —	$ —
253		Total Cash Working Capital		$ (47,292)	$ (18,577)	$ —	$ —	$ —
254		**Total Rate Base**						
255		Customer		$ 123,261	$ 29,668	$ —	$ —	$ —
256		Demand		$ 7,455,172	$ 3,075,042	$ —	$ —	$ —
257		Commodity		$ 56,624	$ 6,873	$ —	$ —	$ —
258		Total Rate Base		$ 7,635,057	$ 3,111,583	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1		**Transmission and Distribution Op. Exp.**									
2	814-865	**Transmission Expenses**									
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 5,488,388	$ 1,676,603	$ 2,452,214	$ 71,822	$ 390,838	$ —	$ —	$ 250,022
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 5,488,388	$ 1,676,603	$ 2,452,214	$ 71,822	$ 390,838	$ —	$ —	$ 250,022
7	8650	**Odorization**									
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
11		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
12	8700	**Operation Supervision & Engineering**									
13		Customer	871-879CUS	$ 344,706	$ 309,027	$ 30,409	$ 533	$ 3,425	$ —	$ —	$ 512
14		Demand	DEM	$ 82,252	$ 25,127	$ 36,750	$ 1,076	$ 5,857	$ —	$ —	$ 3,747
15		Commodity	COM	$ 4,660	$ 760	$ 2,131	$ 248	$ 158	$ —	$ —	$ 481
16		Total Supervision & Engineering		$ 431,618	$ 334,913	$ 69,290	$ 1,858	$ 9,441	$ —	$ —	$ 4,740
17	8710	**Distribution Load Dispatch**									
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 53,185	$ 8,678	$ 24,322	$ 2,833	$ 1,809	$ —	$ —	$ 5,491
21		Total Distribution Load Dispatch		$ 53,185	$ 8,678	$ 24,322	$ 2,833	$ 1,809	$ —	$ —	$ 5,491
22	8740	**Mains & Services - Allocated**									
23		Customer	MSCUS-ALL	$ 2,160,718	$ 1,986,662	$ 150,760	$ 1,469	$ 18,828	$ —	$ —	$ 1,234
24		Demand	DEM	$ 656,044	$ 200,410	$ 293,121	$ 8,585	$ 46,718	$ —	$ —	$ 29,886
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 2,816,762	$ 2,187,071	$ 443,881	$ 10,054	$ 65,546	$ —	$ —	$ 31,120
27	8740	**Mains & Services - Dir. Assn.**									
28		Customer	MSCUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
32	8740	**Odorization**									
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
36		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
37	8750	**Meas. & Reg. Station - Gen. - Allocated**									
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 213,445	$ 65,204	$ 95,368	$ 2,793	$ 15,200	$ —	$ —	$ 9,723
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 213,445	$ 65,204	$ 95,368	$ 2,793	$ 15,200	$ —	$ —	$ 9,723
42		**Meas. & Reg. Station - Gen. - DA**									
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	8750	**Odorization**									
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 95,703	$ 15,616	$ 43,766	$ 5,098	$ 3,254	$ —	$ —	$ 9,881
51		Total Odorization		$ 95,703	$ 15,616	$ 43,766	$ 5,098	$ 3,254	$ —	$ —	$ 9,881
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**									
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 25,374	$ —	$ 16,324	$ 478	$ 2,602	$ —	$ —	$ 1,664
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 25,374	$ —	$ 16,324	$ 478	$ 2,602	$ —	$ —	$ 1,664
57	8760	**Meas. & Reg. Stat. - Ind. - DA**									
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
62	8770	**Meas. & Reg. Stat.- City Gate**									
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 43,956	$ 13,428	$ 19,640	$ 575	$ 3,130	$ —	$ —	$ 2,002
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 43,956	$ 13,428	$ 19,640	$ 575	$ 3,130	$ —	$ —	$ 2,002
67	8780	**Meter & House Reg. Exp. - Alloc.**									
68		Customer	MTRGCUS-ALL	$ 1,771,500	$ 1,538,604	$ 196,078	$ 4,612	$ 20,238	$ —	$ —	$ 4,609

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
71		Total Meter & House Reg. Exp. - Alloc.		$ 1,771,500	$ 1,538,604	$ 196,078	$ 4,612	$ 20,238	$ —	$ —	$ 4,609
72	8780	**Meter & House Reg. Exp - Dir. Assn.**									
73		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
77	8780	**Odorization**									
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
82	8790	**Customer Installation Expense**									
83		Customer	METCUS-ALL	$ 2,227	$ 1,940	$ 245	$ 5	$ 24	$ —	$ —	$ 5
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 2,227	$ 1,940	$ 245	$ 5	$ 24	$ —	$ —	$ 5
87	8800	**Other Expenses**									
88		Customer	871-879CUS	$ 280,982	$ 251,899	$ 24,787	$ 435	$ 2,792	$ —	$ —	$ 418
89		Demand	DEM	$ 67,047	$ 20,482	$ 29,957	$ 877	$ 4,775	$ —	$ —	$ 3,054
90		Commodity	COM	$ 3,798	$ 620	$ 1,737	$ 202	$ 129	$ —	$ —	$ 392
91		Total Other Expenses		$ 351,827	$ 273,000	$ 56,481	$ 1,514	$ 7,695	$ —	$ —	$ 3,864
92	8800	**Odorization**									
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 652	$ 106	$ 298	$ 35	$ 22	$ —	$ —	$ 67
96		Total Odorization		$ 652	$ 106	$ 298	$ 35	$ 22	$ —	$ —	$ 67
97	8810	**Rents**									
98		Customer	871-879CUS	$ 12,343	$ 11,065	$ 1,089	$ 19	$ 123	$ —	$ —	$ 18
99		Demand	DEM	$ 2,945	$ 900	$ 1,316	$ 39	$ 210	$ —	$ —	$ 134
100		Commodity	COM	$ 167	$ 27	$ 76	$ 9	$ 6	$ —	$ —	$ 17
101		Total Rents		$ 15,455	$ 11,992	$ 2,481	$ 67	$ 338	$ —	$ —	$ 170
102	8820	**Corporate & Div. Exp.**									

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**									
108		Customer		$ 4,572,476	$ 4,099,196	$ 403,368	$ 7,074	$ 45,429	$ —	$ —	$ 6,796
109		Demand		$ 6,579,452	$ 2,002,152	$ 2,944,689	$ 86,246	$ 469,330	$ —	$ —	$ 300,234
110		Commodity		$ 158,165	$ 25,808	$ 72,331	$ 8,426	$ 5,378	$ —	$ —	$ 16,330
111		Total Distr. & Trans. Operations Exp.		$ 11,310,094	$ 6,127,156	$ 3,420,388	$ 101,746	$ 520,137	$ —	$ —	$ 323,361
112		**Distribution Maintenance Expenses**									
113	8850	**Maintenance Supervision and Engineering**									
114		Customer	887-893CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
115		Demand	887-893DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
118	8860	**Structures and Improvements**									
119		Customer	887-893CUS	$ 173,851	$ 160,295	$ 11,766	$ 112	$ 1,458	$ —	$ —	$ 91
120		Demand	887-893DEM	$ 252,023	$ 61,986	$ 122,256	$ 3,581	$ 19,485	$ —	$ —	$ 12,465
121		Commodity	COM	$ 11,165	$ 1,822	$ 5,106	$ 595	$ 380	$ —	$ —	$ 1,153
122		Total Structures and Improvements		$ 437,039	$ 224,102	$ 139,128	$ 4,287	$ 21,323	$ —	$ —	$ 13,708
123	8870	**Maintenance of Mains-Allocated**									
124		Customer	CUS	$ 742,984	$ 688,754	$ 47,279	$ 425	$ 5,758	$ —	$ —	$ 316
125		Demand	DEM	$ 582,278	$ 177,875	$ 260,162	$ 7,620	$ 41,465	$ —	$ —	$ 26,526
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 1,325,262	$ 866,630	$ 307,441	$ 8,045	$ 47,223	$ —	$ —	$ 26,842
128	8870	**Maintenance of Mains - Directly Assigned**									
129		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**									
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 854,498	$ 261,033	$ 381,790	$ 11,182	$ 60,850	$ —	$ —	$ 38,926
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 854,498	$ 261,033	$ 381,790	$ 11,182	$ 60,850	$ —	$ —	$ 38,926
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**									
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
143	8890	**Odorization**									
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 80,021	$ 13,057	$ 36,595	$ 4,263	$ 2,721	$ —	$ —	$ 8,262
147		Total Odorization		$ 80,021	$ 13,057	$ 36,595	$ 4,263	$ 2,721	$ —	$ —	$ 8,262
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**									
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 351,993	$ —	$ 226,446	$ 6,632	$ 36,091	$ —	$ —	$ 23,088
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 351,993	$ —	$ 226,446	$ 6,632	$ 36,091	$ —	$ —	$ 23,088
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**									
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**									
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 17,564	$ 5,366	$ 7,848	$ 230	$ 1,251	$ —	$ —	$ 800
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 17,564	$ 5,366	$ 7,848	$ 230	$ 1,251	$ —	$ —	$ 800
163	8910	**Odorization**									
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
167		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
168	8920	**Services - Allocated**									
169		Customer	SERCUS-ALL	$ 503,061	$ 460,130	$ 37,054	$ 376	$ 4,690	$ —	$ —	$ 334
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 503,061	$ 460,130	$ 37,054	$ 376	$ 4,690	$ —	$ —	$ 334
173	8920	**Services - Directly Assigned**									
174		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178	8930	**Meters & House Regulators - Alloc.**									
179		Customer	MTRGCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
183	8930	**Meters & House Regulators - DA**									
184		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188	8940	**Maintenance of Other Equipment**									
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**									
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**									
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**									
204		Customer		$ 1,419,895	$ 1,309,178	$ 96,099	$ 913	$ 11,906	$ —	$ —	$ 741

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
205		Demand		$ 2,058,356	$ 506,261	$ 998,501	$ 29,245	$ 159,143	$ —	$ —	$ 101,805
206		Commodity		$ 91,186	$ 14,879	$ 41,700	$ 4,858	$ 3,101	$ —	$ —	$ 9,415
207		Total Distr. Maintenance Expense		$ 3,569,438	$ 1,830,318	$ 1,136,300	$ 35,016	$ 174,149	$ —	$ —	$ 111,960
208		**Total Oper. & Maint. Expense**									
209		Customer		$ 5,992,371	$ 5,408,374	$ 499,467	$ 7,987	$ 57,335	$ —	$ —	$ 7,537
210		Demand		$ 8,637,809	$ 2,508,413	$ 3,943,190	$ 115,491	$ 628,473	$ —	$ —	$ 402,039
211		Commodity		$ 249,351	$ 40,686	$ 114,031	$ 13,284	$ 8,479	$ —	$ —	$ 25,745
212		Total Operations & Maint. Expense		$ 14,879,531	$ 7,957,473	$ 4,556,688	$ 136,762	$ 694,287	$ —	$ —	$ 435,321
213		**Customer Accounts Expense**									
214	901	**Supervision**									
215		Customer	902-904CUS	$ 59	$ 53	$ 5	$ 0	$ 0	$ —	$ —	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 59	$ 53	$ 5	$ 0	$ 0	$ —	$ —	$ 0
219	902	**Meter Reading Expense**									
220		Customer	METCUS-TOT	$ 403,018	$ 351,014	$ 44,388	$ 917	$ 4,414	$ —	$ —	$ 884
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 403,018	$ 351,014	$ 44,388	$ 917	$ 4,414	$ —	$ —	$ 884
224	903	**Customer Accounting**									
225		Customer	903CUS	$ 1,059,614	$ 997,473	$ 57,963	$ 456	$ 3,357	$ —	$ —	$ 150
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 1,059,614	$ 997,473	$ 57,963	$ 456	$ 3,357	$ —	$ —	$ 150
229	904	**Bad Debt Expense**									
230		Customer	904CUS	$ 593,604	$ 512,142	$ 78,648	$ 2,814	$ —	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ 593,604	$ 512,142	$ 78,648	$ 2,814	$ —	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**									
235		Customer	902-904CUS	$ 79,908	$ 72,306	$ 7,034	$ 163	$ 302	$ —	$ —	$ 40
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 79,908	$ 72,306	$ 7,034	$ 163	$ 302	$ —	$ —	$ 40

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
239	907-910	**Customer Information Expense**									
240		Customer	CUS	$ 237,686	$ 220,337	$ 15,125	$ 136	$ 1,842	$ —	$ —	$ 101
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 237,686	$ 220,337	$ 15,125	$ 136	$ 1,842	$ —	$ —	$ 101
244		**Sales and Advertising Expense**									
245	911	**Supervision**									
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**									
251		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
255	913	**Advertising**									
256		Customer	CUS	$ 7,711	$ 7,148	$ 491	$ 4	$ 60	$ —	$ —	$ 3
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 7,711	$ 7,148	$ 491	$ 4	$ 60	$ —	$ —	$ 3
260	914	**Employee Sales Referrals**									
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**									
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**									
271	920-940	**Administrative & General Expenses**									
272		Customer	OPEXPCUS	$ 5,415,032	$ 4,911,381	$ 436,823	$ 6,914	$ 46,285	$ —	$ —	$ 5,377

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
273		Demand	OPEXPDEM	$ 1,580,286	$ 461,517	$ 719,731	$ 21,080	$ 114,712	$ —	$ —	$ 73,382
274		Commodity	COM	$ 45,619	$ 7,444	$ 20,862	$ 2,430	$ 1,551	$ —	$ —	$ 4,710
275		Total Administrative & General Exp.		$ 7,040,937	$ 5,380,342	$ 1,177,417	$ 30,424	$ 162,549	$ —	$ —	$ 83,470
276		**Depreciation & Amortization Expense**									
277	301-303	**Intangible Plant - Allocated**									
278		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
279		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
280		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
281		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
282	301-303	**Intangible Plant - Directly Assigned**									
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**									
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**									
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 49,857	$ 15,230	$ 22,276	$ 652	$ 3,550	$ —	$ —	$ 2,271
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ 49,857	$ 15,230	$ 22,276	$ 652	$ 3,550	$ —	$ —	$ 2,271
297	367	**Transmission Mains**									
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 1,022,631	$ 312,395	$ 456,912	$ 13,382	$ 72,823	$ —	$ —	$ 46,586
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 1,022,631	$ 312,395	$ 456,912	$ 13,382	$ 72,823	$ —	$ —	$ 46,586
302	368	**Compression Station Equipment**									
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ 3,937	$ 1,203	$ 1,759	$ 52	$ 280	$ —	$ —	$ 179
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ 3,937	$ 1,203	$ 1,759	$ 52	$ 280	$ —	$ —	$ 179

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
307	369	**Meas. & Reg. Station Equipment**									
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 471,437	$ 144,016	$ 210,638	$ 6,169	$ 33,572	$ —	$ —	$ 21,476
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 471,437	$ 144,016	$ 210,638	$ 6,169	$ 33,572	$ —	$ —	$ 21,476
312	369	**Odorization**									
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ 6,540	$ 1,067	$ 2,991	$ 348	$ 222	$ —	$ —	$ 675
316		Total Odorization		$ 6,540	$ 1,067	$ 2,991	$ 348	$ 222	$ —	$ —	$ 675
317	371	**Other Equipment**									
318		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
319		Demand	DEM	$ 2,818	$ 861	$ 1,259	$ 37	$ 201	$ —	$ —	$ 128
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
321		Total Other Equipment		$ 2,818	$ 861	$ 1,259	$ 37	$ 201	$ —	$ —	$ 128
322	375	**Structures and Improvements**									
323		Customer	376-379CUS	$ 2,731	$ 2,531	$ 174	$ 2	$ 21	$ —	$ —	$ 1
324		Demand	DEM	$ 2,603	$ 795	$ 1,163	$ 34	$ 185	$ —	$ —	$ 119
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Structures and Improvements		$ 5,334	$ 3,327	$ 1,337	$ 36	$ 207	$ —	$ —	$ 120
327	376	**Distribution Mains - Allocated**									
328		Customer	CUS	$ 1,413,467	$ 1,310,299	$ 89,944	$ 809	$ 10,954	$ —	$ —	$ 601
329		Demand	DEM	$ 1,107,737	$ 338,394	$ 494,937	$ 14,496	$ 78,884	$ —	$ —	$ 50,463
330		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
331		Total Distribution Mains - Allocated		$ 2,521,204	$ 1,648,692	$ 584,881	$ 15,305	$ 89,838	$ —	$ —	$ 51,064
332	376	**Distribution Mains - Directly Assigned**									
333		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
336		Distribution Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
337	376	**Odorization**									
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
341		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
342	377	**Compressor Station Equipment**									
343		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
345		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
346		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
347	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**									
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ 127,761	$ 39,029	$ 57,084	$ 1,672	$ 9,098	$ —	$ —	$ 5,820
350		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
351		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 127,761	$ 39,029	$ 57,084	$ 1,672	$ 9,098	$ —	$ —	$ 5,820
352	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**									
353		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
355		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
357	378	**Odorization**									
358		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM	$ 4,541	$ 741	$ 2,076	$ 242	$ 154	$ —	$ —	$ 469
361		Total Odorization		$ 4,541	$ 741	$ 2,076	$ 242	$ 154	$ —	$ —	$ 469
362	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**									
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ 70,918	$ 21,664	$ 31,686	$ 928	$ 5,050	$ —	$ —	$ 3,231
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
366		Total Meas. & Reg. Sta. Eq.- City Gate		$ 70,918	$ 21,664	$ 31,686	$ 928	$ 5,050	$ —	$ —	$ 3,231
367	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**									
368		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
369		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
371		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
372	379	**Odorization**									
373		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
374		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
375		Commodity	COM	$ 377	$ 62	$ 173	$ 20	$ 13	$ —	$ —	$ 39
376		Total Odorization		$ 377	$ 62	$ 173	$ 20	$ 13	$ —	$ —	$ 39
377	380	**Services - Allocated**									
378		Customer	SERCUS-ALL	$ 2,798,442	$ 2,559,625	$ 206,123	$ 2,094	$ 26,090	$ —	$ —	$ 1,857
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
381		Total Services - Allocated		$ 2,798,442	$ 2,559,625	$ 206,123	$ 2,094	$ 26,090	$ —	$ —	$ 1,857
382	380	**Services - Directly Assigned**									
383		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
386		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
387	381	**Meters - Allocated**									
388		Customer	METCUS-ALL	$ 959,674	$ 835,841	$ 105,698	$ 2,184	$ 10,510	$ —	$ —	$ 2,106
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
391		Total Meters - Allocated		$ 959,674	$ 835,841	$ 105,698	$ 2,184	$ 10,510	$ —	$ —	$ 2,106
392	381	**Meters - Directly Assigned**									
393		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
394		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
396		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
397	382	**Meter Installations**									
398		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
399		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
401		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
402	383	**House Regulators - Allocated**									
403		Customer	REGCUS-ALL	$ 213,071	$ 182,636	$ 24,126	$ 881	$ 2,905	$ —	$ —	$ 960
404		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
406		Total House Regulators - Allocated		$ 213,071	$ 182,636	$ 24,126	$ 881	$ 2,905	$ —	$ —	$ 960
407	383	**House Regulators - Directly Assn.**									
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
411		House Regulators - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
412	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**									
413		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
414		Demand	NRDEM	$ 74,665	$ —	$ 48,034	$ 1,407	$ 7,656	$ —	$ —	$ 4,897
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
416		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 74,665	$ —	$ 48,034	$ 1,407	$ 7,656	$ —	$ —	$ 4,897
417	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**									
418		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
421		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
422	385	**Odorization**									
423		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
424		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
425		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
426		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
427	386	**Other Prop.- Customer Premises**									
428		Customer	CUS	$ 1,371	$ 1,271	$ 87	$ 1	$ 11	$ —	$ —	$ 1
429		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
430		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
431		Total Other Prop. - Customer Premises		$ 1,371	$ 1,271	$ 87	$ 1	$ 11	$ —	$ —	$ 1
432	387	**Other Equipment**									
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
435		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
436		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
437	389-98	**General Plant - Allocated**									
438		Customer	GENPTCUS	$ 1,809,244	$ 1,662,313	$ 127,118	$ 1,443	$ 15,312	$ —	$ —	$ 1,229
439		Demand	DISPLTDEM	$ 332,850	$ 94,692	$ 153,213	$ 4,487	$ 24,419	$ —	$ —	$ 15,621
440		Commodity	COM	$ 5,195	$ 848	$ 2,376	$ 277	$ 177	$ —	$ —	$ 536
441		Total General Plant - Allocated		$ 2,147,289	$ 1,757,852	$ 282,707	$ 6,207	$ 39,908	$ —	$ —	$ 17,387
442	389-98	**General Plant - Directly Assigned**									

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
443		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
444		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
445		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
446		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
447	389-98	**General Plant - Odorization**									
448		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
449		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
450		Commodity	COM	$ 4,541	$ 741	$ 2,076	$ 242	$ 154	$ —	$ —	$ 469
451		Total General Plant - Odorization		$ 4,541	$ 741	$ 2,076	$ 242	$ 154	$ —	$ —	$ 469
452	40730	**Pension & FAS 106 Amort. Expense**									
453		Customer	CUS	$ 13,050	$ 12,097	$ 830	$ 7	$ 101	$ —	$ —	$ 6
454		Demand	DEM	$ 9,670	$ 2,954	$ 4,321	$ 127	$ 689	$ —	$ —	$ 441
455		Commodity	COM	$ 279	$ 46	$ 128	$ 15	$ 9	$ —	$ —	$ 29
456		Total Pension & FAS 106 Amort. Exp.		$ 22,999	$ 15,097	$ 5,279	$ 149	$ 799	$ —	$ —	$ 475
457		**Total Depreciation & Amort. Exp.**									
458		Customer		$ 7,211,049	$ 6,566,613	$ 554,101	$ 7,421	$ 65,905	$ —	$ —	$ 6,761
459		Demand		$ 3,276,884	$ 971,232	$ 1,483,282	$ 43,443	$ 236,408	$ —	$ —	$ 151,232
460		Commodity		$ 21,472	$ 3,504	$ 9,820	$ 1,144	$ 730	$ —	$ —	$ 2,217
461		Total Depreciation & Amort. Expense		$ 10,509,406	$ 7,541,348	$ 2,047,203	$ 52,008	$ 303,043	$ —	$ —	$ 160,210
462		**Taxes Other Than Income**									
463	4081	**Payroll and Other Taxes**									
464		Customer	OPEXPCUS	$ 400,463	$ 363,216	$ 32,305	$ 511	$ 3,423	$ —	$ —	$ 398
465		Demand	OPEXPDEM	$ 296,756	$ 86,666	$ 135,156	$ 3,959	$ 21,541	$ —	$ —	$ 13,780
466		Commodity	COM	$ 8,567	$ 1,398	$ 3,918	$ 456	$ 291	$ —	$ —	$ 884
467		Total Payroll and Other Taxes		$ 705,785	$ 451,280	$ 171,378	$ 4,926	$ 25,256	$ —	$ —	$ 15,062
468	4081	**Ad Valorem Taxes - Allocated**									
469		Customer	CUS	$ 1,130,371	$ 1,047,866	$ 71,929	$ 647	$ 8,760	$ —	$ —	$ 481
470		Demand	DEM	$ 659,102	$ 201,344	$ 294,487	$ 8,625	$ 46,936	$ —	$ —	$ 30,025
471		Commodity	COM	$ 2,276	$ 371	$ 1,041	$ 121	$ 77	$ —	$ —	$ 235
472		Total Ad Valorem Taxes - Allocated		$ 1,791,750	$ 1,249,581	$ 367,458	$ 9,393	$ 55,773	$ —	$ —	$ 30,741
473	4081	**Ad Valorem Taxes - Directly Assn.**									
474		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
475		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
477		Total Ad Valorem Taxes - Directly Assn.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
478		**Revenue Related Taxes**									
479		Customer	TOTREVCUS	$ 53,062	$ 28,565	$ 19,042	$ 1,664	$ 1,895	$ —	$ —	$ 616
480		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
481		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
482		Total Revenue Related Taxes		$ 53,062	$ 28,565	$ 19,042	$ 1,664	$ 1,895	$ —	$ —	$ 616
483		**Total Taxes Other Than Income**									

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COM. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
484		Customer		$ 1,583,896	$ 1,439,647	$ 123,277	$ 2,822	$ 14,079	$ —	$ —	$ 1,495
485		Demand		$ 955,858	$ 288,010	$ 429,643	$ 12,584	$ 68,477	$ —	$ —	$ 43,805
486		Commodity		$ 10,843	$ 1,769	$ 4,959	$ 578	$ 369	$ —	$ —	$ 1,120
487		Total Taxes Other Than Income		$ 2,550,597	$ 1,729,426	$ 557,878	$ 15,984	$ 82,925	$ —	$ —	$ 46,420
488		**Excess Def. Income Tax Amort. - Directly Assn.**									
489		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
490		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
491		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
492		**Total Excess Def. Income Tax Amort. - DA**		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
493		**Excess Def. Income Tax Amort. - Alloc.**									
494		Customer	CUS	$ (67,623)	$ (62,687)	$ (4,303)	$ (39)	$ (524)	$ —	$ —	$ (29)
495		Demand	DEM	$ (43,206)	$ (13,199)	$ (19,304)	$ (565)	$ (3,077)	$ —	$ —	$ (1,968)
496		Commodity	COM	$ (143)	$ (23)	$ (65)	$ (8)	$ (5)	$ —	$ —	$ (15)
497		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (110,971)	$ (75,909)	$ (23,673)	$ (612)	$ (3,606)	$ —	$ —	$ (2,012)
498		**Interest on Customer Deposits**									
499		Customer	DEPCUS	$ 126,959	$ 39,577	$ 82,597	$ 1,975	$ 821	$ —	$ —	$ 252
500		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
501		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
502		Total Interest on Cust. Deposits		$ 126,959	$ 39,577	$ 82,597	$ 1,975	$ 821	$ —	$ —	$ 252
503		**Req. Return - Other Than Directly Assn.**									
504		Customer	CUS	$ 10,840,231	$ 10,049,009	$ 689,802	$ 6,203	$ 84,010	$ —	$ —	$ 4,613
505		Demand	DEM	$ 6,926,136	$ 2,115,809	$ 3,094,601	$ 90,637	$ 493,223	$ —	$ —	$ 315,519
506		Commodity	COM	$ 22,889	$ 3,735	$ 10,467	$ 1,219	$ 778	$ —	$ —	$ 2,363
507		Tot. Req. Return - Other Than Dir. Assn.		$ 17,789,255	$ 12,168,553	$ 3,794,870	$ 98,059	$ 578,011	$ —	$ —	$ 322,495
508		**Req. Return - Directly Assigned**									
509		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
510		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
511		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
512		Tot. Req. Return - Directly Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
513		**Income Taxes - Other Than DA**									
514		Customer	CUS	$ 2,243,126	$ 2,079,402	$ 142,738	$ 1,284	$ 17,384	$ —	$ —	$ 955
515		Demand	DEM	$ 1,433,198	$ 437,816	$ 640,353	$ 18,755	$ 102,061	$ —	$ —	$ 65,289
516		Commodity	COM	$ 4,736	$ 773	$ 2,166	$ 252	$ 161	$ —	$ —	$ 489
517		Total Income Taxes - Other Than DA		$ 3,681,060	$ 2,517,990	$ 785,257	$ 20,291	$ 119,606	$ —	$ —	$ 66,733
518		**Income Taxes - Directly Assigned**									
519		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
520		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
521		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
522		Total Income Taxes - Dir. Assigned		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
523		**Total Cost of Service Before Revenue Credits**									
524		Customer		$ 35,726,640	$ 32,591,790	$ 2,728,156	$ 39,058	$ 295,268	$ —	$ —	$ 28,140
525		Demand		$ 22,766,964	$ 6,769,598	$ 10,291,496	$ 301,425	$ 1,640,277	$ —	$ —	$ 1,049,299
526		Commodity		$ 354,768	$ 57,887	$ 162,240	$ 18,900	$ 12,064	$ —	$ —	$ 36,629
527		**Total Cost of Service Before Revenue Credits**		$ 58,848,372	$ 39,419,275	$ 13,181,892	$ 359,382	$ 1,947,609	$ —	$ —	$ 1,114,068

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
1		**Transmission and Distribution Op. Exp.**						
2	814-865	**Transmission Expenses**						
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 457,983	$ 188,905	$ —	$ —	$ —
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 457,983	$ 188,905	$ —	$ —	$ —
7	8650	**Odorization**						
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ —	$ —	$ —	$ —	$ —
11		Total Odorization		$ —	$ —	$ —	$ —	$ —
12	8700	**Operation Supervision & Engineering**						
13		Customer	871-879CUS	$ 672	$ 128	$ —	$ —	$ —
14		Demand	DEM	$ 6,864	$ 2,831	$ —	$ —	$ —
15		Commodity	COM	$ 785	$ 95	$ —	$ —	$ —
16		Total Supervision & Engineering		$ 8,321	$ 3,055	$ —	$ —	$ —
17	8710	**Distribution Load Dispatch**						
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 8,964	$ 1,088	$ —	$ —	$ —
21		Total Distribution Load Dispatch		$ 8,964	$ 1,088	$ —	$ —	$ —
22	8740	**Mains & Services - Allocated**						
23		Customer	MSCUS-ALL	$ 1,492	$ 273	$ —	$ —	$ —
24		Demand	DEM	$ 54,744	$ 22,580	$ —	$ —	$ —
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 56,236	$ 22,853	$ —	$ —	$ —
27	8740	**Mains & Services - Dir. Assn.**						
28		Customer	MSCUS-DA	$ —	$ —	$ —	$ —	$ —
29		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ —	$ —	$ —	$ —	$ —
32	8740	**Odorization**						
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
35		Commodity	COM	$ —	$ —	$ —	$ —	$ —
36		Total Odorization		$ —	$ —	$ —	$ —	$ —
37	8750	**Meas. & Reg. Station - Gen. - Allocated**						
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 17,811	$ 7,347	$ —	$ —	$ —
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 17,811	$ 7,347	$ —	$ —	$ —
42		**Meas. & Reg. Station - Gen. - DA**						
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ —	$ —	$ —	$ —	$ —
47	8750	**Odorization**						
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 16,130	$ 1,958	$ —	$ —	$ —
51		Total Odorization		$ 16,130	$ 1,958	$ —	$ —	$ —
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**						
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 3,049	$ 1,257	$ —	$ —	$ —
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 3,049	$ 1,257	$ —	$ —	$ —
57	8760	**Meas. & Reg. Stat. - Ind. - DA**						
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ —	$ —	$ —	$ —	$ —
62	8770	**Meas. & Reg. Stat.- City Gate**						
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 3,668	$ 1,513	$ —	$ —	$ —
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 3,668	$ 1,513	$ —	$ —	$ —
67	8780	**Meter & House Reg. Exp. - Alloc.**						
68		Customer	MTRGCUS-ALL	$ 6,167	$ 1,192	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —
71		Total Meter & House Reg. Exp. - Alloc.		$ 6,167	$ 1,192	$ —	$ —	$ —
72	8780	**Meter & House Reg. Exp - Dir. Assn.**						
73		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ —	$ —	$ —	$ —	$ —
77	8780	**Odorization**						
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ —	$ —	$ —	$ —	$ —
81		Total Odorization		$ —	$ —	$ —	$ —	$ —
82	8790	**Customer Installation Expense**						
83		Customer	METCUS-ALL	$ 6	$ 1	$ —	$ —	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 6	$ 1	$ —	$ —	$ —
87	8800	**Other Expenses**						
88		Customer	871-879CUS	$ 547	$ 105	$ —	$ —	$ —
89		Demand	DEM	$ 5,595	$ 2,308	$ —	$ —	$ —
90		Commodity	COM	$ 640	$ 78	$ —	$ —	$ —
91		Total Other Expenses		$ 6,782	$ 2,490	$ —	$ —	$ —
92	8800	**Odorization**						
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 110	$ 13	$ —	$ —	$ —
96		Total Odorization		$ 110	$ 13	$ —	$ —	$ —
97	8810	**Rents**						
98		Customer	871-879CUS	$ 24	$ 5	$ —	$ —	$ —
99		Demand	DEM	$ 246	$ 101	$ —	$ —	$ —
100		Commodity	COM	$ 28	$ 3	$ —	$ —	$ —
101		Total Rents		$ 298	$ 109	$ —	$ —	$ —
102	8820	**Corporate & Div. Exp.**						

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**						
108		Customer		$ 8,909	$ 1,703	$ —	$ —	$ —
109		Demand		$ 549,959	$ 226,842	$ —	$ —	$ —
110		Commodity		$ 26,657	$ 3,235	$ —	$ —	$ —
111		Total Distr. & Trans. Operations Exp.		$ 585,525	$ 231,781	$ —	$ —	$ —
112		**Distribution Maintenance Expenses**						
113	8850	**Maintenance Supervision and Engineering**						
114		Customer	887-893CUS	$ —	$ —	$ —	$ —	$ —
115		Demand	887-893DEM	$ —	$ —	$ —	$ —	$ —
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ —	$ —	$ —	$ —	$ —
118	8860	**Structures and Improvements**						
119		Customer	887-893CUS	$ 110	$ 20	$ —	$ —	$ —
120		Demand	887-893DEM	$ 22,833	$ 9,418	$ —	$ —	$ —
121		Commodity	COM	$ 1,882	$ 228	$ —	$ —	$ —
122		Total Structures and Improvements		$ 24,824	$ 9,666	$ —	$ —	$ —
123	8870	**Maintenance of Mains-Allocated**						
124		Customer	CUS	$ 382	$ 70	$ —	$ —	$ —
125		Demand	DEM	$ 48,589	$ 20,041	$ —	$ —	$ —
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 48,971	$ 20,111	$ —	$ —	$ —
128	8870	**Maintenance of Mains - Directly Assigned**						
129		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
130		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ —
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**						
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 71,304	$ 29,411	$ —	$ —	$ —
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 71,304	$ 29,411	$ —	$ —	$ —
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**						
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ —	$ —	$ —	$ —	$ —
143	8890	**Odorization**						
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 13,487	$ 1,637	$ —	$ —	$ —
147		Total Odorization		$ 13,487	$ 1,637	$ —	$ —	$ —
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**						
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 42,292	$ 17,444	$ —	$ —	$ —
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 42,292	$ 17,444	$ —	$ —	$ —
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**						
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ —	$ —	$ —	$ —	$ —
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**						
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 1,466	$ 605	$ —	$ —	$ —
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 1,466	$ 605	$ —	$ —	$ —
163	8910	**Odorization**						
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ —	$ —	$ —	$ —	$ —
167		Total Odorization		$ —	$ —	$ —	$ —	$ —
168	8920	**Services - Allocated**						
169		Customer	SERCUS-ALL	$ 403	$ 74	$ —	$ —	$ —
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 403	$ 74	$ —	$ —	$ —
173	8920	**Services - Directly Assigned**						
174		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —
178	8930	**Meters & House Regulators - Alloc.**						
179		Customer	MTRGCUS-ALL	$ —	$ —	$ —	$ —	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ —	$ —	$ —	$ —	$ —
183	8930	**Meters & House Regulators - DA**						
184		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
187		Total Meters & House Regulators - DA		$ —	$ —	$ —	$ —	$ —
188	8940	**Maintenance of Other Equipment**						
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**						
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**						
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**						
204		Customer		$ 895	$ 164	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
205		Demand		$ 186,483	$ 76,919	$ —	$ —	$ —
206		Commodity		$ 15,368	$ 1,865	$ —	$ —	$ —
207		Total Distr. Maintenance Expense		$ 202,747	$ 78,948	$ —	$ —	$ —
208		**Total Oper. & Maint. Expense**						
209		Customer		$ 9,804	$ 1,867	$ —	$ —	$ —
210		Demand		$ 736,442	$ 303,761	$ —	$ —	$ —
211		Commodity		$ 42,025	$ 5,101	$ —	$ —	$ —
212		Total Operations & Maint. Expense		$ 788,272	$ 310,729	$ —	$ —	$ —
213		**Customer Accounts Expense**						
214	901	**Supervision**						
215		Customer	902-904CUS	$ 0	$ 0	$ —	$ —	$ —
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 0	$ 0	$ —	$ —	$ —
219	902	**Meter Reading Expense**						
220		Customer	METCUS-TOT	$ 1,174	$ 226	$ —	$ —	$ —
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 1,174	$ 226	$ —	$ —	$ —
224	903	**Customer Accounting**						
225		Customer	903CUS	$ 182	$ 33	$ —	$ —	$ —
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 182	$ 33	$ —	$ —	$ —
229	904	**Bad Debt Expense**						
230		Customer	904CUS	$ —	$ —	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ —	$ —	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**						
235		Customer	902-904CUS	$ 53	$ 10	$ —	$ —	$ —
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 53	$ 10	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
239	907-910	**Customer Information Expense**						
240		Customer	CUS	$ 122	$ 22	$ —	$ —	$ —
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 122	$ 22	$ —	$ —	$ —
244		**Sales and Advertising Expense**						
245	911	**Supervision**						
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**						
251		Customer	CUS	$ —	$ —	$ —	$ —	$ —
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ —	$ —	$ —	$ —	$ —
255	913	**Advertising**						
256		Customer	CUS	$ 4	$ 1	$ —	$ —	$ —
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 4	$ 1	$ —	$ —	$ —
260	914	**Employee Sales Referrals**						
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**						
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**						
271	920-940	**Administrative & General Expenses**						
272		Customer	OPEXPCUS	$ 6,936	$ 1,315	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
273		Demand	OPEXPDEM	$ 134,419	$ 55,444	$ —	$ —	$ —
274		Commodity	COM	$ 7,689	$ 933	$ —	$ —	$ —
275		Total Administrative & General Exp.		$ 149,044	$ 57,692	$ —	$ —	$ —
276		**Depreciation & Amortization Expense**						
277	301-303	**Intangible Plant - Allocated**						
278		Customer	CUS	$ —	$ —	$ —	$ —	$ —
279		Demand	DEM	$ —	$ —	$ —	$ —	$ —
280		Commodity	COM	$ —	$ —	$ —	$ —	$ —
281		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —
282	301-303	**Intangible Plant - Directly Assigned**						
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**						
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**						
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 4,160	$ 1,716	$ —	$ —	$ —
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ 4,160	$ 1,716	$ —	$ —	$ —
297	367	**Transmission Mains**						
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 85,334	$ 35,198	$ —	$ —	$ —
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 85,334	$ 35,198	$ —	$ —	$ —
302	368	**Compression Station Equipment**						
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ 328	$ 135	$ —	$ —	$ —
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ 328	$ 135	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
307	369	**Meas. & Reg. Station Equipment**						
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 39,339	$ 16,226	$ —	$ —	$ —
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —
311		Total Meas. & Reg. Stat. Equipment		$ 39,339	$ 16,226	$ —	$ —	$ —
312	369	**Odorization**						
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ —	$ —	$ —	$ —	$ —
315		Commodity	COM	$ 1,102	$ 134	$ —	$ —	$ —
316		Total Odorization		$ 1,102	134	$ —	$ —	$ —
317	371	**Other Equipment**						
318		Customer	CUS	$ —	$ —	$ —	$ —	$ —
319		Demand	DEM	$ 235	$ 97	$ —	$ —	$ —
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —
321		Total Other Equipment		$ 235	$ 97	$ —	$ —	$ —
322	375	**Structures and Improvements**						
323		Customer	376-379CUS	$ 1	$ 0	$ —	$ —	$ —
324		Demand	DEM	$ 217	$ 90	$ —	$ —	$ —
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —
326		Total Structures and Improvements		$ 219	$ 90	$ —	$ —	$ —
327	376	**Distribution Mains - Allocated**						
328		Customer	CUS	$ 727	$ 133	$ —	$ —	$ —
329		Demand	DEM	$ 92,436	$ 38,127	$ —	$ —	$ —
330		Commodity	COM	$ —	$ —	$ —	$ —	$ —
331		Total Distribution Mains - Allocated		$ 93,163	$ 38,260	$ —	$ —	$ —
332	376	**Distribution Mains - Directly Assigned**						
333		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
336		Distribution Mains - Directly Assigned		$ —	$ —	$ —	$ —	$ —
337	376	**Odorization**						
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ —	$ —	$ —	$ —	$ —
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
341		Total Odorization		$ —	$ —	$ —	$ —	$ —
342	377	**Compressor Station Equipment**						
343		Customer	CUS	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM	$ —	$ —	$ —	$ —	$ —
345		Commodity	COM	$ —	$ —	$ —	$ —	$ —
346		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —
347	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**						
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ 10,661	$ 4,397	$ —	$ —	$ —
350		Commodity	COM	$ —	$ —	$ —	$ —	$ —
351		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 10,661	$ 4,397	$ —	$ —	$ —
352	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**						
353		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
355		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ —	$ —	$ —	$ —	$ —
357	378	**Odorization**						
358		Customer	CUS	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM	$ 765	$ 93	$ —	$ —	$ —
361		Total Odorization		$ 765	$ 93	$ —	$ —	$ —
362	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**						
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ 5,918	$ 2,441	$ —	$ —	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —
366		Total Meas. & Reg. Sta. Eq.- City Gate		$ 5,918	$ 2,441	$ —	$ —	$ —
367	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**						
368		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
369		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
371		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —
372	379	**Odorization**						
373		Customer	CUS	$ —	$ —	$ —	$ —	$ —
374		Demand	DEM	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
375		Commodity	COM	$ 64	$ 8	$ —	$ —	$ —
376		Total Odorization		$ 64	$ 8	$ —	$ —	$ —
377	380	**Services - Allocated**						
378		Customer	SERCUS-ALL	$ 2,244	$ 410	$ —	$ —	$ —
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —
381		Total Services - Allocated		$ 2,244	$ 410	$ —	$ —	$ —
382	380	**Services - Directly Assigned**						
383		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
386		Total Services - Directly Assigned		$ —	$ —	$ —	$ —	$ —
387	381	**Meters - Allocated**						
388		Customer	METCUS-ALL	$ 2,795	$ 539	$ —	$ —	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —
391		Total Meters - Allocated		$ 2,795	$ 539	$ —	$ —	$ —
392	381	**Meters - Directly Assigned**						
393		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
394		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
396		Total Meters - Directly Assigned		$ —	$ —	$ —	$ —	$ —
397	382	**Meter Installations**						
398		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —
399		Demand	DEM	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM	$ —	$ —	$ —	$ —	$ —
401		Total Meter Installations		$ —	$ —	$ —	$ —	$ —
402	383	**House Regulators - Allocated**						
403		Customer	REGCUS-ALL	$ 1,309	$ 254	$ —	$ —	$ —
404		Demand	DEM	$ —	$ —	$ —	$ —	$ —
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —
406		Total House Regulators - Allocated		$ 1,309	$ 254	$ —	$ —	$ —
407	383	**House Regulators - Directly Assn.**						
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
411		House Regulators - Directly Assn.		$ —	$ —	$ —	$ —	$ —
412	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**						
413		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —
414		Demand	NRDEM	$ 8,971	$ 3,700	$ —	$ —	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —
416		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 8,971	$ 3,700	$ —	$ —	$ —
417	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**						
418		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
421		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —
422	385	**Odorization**						
423		Customer	CUS	$ —	$ —	$ —	$ —	$ —
424		Demand	DEM	$ —	$ —	$ —	$ —	$ —
425		Commodity	COM	$ —	$ —	$ —	$ —	$ —
426		Total Odorization		$ —	$ —	$ —	$ —	$ —
427	386	**Other Prop.- Customer Premises**						
428		Customer	CUS	$ 1	$ 0	$ —	$ —	$ —
429		Demand	DEM	$ —	$ —	$ —	$ —	$ —
430		Commodity	COM	$ —	$ —	$ —	$ —	$ —
431		Total Other Prop. - Customer Premises		$ 1	$ 0	$ —	$ —	$ —
432	387	**Other Equipment**						
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —
435		Commodity	COM	$ —	$ —	$ —	$ —	$ —
436		Total Other Equipment		$ —	$ —	$ —	$ —	$ —
437	389-98	**General Plant - Allocated**						
438		Customer	GENPTCUS	$ 1,541	$ 288	$ —	$ —	$ —
439		Demand	DISPLTDEM	$ 28,615	$ 11,803	$ —	$ —	$ —
440		Commodity	COM	$ 876	$ 106	$ —	$ —	$ —
441		Total General Plant - Allocated		$ 31,031	$ 12,196	$ —	$ —	$ —
442	389-98	**General Plant - Directly Assigned**						

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
443		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
444		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
445		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
446		Total General Plant - Directly Assn.		$ —	$ —	$ —	$ —	$ —
447	389-98	**General Plant - Odorization**						
448		Customer	CUS	$ —	$ —	$ —	$ —	$ —
449		Demand	DEM	$ —	$ —	$ —	$ —	$ —
450		Commodity	COM	$ 765	$ 93	$ —	$ —	$ —
451		Total General Plant - Odorization		$ 765	$ 93	$ —	$ —	$ —
452	40730	**Pension & FAS 106 Amort. Expense**						
453		Customer	CUS	$ 7	$ 1	$ —	$ —	$ —
454		Demand	DEM	$ 807	$ 333	$ —	$ —	$ —
455		Commodity	COM	$ 47	$ 6	$ —	$ —	$ —
456		Total Pension & FAS 106 Amort. Exp.		$ 861	$ 340	$ —	$ —	$ —
457		**Total Depreciation & Amort. Exp.**						
458		Customer		$ 8,624	$ 1,625	$ —	$ —	$ —
459		Demand		$ 277,022	$ 114,264	$ —	$ —	$ —
460		Commodity		$ 3,619	$ 439	$ —	$ —	$ —
461		Total Depreciation & Amort. Expense		$ 289,265	$ 116,328	$ —	$ —	$ —
462		**Taxes Other Than Income**						
463	4081	**Payroll and Other Taxes**						
464		Customer	OPEXPCUS	$ 513	$ 97	$ —	$ —	$ —
465		Demand	OPEXPDEM	$ 25,242	$ 10,412	$ —	$ —	$ —
466		Commodity	COM	$ 1,444	$ 175	$ —	$ —	$ —
467		Total Payroll and Other Taxes		$ 27,199	$ 10,684	$ —	$ —	$ —
468	4081	**Ad Valorem Taxes - Allocated**						
469		Customer	CUS	$ 581	$ 106	$ —	$ —	$ —
470		Demand	DEM	$ 54,999	$ 22,686	$ —	$ —	$ —
471		Commodity	COM	$ 384	$ 47	$ —	$ —	$ —
472		Total Ad Valorem Taxes - Allocated		$ 55,964	$ 22,838	$ —	$ —	$ —
473	4081	**Ad Valorem Taxes - Directly Assn.**						
474		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
475		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
477		Total Ad Valorem Taxes - Directly Assn.		$ —	$ —	$ —	$ —	$ —
478		**Revenue Related Taxes**						
479		Customer	TOTREVCUS	$ 1,106	$ 173	$ —	$ —	$ —
480		Demand	DEM	$ —	$ —	$ —	$ —	$ —
481		Commodity	COM	$ —	$ —	$ —	$ —	$ —
482		Total Revenue Related Taxes		$ 1,106	$ 173	$ —	$ —	$ —
483		**Total Taxes Other Than Income**						

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(l)	(m)	(n)	(o)	(p)
484		Customer		$ 2,200	$ 376	$ —	$ —	$ —
485		Demand		$ 80,241	$ 33,097	$ —	$ —	$ —
486		Commodity		$ 1,827	$ 222	$ —	$ —	$ —
487		Total Taxes Other Than Income		$ 84,269	$ 33,695	$ —	$ —	$ —
488		**Excess Def. Income Tax Amort. - Directly Assn.**						
489		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
490		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
491		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
492		**Total Excess Def. Income Tax Amort. - DA**		$ —	$ —	$ —	$ —	$ —
493		**Excess Def. Income Tax Amort. - Alloc.**						
494		Customer	CUS	$ (35)	$ (6)	$ —	$ —	$ —
495		Demand	DEM	$ (3,605)	$ (1,487)	$ —	$ —	$ —
496		Commodity	COM	$ (24)	$ (3)	$ —	$ —	$ —
497		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (3,664)	$ (1,496)	$ —	$ —	$ —
498		**Interest on Customer Deposits**						
499		Customer	DEPCUS	$ 1,737	$ —	$ —	$ —	$ —
500		Demand	DEM	$ —	$ —	$ —	$ —	$ —
501		Commodity	COM	$ —	$ —	$ —	$ —	$ —
502		Total Interest on Cust. Deposits		$ 1,737	$ —	$ —	$ —	$ —
503		**Req. Return - Other Than Directly Assn.**						
504		Customer	CUS	$ 5,575	$ 1,019	$ —	$ —	$ —
505		Demand	DEM	$ 577,957	$ 238,391	$ —	$ —	$ —
506		Commodity	COM	$ 3,858	$ 468	$ —	$ —	$ —
507		Tot. Req. Return - Other Than Dir. Assn.		$ 587,390	$ 239,878	$ —	$ —	$ —
508		**Req. Return - Directly Assigned**						
509		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
510		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
511		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
512		Tot. Req. Return - Directly Assigned		$ —	$ —	$ —	$ —	$ —
513		**Income Taxes - Other Than DA**						
514		Customer	CUS	$ 1,154	$ 211	$ —	$ —	$ —
515		Demand	DEM	$ 119,594	$ 49,329	$ —	$ —	$ —
516		Commodity	COM	$ 798	$ 97	$ —	$ —	$ —
517		Total Income Taxes - Other Than DA		$ 121,546	$ 49,637	$ —	$ —	$ —
518		**Income Taxes - Directly Assigned**						
519		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —
520		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —
521		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —
522		Total Income Taxes - Dir. Assigned		$ —	$ —	$ —	$ —	$ —
523		**Total Cost of Service Before Revenue Credits**						
524		Customer		$ 37,529	$ 6,699	$ —	$ —	$ —
525		Demand		$ 1,922,072	$ 792,799	$ —	$ —	$ —
526		Commodity		$ 59,792	$ 7,257	$ —	$ —	$ —
527		**Total Cost of Service Before Revenue Credits**		$ 2,019,393	$ 806,755	$ —	$ —	$ —

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Customer Cost Allocation Factors										
2											
3	Total Customers		63,841	59,182	4,062	37	495	0	0	27	33
4	Total Customers Factor (CUS)	CUS	1.00000	0.92701	0.06363	0.00057	0.00775	0.00000	0.00000	0.00043	0.00051
5											
6	Customers - Directly Assigned		—	0	0	0	0	0	0	0	0
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
8											
9	Services - Allocated Weighting			1.00000	1.17314	1.32517	1.21925	0.00000	0.00000	1.58011	1.58011
10	Weighted Customers		64,703	59,182	4,766	48	603	0	0	43	52
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.91466	0.07366	0.00075	0.00932	0.00000	0.00000	0.00066	0.00080
12											
13	Meters - Allocated Weighting			1.00000	1.84223	4.23387	1.50406	0.00000	0.00000	5.48847	6.02740
14	Weighted Customers		67,950	59,182	7,484	155	744	0	0	149	198
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.87096	0.11014	0.00228	0.01095	0.00000	0.00000	0.00219	0.00291
16											
17	Meters - Total Weighting			1.00000	1.84223	4.23387	1.50406	0.00000	0.00000	5.48847	6.02740
18	Weighted Customers		67,950	59,182	7,484	155	744	0	0	149	198
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.87096	0.11014	0.00228	0.01095	0.00000	0.00000	0.00219	0.00291
20											
21	Regulators - Allocated Weighting			1.00000	1.92443	7.81443	1.90295	0.00000	0.00000	11.45264	12.91516
22	Weighted Customers		69,044	59,182	7,818	285	941	0	0	311	424
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.85716	0.11323	0.00413	0.01364	0.00000	0.00000	0.00451	0.00614
24											
25	Meters and Regulators - Allocated Weighting			1.00000	1.85652	4.85645	1.57341	0.00000	0.00000	6.52551	7.22502
26	Weighted Customers		68,140	59,182	7,542	177	778	0	0	177	237
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.86853	0.11068	0.00260	0.01142	0.00000	0.00000	0.00260	0.00348
28											
29	Non-Residential Customers		4,660	0	4,062	37	495	0	0	27	33
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.87182	0.00784	0.10618	0.00000	0.00000	0.00583	0.00705
31											
32	Customer Cost Allocation Factors										
33											
34	Distribution Plant Customer Costs		$ 148,916,731	$ 135,536,955	$ 11,499,483	$ 154,048	$ 1,371,933	$ —	$ —	$ 140,905	$ 179,586
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.91015	0.07722	0.00103	0.00921	0.00000	0.00000	0.00095	0.00121
36											
37	Account 376-379 Customer Costs		$ 47,163,394	$ 43,720,969	$ 3,001,172	$ 26,988	$ 365,507	$ —	$ —	$ 20,070	$ 24,256
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.92701	0.06363	0.00057	0.00775	0.00000	0.00000	0.00043	0.00051
39											
40	Total Revenue (inc. cost of gas)		$ 58,611,057	$ 31,552,208	$ 21,033,873	$ 1,838,324	$ 2,093,688	$ —	$ —	$ 680,834	$ 1,221,564
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.53833	0.35887	0.03136	0.03572	0.00000	0.00000	0.01162	0.02084
42											
43	Mains - Allocated Customer Cost Factor		0.38742	0.35914	0.02465	0.00022	0.00300	0.00000	0.00000	0.00016	0.00020

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
44	Services - Allocated Customer Cost Factor		0.61258	0.56030	0.04512	0.00046	0.00571	0.00000	0.00000	0.00041	0.00049
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.91945	0.06977	0.00068	0.00871	0.00000	0.00000	0.00057	0.00069
46											
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
48											
49	Total Plant Customer		$ 181,333,908	$ 165,321,493	$ 13,777,122	$ 179,906	$ 1,646,289	$ —	$ —	$ 162,931	$ 207,193
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.91170	0.07598	0.00099	0.00908	0.00000	0.00000	0.00090	0.00114
51											
52	Non-Intangible Plant Customer										
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 181,333,908	$ 168,098,463	$ 11,538,913	$ 103,764	$ 1,405,303	$ —	$ —	$ 77,164	$ 93,259
54		NONINCUS	1.00000	0.92701	0.06363	0.00057	0.00775	0.00000	0.00000	0.00043	0.00051
55											
56	Account 871-879 Customer Costs		$ 3,934,445	$ 3,527,205	$ 347,083	$ 6,087	$ 39,090	$ —	$ —	$ 5,848	$ 7,666
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.89649	0.08822	0.00155	0.00994	0.00000	0.00000	0.00149	0.00195
58											
59	Account 887-893 Customer Costs		$ 1,246,044	$ 1,148,884	$ 84,332	$ 802	$ 10,448	$ —	$ —	$ 650	$ 785
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.92202	0.06768	0.00064	0.00838	0.00000	0.00000	0.00052	0.00063
61											
62	Account 903 Customer		$ 1,059,614	$ 997,473	$ 57,963	$ 456	$ 3,357	$ —	$ —	$ 150	$ 182
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.94135	0.05470	0.00043	0.00317	0.00000	0.00000	0.00014	0.00017
64											
65	Customer Cost Allocation Factors										
66											
67	Account 904 Customer		$ 593,604	$ 512,142	$ 78,648	$ 2,814	$ —	$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.86277	0.13249	0.00474	0.00000	0.00000	0.00000	0.00000	0.00000
69											
70	Accounts 902-904 Customer		$ 2,056,235	$ 1,860,628	$ 181,000	$ 4,187	$ 7,770	$ —	$ —	$ 1,035	$ 1,355
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.90487	0.08802	0.00204	0.00378	0.00000	0.00000	0.00050	0.00066
72											
73	Operating Expense Customer		$ 15,585,019	$ 14,135,461	$ 1,257,222	$ 19,899	$ 133,214	$ —	$ —	$ 15,477	$ 19,962
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.90699	0.08067	0.00128	0.00855	0.00000	0.00000	0.00099	0.00128
75											
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 22,640,955	$ 20,606,725	$ 1,748,355	$ 23,421	$ 208,585	$ —	$ —	$ 21,423	$ 27,304
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 23,781,703	$ 22,045,891	$ 1,513,313	$ 13,609	$ 184,304	$ —	$ —	$ 10,120	$ 12,231
78	Total General Plant Customer Costs		$ 46,422,658	$ 42,652,617	$ 3,261,668	$ 37,030	$ 392,889	$ —	$ —	$ 31,543	$ 39,535
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.91879	0.07026	0.00080	0.00846	0.00000	0.00000	0.00068	0.00085
80											
81	Customer Deposits		$ (2,514,038)	$ (783,706)	$ (1,635,587)	$ (39,110)	$ (16,250)	$ —	$ —	$ (4,990)	$ (34,395)
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.31173	0.65058	0.01556	0.00646	0.00000	0.00000	0.00198	0.01368
83											
84	Demand Cost Allocation Factors										
85											
86	System Demand										

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
87	**System Demand Factor (DEM)**	DEM	1.00000	0.30548	0.44680	0.01309	0.07121	0.00000	0.00000	0.04555	0.08345
88											
89	Non-Residential Demand										
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.64332	0.01884	0.10253	0.00000	0.00000	0.06559	0.12015
91											
92	Directly Assigned Demand										
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
94											
95	Distribution Plant Demand		$ 48,358,439	$ 13,757,343	$ 22,259,729	$ 651,959	$ 3,547,795	$ —	$ —	$ 2,269,553	$ 4,157,296
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.28449	0.46031	0.01348	0.07336	0.00000	0.00000	0.04693	0.08597
97											
98	Demand Cost Allocation Factors										
99											
100	Non-Intangible Plant Demand		$ 105,733,065	$ 32,299,534	$ 47,241,581	$ 1,383,646	$ 7,529,447	$ —	$ —	$ 4,816,649	$ 8,822,984
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.30548	0.44680	0.01309	0.07121	0.00000	0.00000	0.04555	0.08345
102											
103	Total Plant Demand		$ 105,733,065	$ 31,127,517	$ 47,995,568	$ 1,405,729	$ 7,649,619	$ —	$ —	$ 4,893,524	$ 8,963,801
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.29440	0.45393	0.01330	0.07235	0.00000	0.00000	0.04628	0.08478
105											
106	Operating Expense Demand		$ 11,914,693	$ 3,479,644	$ 5,426,472	$ 158,934	$ 864,881	$ —	$ —	$ 553,271	$ 1,013,465
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.29205	0.45544	0.01334	0.07259	0.00000	0.00000	0.04644	0.08506
108											
109	Acct. 887-893 Demand		$ 1,806,333	$ 444,275	$ 876,246	$ 25,664	$ 139,658	$ —	$ —	$ 89,340	$ 163,650
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.24595	0.48510	0.01421	0.07732	0.00000	0.00000	0.04946	0.09060
111											
112	Rate Base Demand		$ 88,010,824	$ 25,961,566	$ 39,917,800	$ 1,169,141	$ 6,362,170	$ —	$ —	$ 4,069,932	$ 7,455,172
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.29498	0.45356	0.01328	0.07229	0.00000	0.00000	0.04624	0.08471
114											
115	Commodity Cost Allocation Factors										
116											
117	Annual Distribution Volumes (Ccf)		46,213,536	7,540,608	21,134,005	2,461,937	1,571,444	—	—	4,771,432	7,788,782
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.16317	0.45731	0.05327	0.03400	0.00000	0.00000	0.10325	0.16854
119											
120	Commodity - Direct Assignment		—	—	—	—	—	—	—	—	—
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(l)	(m)	(n)	(o)
1	Customer Cost Allocation Factors					
2						
3	Total Customers		6	0	0	0
4	Total Customers Factor (CUS)	CUS	0.00009	0.00000	0.00000	0.00000
5						
6	Customers - Directly Assigned		0	0	0	0
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	0.00000	0.00000	0.00000	0.00000
8						
9	Services - Allocated Weighting		1.58011	0.00000	0.00000	0.00000
10	Weighted Customers		9	0	0	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	0.00015	0.00000	0.00000	0.00000
12						
13	Meters - Allocated Weighting		6.36255	0.00000	0.00000	0.00000
14	Weighted Customers		38	0	0	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	0.00056	0.00000	0.00000	0.00000
16						
17	Meters - Total Weighting		6.36255	0.00000	0.00000	0.00000
18	Weighted Customers		38	0	0	0
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	0.00056	0.00000	0.00000	0.00000
20						
21	Regulators - Allocated Weighting		13.70951	0.00000	0.00000	0.00000
22	Weighted Customers		82	0	0	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	0.00119	0.00000	0.00000	0.00000
24						
25	Meters and Regulators - Allocated Weighting		7.64002	0.00000	0.00000	0.00000
26	Weighted Customers		46	0	0	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	0.00067	0.00000	0.00000	0.00000
28						
29	Non-Residential Customers		6	0	0	0
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	0.00129	0.00000	0.00000	0.00000
31						
32	Customer Cost Allocation Factors					
33						
34	Distribution Plant Customer Costs		$ 33,822	$ —	$ —	$ —
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	0.00023	0.00000	0.00000	0.00000
36						
37	Account 376-379 Customer Costs		$ 4,433	$ —	$ —	$ —
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	0.00009	0.00000	0.00000	0.00000
39						
40	Total Revenue (inc. cost of gas)		$ 190,566	$ —	$ —	$ —
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	0.00325	0.00000	0.00000	0.00000
42						
43	Mains - Allocated Customer Cost Factor		0.00004	0.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(l)	(m)	(n)	(o)
44	Services - Allocated Customer Cost Factor		0.00009	0.00000	0.00000	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	0.00013	0.00000	0.00000	0.00000
46						
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	0.00000	0.00000	0.00000	1.00000
48						
49	Total Plant Customer		$ 38,974	$ —	$ —	$ —
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	0.00021	0.00000	0.00000	0.00000
51						
52	Non-Intangible Plant Customer					
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 17,042	$ —	$ —	$ —
54		NONINCUS	0.00009	0.00000	0.00000	0.00000
55						
56	Account 871-879 Customer Costs		$ 1,466	$ —	$ —	$ —
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	0.00037	0.00000	0.00000	0.00000
58						
59	Account 887-893 Customer Costs		$ 144	$ —	$ —	$ —
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	0.00012	0.00000	0.00000	0.00000
61						
62	Account 903 Customer		$ 33	$ —	$ —	$ —
63	**Account 903 Customer Factor (903CUS)**	903CUS	0.00003	0.00000	0.00000	0.00000
64						
65	Customer Cost Allocation Factors					
66						
67	Account 904 Customer		$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	0.00000	0.00000	0.00000	0.00000
69						
70	Accounts 902-904 Customer		$ 260	$ —	$ —	$ —
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	0.00013	0.00000	0.00000	0.00000
72						
73	Operating Expense Customer		$ 3,785	$ —	$ —	$ —
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	0.00024	0.00000	0.00000	0.00000
75						
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 5,142	$ —	$ —	$ —
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 2,235	$ —	$ —	$ —
78	Total General Plant Customer Costs		$ 7,377	$ —	$ —	$ —
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	0.00016	0.00000	0.00000	0.00000
80						
81	Customer Deposits		$ —	$ —	$ —	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	0.00000	0.00000	0.00000	0.00000
83						
84	Demand Cost Allocation Factors					
85						
86	System Demand					

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(l)	(m)	(n)	(o)
87	**System Demand Factor (DEM)**	DEM	0.03442	0.00000	0.00000	0.00000
88						
89	Non-Residential Demand					
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	0.04956	0.00000	0.00000	0.00000
91						
92	Directly Assigned Demand					
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	0.00000	0.00000	0.00000	1.00000
94						
95	Distribution Plant Demand		$ 1,714,764	$ —	$ —	$ —
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	0.03546	0.00000	0.00000	0.00000
97						
98	Demand Cost Allocation Factors					
99						
100	Non-Intangible Plant Demand		$ 3,639,225	$ —	$ —	$ —
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	0.03442	0.00000	0.00000	0.00000
102						
103	Total Plant Demand		$ 3,697,308	$ —	$ —	$ —
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	0.03497	0.00000	0.00000	0.00000
105						
106	Operating Expense Demand		$ 418,025	$ —	$ —	$ —
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	0.03508	0.00000	0.00000	0.00000
108						
109	Acct. 887-893 Demand		$ 67,501	$ —	$ —	$ —
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	0.03737	0.00000	0.00000	0.00000
111						
112	Rate Base Demand		$ 3,075,042	$ —	$ —	$ —
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	0.03494	0.00000	0.00000	0.00000
114						
115	Commodity Cost Allocation Factors					
116						
117	Annual Distribution Volumes (Ccf)		945,327	—	—	—
118	**Distribution Commodity Factor (COM)**	COM	0.02046	0.00000	0.00000	0.00000
119						
120	Commodity - Direct Assignment		—	—	—	—
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	0.00000	0.00000	0.00000	0.00000

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELEC. GEN.	COM. TRANS.	IND. TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	ELEC. GEN. TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Current Revenue-to-Cost Ratio (1)	0.8798	0.7766	1.2168	3.4412	0.8909	0.0000	0.0000	0.6258	0.6196	0.2509	0.0000	0.0000	0.0000
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	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000
4	Rate Design Revenue Increase	$ 7,074,940	$ 8,807,990	$ (2,857,518)	$ (877,307)	$ 212,422	$ —	$ —	$ 416,894	$ 768,103	$ 604,356	$ —	$ —	$ —
5	% Increase - Non-Gas Revenue (2)	13.67%	28.77%	-17.82%	-70.94%	12.24%	— %	— %	59.80%	61.38%	298.60%	— %	— %	— %
6	% Increase - Total Revenue (3)	11.82%	27.13%	-13.45%	-47.58%	10.01%	— %	— %	59.80%	61.38%	298.60%	— %	— %	— %
7	% Total Revenue (for GRIP)	100.00 %	66.82 %	22.50 %	0.61 %	3.33 %	— %	— %	1.91 %	3.45 %	1.38 %	— %	— %	— %
8	Movement Toward Cost of Service (4)													
9	Revenue-to-Cost Ratio	1.0000	0.9242	1.1734	2.9529	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000
10	Rate Design Revenue Increase	$ 7,074,940	$ 5,820,130	$ (571,504)	$ (175,461)	$ 212,422	$ —	$ —	$ 416,894	$ 768,103	$ 604,356	$ —	$ —	$ —
11	% Increase - Non-Gas Revenue (2)	13.67%	19.01%	-3.56%	-14.19%	12.24%	— %	— %	59.80%	61.38%	298.60%	— %	— %	— %
12	% Increase - Total Revenue (3)	11.82%	17.92%	-2.69%	-9.52%	10.01%	— %	— %	59.80%	61.38%	298.60%	— %	— %	— %
13	% Total Revenue (for GRIP)	100.00 %	61.63 %	26.47 %	1.83 %	3.33 %	— %	— %	1.91 %	3.45 %	1.38 %	— %	— %	— %
14	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)													
15	Revenue-to-Cost Ratio	1.0000	0.9053	1.2168	3.4412	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000
16	Rate Design Revenue Increase	$ 7,074,940	$ 5,073,165	$ —	$ —	$ 212,422	$ —	$ —	$ 416,894	$ 768,103	$ 604,356	$ —	$ —	$ —
17	% Increase - Non-Gas Revenue (2)	13.67%	16.57%	0.00%	0.00%	12.24%	— %	— %	59.80 %	61.38 %	298.60 %	— %	— %	— %
18	% Increase - Total Revenue (3)	11.82%	15.62%	0.00%	0.00%	10.01%	— %	— %	59.80 %	61.38 %	298.60 %	— %	— %	— %
19	% Total Revenue (for GRIP)	100.00 %	60.34 %	27.46 %	2.14 %	3.33 %	— %	— %	1.91 %	3.45 %	1.38 %	— %	— %	— %

(1) Revenue-to-cost ratios are the ratios of each class' non-gas revenue (including revenue credits) to

(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 decreases 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 deceases 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 Teresa D. Serna. 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

SUBSCRIBED AND SWORN TO BEFORE ME by the said Teresa D. Serna on this 5th day of June 2025.

Notary Public in and for the State of Texas

My commission expires: 2/23/2028

CHRISTINE MARIE BELL
Notary ID #130547096
My Commission Expires
February 23, 2028

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

ZANE M. DRUMMOND

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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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. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony on behalf of TGS in Docket No. OS-24-00017471 ("Docket No. 17471") before the Railroad Commission of Texas ("Commission").

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 all of TGS's customers in Texas, which includes the existing Central-Gulf Service Area ("CGSA"), West North Service Area ("WNSA"), and Rio Grande Valley Service Area ("RGVSA").

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I am co-sponsoring Schedule G and sponsoring Schedules G-1 through G-3.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

II. REVENUE ADJUSTMENTS

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 ("COG Clause") 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 COG Clause 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 COG clause, 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 myself and Company witnesses Anthony Q. Brown and Keara J. Downum.

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, 2024, 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 the Base Sales Revenue shown on line 3.

Q. PLEASE EXPLAIN THE RECLASS AND ANNUALIZATION ADJUSTMENT ON LINE 4 OF SCHEDULE G-2.

A. During the twelve months ended December 31, 2024, some customer classes in the CGSA and RGVSA underwent rate structure changes in accordance with the final orders in Docket No. OS-23-00014399 ("Docket No. 14399") and Docket No. 17471. To account for the changes in rate structures, an adjustment was needed to reclassify the bills and volumes in discontinued classes to the rate structures in effect at December 31, 2024. The reclassified bills and volumes were then annualized to current base rates to accurately reflect the revenues associated with this adjustment as if the rates were in effect for the entire test year.

Q. HOW IS THE RECLASS AND ANNUALIZATION ADJUSTMENT CALCULATED?

A. For residential and commercial tariffs that were replaced with the implementation of Small and Large rate tariffs, this adjustment was calculated by using the ratio of actual bills and volumes between the Small and Large rate tariffs in each existing service area to allocate test year residential and commercial bills and volumes to the Small/Large rate structures. The allocated bills and volumes were then annualized to current rates to calculate the revenue adjustment to capture the increase in revenue if the bills and volumes were on the new rate structure for the entire year. Test year bills, volumes and base rate revenues were then removed from discontinued classes where bills and volumes were allocated among the new rates. In addition, in the CGSA, the public schools space heating tariff was discontinued and reclassified under public authority. The reclassified bills and

volumes were then annualized to current base rates and removed from the discontinued class using the same methodology.

Q. PLEASE EXPLAIN LINE 5 OF SCHEDULE G-2.

A. The adjustment shown on line 5 removes revenue collected through a Gas Reliability Infrastructure Program ("GRIP") adjustment during the twelve months ended December 31, 2024. This adjustment is necessary because the reclass and annualization adjustment shown on line 4, and the GRIP Annualization adjustment on line 6, already include the 2024 GRIP revenues.

Q. PLEASE EXPLAIN THE GRIP ANNUALIZATION ADJUSTMENT ON LINE 6 OF SCHEDULE G-2.

A. Following the completion of the twelve months ended December 31, 2024, TGS filed GRIP adjustments in each existing service area. The annualization of this revenue impact over the entire test year based upon the rates requested in those filings results in an increase to base sales revenues. The adjustment is derived by taking the difference between revenues calculated based on current requested GRIP rates and revenues generated during the test year ending December 31, 2024.

Q. PLEASE EXPLAIN THE WEATHER NORMALIZATION ADJUSTMENT ("WNA") ON LINE 7 OF SCHEDULE G-2.

A. TGS currently has WNAs in effect for all service areas. 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 on line 7 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, 2024.

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 Commission orders issued in Docket No. OS-22-00009896 and Gas Utilities Docket ("GUD") No. 10506, which were fully litigated, and GUD Nos. 9988, 10928, 10488, 10526, 10656, 10739 and 10766 and Docket Nos. 17471 and 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 8 OF SCHEDULE G-2 WAS DEVELOPED.

A. The adjustment on line 8 of Schedule G-2 is required to weather normalize revenues. The analysis was developed based on data from the nine weather stations used by TGS. These weather stations are: Austin Camp Mabry (KATT), Beaumont/Port Arthur Southeast Regional Airport (KBPT), Scholes International Airport/Galveston (KGLS), San Antonio International Airport (KSAT), El Paso International Airport (KELP), Midland International Air and Space Port (KMAF), Rick Husband Amarillo International Airport (KAMA), Abilene Regional Airport

[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.").

(KABI), and Brownsville/South Padre Island International Airport (KBRO). 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. 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 shown on line 8 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 and applying 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

[3] This methodology was utilized in the Company's RGVSA 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); WNSA 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); CGSA 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-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order (Nov. 19, 2024).

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 9 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, this adjustment annualizes the growth or loss in customers that occurred during the twelve months ended December 31, 2024, 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 at the end of the test year.

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, 2024, was calculated by comparing the number of active customers at December 31, 2023, to the number of active customers at December 31, 2024. The adjustment shown on line 7 on Schedule G-2 annualizes the customer growth, which is an increase to test year base sales revenue.

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 $53,031,084, as shown on line 10 of Schedule G-2. This results in a total Base Sales Revenue amount, as adjusted, of $392,752,255, as shown on line 11 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 to reclassify and annualize standard transport revenue from discontinued tariffs during the test year. As previously described for gas sales revenue, this adjustment was necessary due to rate structure changes that were implemented during the test year.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 3 OF SCHEDULE G-3.

A. Line 3 reflects a revenue adjustment to remove GRIP revenue collected during the twelve months ended December 31, 2024. As previously described for gas sales revenue, this adjustment is necessary because the reclass and annualization adjustment shown on line 2, and GRIP annualization shown on line 4 already includes the 2024 GRIP revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 4 OF SCHEDULE G-3.

A. As previously described, TGS has filed GRIP adjustments in each existing service area following the test year. The annualization of this revenue impact over the entire test year results in an increase to transportation revenues that accurately reflects the current and proposed GRIP charges.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 5 OF SCHEDULE G-3.

A. TGS implements an annual recalculation of the contract rate charge ("CRC") for gas utility service at Fort Bliss. In 2025, this adjustment increased monthly revenues by $14,934. In addition to the CRC, the Company charges an Extraordinary Operating and Maintenance ("EOM") monthly charge of $4,000. This fee is commonly used in privatization agreements in the utility sector to help cover additional Operating and Maintenance expenses. Annualizing for the CRC and EOM over the entire test year results in a $71,733 increase to transportation revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 6 OF SCHEDULE G-3.

A. The adjustment on line 6 annualizes TGS contract work for Fort Bliss in the amount of $25,000 per month. Fort Bliss contracts with TGS to perform operations and maintenance work in the East Bliss area. Annualizing the revenues associated with this contract work over the test year period increases transportation revenues by $300,000.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 7 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.

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 $101,169, as shown on line 8, of Schedule G-3.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO SERVICE FEES ON LINE 11 OF SCHEDULE G-3.

A. Mr. Brown presents the proposed changes to service fees. Line 11, 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 to test year revenues is included on line 11, of Schedule G-3.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO OTHER UTILITY REVENUE ON LINE 13 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 decrease to test year revenues.

Q. PLEASE EXPLAIN THE SCHEDULES G-2 AND G-3 COMMON BILLING PRESSURE ADJUSTMENT.

A. The Common Billing Pressure Adjustment is an adjustment to convert as-adjusted test year volumes to the common billing pressure used in Texas, which is 14.65 pounds per square inch (psi). As explained in the direct testimony of Company witness Stacey McTaggart, the local serving pressure at a customer meter varies across the areas TGS serves due to elevation changes that affect atmospheric pressure, which affects the heating value of the gas that passes through the customer meter. For the purpose of designing rates for all TGS customers, volumes must be converted to a common billing pressure to standardize the heating value of the volumes used in rate design.

Q. WHAT IS THE TOTAL TRANSPORTATION REVENUE, SERVICE FEE REVENUE AND OTHER UTILITY REVENUE AS ADJUSTED?

A. As shown on line 17, of Schedule G-3, the total transportation revenue, service fee revenue, and other utility revenue as adjusted is $25,007,130.

III. CONCLUSION

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 Rates Analyst 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.

Zane M. Drummond

SUBSCRIBED AND SWORN TO BEFORE ME by the said Zane M. Drummond on this 5th day of June 2025.

Notary Public in and for the State of Texas

My commission expires: 2/23/2028

CHRISTINE MARIE BELL
Notary ID #130547096
My Commission Expires
February 23, 2028

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

PAUL H. RAAB

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2025

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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 other 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 TGS based on the 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. In general, the Company is proposing to maintain its existing rate structures, adjusted to meet the revenue levels associated with its current cost of providing service to customers. In the case of rates for service to residential and commercial sales customers, the Company is proposing to continue with its existing split of these two classes 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. For all classes other than the residential and commercial classes, the Company is proposing to maintain its existing two-part rates for all customers within a given class, except for Electric Generation transport customers, who will be served under a three-part rate structure that includes a demand charge.

Q. WHAT ARE THE ADVANTAGES OF THE RESIDENTIAL AND COMMERCIAL RATE STRUCTURES BEING PROPOSED.

A. These rate structures minimize the bill impacts associated with rate level increases, encourage customer choice, and more appropriately reflect the Company's costs of providing service.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED SUCH RATES FOR TGS?

A. Yes. This same "two-tiered" rate structure has been previously approved by the Commission for TGS residential customers in all of the Company's existing service areas.[1] The Commission also approved two-tiered rates for TGS commercial customers in the Company's existing Central-Gulf and Rio Grande Valley Service Areas.[2]

Q. WHAT EXHIBITS HAVE YOU PROVIDED TO SUPPORT THE PROPOSED RATE DESIGNS FOR EACH CUSTOMER CLASS?

A. I have developed five exhibits, Exhibit PHR-2 through Exhibit PHR-6, 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.

[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 ("FoF") No. 103 ("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.") and Attachment 1, Approved Tariffs at Rate Schedules 1Y, 1Z, 10, and 15 (Jan. 18, 2023); *see also 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. 55 and Attachment 1, Tariffs and Rate Schedules at Rate Schedules 1Y, 1Z, 10, and 15 (Jan. 30, 2024); 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 Central-Gulf Service Area*, Docket No. OS-24-00017471 consol., Final Order at FoF No. 47 and Attachment 1, Tariffs and Rate Schedules at Rate Schedules 1Y, 1Z, 10, and 15 (Nov. 19, 2024).

[2] Docket No. OS-23-00014399 consol., Final Order at FoF No. 55 and Attachment 1, Tariffs and Rate Schedules at Rate Schedules 2Y, 2Z, 20, and 25; Docket No. OS-24-00017471 consol., Final Order at FoF No. 47 and Attachment 1, Tariffs and Rate Schedules at Rate Schedules 2Y, 2Z, 20, and 25.

Exhibit PHR-2 begins with a summary of Current and Recommended Rates. Bill impacts are documented in Exhibits PHR-3 through PHR-5. 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-6 contains a proof of revenues that demonstrates that the new rate structures recover Company-proposed levels of revenues in this case.

B. Current Rates

Q. PLEASE DESCRIBE THE CURRENT RESIDENTIAL RATES.

A. As indicated previously, current residential rate structures apply to two residential class 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 "large" subclasses are served under two-part rates comprised of fixed monthly customer charges that vary between $33.36 and $38.64/customer/month for large customers, depending on the customer's currently-designated service area, and a volumetric rate that serves to reflect the underlying cost of service characteristics of the service area. The "small" subclasses are served under two-part rates comprised of a fixed monthly customer charge that varies between $21.36 and $23.64/customer/month for small customers, depending on the customer's currently-designated service area, and a volumetric rate that serves to reflect the underlying cost of service characteristics of the service area. Specific charges are shown by the Company's current service area designations in Exhibit PHR-2.

Q. PLEASE DESCRIBE THE CURRENT COMMERCIAL SALES RATES.

A. Also as shown in Exhibit PHR-2, current charges for commercial sales customers mirror the residential class rates: customer charges that vary between $87.88 and $275.32/customer/month for large customers, depending on the customer's currently-designated service area; "small" customer charges that vary between $72.88 and $120.32/customer/month, depending on the customer's currently-designated service area; and volumetric rates that reflect the underlying cost of service characteristics of the different service areas.

Q. PLEASE DESCRIBE THE CURRENT INDUSTRIAL SALES RATES.

A. Current industrial sales rate structures are also summarized in Exhibit PHR-2. As shown there, current customer charges for industrial sales customers range from $1,033.21/customer/month in the Company's currently-designated Central-Gulf Service Area to $1,295.93/customer/month in the Company's currently-designated West North Service Area. Usage for these customers is priced at a single per Ccf rate, which varies from a low of $0.11486/Ccf in the currently-designated West North Service Area to a high of $0.28220/Ccf in the currently-designated Rio Grande Valley Service Area.

Q. PLEASE DESCRIBE THE CURRENT PUBLIC AUTHORITY SALES RATES.

A. For public authority sales customers, the current customer charges range from $181.93/customer/month in the Company's currently-designated Central-Gulf Service Area to $253.05/customer/month in the Company's currently-designated West North Service Area. Usage for these customers is priced at a single per Ccf

rate, which varies from a low of $0.13511/Ccf in the currently-designated West North Service Area to a high of $0.16208/Ccf in the currently-designated Rio Grande Valley Service Area.

Q. PLEASE DESCRIBE THE CURRENT COMPRESSED NATURAL GAS RATES.

A. The Company serves compressed natural gas ("CNG") sales customers in only its currently-designated Central-Gulf and West North Service Areas. Current Central-Gulf CNG rates are a customer charge of $746.15/customer/month and a usage rate of $0.07817/Ccf. Current West North CNG rates are a customer charge of $1,955.67/customer/month and a usage rate of $0.08643/Ccf.

Q. PLEASE DESCRIBE THE ELECTRIC GENERATION SALES RATES.

A. Although there are currently no electric generation sales customers, the Company offers a variety of rate structures to serve customers who could choose to rely on sales service for natural gas for electrical generation. Customers in the Company's currently-designated Central-Gulf Service Area are offered service under a declining block rate structure. Customers in the Company's currently-designated West North Service Area are also offered service under a declining block rate structure, although it is seasonally-differentiated. Finally, customers in the Company's currently-designated Rio Grande Valley Service Area are offered service under a two-part rate that is not seasonally-differentiated.

Q. PLEASE DESCRIBE THE CURRENT TRANSPORTATION RATES.

A. Current individual Transportation rates apply to Commercial, Industrial, Public Authority, and CNG Transportation customers under two-part rates with a range of prices depending on the currently designated service area in which the customer is located, as shown on Exhibit PHR-2. In addition, the Company offers transportation rates to those customers who rely on the Company for the transportation of natural gas for the purpose of Electric Generation. Similar to sales rates for these customers, the Company provides transportation service under declining block rates in the currently designated Central-Gulf Service Area, under seasonally differentiated declining block rates in the currently designated West North Service Area, and under a two-part rate in the currently designated Rio Grande Valley Service Area. Specific rates for these areas are shown in Exhibit PHR-2.

C. Proposed Rates

Q. HOW DID YOU DESIGN THE PROPOSED RATE RECOMMENDATIONS?

A. I relied on the same process that was relied on to develop the approved rates in the Company's prior proceedings. 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 excesses 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's 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.

Development of these rates also considers intraclass equity, which relates to the fairness of 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. Because the Company is proposing rate structures for the residential and commercial classes that rely on definitions of "small" and "large" customers that are different from those 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.

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 330 Ccf per year, I recommend the following charges:

Customer charge:	$29.50/customer/month
Volumetric Charge:	$0.67553/Ccf

For "Large" Residential customers whose weather normalized consumption is greater than 330 Ccf per year, I recommend the following charges:

Customer charge:	$39.50/customer/month
Volumetric Charge:	$0.31189/Ccf

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THESE CHARGES.

A. As stated above, I began with the Company's CCOSS. Ms. Serna calculates that a customer charge of $49.29 most accurately captures the customer-related and demand-related costs (fixed costs) by class identified in the Company's CCOSS. This fixed 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. ARE YOU THEN PROPOSING THE STRAIGHT FIXED-VARIABLE RATE DESIGN YOU JUST DESCRIBED FOR ALL RESIDENTIAL CUSTOMERS?

A. No. Because such a 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 $29.50/customer/month, a level forty per cent less than the identified 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. For purposes of this rate design, I propose a customer charge of $39.50/customer/month for higher usage customers.

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. In this case, implementation of these new rates is simply a continuation of the rate structures on which these customers are already being served, but adjusted for the current cost of providing service.

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 330 Ccfs per year. A Small Residential Customer's annual bill is $576.92, the same amount as a Large Residential Customer, subject to rounding. If the customer reduces usage by 10%, to 297 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 ($566.63 versus $554.63, or $1.00 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 in all its current service area designations, 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 relied on this same process when it initially rolled out this rate design for its Texas residential customers.

Q. IS THE COMPANY PROPOSING ANY OTHER RESIDENTIAL RATES IN THIS PROCEEDING?

A. Yes, the Company also is proposing a "customer assistance" rate for income-qualified residential customers.

Q. AND HOW DID YOU DEVELOP THIS RATE?

A. The Company decided that such a rate should have two attributes. First, the rate should reflect a discount of 25% to the "small" residential customer rate. Second, the resulting subsidy to these customers should be borne by the remaining residential customers.

The results of this process are a customer charge of $22.13/customer/month and a usage charge of $0.55000/customer/month.

Q. WHAT ARE YOUR RECOMMENDED COMMERCIAL CUSTOMER AND USAGE CHARGES?

A. For "Small" Commercial customers whose weather normalized consumption is less than or equal to 3,000 Ccf per year, I recommend the following charges:

Customer charge:	$75.00/customer/month
Volumetric Charge:	$0.43589/Ccf

For "Large" Commercial customers whose weather normalized consumption is greater than 3,000 Ccf per year, I recommend the following charges:

Customer charge:	$150.00/customer/month
Volumetric Charge:	$0.13589/Ccf

Q. WERE THESE COMMERCIAL CUSTOMER RATES DEVELOPED IN THE SAME MANNER AND DOES THEIR DEVELOPMENT INVOLVE THE SAME CONSIDERATIONS AS THE TIERED 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 $98.63 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 $75/customer/month, a level approximating the current commercial customer charges, and set the customer charge for higher usage customers equal to

$150/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. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE INDUSTRIAL SALES CLASS.

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 customer charge equal to $1,250/customer/month, a level consistent with the current customer charges. I then developed the usage charge for this class, considering the current cost to serve these customers as determined within Ms. Serna's CCOSS. This resulted in a usage rate of $0.11849/Ccf. These rates are summarized in Exhibit PHR-2.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE PUBLIC AUTHORITY SALES CLASS.

A. As with the industrial sales class above, to develop rates for the public authority sales class, I set the customer charge equal to a level consistent with the current customer charges. I then developed the usage charge for this class, considering the current cost to serve these customers as determined within Ms. Serna's CCOSS. The resulting rates of $200/customer/month with a volumetric charge of $0.13745/Ccf are summarized in Exhibit PHR-2.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE COMPRESSED NATURAL GAS SALES CLASS.

A. For the CNG sales class, I also recommend the same two-part, single-block rate structure that is currently in place. Development of this rate is complicated by the fact that, while there is a customer currently on the CNG sales rate, that customer took no volumes in the test year. As a result, in order to develop rates for these customers, I needed to make some assumptions that may not prove to be correct if and when the Company needs to provide CNG sales service again.

To develop the customer cost component of the rate, I relied on test year bills and revenues and calculated a customer charge rate of $320/customer/month. I then set the usage charge for the rate equal to a simple average of current usage charges, $0.08831/Ccf. These values are consistent with the costs implied by Ms. Serna's CCOSS. However, these costs (and rates) will need to be reexamined if and when the Company again provides CNG sales service to customers.

Q. HOW DID YOU DESIGN GENERAL TRANSPORTATION RATES?

A. Consistent with the final order in Docket No. OS-24-00017471, I developed a general transportation rate that will replace transportation rates that currently apply individually to commercial, industrial, public authority, and CNG customers with disparate customer and volumetric charges.[3] Given this objective, and in an effort to avoid rate shock, I first developed a customer charge for the combined classes that is approximately an average of existing customer cost levels. I then calculated a usage charge consistent with the costs implied by Ms. Serna's CCOSS. The

[3] Docket No. OS-24-00017471 consol., Final Order at FoF No. 56.

resulting rates for general transportation customers are customer charges of $500/customer/month and volumetric charges of $0.08831/Ccf.

Q. PLEASE DESCRIBE THE NEW ELECTRICAL GENERATION TRANSPORTATION RATES.

A. The new electrical generation rate is a three-part rate consisting of a customer charge of $1,000/customer/month, a demand charge of $0.72542/Maximum Daily Quantity (MDQ) in Ccfs, and a volumetric charge of $0.02000/Ccf. Electrical generation customers place significant peak demands on the system and the introduction of the demand charge is designed to provide this price signal to customers.

Q. IN YOUR OPINION, IS YOUR RATE DESIGN JUST AND REASONABLE?

A. Yes. The new rate designs better reflect costs and therefore attempt to improve efficiency and inter- and intra-class equity. They also reflect gradualism in that movements to more cost-based rates are tempered by the impact of rate increases on customers. Furthermore, by generally relying on the current rate structures for each class as the starting point in designing the recommended consolidated rates, the proposed rates reflect the concept of rate continuity.

III. CUSTOMER BILL IMPACTS

Q. HAVE YOU CALCULATED CUSTOMER BILL IMPACTS RESULTING FROM YOUR RECOMMENDED 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.

As can be seen in this exhibit, average rate impacts are relatively modest, consistent with an objective of moving customers closer to the underlying cost to serve them as identified in Ms. Serna's CCOSS. However, in the case of Residential and Commercial customer bill impacts, the results of the average analysis do not completely capture the impact of the rate design changes.

Q. WHY NOT?

A. Because the full impact of the rate design changes for Residential and Commercial customers is the result of two changes: (1) a change in rate levels to better reflect the current cost of service; and (2) a change in customer designation between "Small" and "Large" customers. For example, as a result of rate area consolidation, a Small Residential customer is one whose annual consumption is less than 330 Ccfs per year. This compares to the current definition of a Small Residential customer in the currently-designated Rio Grande Valley Service Area as one whose annual consumption is less than 130 Ccfs per year.

Therefore, to demonstrate the full impact of the rate change for the range of weather-normalized consumption observed for residential customers, I have prepared Exhibit PHR-4. Exhibit PHR-4 contains six schedules that examine the impact of the rate change for each of the three currently-designated rate areas and for each Small/Large customer designation. For example, the first schedule of the exhibit summarizes the rate impact of the consolidated rate change on customers who are currently classified as "Small" customers in the currently-designated Central-Gulf Service Area. As can be seen in that schedule, the rate impacts are relatively modest, approximately 7-20% for most customers. Furthermore, current

Small customers who now choose service as Large customers under consolidated rates will even see significant declines in their annual bills. Bill impacts vary depending on the customer's current service area designation.

Q. HAVE YOU PERFORMED A SIMILAR ANALYSIS OF THE NEW RATE DESIGNS ON COMMERCIAL CUSTOMERS?

A. Yes. The impacts of the proposed rates on Commercial customer annual bills are shown on Exhibit PHR-5. In general, the individual schedules of that exhibit show the same bill impact pattern as observed for Residential customers: relatively modest increases and decreases for customers in the currently-designated Central-Gulf and West North Service Areas and significant reductions for customers in the currently-designated Rio Grande Valley Service Area. Please note that commercial customers in the currently-designated West North Service Area have not been previously classified into Small and Large designations. Thus, the annual bill impact on these customers represents the impact of both the rate level change and the rate structure change.

IV. PROOF OF REVENUE

Q. HAVE YOU PREPARED A PROOF OF REVENUE TO SHOW THAT THE 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 system is provided in Exhibit PHR-6. 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 that exhibit.

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
	1169	Costing/Rate Design
	1180	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
	24-KGSG-610-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
	2024-00276	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 BPU# 822-0116	Load Forecasting

Jurisdiction	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
	PUD 202400010	Demand Side Planning
	PUD 202500011	Demand Side Planning
	PUD 202500027	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
	Case No.00018879	Costing/Rate Design
	Case No.00019196	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.

Exhibit PHR-2
Current and Recommended Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CURRENT AND RECOMMENDED RATES

Description		CGSA Incorporated and Environs Rates		WNSA Incorporated and Environs Rates		RGVSA Incorporated and Environs Rates		All TGS Customers Incorporated and Environs Rates	
		Current		Current		Current		Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Small	Large	Small	Large	Small	Large	Small	Large
Residential									
Customer Charge		$ 21.36	$ 33.36	$ 21.85	$ 38.35	$ 23.64	$ 38.64	$ 29.50	$ 39.50
Usage Rates	All Ccf	$ 0.87646	$ 0.46737	$ 0.46668	$ 0.01668	$ 2.02007	$ 0.63545	$ 0.67553	$ 0.31189
Customer Assistance Program									
Customer Charge		N/A	N/A	N/A	N/A	N/A	N/A	$ 22.13	$ 22.13
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	N/A	N/A	$ 0.55000	$ 0.55000
Commercial									
Customer Charge - Sales		$ 72.88	$ 87.88	$ 92.73	$ 92.73	$ 120.32	$ 275.32	$ 75.00	$ 150.00
Usage Rates	All Ccf	$ 0.27930	$ 0.22985	$ 0.09394	$ 0.09394	$ 0.63855	$ 0.26655	$ 0.43589	$ 0.13589
Industrial									
Customer Charge - Sales		$ 1,033.21		$ 1,295.93		$ 1,234.53		$ 1,250.00	
Usage Rates	All Ccf	$ 0.14569		$ 0.11486		$ 0.28220		$ 0.11849	
Public Authority									
Customer Charge - Sales		$ 181.93		$ 253.05		$ 243.91		$ 200.00	
Usage Rates	All Ccf	$ 0.13768		$ 0.13511		$ 0.16208		$ 0.13745	
CNG									
Customer Charge - Sales		$ 746.15		$ 1,955.67		N/A		$ 320.00	
Usage Rates	All Ccf	$ 0.07817		$ 0.08643		N/A		$ 0.08831	
Transportation									
Customer Charge		N/A	N/A	N/A	N/A	N/A	N/A	$ 500.00	
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	N/A	N/A	$ 0.08831	
Commercial Customer Charge		$ 320.96		$ 517.73		$ 545.32		N/A	
Usage Rates	All Ccf	$ 0.12679		$ 0.09394		$ 0.10770		N/A	
Industrial Customer Charge		$ 1,233.21		$ 1,495.93		$ 1,384.53		N/A	
Usage Rates	All Ccf	$ 0.14569		$ 0.11486		$ 0.08722		N/A	
Public Authority Customer Charge		$ 204.93		$ 553.05		$ 2,543.91		N/A	
Usage Rates	All Ccf	$ 0.13768		$ 0.13511		$ 0.00840		N/A	
Compressed Natural Gas Customer Charge		$ 771.15		$ 2,255.67		N/A		N/A	
Usage Rates	All Ccf	$ 0.07817		$ 0.08643		N/A		N/A	
Electric Generation Transportation									
Customer Charge		$ 201.64		$ 717.73		$ 545.32		$ 1,000.00	
Demand Charges	MDQ/month	N/A		N/A		N/A		$ 0.72542	
Usage Rates	All Ccf	N/A		N/A		N/A		$ 0.02000	
Usage Rates (Year-Round)	All Ccf					$ 0.10770			
	First 5,000	$ 0.07724		N/A		N/A			
	Next 35,000	$ 0.06853		N/A		N/A			
	Next 60,000	$ 0.05527		N/A		N/A			
	All Over 100,000	$ 0.04018		N/A		N/A			
Usage Rates - (October - April)	All Ccf								
	First 5,000	N/A		$ 0.05260		N/A			
	Next 95,000	N/A		$ 0.04260		N/A			
	Next 300,000	N/A		$ 0.03260		N/A			
	All Over 400,000	N/A		$ 0.02260		N/A			
Usage Rates - (May - September)	All Ccf								
	First 5,000	N/A		$ 0.04259		N/A			
	Next 95,000	N/A		$ 0.03258		N/A			
	Next 300,000	N/A		$ 0.02259		N/A			
	All Over 400,000	N/A		$ 0.01258		N/A			
Unmetered Gas Light									
	Residential All Ccf	$ 0.87646		$ 0.46668		$ 2.02007		$ 0.67553	
	Commercial All Ccf	$ 0.27930		$ 0.09394		$ 0.63855		$ 0.43589	
	Industrial All Ccf	$ 0.14569		$ 0.11486		$ 0.28220		$ 0.11849	
	Public Authority All Ccf	$ 0.13768		$ 0.13511		$ 0.16208		$ 0.13745	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER BILL IMPACTS

Description	Average Monthly Bill		Change	
	Current Service Area	Recommended TGS All Customers	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
CGSA Incorporated and Environs	$ 44.88	$ 48.82	$ 3.94	8.8%
WNSA Incorporated and Environs	$ 38.44	$ 48.82	$ 10.38	27.0%
RGVSA Incorporated and Environs	$ 62.53	$ 48.82	$ (13.71)	-21.9%
Residential - Large				
CGSA Incorporated and Environs	$ 77.29	$ 74.30	$ (2.99)	-3.9%
WNSA Incorporated and Environs	$ 59.66	$ 74.30	$ 14.64	24.5%
RGVSA Incorporated and Environs	$ 78.89	$ 74.30	$ (4.59)	-5.8%
Customer Assistance				
CGSA Incorporated and Environs	$ 44.88	$ 39.30	$ (5.58)	-12.4%
WNSA Incorporated and Environs	$ 38.44	$ 39.30	$ 0.86	2.2%
RGVSA Incorporated and Environs	$ 62.53	$ 39.30	$ (23.23)	-37.2%
Commercial - Small				
CGSA Incorporated and Environs	$ 107.56	$ 114.67	$ 7.11	6.6%
WNSA Incorporated and Environs	$ 117.47	$ 114.67	$ (2.80)	-2.4%
RGVSA Incorporated and Environs	$ 159.93	$ 114.67	$ (45.26)	-28.3%
Commercial - Large				
CGSA Incorporated and Environs	$ 739.73	$ 676.72	$ (63.01)	-8.5%
WNSA Incorporated and Environs	$ 589.26	$ 676.72	$ 87.46	14.8%
RGVSA Incorporated and Environs	$ 736.13	$ 676.72	$ (59.41)	-8.1%
Industrial				
CGSA Incorporated and Environs	$ 3,652.60	$ 3,572.33	$ (80.27)	-2.2%
WNSA Incorporated and Environs	$ 3,646.91	$ 3,572.33	$ (74.58)	-2.0%
RGVSA Incorporated and Environs	$ 3,392.24	$ 3,572.33	$ 180.09	5.3%
Public Authority				
CGSA Incorporated and Environs	$ 530.03	$ 522.93	$ (7.10)	-1.3%
WNSA Incorporated and Environs	$ 581.78	$ 522.93	$ (58.85)	-10.1%
RGVSA Incorporated and Environs	$ 468.32	$ 522.93	$ 54.61	11.7%
Compressed Natural Gas				
CGSA Incorporated and Environs	$ 746.15	$ 320.00	$ (426.15)	-57.1%
WNSA Incorporated and Environs	N/A	N/A	N/A	N/A
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A
Transportation Service: (3)				
Commercial Transportation				
CGSA Incorporated and Environs	$ 3,807.64	$ 3,886.69	$ 79.05	2.1%
WNSA Incorporated and Environs	$ 4,161.74	$ 3,886.69	$ (275.05)	-6.6%
RGVSA Incorporated and Environs	$ 3,915.94	$ 3,886.69	$ (29.25)	-0.7%
Industrial Transportation				
CGSA Incorporated and Environs	$ 20,758.98	$ 18,816.36	$ (1,942.62)	-9.4%
WNSA Incorporated and Environs	$ 22,028.20	$ 18,816.36	$ (3,211.84)	-14.6%
RGVSA Incorporated and Environs	$ 18,887.56	$ 18,816.36	$ (71.20)	-0.4%
Public Authority Transportation				
CGSA Incorporated and Environs	$ 1,477.92	$ 1,711.73	$ 233.81	15.8%
WNSA Incorporated and Environs	$ 1,964.16	$ 1,711.73	$ (252.43)	-12.9%
RGVSA Incorporated and Environs	$ 3,516.89	$ 1,711.73	$ (1,805.16)	-51.3%
Compressed Natural Gas Transportation				
CGSA Incorporated and Environs	$ 29,828.01	$ 31,556.20	$ 1,728.19	5.8%
WNSA Incorporated and Environs	$ 35,169.78	$ 31,556.20	$ (3,613.58)	-10.3%
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A
Electric Generation Transportation				
CGSA Incorporated and Environs	$ 184,636.19	$ 185,400.48	$ 764.29	0.4%
WNSA Incorporated and Environs	N/A	N/A	N/A	N/A
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A

(1) Bill impacts are shown for those schedules with customers during the test year. The test year cost of gas in each area 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) Current and recommended bills are based on the following average monthly usage levels at local pressure and at 14.65 psi, respectively.

	CGSA	WNSA	RGVSA	CGSA	WNSA	RGVSA
	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure
Residential - Small	17	17	17	17	19	17
Residential - Large	46	46	46	46	51	46
Commercial - Small	45	45	45	45	50	45
Commercial - Large	898	898	898	896	998	898
Industrial	4081	4081	4081	4070	4533	4081
Public Authority	549	549	549	548	610	549
Compressed Natural Gas	0	N/A	N/A	0	N/A	N/A

(3) 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. Current and recommended bills are based on the following usage levels at local pressure and at 14.65 psi, respectively.

	CGSA	WNSA	RGVSA	CGSA	WNSA	RGVSA
	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure
Commercial Transportation	6,558	6,558	6,558	6,541	7,285	6,558
Industrial Transportation	35,469	35,469	35,469	35,376	39,400	35,469
Public Authority Transportation	2,346	2,346	2,346	2,340	2,607	2,346
Compressed Natural Gas Transportation	60,139	60,139	N/A	59,982	66,805	N/A
Electric Generation Transportation	355,327	355,327	N/A	355,327	N/A	N/A

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Small Rates

			$ 21.36	$ 1.32709	$ 1.32709	Small		$ 29.50	$ 1.12616	$ 1.12616	Small				
			$ 33.36	$ 0.91800	$ 0.91800	Large		$ 39.50	$ 0.76252	$ 0.76252	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	20	55,404	$ 256.29	$ -	$ 26.54	$ 256.29	$ 282.83	$ 354.00	$ -	$ 22.52	$ 354.00	$ 376.52	$ 8.14	$ 7.81	38%	33%
21	40	46,592	$ 256.29	$ 27.87	$ 53.08	$ 284.16	$ 309.38	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ 7.79	$ 7.47	33%	29%
41	60	61,047	$ 256.29	$ 54.41	$ 79.63	$ 310.70	$ 335.92	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ 7.46	$ 7.14	29%	25%
61	80	74,953	$ 256.29	$ 80.95	$ 106.17	$ 337.24	$ 362.46	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ 7.12	$ 6.80	25%	23%
81	100	95,123	$ 256.29	$ 107.49	$ 132.71	$ 363.79	$ 389.00	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ 6.79	$ 6.47	22%	20%
101	120	117,870	$ 256.29	$ 134.04	$ 159.25	$ 390.33	$ 415.54	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ 6.45	$ 6.13	20%	18%
121	140	138,214	$ 256.29	$ 160.58	$ 185.79	$ 416.87	$ 442.08	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ 6.12	$ 5.80	18%	16%
141	160	159,441	$ 256.29	$ 187.12	$ 212.33	$ 443.41	$ 468.63	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ 5.78	$ 5.46	16%	14%
161	180	180,046	$ 256.29	$ 213.66	$ 238.88	$ 469.95	$ 495.17	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ 5.45	$ 5.13	14%	12%
181	200	198,335	$ 256.29	$ 240.20	$ 265.42	$ 496.50	$ 521.71	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ 5.11	$ 4.79	12%	11%
201	220	209,086	$ 256.29	$ 266.75	$ 291.96	$ 523.04	$ 548.25	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ 4.78	$ 4.46	11%	10%
221	240	209,535	$ 256.29	$ 293.29	$ 318.50	$ 549.58	$ 574.79	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ 4.44	$ 4.12	10%	9%
241	260	205,802	$ 256.29	$ 319.83	$ 345.04	$ 576.12	$ 601.34	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ 4.11	$ 3.79	9%	8%
261	280	200,434	$ 256.29	$ 346.37	$ 371.59	$ 602.66	$ 627.88	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ 3.77	$ 3.45	8%	7%
281	300	187,483	$ 256.29	$ 372.91	$ 398.13	$ 629.20	$ 654.42	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ 3.44	$ 3.12	7%	6%
301	330	246,664	$ 256.29	$ 399.45	$ 437.94	$ 655.75	$ 694.23	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ 3.10	$ 2.62	6%	5%
331	530	208,783	$ 256.29	$ 439.27	$ 703.36	$ 695.56	$ 959.65	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ 2.57	$ (6.79)	4%	-8%
531	730	9,029	$ 256.29	$ 704.68	$ 968.78	$ 960.98	$ 1,225.07	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ (6.84)	$ (16.20)	-9%	-16%
731	930	2,662	$ 256.29	$ 970.10	$ 1,234.19	$1,226.39	$ 1,490.49	$ 474.00	$ 557.40	$ 709.14	$1,031.40	$ 1,183.14	$ (16.25)	$ (25.61)	-16%	-21%
931	1,130	1,013	$ 256.29	$ 1,235.52	$ 1,499.61	$1,491.81	$ 1,755.90	$ 474.00	$ 709.91	$ 861.65	$1,183.91	$ 1,335.65	$ (25.66)	$ (35.02)	-21%	-24%
1131	1,330	767	$ 256.29	$ 1,500.94	$ 1,765.03	$1,757.23	$ 2,021.32	$ 474.00	$ 862.41	$ 1,014.15	$1,336.41	$ 1,488.15	$ (35.07)	$ (44.43)	-24%	-26%
1331	1,530	347	$ 256.29	$ 1,766.36	$ 2,030.45	$2,022.65	$ 2,286.74	$ 474.00	$1,014.91	$ 1,166.66	$1,488.91	$ 1,640.66	$ (44.48)	$ (53.84)	-26%	-28%
1531	1,730	304	$ 256.29	$ 2,031.78	$ 2,295.87	$2,288.07	$ 2,552.16	$ 474.00	$1,167.42	$ 1,319.16	$1,641.42	$ 1,793.16	$ (53.89)	$ (63.25)	-28%	-30%
1731	1,930	217	$ 256.29	$ 2,297.19	$ 2,561.28	$2,553.48	$ 2,817.58	$ 474.00	$1,319.92	$ 1,471.66	$1,793.92	$ 1,945.66	$ (63.30)	$ (72.66)	-30%	-31%
1931	2,130	116	$ 256.29	$ 2,562.61	$ 2,826.70	$2,818.90	$ 3,082.99	$ 474.00	$1,472.43	$ 1,624.17	$1,946.43	$ 2,098.17	$ (72.71)	$ (82.07)	-31%	-32%
2131	2,330	72	$ 256.29	$ 2,828.03	$ 3,092.12	$3,084.32	$ 3,348.41	$ 474.00	$1,624.93	$ 1,776.67	$2,098.93	$ 2,250.67	$ (82.12)	$ (91.48)	-32%	-33%
2331	2,530	72	$ 256.29	$ 3,093.45	$ 3,357.54	$3,349.74	$ 3,613.83	$ 474.00	$1,777.43	$ 1,929.18	$2,251.43	$ 2,403.18	$ (91.53)	$ (100.89)	-33%	-34%
2531	2,730	72	$ 256.29	$ 3,358.87	$ 3,622.96	$3,615.16	$ 3,879.25	$ 474.00	$1,929.94	$ 2,081.68	$2,403.94	$ 2,555.68	$ (100.93)	$ (110.30)	-34%	-34%
2731	2,930	29	$ 256.29	$ 3,624.28	$ 3,888.37	$3,880.58	$ 4,144.67	$ 474.00	$2,082.44	$ 2,234.18	$2,556.44	$ 2,708.18	$ (110.34)	$ (119.71)	-34%	-35%
2931	3,130	58	$ 256.29	$ 3,889.70	$ 4,153.79	$4,145.99	$ 4,410.08	$ 474.00	$2,234.95	$ 2,386.69	$2,708.95	$ 2,860.69	$ (119.75)	$ (129.12)	-35%	-35%
3131	55,767	289	$ 256.29	$ 4,155.12	$ 74,007.84	$4,411.41	$74,264.13	$ 474.00	$2,387.45	$42,523.47	$2,861.45	$42,997.47	$ (129.16)	$ (2,605.56)	-35%	-42%

Annual Residential Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Large Rates

			$ 21.36	$ 1.32709	$ 1.32709	Small		$ 29.50	$ 1.12616	$ 1.12616	Small				
			$ 33.36	$ 0.91800	$ 0.91800	Large		$ 39.50	$ 0.76252	$ 0.76252	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	20	29	$ 400.29	$ -	$ 18.36	$ 400.29	$ 418.65	$ 354.00	$ -	$ 22.52	$ 354.00	$ 376.52	$ (3.86)	$ (3.51)	-12%	-10%
21	40	-	$ 400.29	$ 19.28	$ 36.72	$ 419.57	$ 437.01	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ (3.49)	$ (3.16)	-10%	-9%
41	60	-	$ 400.29	$ 37.64	$ 55.08	$ 437.93	$ 455.37	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ (3.15)	$ (2.82)	-9%	-7%
61	80	-	$ 400.29	$ 56.00	$ 73.44	$ 456.29	$ 473.73	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ (2.80)	$ (2.47)	-7%	-6%
81	100	-	$ 400.29	$ 74.36	$ 91.80	$ 474.65	$ 492.09	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ (2.45)	$ (2.12)	-6%	-5%
101	120	-	$ 400.29	$ 92.72	$ 110.16	$ 493.01	$ 510.45	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ (2.11)	$ (1.78)	-5%	-4%
121	140	-	$ 400.29	$ 111.08	$ 128.52	$ 511.37	$ 528.81	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ (1.76)	$ (1.43)	-4%	-3%
141	160	14	$ 400.29	$ 129.44	$ 146.88	$ 529.73	$ 547.17	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ (1.41)	$ (1.08)	-3%	-2%
161	180	188	$ 400.29	$ 147.80	$ 165.24	$ 548.09	$ 565.53	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ (1.06)	$ (0.74)	-2%	-2%
181	200	449	$ 400.29	$ 166.16	$ 183.60	$ 566.45	$ 583.89	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ (0.72)	$ (0.39)	-2%	-1%
201	220	781	$ 400.29	$ 184.52	$ 201.96	$ 584.81	$ 602.25	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ (0.37)	$ (0.04)	-1%	0%
221	240	492	$ 400.29	$ 202.88	$ 220.32	$ 603.17	$ 620.61	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ (0.02)	$ 0.31	0%	1%
241	260	362	$ 400.29	$ 221.24	$ 238.68	$ 621.53	$ 638.97	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ 0.32	$ 0.65	1%	1%
261	280	752	$ 400.29	$ 239.60	$ 257.04	$ 639.89	$ 657.33	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ 0.67	$ 1.00	1%	2%
281	300	1,375	$ 400.29	$ 257.96	$ 275.40	$ 658.25	$ 675.69	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ 1.02	$ 1.35	2%	2%
301	330	9,839	$ 400.29	$ 276.32	$ 302.94	$ 676.61	$ 703.23	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ 1.36	$ 1.87	2%	3%
331	530	719,749	$ 400.29	$ 303.86	$ 486.54	$ 704.15	$ 886.83	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ 1.85	$ (0.72)	3%	-1%
531	730	259,933	$ 400.29	$ 487.46	$ 670.14	$ 887.75	$ 1,070.43	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ (0.74)	$ (3.32)	-1%	-4%
731	930	84,083	$ 400.29	$ 671.06	$ 853.74	$1,071.35	$ 1,254.03	$ 474.00	$ 557.40	$ 709.14	$1,031.40	$ 1,183.14	$ (3.33)	$ (5.91)	-4%	-6%
931	1,130	34,221	$ 400.29	$ 854.66	$ 1,037.34	$1,254.95	$ 1,437.63	$ 474.00	$ 709.91	$ 861.65	$1,183.91	$ 1,335.65	$ (5.92)	$ (8.50)	-6%	-7%
1131	1,330	17,798	$ 400.29	$ 1,038.26	$ 1,220.94	$1,438.55	$ 1,621.23	$ 474.00	$ 862.41	$ 1,014.15	$1,336.41	$ 1,488.15	$ (8.51)	$ (11.09)	-7%	-8%
1331	1,530	9,912	$ 400.29	$ 1,221.86	$ 1,404.54	$1,622.15	$ 1,804.83	$ 474.00	$1,014.91	$ 1,166.66	$1,488.91	$ 1,640.66	$ (11.10)	$ (13.68)	-8%	-9%
1531	1,730	6,396	$ 400.29	$ 1,405.46	$ 1,588.14	$1,805.75	$ 1,988.43	$ 474.00	$1,167.42	$ 1,319.16	$1,641.42	$ 1,793.16	$ (13.69)	$ (16.27)	-9%	-10%
1731	1,930	4,196	$ 400.29	$ 1,589.06	$ 1,771.74	$1,989.35	$ 2,172.03	$ 474.00	$1,319.92	$ 1,471.66	$1,793.92	$ 1,945.66	$ (16.29)	$ (18.86)	-10%	-10%
1931	2,130	3,169	$ 400.29	$ 1,772.66	$ 1,955.34	$2,172.95	$ 2,355.63	$ 474.00	$1,472.43	$ 1,624.17	$1,946.43	$ 2,098.17	$ (18.88)	$ (21.46)	-10%	-11%
2131	2,330	2,359	$ 400.29	$ 1,956.26	$ 2,138.94	$2,356.55	$ 2,539.23	$ 474.00	$1,624.93	$ 1,776.67	$2,098.93	$ 2,250.67	$ (21.47)	$ (24.05)	-11%	-11%
2331	2,530	1,982	$ 400.29	$ 2,139.86	$ 2,322.54	$2,540.15	$ 2,722.83	$ 474.00	$1,777.43	$ 1,929.18	$2,251.43	$ 2,403.18	$ (24.06)	$ (26.64)	-11%	-12%
2531	2,730	1,534	$ 400.29	$ 2,323.46	$ 2,506.14	$2,723.75	$ 2,906.43	$ 474.00	$1,929.94	$ 2,081.68	$2,403.94	$ 2,555.68	$ (26.65)	$ (29.23)	-12%	-12%
2731	2,930	1,042	$ 400.29	$ 2,507.06	$ 2,689.74	$2,907.35	$ 3,090.03	$ 474.00	$2,082.44	$ 2,234.18	$2,556.44	$ 2,708.18	$ (29.24)	$ (31.82)	-12%	-12%
2931	3,130	1,056	$ 400.29	$ 2,690.66	$ 2,873.34	$3,090.95	$ 3,273.63	$ 474.00	$2,234.95	$ 2,386.69	$2,708.95	$ 2,860.69	$ (31.83)	$ (34.41)	-12%	-13%
3131	55,767	8,928	$ 400.29	$ 2,874.26	$ 51,194.12	$3,274.55	$51,594.41	$ 474.00	$2,387.45	$42,523.47	$2,861.45	$42,997.47	$ (34.42)	$ (716.41)	-13%	-17%

Annual Residential Bill Impacts of Proposed Rates Relative to Existing West-North Small Service Area Rates

			$ 21.85	$ 0.91731	$ 0.91731	Small			$ 29.50	$ 1.12616	$ 1.12616	Small								
			$ 38.35	$ 0.46731	$ 0.46731	Large			$ 39.50	$ 0.76252	$ 0.76252	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	20	23,540	$ 262.20	$ -	$ 18.35	$ 262.20	$ 280.55		$ 354.00	$ -	$ 22.52	$ 354.00	$ 376.52		$ 7.65	$	8.00	35%	34%	
21	40	13,525	$ 262.20	$ 19.26	$ 36.69	$ 281.46	$ 298.89		$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05		$ 8.02	$	8.35	34%	34%	
41	60	19,339	$ 262.20	$ 37.61	$ 55.04	$ 299.81	$ 317.24		$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57		$ 8.36	$	8.69	33%	33%	
61	80	24,218	$ 262.20	$ 55.96	$ 73.38	$ 318.16	$ 335.58		$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09		$ 8.71	$	9.04	33%	32%	
81	100	29,896	$ 262.20	$ 74.30	$ 91.73	$ 336.50	$ 353.93		$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62		$ 9.06	$	9.39	32%	32%	
101	120	35,399	$ 262.20	$ 92.65	$ 110.08	$ 354.85	$ 372.28		$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14		$ 9.41	$	9.74	32%	31%	
121	140	44,099	$ 262.20	$ 110.99	$ 128.42	$ 373.19	$ 390.62		$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66		$ 9.76	$	10.09	31%	31%	
141	160	51,919	$ 262.20	$ 129.34	$ 146.77	$ 391.54	$ 408.97		$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19		$ 10.10	$	10.43	31%	31%	
161	180	60,443	$ 262.20	$ 147.69	$ 165.12	$ 409.89	$ 427.32		$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71		$ 10.45	$	10.78	31%	30%	
181	200	71,299	$ 262.20	$ 166.03	$ 183.46	$ 428.23	$ 445.66		$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23		$ 10.80	$	11.13	30%	30%	
201	220	81,761	$ 262.20	$ 184.38	$ 201.81	$ 446.58	$ 464.01		$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76		$ 11.15	$	11.48	30%	30%	
221	240	94,893	$ 262.20	$ 202.73	$ 220.15	$ 464.93	$ 482.35		$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28		$ 11.50	$	11.83	30%	29%	
241	260	104,421	$ 262.20	$ 221.07	$ 238.50	$ 483.27	$ 500.70		$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80		$ 11.84	$	12.18	29%	29%	
261	280	114,856	$ 262.20	$ 239.42	$ 256.85	$ 501.62	$ 519.05		$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32		$ 12.19	$	12.52	29%	29%	
281	300	124,193	$ 262.20	$ 257.76	$ 275.19	$ 519.96	$ 537.39		$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85		$ 12.54	$	12.87	29%	29%	
301	330	196,075	$ 262.20	$ 276.11	$ 302.71	$ 538.31	$ 564.91		$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63		$ 12.89	$	13.39	29%	28%	
331	530	822,314	$ 262.20	$ 303.63	$ 486.17	$ 565.83	$ 748.37		$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14		$ 13.38	$	10.81	28%	17%	
531	730	73,223	$ 262.20	$ 487.09	$ 669.64	$ 749.29	$ 931.84		$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64		$ 10.80	$	8.23	17%	11%	
731	930	12,129	$ 262.20	$ 670.55	$ 853.10	$ 932.75	$ 1,115.30		$ 474.00	$ 557.40	$ 709.14	$1,031.40	$ 1,183.14		$ 8.22	$	5.65	11%	6%	
931	1,130	3,117	$ 262.20	$ 854.02	$ 1,036.56	$1,116.22	$ 1,298.76		$ 474.00	$ 709.91	$ 861.65	$1,183.91	$ 1,335.65		$ 5.64	$	3.07	6%	3%	
1131	1,330	1,409	$ 262.20	$ 1,037.48	$ 1,220.02	$1,299.68	$ 1,482.22		$ 474.00	$ 862.41	$ 1,014.15	$1,336.41	$ 1,488.15		$ 3.06	$	0.49	3%	0%	
1331	1,530	583	$ 262.20	$ 1,220.94	$ 1,403.48	$1,483.14	$ 1,665.68		$ 474.00	$1,014.91	$ 1,166.66	$1,488.91	$ 1,640.66		$ 0.48	$	(2.09)	0%	-2%	
1531	1,730	271	$ 262.20	$ 1,404.40	$ 1,586.95	$1,666.60	$ 1,849.15		$ 474.00	$1,167.42	$ 1,319.16	$1,641.42	$ 1,793.16		$ (2.10)	$	(4.67)	-2%	-3%	
1731	1,930	244	$ 262.20	$ 1,587.86	$ 1,770.41	$1,850.06	$ 2,032.61		$ 474.00	$1,319.92	$ 1,471.66	$1,793.92	$ 1,945.66		$ (4.68)	$	(7.25)	-3%	-4%	
1931	2,130	203	$ 262.20	$ 1,771.33	$ 1,953.87	$2,033.53	$ 2,216.07		$ 474.00	$1,472.43	$ 1,624.17	$1,946.43	$ 2,098.17		$ (7.26)	$	(9.83)	-4%	-5%	
2131	2,330	108	$ 262.20	$ 1,954.79	$ 2,137.33	$2,216.99	$ 2,399.53		$ 474.00	$1,624.93	$ 1,776.67	$2,098.93	$ 2,250.67		$ (9.84)	$	(12.41)	-5%	-6%	
2331	2,530	68	$ 262.20	$ 2,138.25	$ 2,320.79	$2,400.45	$ 2,582.99		$ 474.00	$1,777.43	$ 1,929.18	$2,251.43	$ 2,403.18		$ (12.42)	$	(14.98)	-6%	-7%	
2531	2,730	54	$ 262.20	$ 2,321.71	$ 2,504.26	$2,583.91	$ 2,766.46		$ 474.00	$1,929.94	$ 2,081.68	$2,403.94	$ 2,555.68		$ (15.00)	$	(17.56)	-7%	-8%	
2731	2,930	41	$ 262.20	$ 2,505.17	$ 2,687.72	$2,767.37	$ 2,949.92		$ 474.00	$2,082.44	$ 2,234.18	$2,556.44	$ 2,708.18		$ (17.58)	$	(20.14)	-8%	-8%	
2931	3,130	27	$ 262.20	$ 2,688.64	$ 2,871.18	$2,950.84	$ 3,133.38		$ 474.00	$2,234.95	$ 2,386.69	$2,708.95	$ 2,860.69		$ (20.16)	$	(22.72)	-8%	-9%	
3131	88,392	176	$ 262.20	$ 2,872.10	$ 81,082.89	$3,134.30	$81,345.09		$ 474.00	$2,387.45	$67,400.69	$2,861.45	$67,874.69		$ (22.74)	$	(1,122.53)	-9%	-17%	

Annual Residential Bill Impacts of Proposed Rates Relative to Existing West-North Large Service Area Rates

			$ 21.85	$ 0.91731	$ 0.91731	Small	$ 29.50	$ 1.12616	$ 1.12616	Small				
			$ 38.35	$ 0.46731	$ 0.46731	Large	$ 39.50	$ 0.76252	$ 0.76252	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	20	1,450	$ 460.20	$ -	$ 9.35	$ 460.20	$ 469.55	$ 354.00	$ -	$ 22.52	$ 354.00	$ 376.52	$ (8.85)	$ (7.75)	-23%	-20%
21	40	745	$ 460.20	$ 9.81	$ 18.69	$ 470.01	$ 478.89	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ (7.70)	$ (6.65)	-20%	-17%
41	60	1,328	$ 460.20	$ 19.16	$ 28.04	$ 479.36	$ 488.24	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ (6.60)	$ (5.56)	-17%	-14%
61	80	1,355	$ 460.20	$ 28.51	$ 37.38	$ 488.71	$ 497.58	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ (5.50)	$ (4.46)	-14%	-11%
81	100	1,721	$ 460.20	$ 37.85	$ 46.73	$ 498.05	$ 506.93	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ (4.40)	$ (3.36)	-11%	-8%
101	120	2,236	$ 460.20	$ 47.20	$ 56.08	$ 507.40	$ 516.28	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ (3.30)	$ (2.26)	-8%	-5%
121	140	2,046	$ 460.20	$ 56.54	$ 65.42	$ 516.74	$ 525.62	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ (2.21)	$ (1.16)	-5%	-3%
141	160	2,819	$ 460.20	$ 65.89	$ 74.77	$ 526.09	$ 534.97	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ (1.11)	$ (0.07)	-3%	0%
161	180	3,063	$ 460.20	$ 75.24	$ 84.12	$ 535.44	$ 544.32	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ (0.01)	$ 1.03	0%	2%
181	200	3,429	$ 460.20	$ 84.58	$ 93.46	$ 544.78	$ 553.66	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ 1.09	$ 2.13	2%	5%
201	220	4,391	$ 460.20	$ 93.93	$ 102.81	$ 554.13	$ 563.01	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ 2.19	$ 3.23	5%	7%
221	240	5,448	$ 460.20	$ 103.28	$ 112.15	$ 563.48	$ 572.35	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ 3.28	$ 4.33	7%	9%
241	260	6,586	$ 460.20	$ 112.62	$ 121.50	$ 572.82	$ 581.70	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ 4.38	$ 5.43	9%	11%
261	280	7,101	$ 460.20	$ 121.97	$ 130.85	$ 582.17	$ 591.05	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ 5.48	$ 6.52	11%	13%
281	300	9,053	$ 460.20	$ 131.31	$ 140.19	$ 591.51	$ 600.39	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ 6.58	$ 7.62	13%	15%
301	330	17,550	$ 460.20	$ 140.66	$ 154.21	$ 600.86	$ 614.41	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ 7.68	$ 9.27	15%	18%
331	530	521,710	$ 460.20	$ 154.68	$ 247.67	$ 614.88	$ 707.87	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ 9.29	$ 14.19	18%	24%
531	730	557,759	$ 460.20	$ 248.14	$ 341.14	$ 708.34	$ 801.34	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ 14.21	$ 19.11	24%	29%
731	930	203,515	$ 460.20	$ 341.60	$ 434.60	$ 801.80	$ 894.80	$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14	$ 19.13	$ 24.03	29%	32%
931	1,130	74,307	$ 460.20	$ 435.07	$ 528.06	$ 895.27	$ 988.26	$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65	$ 24.05	$ 28.95	32%	35%
1131	1,330	31,875	$ 460.20	$ 528.53	$ 621.52	$ 988.73	$ 1,081.72	$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15	$ 28.97	$ 33.87	35%	38%
1331	1,530	15,233	$ 460.20	$ 621.99	$ 714.98	$ 1,082.19	$ 1,175.18	$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66	$ 33.89	$ 38.79	38%	40%
1531	1,730	8,524	$ 460.20	$ 715.45	$ 808.45	$ 1,175.65	$ 1,268.65	$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16	$ 38.81	$ 43.71	40%	41%
1731	1,930	5,611	$ 460.20	$ 808.91	$ 901.91	$ 1,269.11	$ 1,362.11	$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66	$ 43.73	$ 48.63	41%	43%
1931	2,130	3,225	$ 460.20	$ 902.38	$ 995.37	$ 1,362.58	$ 1,455.57	$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17	$ 48.65	$ 53.55	43%	44%
2131	2,330	2,006	$ 460.20	$ 995.84	$ 1,088.83	$ 1,456.04	$ 1,549.03	$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67	$ 53.57	$ 58.47	44%	45%
2331	2,530	1,586	$ 460.20	$ 1,089.30	$ 1,182.29	$ 1,549.50	$ 1,642.49	$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18	$ 58.49	$ 63.39	45%	46%
2531	2,730	1,084	$ 460.20	$ 1,182.76	$ 1,275.76	$ 1,642.96	$ 1,735.96	$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68	$ 63.41	$ 68.31	46%	47%
2731	2,930	772	$ 460.20	$ 1,276.22	$ 1,369.22	$ 1,736.42	$ 1,829.42	$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18	$ 68.33	$ 73.23	47%	48%
2931	3,130	854	$ 460.20	$ 1,369.69	$ 1,462.68	$ 1,829.89	$ 1,922.88	$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69	$ 73.26	$ 78.15	48%	49%
3131	88,392	3,768	$ 460.20	$ 1,463.15	$ 41,306.49	$ 1,923.35	$41,766.69	$ 474.00	$ 2,387.45	$67,400.69	$ 2,861.45	$67,874.69	$ 78.18	$ 2,175.67	49%	63%

Annual Residential Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Small Rates

			$ 23.64	$ 2.47070	$ 2.47070	Small		$ 29.50	$ 1.12616	$ 1.12616	Small							
			$ 38.64	$ 1.08608	$ 1.08608	Large		$ 39.50	$ 0.76252	$ 0.76252	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	20	6,098	$ 283.71	$ -	$ 49.41	$ 283.71	$ 333.12	$ 354.00	$ -	$ 22.52	$ 354.00	$ 376.52	$ 5.86	$ 3.62	25%	13%
21	40	5,097	$ 283.71	$ 51.88	$ 98.83	$ 335.59	$ 382.54	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ 3.50	$ 1.38	13%	4%
41	60	4,941	$ 283.71	$ 101.30	$ 148.24	$ 385.01	$ 431.95	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ 1.26	$ (0.87)	4%	-2%
61	80	5,623	$ 283.71	$ 150.71	$ 197.66	$ 434.42	$ 481.36	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ (0.98)	$ (3.11)	-3%	-8%
81	100	5,654	$ 283.71	$ 200.13	$ 247.07	$ 483.83	$ 530.78	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ (3.22)	$ (5.35)	-8%	-12%
101	120	4,143	$ 283.71	$ 249.54	$ 296.48	$ 533.25	$ 580.19	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ (5.46)	$ (7.59)	-12%	-16%
121	140	1,841	$ 283.71	$ 298.95	$ 345.90	$ 582.66	$ 629.61	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ (7.70)	$ (9.83)	-16%	-19%
141	160	756	$ 283.71	$ 348.37	$ 395.31	$ 632.08	$ 679.02	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ (9.94)	$ (12.07)	-19%	-21%
161	180	348	$ 283.71	$ 397.78	$ 444.73	$ 681.49	$ 728.43	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ (12.18)	$ (14.31)	-21%	-24%
181	200	169	$ 283.71	$ 447.20	$ 494.14	$ 730.90	$ 777.85	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ (14.42)	$ (16.55)	-24%	-26%
201	220	107	$ 283.71	$ 496.61	$ 543.55	$ 780.32	$ 827.26	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ (16.66)	$ (18.79)	-26%	-27%
221	240	62	$ 283.71	$ 546.02	$ 592.97	$ 829.73	$ 876.68	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ (18.90)	$ (21.03)	-27%	-29%
241	260	40	$ 283.71	$ 595.44	$ 642.38	$ 879.15	$ 926.09	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ (21.15)	$ (23.27)	-29%	-30%
261	280	32	$ 283.71	$ 644.85	$ 691.80	$ 928.56	$ 975.50	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ (23.39)	$ (25.51)	-30%	-31%
281	300	12	$ 283.71	$ 694.27	$ 741.21	$ 977.97	$ 1,024.92	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ (25.63)	$ (27.76)	-31%	-32%
301	330	18	$ 283.71	$ 743.68	$ 815.33	$1,027.39	$ 1,099.04	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ (27.87)	$ (31.12)	-33%	-34%
331	530	33	$ 283.71	$ 817.80	$ 1,309.47	$1,101.51	$ 1,593.18	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ (31.26)	$ (59.59)	-34%	-45%
531	730	13	$ 283.71	$ 1,311.94	$ 1,803.61	$1,595.65	$ 2,087.32	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ (59.73)	$ (88.06)	-45%	-51%
731	930	2	$ 283.71	$ 1,806.08	$ 2,297.75	$2,089.79	$ 2,581.46	$ 474.00	$ 557.40	$ 709.14	$1,031.40	$ 1,183.14	$ (88.20)	$ (116.53)	-51%	-54%
931	1,130	4	$ 283.71	$ 2,300.22	$ 2,791.89	$2,583.93	$ 3,075.60	$ 474.00	$ 709.91	$ 861.65	$1,183.91	$ 1,335.65	$ (116.67)	$ (145.00)	-54%	-57%
1131	1,330	3	$ 283.71	$ 2,794.36	$ 3,286.03	$3,078.07	$ 3,569.74	$ 474.00	$ 862.41	$ 1,014.15	$1,336.41	$ 1,488.15	$ (145.14)	$ (173.47)	-57%	-58%
1331	1,530	-	$ 283.71	$ 3,288.50	$ 3,780.17	$3,572.21	$ 4,063.88	$ 474.00	$1,014.91	$ 1,166.66	$1,488.91	$ 1,640.66	$ (173.61)	$ (201.94)	-58%	-60%
1531	1,730	-	$ 283.71	$ 3,782.64	$ 4,274.31	$4,066.35	$ 4,558.02	$ 474.00	$1,167.42	$ 1,319.16	$1,641.42	$ 1,793.16	$ (202.08)	$ (230.40)	-60%	-61%
1731	1,930	-	$ 283.71	$ 4,276.78	$ 4,768.45	$4,560.49	$ 5,052.16	$ 474.00	$1,319.92	$ 1,471.66	$1,793.92	$ 1,945.66	$ (230.55)	$ (258.87)	-61%	-61%
1931	2,130	-	$ 283.71	$ 4,770.92	$ 5,262.59	$5,054.63	$ 5,546.30	$ 474.00	$1,472.43	$ 1,624.17	$1,946.43	$ 2,098.17	$ (259.02)	$ (287.34)	-61%	-62%
2131	2,330	1	$ 283.71	$ 5,265.06	$ 5,756.73	$5,548.77	$ 6,040.44	$ 474.00	$1,624.93	$ 1,776.67	$2,098.93	$ 2,250.67	$ (287.49)	$ (315.81)	-62%	-63%
2331	2,530	-	$ 283.71	$ 5,759.20	$ 6,250.87	$6,042.91	$ 6,534.58	$ 474.00	$1,777.43	$ 1,929.18	$2,251.43	$ 2,403.18	$ (315.96)	$ (344.28)	-63%	-63%
2531	2,730	-	$ 283.71	$ 6,253.34	$ 6,745.01	$6,537.05	$ 7,028.72	$ 474.00	$1,929.94	$ 2,081.68	$2,403.94	$ 2,555.68	$ (344.43)	$ (372.75)	-63%	-64%
2731	2,930	-	$ 283.71	$ 6,747.48	$ 7,239.15	$7,031.19	$ 7,522.86	$ 474.00	$2,082.44	$ 2,234.18	$2,556.44	$ 2,708.18	$ (372.90)	$ (401.22)	-64%	-64%
2931	3,130	-	$ 283.71	$ 7,241.62	$ 7,733.29	$7,525.33	$ 8,017.00	$ 474.00	$2,234.95	$ 2,386.69	$2,708.95	$ 2,860.69	$ (401.37)	$ (429.69)	-64%	-64%
3131	30,012	2	$ 283.71	$ 7,735.76	$ 74,150.66	$8,019.47	$74,434.36	$ 474.00	$2,387.45	$22,884.76	$2,861.45	$23,358.76	$ (429.83)	$ (4,256.30)	-64%	-69%

Annual Residential Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Large Rates

			$ 23.64	$ 2.47070	$ 2.47070	Small		$ 29.50	$ 1.12616	$ 1.12616	Small								
			$ 38.64	$ 1.08608	$ 1.08608	Large		$ 39.50	$ 0.76252	$ 0.76252	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	20	73	$ 463.71	$ -	$ 21.72	$ 463.71	$ 485.43	$ 354.00	$ -	$ 22.52	$ 354.00	$ 376.52	$ (9.14)	$ (9.08)	-24%	-22%
21	40	74	$ 463.71	$ 22.81	$ 43.44	$ 486.52	$ 507.15	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ (9.07)	$ (9.01)	-22%	-21%
41	60	184	$ 463.71	$ 44.53	$ 65.16	$ 508.24	$ 528.87	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ (9.01)	$ (8.94)	-21%	-20%
61	80	390	$ 463.71	$ 66.25	$ 86.89	$ 529.96	$ 550.59	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ (8.94)	$ (8.88)	-20%	-19%
81	100	843	$ 463.71	$ 87.97	$ 108.61	$ 551.68	$ 572.32	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ (8.87)	$ (8.81)	-19%	-18%
101	120	2,155	$ 463.71	$ 109.69	$ 130.33	$ 573.40	$ 594.04	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ (8.80)	$ (8.74)	-18%	-18%
121	140	3,529	$ 463.71	$ 131.42	$ 152.05	$ 595.12	$ 615.76	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ (8.74)	$ (8.67)	-18%	-17%
141	160	3,726	$ 463.71	$ 153.14	$ 173.77	$ 616.85	$ 637.48	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ (8.67)	$ (8.61)	-17%	-16%
161	180	3,182	$ 463.71	$ 174.86	$ 195.49	$ 638.57	$ 659.20	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ (8.60)	$ (8.54)	-16%	-16%
181	200	2,425	$ 463.71	$ 196.58	$ 217.22	$ 660.29	$ 680.92	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ (8.54)	$ (8.47)	-16%	-15%
201	220	1,850	$ 463.71	$ 218.30	$ 238.94	$ 682.01	$ 702.65	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ (8.47)	$ (8.41)	-15%	-14%
221	240	1,361	$ 463.71	$ 240.02	$ 260.66	$ 703.73	$ 724.37	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ (8.40)	$ (8.34)	-14%	-14%
241	260	1,010	$ 463.71	$ 261.75	$ 282.38	$ 725.45	$ 746.09	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ (8.34)	$ (8.27)	-14%	-13%
261	280	712	$ 463.71	$ 283.47	$ 304.10	$ 747.17	$ 767.81	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ (8.27)	$ (8.21)	-13%	-13%
281	300	541	$ 463.71	$ 305.19	$ 325.82	$ 768.90	$ 789.53	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ (8.20)	$ (8.14)	-13%	-12%
301	330	554	$ 463.71	$ 326.91	$ 358.41	$ 790.62	$ 822.11	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ (8.14)	$ (8.04)	-12%	-12%
331	530	1,127	$ 463.71	$ 359.49	$ 575.62	$ 823.20	$ 1,039.33	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ (8.07)	$ (13.43)	-12%	-16%
531	730	183	$ 463.71	$ 576.71	$ 792.84	$1,040.42	$ 1,256.55	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ (13.46)	$ (18.83)	-16%	-18%
731	930	94	$ 463.71	$ 793.92	$ 1,010.05	$1,257.63	$ 1,473.76	$ 474.00	$ 557.40	$ 709.14	$1,031.40	$ 1,183.14	$ (18.85)	$ (24.22)	-18%	-20%
931	1,130	51	$ 463.71	$ 1,011.14	$ 1,227.27	$1,474.85	$ 1,690.98	$ 474.00	$ 709.91	$ 861.65	$1,183.91	$ 1,335.65	$ (24.25)	$ (29.61)	-20%	-21%
1131	1,330	29	$ 463.71	$ 1,228.36	$ 1,444.49	$1,692.06	$ 1,908.19	$ 474.00	$ 862.41	$ 1,014.15	$1,336.41	$ 1,488.15	$ (29.64)	$ (35.00)	-21%	-22%
1331	1,530	15	$ 463.71	$ 1,445.57	$ 1,661.70	$1,909.28	$ 2,125.41	$ 474.00	$1,014.91	$ 1,166.66	$1,488.91	$ 1,640.66	$ (35.03)	$ (40.40)	-22%	-23%
1531	1,730	9	$ 463.71	$ 1,662.79	$ 1,878.92	$2,126.50	$ 2,342.63	$ 474.00	$1,167.42	$ 1,319.16	$1,641.42	$ 1,793.16	$ (40.42)	$ (45.79)	-23%	-23%
1731	1,930	9	$ 463.71	$ 1,880.00	$ 2,096.13	$2,343.71	$ 2,559.84	$ 474.00	$1,319.92	$ 1,471.66	$1,793.92	$ 1,945.66	$ (45.82)	$ (51.18)	-23%	-24%
1931	2,130	8	$ 463.71	$ 2,097.22	$ 2,313.35	$2,560.93	$ 2,777.06	$ 474.00	$1,472.43	$ 1,624.17	$1,946.43	$ 2,098.17	$ (51.21)	$ (56.57)	-24%	-24%
2131	2,330	7	$ 463.71	$ 2,314.44	$ 2,530.57	$2,778.14	$ 2,994.27	$ 474.00	$1,624.93	$ 1,776.67	$2,098.93	$ 2,250.67	$ (56.60)	$ (61.97)	-24%	-25%
2331	2,530	11	$ 463.71	$ 2,531.65	$ 2,747.78	$2,995.36	$ 3,211.49	$ 474.00	$1,777.43	$ 1,929.18	$2,251.43	$ 2,403.18	$ (61.99)	$ (67.36)	-25%	-25%
2531	2,730	6	$ 463.71	$ 2,748.87	$ 2,965.00	$3,212.58	$ 3,428.71	$ 474.00	$1,929.94	$ 2,081.68	$2,403.94	$ 2,555.68	$ (67.39)	$ (72.75)	-25%	-25%
2731	2,930	2	$ 463.71	$ 2,966.09	$ 3,182.22	$3,429.79	$ 3,645.92	$ 474.00	$2,082.44	$ 2,234.18	$2,556.44	$ 2,708.18	$ (72.78)	$ (78.14)	-25%	-26%
2931	3,130	3	$ 463.71	$ 3,183.30	$ 3,399.43	$3,647.01	$ 3,863.14	$ 474.00	$2,234.95	$ 2,386.69	$2,708.95	$ 2,860.69	$ (78.17)	$ (83.54)	-26%	-26%
3131	30,012	23	$ 463.71	$ 3,400.52	$ 32,595.44	$3,864.23	$33,059.15	$ 474.00	$2,387.45	$22,884.76	$2,861.45	$23,358.76	$ (83.56)	$ (808.37)	-26%	-29%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Small Rates

			$ 72.88	$ 0.72993	$ 0.72993	Small			$ 75.00	$ 0.88652	$ 0.88652	Small						
			$ 87.88	$ 0.68048	$ 0.68048	Large			$ 150.00	$ 0.58652	$ 0.58652	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
-	188	3,136	$ 874.51	$ -	$ 137.23	$ 874.51	$ 1,011.74		$ 900.00	$ -	$ 166.67	$ 900.00	$ 1,066.67		$ 2.12	$ 4.58	3%	5%
189	375	1,753	$ 874.51	$ 137.96	$ 273.72	$ 1,012.47	$ 1,148.23		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ 4.59	$ 7.02	5%	7%
376	563	1,017	$ 874.51	$ 274.45	$ 410.95	$ 1,148.96	$ 1,285.46		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ 7.03	$ 9.47	7%	9%
564	750	668	$ 874.51	$ 411.68	$ 547.45	$ 1,286.19	$ 1,421.96		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ 9.48	$ 11.91	9%	10%
751	938	492	$ 874.51	$ 548.18	$ 684.67	$ 1,422.69	$ 1,559.18		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ 11.92	$ 14.36	10%	11%
939	1,125	385	$ 874.51	$ 685.40	$ 821.17	$ 1,559.91	$ 1,695.68		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ 14.38	$ 16.80	11%	12%
1,126	1,313	333	$ 874.51	$ 821.90	$ 958.40	$ 1,696.41	$ 1,832.91		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ 16.82	$ 19.26	12%	13%
1,314	1,500	233	$ 874.51	$ 959.13	$ 1,094.90	$ 1,833.64	$ 1,969.40		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ 19.27	$ 21.70	13%	13%
1,501	1,688	229	$ 874.51	$ 1,095.63	$ 1,232.12	$ 1,970.13	$ 2,106.63		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ 21.71	$ 24.15	13%	14%
1,689	1,875	193	$ 874.51	$ 1,232.85	$ 1,368.62	$ 2,107.36	$ 2,243.13		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ 24.16	$ 26.59	14%	14%
1,876	2,063	150	$ 874.51	$ 1,369.35	$ 1,505.85	$ 2,243.86	$ 2,380.36		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ 26.60	$ 29.04	14%	15%
2,064	2,250	158	$ 874.51	$ 1,506.58	$ 1,642.34	$ 2,381.09	$ 2,516.85		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ 29.06	$ 31.48	15%	15%
2,251	2,438	145	$ 874.51	$ 1,643.07	$ 1,779.57	$ 2,517.58	$ 2,654.08		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ 31.50	$ 33.94	15%	15%
2,439	2,625	105	$ 874.51	$ 1,780.30	$ 1,916.07	$ 2,654.81	$ 2,790.58		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ 33.95	$ 36.38	15%	16%
2,626	2,813	119	$ 874.51	$ 1,916.80	$ 2,053.29	$ 2,791.31	$ 2,927.80		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ 36.39	$ 38.83	16%	16%
2,814	3,000	112	$ 874.51	$ 2,054.02	$ 2,189.79	$ 2,928.53	$ 3,064.30		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ 38.84	$ 41.27	16%	16%
3,001	5,000	336	$ 874.51	$ 2,190.52	$ 3,649.65	$ 3,065.03	$ 4,524.16		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ 41.26	$ 17.37	16%	5%
5,001	7,000	5	$ 874.51	$ 3,650.38	$ 5,109.51	$ 4,524.89	$ 5,984.02		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ 17.36	$ (6.53)	5%	-1%
7,001	9,000	9	$ 874.51	$ 5,110.24	$ 6,569.37	$ 5,984.75	$ 7,443.88		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ (6.54)	$ (30.43)	-1%	-5%
9,001	11,000	6	$ 874.51	$ 6,570.10	$ 8,029.23	$ 7,444.61	$ 8,903.74		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (30.45)	$ (54.33)	-5%	-7%
11,001	13,000	1	$ 874.51	$ 8,029.96	$ 9,489.09	$ 8,904.47	$ 10,363.60		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (54.35)	$ (78.24)	-7%	-9%
13,001	15,000	-	$ 874.51	$ 9,489.82	$ 10,948.95	$ 10,364.33	$ 11,823.46		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (78.25)	$ (102.14)	-9%	-10%
15,001	17,000	-	$ 874.51	$ 10,949.68	$ 12,408.81	$ 11,824.19	$ 13,283.32		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (102.15)	$ (126.04)	-10%	-11%
17,001	19,000	-	$ 874.51	$ 12,409.54	$ 13,868.67	$ 13,284.05	$ 14,743.18		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (126.05)	$ (149.94)	-11%	-12%
19,001	21,000	-	$ 874.51	$ 13,869.40	$ 15,328.53	$ 14,743.91	$ 16,203.04		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (149.95)	$ (173.84)	-12%	-13%
21,001	23,000	1	$ 874.51	$ 15,329.26	$ 16,788.40	$ 16,203.77	$ 17,662.90		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (173.86)	$ (197.74)	-13%	-13%
23,001	25,000	-	$ 874.51	$ 16,789.13	$ 18,248.26	$ 17,663.63	$ 19,122.77		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (197.76)	$ (221.65)	-13%	-14%
25,001	27,000	-	$ 874.51	$ 18,248.99	$ 19,708.12	$ 19,123.49	$ 20,582.63		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (221.66)	$ (245.55)	-14%	-14%
27,001	29,000	-	$ 874.51	$ 19,708.85	$ 21,167.98	$ 20,583.36	$ 22,042.49		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (245.56)	$ (269.45)	-14%	-15%
29,001	31,000	-	$ 874.51	$ 21,168.71	$ 22,627.84	$ 22,043.22	$ 23,502.35		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (269.46)	$ (293.35)	-15%	-15%
31,001	1,305,510	1	$ 874.51	$ 22,628.57	$ 952,931.21	$ 23,503.08	$ 953,805.72		$ 1,800.00	$ 18,182.71	$ 765,708.02	$ 19,982.71	$ 767,508.02		$ (293.36)	$ (15,524.81)	-15%	-20%

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Large Rates

			$ 72.88	$ 0.72993	$ 0.72993	Small			$ 75.00	$ 0.88652	$ 0.88652	Small				
			$ 87.88	$ 0.68048	$ 0.68048	Large			$ 150.00	$ 0.58652	$ 0.58652	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
-	188	-	$ 1,054.51	$ -	$ 127.93	$ 1,054.51	$ 1,182.44		$ 900.00	$ -	$ 166.67	$ 900.00	$ 1,066.67	$ (12.88)	$ (9.65)	-15%	-10%
189	375	-	$ 1,054.51	$ 128.61	$ 255.18	$ 1,183.12	$ 1,309.69		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45	$ (9.63)	$ (6.44)	-10%	-6%
376	563	-	$ 1,054.51	$ 255.86	$ 383.11	$ 1,310.37	$ 1,437.62		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11	$ (6.42)	$ (3.21)	-6%	-3%
564	750	-	$ 1,054.51	$ 383.79	$ 510.36	$ 1,438.30	$ 1,564.87		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89	$ (3.19)	$ 0.00	-3%	0%
751	938	-	$ 1,054.51	$ 511.04	$ 638.29	$ 1,565.55	$ 1,692.80		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56	$ 0.02	$ 3.23	0%	2%
939	1,125	-	$ 1,054.51	$ 638.97	$ 765.54	$ 1,693.48	$ 1,820.05		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34	$ 3.25	$ 6.44	2%	4%
1,126	1,313	-	$ 1,054.51	$ 766.22	$ 893.47	$ 1,820.73	$ 1,947.98		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00	$ 6.46	$ 9.67	4%	6%
1,314	1,500	-	$ 1,054.51	$ 894.15	$ 1,020.72	$ 1,948.66	$ 2,075.23		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78	$ 9.69	$ 12.88	6%	7%
1,501	1,688	-	$ 1,054.51	$ 1,021.40	$ 1,148.65	$ 2,075.91	$ 2,203.16		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45	$ 12.90	$ 16.11	7%	9%
1,689	1,875	-	$ 1,054.51	$ 1,149.33	$ 1,275.90	$ 2,203.84	$ 2,330.41		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23	$ 16.12	$ 19.32	9%	10%
1,876	2,063	-	$ 1,054.51	$ 1,276.58	$ 1,403.83	$ 2,331.09	$ 2,458.34		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89	$ 19.34	$ 22.55	10%	11%
2,064	2,250	-	$ 1,054.51	$ 1,404.51	$ 1,531.08	$ 2,459.02	$ 2,585.59		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67	$ 22.56	$ 25.76	11%	12%
2,251	2,438	3	$ 1,054.51	$ 1,531.76	$ 1,659.01	$ 2,586.27	$ 2,713.52		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34	$ 25.77	$ 28.98	12%	13%
2,439	2,625	1	$ 1,054.51	$ 1,659.69	$ 1,786.26	$ 2,714.20	$ 2,840.77		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12	$ 29.00	$ 32.20	13%	14%
2,626	2,813	1	$ 1,054.51	$ 1,786.94	$ 1,914.19	$ 2,841.45	$ 2,968.70		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78	$ 32.21	$ 35.42	14%	14%
2,814	3,000	1	$ 1,054.51	$ 1,914.87	$ 2,041.44	$ 2,969.38	$ 3,095.95		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56	$ 35.44	$ 38.63	14%	15%
3,001	5,000	660	$ 1,054.51	$ 2,042.12	$ 3,402.40	$ 3,096.63	$ 4,456.91		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60	$ 38.63	$ 22.97	15%	6%
5,001	7,000	684	$ 1,054.51	$ 3,403.08	$ 4,763.36	$ 4,457.59	$ 5,817.87		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64	$ 22.97	$ 7.31	6%	2%
7,001	9,000	490	$ 1,054.51	$ 4,764.04	$ 6,124.32	$ 5,818.55	$ 7,178.83		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68	$ 7.31	$ (8.35)	2%	-1%
9,001	11,000	316	$ 1,054.51	$ 6,125.00	$ 7,485.28	$ 7,179.51	$ 8,539.79		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72	$ (8.35)	$ (24.01)	-1%	-3%
11,001	13,000	240	$ 1,054.51	$ 7,485.96	$ 8,846.24	$ 8,540.47	$ 9,900.75		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76	$ (24.01)	$ (39.67)	-3%	-5%
13,001	15,000	168	$ 1,054.51	$ 8,846.92	$ 10,207.20	$ 9,901.43	$ 11,261.71		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80	$ (39.67)	$ (55.33)	-5%	-6%
15,001	17,000	145	$ 1,054.51	$ 10,207.88	$ 11,568.16	$ 11,262.39	$ 12,622.67		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84	$ (55.33)	$ (70.99)	-6%	-7%
17,001	19,000	102	$ 1,054.51	$ 11,568.84	$ 12,929.12	$ 12,623.35	$ 13,983.63		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88	$ (70.99)	$ (86.65)	-7%	-7%
19,001	21,000	61	$ 1,054.51	$ 12,929.80	$ 14,290.08	$ 13,984.31	$ 15,344.59		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92	$ (86.65)	$ (102.31)	-7%	-8%
21,001	23,000	68	$ 1,054.51	$ 14,290.77	$ 15,651.05	$ 15,345.27	$ 16,705.55		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97	$ (102.31)	$ (117.97)	-8%	-8%
23,001	25,000	60	$ 1,054.51	$ 15,651.73	$ 17,012.01	$ 16,706.24	$ 18,066.52		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01	$ (117.97)	$ (133.63)	-8%	-9%
25,001	27,000	33	$ 1,054.51	$ 17,012.69	$ 18,372.97	$ 18,067.20	$ 19,427.48		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05	$ (133.63)	$ (149.29)	-9%	-9%
27,001	29,000	31	$ 1,054.51	$ 18,373.65	$ 19,733.93	$ 19,428.16	$ 20,788.44		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09	$ (149.29)	$ (164.95)	-9%	-10%
29,001	31,000	37	$ 1,054.51	$ 19,734.61	$ 21,094.89	$ 20,789.12	$ 22,149.40		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13	$ (164.95)	$ (180.61)	-10%	-10%
31,001	1,305,510	145	$ 1,054.51	$ 21,095.57	$ 888,373.74	$ 22,150.08	$ 889,428.25		$ 1,800.00	$ 18,182.71	$ 765,708.02	$ 19,982.71	$ 767,508.02	$ (180.61)	$ (10,160.02)	-10%	-14%

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing West-North Service Area Rates

			$ 92.73	$ 0.54457	$ 0.54457	Small			$ 75.00	$ 0.88652	$ 0.88652	Small								
			$ 92.73	$ 0.54457	$ 0.54457	Large			$ 150.00	$ 0.58652	$ 0.58652	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
-	188	2,992	$ 1,112.76	$ -	$ 102.38	$ 1,112.76	$ 1,215.14		$ 900.00	$ -	$ 166.67	$ 900.00	$ 1,066.67		$ (17.73)	$ (12.37)	-19%	-12%		
189	375	2,786	$ 1,112.76	$ 102.92	$ 204.21	$ 1,215.68	$ 1,316.97		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (12.34)	$ (7.04)	-12%	-6%		
376	563	2,012	$ 1,112.76	$ 204.76	$ 306.59	$ 1,317.52	$ 1,419.35		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (7.02)	$ (1.69)	-6%	-1%		
564	750	1,183	$ 1,112.76	$ 307.14	$ 408.43	$ 1,419.90	$ 1,521.19		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (1.66)	$ 3.64	-1%	3%		
751	938	924	$ 1,112.76	$ 408.97	$ 510.81	$ 1,521.73	$ 1,623.57		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ 3.67	$ 9.00	3%	7%		
939	1,125	658	$ 1,112.76	$ 511.35	$ 612.64	$ 1,624.11	$ 1,725.40		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ 9.03	$ 14.33	7%	10%		
1,126	1,313	515	$ 1,112.76	$ 613.19	$ 715.02	$ 1,725.95	$ 1,827.78		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ 14.36	$ 19.69	10%	13%		
1,314	1,500	461	$ 1,112.76	$ 715.57	$ 816.86	$ 1,828.33	$ 1,929.62		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ 19.71	$ 25.01	13%	16%		
1,501	1,688	336	$ 1,112.76	$ 817.40	$ 919.23	$ 1,930.16	$ 2,031.99		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ 25.04	$ 30.37	16%	18%		
1,689	1,875	313	$ 1,112.76	$ 919.78	$ 1,021.07	$ 2,032.54	$ 2,133.83		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ 30.40	$ 35.70	18%	20%		
1,876	2,063	243	$ 1,112.76	$ 1,021.61	$ 1,123.45	$ 2,134.37	$ 2,236.21		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ 35.73	$ 41.06	20%	22%		
2,064	2,250	247	$ 1,112.76	$ 1,123.99	$ 1,225.28	$ 2,236.75	$ 2,338.04		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ 41.09	$ 46.39	22%	24%		
2,251	2,438	217	$ 1,112.76	$ 1,225.83	$ 1,327.66	$ 2,338.59	$ 2,440.42		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ 46.41	$ 51.74	24%	25%		
2,439	2,625	171	$ 1,112.76	$ 1,328.21	$ 1,429.50	$ 2,440.97	$ 2,542.26		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ 51.77	$ 57.07	25%	27%		
2,626	2,813	169	$ 1,112.76	$ 1,430.04	$ 1,531.88	$ 2,542.80	$ 2,644.64		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ 57.10	$ 62.43	27%	28%		
2,814	3,000	153	$ 1,112.76	$ 1,532.42	$ 1,633.71	$ 2,645.18	$ 2,746.47		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ 62.46	$ 67.76	28%	30%		
3,001	5,000	1,072	$ 1,112.76	$ 1,634.26	$ 2,722.85	$ 2,747.02	$ 3,835.61		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ 67.76	$ 74.75	30%	23%		
5,001	7,000	691	$ 1,112.76	$ 2,723.40	$ 3,811.99	$ 3,836.16	$ 4,924.75		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ 74.75	$ 81.74	23%	20%		
7,001	9,000	491	$ 1,112.76	$ 3,812.54	$ 4,901.13	$ 4,925.30	$ 6,013.89		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ 81.74	$ 88.73	20%	18%		
9,001	11,000	294	$ 1,112.76	$ 4,901.68	$ 5,990.27	$ 6,014.44	$ 7,103.03		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ 88.74	$ 95.72	18%	16%		
11,001	13,000	227	$ 1,112.76	$ 5,990.82	$ 7,079.41	$ 7,103.58	$ 8,192.17		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ 95.73	$ 102.72	16%	15%		
13,001	15,000	187	$ 1,112.76	$ 7,079.96	$ 8,168.55	$ 8,192.72	$ 9,281.31		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ 102.72	$ 109.71	15%	14%		
15,001	17,000	141	$ 1,112.76	$ 8,169.10	$ 9,257.69	$ 9,281.86	$ 10,370.45		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ 109.71	$ 116.70	14%	14%		
17,001	19,000	117	$ 1,112.76	$ 9,258.24	$ 10,346.83	$ 10,371.00	$ 11,459.59		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ 116.70	$ 123.69	14%	13%		
19,001	21,000	88	$ 1,112.76	$ 10,347.38	$ 11,435.97	$ 11,460.14	$ 12,548.73		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ 123.69	$ 130.68	13%	12%		
21,001	23,000	81	$ 1,112.76	$ 11,436.52	$ 12,525.12	$ 12,549.28	$ 13,637.88		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ 130.69	$ 137.67	12%	12%		
23,001	25,000	62	$ 1,112.76	$ 12,525.66	$ 13,614.26	$ 13,638.42	$ 14,727.02		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ 137.68	$ 144.67	12%	12%		
25,001	27,000	43	$ 1,112.76	$ 13,614.80	$ 14,703.40	$ 14,727.56	$ 15,816.16		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ 144.67	$ 151.66	12%	12%		
27,001	29,000	28	$ 1,112.76	$ 14,703.94	$ 15,792.54	$ 15,816.70	$ 16,905.30		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ 151.66	$ 158.65	12%	11%		
29,001	31,000	23	$ 1,112.76	$ 15,793.08	$ 16,881.68	$ 16,905.84	$ 17,994.44		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ 158.65	$ 165.64	11%	11%		
31,001	1,520,781	239	$ 1,112.76	$ 16,882.22	$ 828,172.06	$ 17,994.98	$ 829,284.82		$ 1,800.00	$ 18,182.71	$ 891,968.82	$ 19,982.71	$ 893,768.82		$ 165.64	$ 5,373.67	11%	8%		

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Small Rates

			$ 120.32	$ 1.08918	$ 1.08918	Small			$ 75.00	$ 0.88652	$ 0.88652	Small								
			$ 275.32	$ 0.71718	$ 0.71718	Large			$ 150.00	$ 0.58652	$ 0.58652	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
-	188	622	$ 1,443.83	$ -	$ 204.77	$ 1,443.83	$ 1,648.60		$ 900.00	$ -	$ 166.67	$ 900.00	$ 1,066.67		$ (45.32)	$ (48.49)	-38%	-35%		
189	375	213	$ 1,443.83	$ 205.86	$ 408.44	$ 1,649.69	$ 1,852.27		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (48.51)	$ (51.65)	-35%	-33%		
376	563	150	$ 1,443.83	$ 409.53	$ 613.21	$ 1,853.36	$ 2,057.04		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (51.67)	$ (54.83)	-33%	-32%		
564	750	121	$ 1,443.83	$ 614.30	$ 816.89	$ 2,058.13	$ 2,260.72		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (54.84)	$ (57.99)	-32%	-31%		
751	938	103	$ 1,443.83	$ 817.97	$ 1,021.65	$ 2,261.81	$ 2,465.48		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ (58.00)	$ (61.16)	-31%	-30%		
939	1,125	103	$ 1,443.83	$ 1,022.74	$ 1,225.33	$ 2,466.57	$ 2,669.16		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ (61.18)	$ (64.32)	-30%	-29%		
1,126	1,313	92	$ 1,443.83	$ 1,226.42	$ 1,430.09	$ 2,670.25	$ 2,873.93		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ (64.34)	$ (67.49)	-29%	-28%		
1,314	1,500	81	$ 1,443.83	$ 1,431.18	$ 1,633.77	$ 2,875.02	$ 3,077.60		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ (67.51)	$ (70.65)	-28%	-28%		
1,501	1,688	74	$ 1,443.83	$ 1,634.86	$ 1,838.54	$ 3,078.69	$ 3,282.37		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ (70.67)	$ (73.83)	-28%	-27%		
1,689	1,875	83	$ 1,443.83	$ 1,839.63	$ 2,042.21	$ 3,283.46	$ 3,486.05		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ (73.84)	$ (76.98)	-27%	-27%		
1,876	2,063	63	$ 1,443.83	$ 2,043.30	$ 2,246.98	$ 3,487.13	$ 3,690.81		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ (77.00)	$ (80.16)	-26%	-26%		
2,064	2,250	52	$ 1,443.83	$ 2,248.07	$ 2,450.66	$ 3,691.90	$ 3,894.49		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ (80.18)	$ (83.32)	-26%	-26%		
2,251	2,438	55	$ 1,443.83	$ 2,451.74	$ 2,655.42	$ 3,895.58	$ 4,099.25		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ (83.33)	$ (86.49)	-26%	-25%		
2,439	2,625	53	$ 1,443.83	$ 2,656.51	$ 2,859.10	$ 4,100.34	$ 4,302.93		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ (86.51)	$ (89.65)	-25%	-25%		
2,626	2,813	55	$ 1,443.83	$ 2,860.19	$ 3,063.86	$ 4,304.02	$ 4,507.70		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ (89.67)	$ (92.83)	-25%	-25%		
2,814	3,000	68	$ 1,443.83	$ 3,064.95	$ 3,267.54	$ 4,508.79	$ 4,711.37		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ (92.84)	$ (95.98)	-25%	-24%		
3,001	5,000	510	$ 1,443.83	$ 3,268.63	$ 5,445.90	$ 4,712.46	$ 6,889.73		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ (96.03)	$ (179.76)	-24%	-31%		
5,001	7,000	70	$ 1,443.83	$ 5,446.99	$ 7,624.26	$ 6,890.82	$ 9,068.09		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ (179.80)	$ (263.54)	-31%	-35%		
7,001	9,000	22	$ 1,443.83	$ 7,625.35	$ 9,802.62	$ 9,069.18	$ 11,246.45		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ (263.58)	$ (347.31)	-35%	-37%		
9,001	11,000	9	$ 1,443.83	$ 9,803.71	$ 11,980.98	$ 11,247.54	$ 13,424.81		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (347.36)	$ (431.09)	-37%	-39%		
11,001	13,000	4	$ 1,443.83	$ 11,982.07	$ 14,159.34	$ 13,425.90	$ 15,603.18		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (431.13)	$ (514.87)	-39%	-40%		
13,001	15,000	4	$ 1,443.83	$ 14,160.43	$ 16,337.70	$ 15,604.26	$ 17,781.54		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (514.91)	$ (598.64)	-40%	-40%		
15,001	17,000	1	$ 1,443.83	$ 16,338.79	$ 18,516.06	$ 17,782.62	$ 19,959.90		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (598.69)	$ (682.42)	-40%	-41%		
17,001	19,000	-	$ 1,443.83	$ 18,517.15	$ 20,694.42	$ 19,960.99	$ 22,138.26		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (682.46)	$ (766.20)	-41%	-42%		
19,001	21,000	1	$ 1,443.83	$ 20,695.51	$ 22,872.78	$ 22,139.35	$ 24,316.62		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (766.24)	$ (849.97)	-42%	-42%		
21,001	23,000	-	$ 1,443.83	$ 22,873.87	$ 25,051.15	$ 24,317.71	$ 26,494.98		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (850.02)	$ (933.75)	-42%	-42%		
23,001	25,000	2	$ 1,443.83	$ 25,052.23	$ 27,229.51	$ 26,496.07	$ 28,673.34		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (933.79)	$ (1,017.53)	-42%	-43%		
25,001	27,000	-	$ 1,443.83	$ 27,230.59	$ 29,407.87	$ 28,674.43	$ 30,851.70		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (1,017.57)	$ (1,101.30)	-43%	-43%		
27,001	29,000	-	$ 1,443.83	$ 29,408.96	$ 31,586.23	$ 30,852.79	$ 33,030.06		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (1,101.35)	$ (1,185.08)	-43%	-43%		
29,001	31,000	-	$ 1,443.83	$ 31,587.32	$ 33,764.59	$ 33,031.15	$ 35,208.42		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (1,185.12)	$ (1,268.86)	-43%	-43%		
31,001	1,440,450	3	$ 1,443.83	$ 33,765.68	$1,568,909.66	$ 35,209.51	$1,570,353.49		$ 1,800.00	$ 18,182.71	$ 844,853.06	$ 19,982.71	$ 846,653.06		$ (1,268.90)	$ (60,308.37)	-43%	-46%		

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Large Rates

			$ 120.32	$ 1.08918	$ 1.08918	Small			$ 75.00	$ 0.88652	$ 0.88652	Small								
			$ 275.32	$ 0.71718	$ 0.71718	Large			$ 150.00	$ 0.58652	$ 0.58652	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
-	188	-	$ 3,303.83	$ -	$ 134.83	$ 3,303.83	$ 3,438.66		$ 900.00	$ -	$ 166.67	$ 900.00	$ 1,066.67		$ (200.32)	$ (197.67)	-73%	-69%
189	375	-	$ 3,303.83	$ 135.55	$ 268.94	$ 3,439.38	$ 3,572.77		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (197.65)	$ (195.03)	-69%	-66%
376	563	1	$ 3,303.83	$ 269.66	$ 403.77	$ 3,573.49	$ 3,707.60		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (195.01)	$ (192.37)	-65%	-62%
564	750	1	$ 3,303.83	$ 404.49	$ 537.89	$ 3,708.32	$ 3,841.72		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (192.36)	$ (189.74)	-62%	-59%
751	938	-	$ 3,303.83	$ 538.60	$ 672.72	$ 3,842.43	$ 3,976.55		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ (189.72)	$ (187.08)	-59%	-56%
939	1,125	-	$ 3,303.83	$ 673.43	$ 806.83	$ 3,977.26	$ 4,110.66		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ (187.07)	$ (184.44)	-56%	-54%
1,126	1,313	-	$ 3,303.83	$ 807.54	$ 941.66	$ 4,111.38	$ 4,245.49		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ (184.43)	$ (181.79)	-54%	-51%
1,314	1,500	1	$ 3,303.83	$ 942.37	$ 1,075.77	$ 4,246.21	$ 4,379.60		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ (181.78)	$ (179.15)	-51%	-49%
1,501	1,688	1	$ 3,303.83	$ 1,076.49	$ 1,210.60	$ 4,380.32	$ 4,514.43		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ (179.14)	$ (176.50)	-49%	-47%
1,689	1,875	-	$ 3,303.83	$ 1,211.32	$ 1,344.71	$ 4,515.15	$ 4,648.55		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ (176.48)	$ (173.86)	-47%	-45%
1,876	2,063	1	$ 3,303.83	$ 1,345.43	$ 1,479.54	$ 4,649.26	$ 4,783.38		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ (173.85)	$ (171.21)	-45%	-43%
2,064	2,250	-	$ 3,303.83	$ 1,480.26	$ 1,613.66	$ 4,784.09	$ 4,917.49		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ (171.19)	$ (168.57)	-43%	-41%
2,251	2,438	-	$ 3,303.83	$ 1,614.37	$ 1,748.49	$ 4,918.20	$ 5,052.32		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ (168.55)	$ (165.92)	-41%	-39%
2,439	2,625	-	$ 3,303.83	$ 1,749.20	$ 1,882.60	$ 5,053.03	$ 5,186.43		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ (165.90)	$ (163.28)	-39%	-38%
2,626	2,813	1	$ 3,303.83	$ 1,883.32	$ 2,017.43	$ 5,187.15	$ 5,321.26		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ (163.26)	$ (160.62)	-38%	-36%
2,814	3,000	-	$ 3,303.83	$ 2,018.15	$ 2,151.54	$ 5,321.98	$ 5,455.37		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ (160.61)	$ (157.98)	-36%	-35%
3,001	5,000	70	$ 3,303.83	$ 2,152.26	$ 3,585.90	$ 5,456.09	$ 6,889.73		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ (158.00)	$ (179.76)	-35%	-31%
5,001	7,000	296	$ 3,303.83	$ 3,586.62	$ 5,020.26	$ 6,890.45	$ 8,324.09		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ (179.77)	$ (201.54)	-31%	-29%
7,001	9,000	297	$ 3,303.83	$ 5,020.98	$ 6,454.62	$ 8,324.81	$ 9,758.45		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ (201.55)	$ (223.31)	-29%	-27%
9,001	11,000	168	$ 3,303.83	$ 6,455.34	$ 7,888.98	$ 9,759.17	$ 11,192.81		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (223.33)	$ (245.09)	-27%	-26%
11,001	13,000	125	$ 3,303.83	$ 7,889.70	$ 9,323.34	$ 11,193.53	$ 12,627.18		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (245.10)	$ (266.87)	-26%	-25%
13,001	15,000	115	$ 3,303.83	$ 9,324.06	$ 10,757.70	$ 12,627.89	$ 14,061.54		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (266.88)	$ (288.64)	-25%	-25%
15,001	17,000	63	$ 3,303.83	$ 10,758.42	$ 12,192.06	$ 14,062.25	$ 15,495.90		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (288.66)	$ (310.42)	-25%	-24%
17,001	19,000	61	$ 3,303.83	$ 12,192.78	$ 13,626.42	$ 15,496.61	$ 16,930.26		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (310.43)	$ (332.20)	-24%	-24%
19,001	21,000	41	$ 3,303.83	$ 13,627.14	$ 15,060.78	$ 16,930.97	$ 18,364.62		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (332.21)	$ (353.97)	-24%	-23%
21,001	23,000	43	$ 3,303.83	$ 15,061.50	$ 16,495.15	$ 18,365.33	$ 19,798.98		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (353.99)	$ (375.75)	-23%	-23%
23,001	25,000	21	$ 3,303.83	$ 16,495.86	$ 17,929.51	$ 19,799.69	$ 21,233.34		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (375.76)	$ (397.53)	-23%	-22%
25,001	27,000	11	$ 3,303.83	$ 17,930.22	$ 19,363.87	$ 21,234.06	$ 22,667.70		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (397.54)	$ (419.30)	-22%	-22%
27,001	29,000	17	$ 3,303.83	$ 19,364.58	$ 20,798.23	$ 22,668.42	$ 24,102.06		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (419.32)	$ (441.08)	-22%	-22%
29,001	31,000	14	$ 3,303.83	$ 20,798.94	$ 22,232.59	$ 24,102.78	$ 25,536.42		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (441.09)	$ (462.86)	-22%	-22%
31,001	1,440,450	68	$ 3,303.83	$ 22,233.30	$1,033,062.26	$ 25,537.14	$1,036,366.09		$ 1,800.00	$ 18,182.71	$ 844,853.06	$ 19,982.71	$ 846,653.06		$ (462.87)	$ (15,809.42)	-22%	-18%

Exhibit PHR-6
Proof of Revenues

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	4,773,445			$ 29.50		$ 140,816,628				
2			All Ccf	81,903,217		$ 0.67553	$ 55,328,080				
3	Residential - Large	2,863,233			$ 39.50		$ 113,097,704				
4			All Ccf	130,659,132		$ 0.31189	$ 40,751,277				
5	Residential Total							$ 349,993,688	$ 349,993,234	$ 454	78.56%
6											
7	Customer Assistance Program	360,000			$ 22.13		$ 7,966,800				
8			All Ccf	10,020,372		$ 0.55000	$ 5,511,204	$ 13,478,004	$ 13,478,004	$ -	3.03%
9											
10	Commercial - Small	304,010			$ 75.00		$ 22,800,750				
11			All Ccf	13,603,609		$ 0.43589	$ 5,929,677				
12	Commercial - Large	108,551			$ 150.00		$ 16,282,650				
13			All Ccf	97,483,364		$ 0.13589	$ 13,247,014				
14	Commercial Total							$ 58,260,091	$ 58,259,612	$ 479	13.08%
15											
16	Electric Generation (Gas Sales)	-			$ -		$ -				
17			Oct.-Apr								
18			First 5000	-		$ -	$ -				
19			Next 95000	-		$ -	$ -				
20			Next 300000	-		$ -	$ -				
21			Over 400000	-		$ -	$ -				
22			May-Sep								
23			First 5000	-		$ -	$ -				
24			Next 95000	-		$ -	$ -				
25			Next 300000	-		$ -	$ -				
26			Over 400000	-		$ -	$ -	$ -			
27	Electric Generation (Gas Sales)								$ -	$ -	0.00%
28											
29	Industrial	1,097			$ 1,250.00		$ 1,371,725				
30			All Ccf	4,477,923		$ 0.11849	$ 530,589	$ 1,902,314	$ 1,902,293	$ 22	0.43%
31											
32	Public Authority	32,735			$ 200.00		$ 6,547,031				
33			All Ccf	17,975,671		$ 0.13745	$ 2,470,756	$ 9,017,787	$ 9,017,789	$ (2)	2.02%
34											
35	CNG (Compressed Natural Gas)	12			$ 320.00		$ 3,840				
36			All Ccf	-		$ -	$ -	$ 3,840	$ 3,816	$ 24	0.00%
37											
38	General Transportation	11,325			$ 500.00		$ 5,662,471				
39			All Ccf	79,391,794		$ 0.08831	$ 7,011,089	$ 12,673,560	$ 12,673,274	$ 286	2.84%
40											
41	Electric Generation Transportation	12			$ 1,000.00		$ 12,000				
42			MDQ	12,709		$ 0.72542	$ 110,632				
43			All Ccf	4,263,918		$ 0.02000	$ 85,278				
44	Electric GenerationTransportation							$ 207,911	$ 207,911	$ -	0.05%
45											
46	Total Revenue - All Classes										
47											
48	Recommended Rate Revenue							$ 445,537,196	$ 445,535,933		
49	Current Rate Revenue							$ 405,051,635	$ 405,051,635		
50	Revenue Change							$ 40,485,561	$ 40,484,298		
51											
52	Fort Bliss Assigned Rev. Change. (1)								$ 585,611		
53	Total Change - All Classes								$ 41,069,909		
54											
55	Schedule A - Revenue Deficiency								$ 41,069,909		

(1) The amount reflects the revenue change assigned to Fort Bliss shown on the Class Revenue Allocation tab within the model.

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 independent 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 4 day of June 2025.

DAVID KIM
Notary Public - State of Maryland
Montgomery County
My Commission Expires May 1, 2027

Notary Public in and for the State of Maryland

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 30, 2025, Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS" or "Company"), filed a Statement of Intent to Change Rates ("Statement of Intent") in the Central-Gulf Service Area ("CGSA"), Rio Grande Valley Service Area ("RGVSA"), and the West North Service Area ("WNSA") with the Railroad Commission of Texas ("Commission") and with the Cities of: Alamo, Aledo, Alton, Andrews, Anthony, Austin, Barstow, Bayou Vista, Beaumont, Bee Cave, Borger, Breckenridge, Brownsville, Bryson, Buda, Cedar Park, Clint, Combes, Crane, Cuero, Dell City, Donna, Dripping Springs, Edcouch, Edinburg, El Paso, Elsa, Galveston, Georgetown, Gonzales, Graford, Graham, Groves, Harlingen, Hidalgo, Horizon City, Hudson Oaks, Hutto, Jacksboro, Jamaica Beach, Jarrell, Kyle, La Feria, La Joya, La Villa, Laguna Vista, Lakeway, Lockhart, Los Fresnos, Luling, Lyford, Marble Falls, McAllen, McCamey, Mercedes, Millsap, Mineral Wells, Mission, Monahans, Mustang Ridge, Nederland, Nixon, Palm Valley, Palmhurst, Palmview, Pecos, Penitas, Pflugerville, Pharr, Port Arthur, Port Isabel, Port Neches, Primera, Progreso, Pyote, Rancho Viejo, Raymondville, Rio Hondo, Rollingwood, San Benito, San Elizario, San Juan, Santa Rosa, Shiner, Skellytown, Socorro, Sunset Valley, Thorntonville, Vinton, Weatherford, Weslaco, West Lake Hills, Wickett, Willow Park, Wink, and Yoakum, Texas for the gas utility rates charged by the Company to customers throughout the state of Texas.

The proposed change in rates will affect all small and large residential, small and large commercial,[1] commercial transportation, industrial, industrial transportation, public authority, public authority transportation, irrigation, compressed natural gas, compressed natural gas transportation, electrical generation, electrical generation transportation, and unmetered gas light service customers within the cities listed above and unincorporated areas TGS serves. The proposed effective date of the requested rate changes is August 19, 2025.

In addition to changing rates, TGS proposes to consolidate the existing CGSA, RGVSA, and WNSA into a single TGS territory. Consistent with its request for consolidation, the Company has developed its proposed rates based on the systemwide cost of providing service to all customers in Texas. The proposed rates and tariffs are expected to increase the Company's annual systemwide revenues by approximately $41.1 million or 7.07% including gas cost or 9.83% 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 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:

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Residential							
Small Customers Affected	202,594	24,158	33,788	2,029	154,319	18,003	—
Small Customer Charge	$21.36	$21.36	$23.64	$23.64	$21.85	$21.85	$29.50
Small Volumetric Charge (per Ccf)	$0.87646	$0.87646	$2.02007	$2.02007	$0.46668	$0.46668	$0.67553
Large Customers Affected	78,883	9,406	22,042	1,324	107,323	12,521	—
Large Customer Charge	$33.36	$33.36	$38.64	$38.64	$38.35	$38.35	$39.50

[1] The currently designated West North Service Area has a single Commercial Customer class.

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Large Volumetric Charge (per Ccf)	$0.46737	$0.46737	$0.63545	$0.63545	$0.01668	$0.01668	$0.31189
Customer Assistance Program (Up to 30,000 qualifying customers)							
Customers Affected	—	—	—	—	—	—	—
Customer Charge	—	—	—	—	—	—	$22.13
Volumetric Charge (per Ccf)	—	—	—	—	—	—	$0.55000
Commercial							
Customers Affected[2]	—	—	—	—	16,057	1,105	
Customer Charge	—	—	—	—	$92.73	$92.73	
Volumetric Charge (per Ccf)	—	—	—	—	$0.09394	$0.09394	
Small Customers Affected	9,576	359	2,610	114	—	—	—
Small Customer Charge	$72.88	$72.88	$120.32	$120.32	$92.73	$92.73	$75.00
Small Volumetric Charge (per Ccf)	$0.27930	$0.27930	$0.63855	$0.63855	$0.09394	$0.09394	$0.43589
Large Customers Affected	3,104	116	1,282	56	—	—	—
Large Customer Charge	$87.88	$87.88	$275.32	$275.32	$92.73	$92.73	$150.00
Large Volumetric Charge (per Ccf)	$0.22985	$0.22985	$0.26655	$0.26655	$0.09394	$0.09394	$0.13589
Commercial Transportation							
Customers Affected	296	11	23	4	21	—	—
Customer Charge	$320.96	$320.96	$545.32	$545.32	$517.73	$517.73	$500.00
Volumetric Charge (per Ccf)	$0.12679	$0.12679	$0.10770	$0.10770	$0.09394	$0.09394	$0.08831
Industrial							
Customers Affected	19	1	22	15	32	3	—
Customer Charge	$1,033.21	$1,033.21	$1,234.53	$1,234.53	$1,295.93	$1,295.93	$1,250.00
Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.28220	$0.28220	$0.11486	$0.11486	$0.11849
Industrial Transportation							
Customers Affected	17	11	16	17	9	4	—
Customer Charge	$1,233.21	$1,233.21	$1,384.53	$1,384.53	$1,495.93	$1,495.93	$500.00

[2] WNSA currently has only one Commercial customer class, and TGS proposes to create Small and Large Commercial customer classes with the rates noticed herein.

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.08722	$0.08722	$0.11486	$0.11486	$0.08831
Public Authority							
Customers Affected	758	53	442	53	1,276	146	—
Customer Charge	$181.93	$181.93	$243.91	$243.91	$253.05	$253.05	$200.00
Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.16208	$0.16208	$0.13511	$0.13511	$0.13745
Public Authority Transportation							
Customers Affected	481	10	3	3	10	—	—
Customer Charge	$204.93	$204.93	$2,543.91	$2,543.91	$553.05	$553.05	$500.00
Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.00840	$0.00840	$0.13511	$0.13511	$0.08831
Electric Generation Transportation							
Customers Affected	1	—	—	—	—	—	—
Customer Charge	$201.64	$201.64	$545.32	$545.32	$717.73	$717.73	$1,000.00
Demand Charge (per MDQ per month)							$0.72542
Volumetric Charge (per Ccf)							
Usage Rates (Year-Round)							
All Ccf	—	—	$0.10770	$0.10770	—	—	$0.02000
First 5,000 Ccf	$0.07724	$0.07724	—	—	—	—	
Next 35,000	$0.06853	$0.06853	—	—	—	—	
Next 60,000	$0.05527	$0.05527	—	—	—	—	
All Over 100,000	$0.04018	$0.04018	—	—	—	—	
Volumetric Charge (per Ccf)							
Usage Rates (October - April)							
All Ccf	—	—	—	—	—	—	—
First 5,000 Ccf	—	—	—	—	$0.05260	$0.05260	—
Next 95,000	—	—	—	—	$0.04260	$0.04260	—
Next 300,000	—	—	—	—	$0.03260	$0.03260	—
All Over 400,000	—	—	—	—	$0.02260	$0.02260	—
Volumetric Charge (per Ccf)							
Usage Rates (May-September)							
All Ccf	—	—	—	—	—	—	—
First 5,000 Ccf	—	—	—	—	$0.04259	$0.04259	—
Next 95,000	—	—	—	—	$0.03258	$0.03258	—
Next 300,000	—	—	—	—	$0.02259	$0.02259	—
All Over 400,000	—	—	—	—	$0.01258	$0.01258	—
Compressed Natural Gas							
Customers Affected	—	—	—	—	—	—	—
Customer Charge	$746.15	$746.15	—	—	$1,955.67	$1,955.67	$320.00

	Incorporated and Unincorporated/Environs Current Rates						
Customer Class	**CGSA Incorporated Rates**	**CGSA Environs Rates**	**RGVSA Incorporated Rates**	**RGVSA Environs Rates**	**WNSA Incorporated Rates**	**WNSA Environs Rates**	**Proposed TGS Rates**
Volumetric Charge (per Ccf)	$0.07817	$0.07817	—	—	$0.08643	$0.08643	$0.08831
Compressed Natural Gas Transportation							
Customers Affected	3	1	—	—	4	—	—
Customer Charge	$771.15	$771.15	—	—	$2,255.67	$2,255.67	$500.00
Volumetric Charge (per Ccf)	$0.07817	$0.07817	—	—	$0.08643	$0.08643	$0.08831
Unmetered Gas Light							
Customers Affected	1	—	—	—	—	—	—
Customer Charge	—	—	—	—	—	—	—
Residential Volumetric Charge (per Ccf)	$0.87646	$0.87646	$2.02007	$2.02007	$0.46668	$0.46668	$0.67553
Commercial Volumetric Charge (per Ccf)	$0.27930	$0.27930	$0.63855	$0.63855	$0.09394	$0.09394	$0.43589
Industrial Volumetric Charge (per Ccf)	$0.14569	$0.14569	$0.28220	$0.28220	$0.11486	$0.11486	$0.11849
Public Authority Volumetric Charge (per Ccf)	$0.13768	$0.13768	$0.16208	$0.16208	$0.13511	$0.13511	$0.13745

TABLE 2 – Impact on Average Bill

Customer Class and Location	**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					
CGSA	$44.88	$48.82	$3.94	8.78%	13.10%
RGVSA	$62.53	$48.82	$(13.71)	(21.93)%	(29.50)%
WNSA	$38.44	$48.82	$10.38	27.00%	33.70%
Residential - Large					
CGSA	$77.29	$74.30	$(2.99)	(3.87)%	(1.50)%
RGVSA	$78.89	$74.30	$(4.59)	(5.82)%	(20.60)%
WNSA	$59.66	$74.30	$14.64	24.54%	37.10%
Residential - Customer Assistance					
CGSA	$44.88	$39.30	$(5.58)	(12.43)%	(13.10)%
RGVSA	$62.53	$39.30	$(23.23)	(37.15)%	(45.80)%
WNSA	$38.44	$39.30	$0.86	2.24%	2.70%

Customer Class and Location	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
Commercial - Small					
CGSA	$107.56	$114.67	$7.11	6.61%	10.70%
RGVSA	$159.93	$114.67	$(45.26)	(28.30)%	(36.50)%
WNSA	$117.47	$114.67	$(2.80)	(2.38)%	(3.00)%
Commercial - Large					
CGSA	$739.73	$676.72	$(63.01)	(8.52)%	(7.40)%
RGVSA	$736.13	$676.72	$(59.41)	(8.07)%	(47.10)%
WNSA	$589.26	$676.72	$87.46	14.84%	45.90%
Industrial					
CGSA	$3,652.60	$3,572.33	$(80.27)	(2.20)%	6.60%
RGVSA	$3,392.24	$3,572.33	$180.09	5.31%	(27.30)%
WNSA	$3,646.91	$3,572.33	$(74.58)	(2.05)%	(4.60)%
Public Authority					
CGSA	$530.03	$522.93	$(7.10)	(1.34)%	7.10%
RGVSA	$468.32	$522.93	$54.61	11.66%	(17.30)%
WNSA	$581.78	$522.93	$(58.85)	(10.12)%	(17.90)%
Compressed Natural Gas					
CGSA	$746.15	$320.00	$(426.15)	(57.11)%	(57.10)%
RGVSA	—	—	—	—	—
WNSA	—	—	—	—	—
Transportation Service					
Commercial Transportation					
CGSA	$3,807.64	$3,886.69	$79.05	2.08%	(6.20)%
RGVSA	$3,915.94	$3,886.69	$(29.25)	(0.75)%	(13.80)%
WNSA	$4,161.74	$3,886.69	$(275.05)	(6.61)%	(10.20)%
Industrial Transportation					
CGSA	$20,758.98	$18,816.36	$(1,942.62)	(9.36)%	(43.10)%
RGVSA	$18,887.56	$18,816.36	$(71.20)	(0.38)%	(18.90)%
WNSA	$22,028.20	$18,816.36	$(3,211.84)	(14.58)%	(39.70)%
Public Authority Transportation					
CGSA	$1,477.92	$1,711.73	$233.81	15.82%	34.20%
RGVSA	$3,516.89	$1,711.73	$(1,805.16)	(51.33)%	(72.40)%
WNSA	$1,964.16	$1,711.73	$(252.43)	(12.85)%	(21.90)%
CNG Transportation					
CGSA	$29,828.01	$31,556.20	$1,728.19	5.79%	6.40%
RGVSA	—	—	—	—	—
WNSA	$35,169.78	$31,556.20	$(3,613.58)	(10.27)%	(27.60)%

Customer Class and Location	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
Electric Generation Transportation					
CGSA	$184,636.19	$185,400.48	$764.29	0.41%	4.60%
RGVSA	—	—	—	—	—
WNSA	—	—	—	—	—

Table 2 calculations are based on a $0.45 cost of gas and do not include revenue-related taxes. Additionally, only classes with customers in the test year are included in Table 2.

The Company also proposes Miscellaneous Service Charges included in Table 3 below:

Table 3 – Miscellaneous Service Charges

Incorporated and Environs	CGSA	RGVSA	WNSA	TGS
Fee or Deposit	Current			Proposed
Connect	$38.00	$38.00	$35.00	$40.00
Reconnect	$38.00	$38.00	$35.00	$40.00
Connect Fee - Read Only	$18.00	$18.00	$15.00	$20.00
Special Handling	$18.00	$18.00	$15.00	$20.00
Expedited Service/Overtime/After Hours	$70.00	$70.00	$65.00	$75.00
Regular Labor Rate	$50.00	$50.00	$48.00	$55.00
No Access Fee (Door Tag)	$18.00	$18.00	$15.00	$20.00
Meter Test Up to 1500 CFH	$150.00	$150.00	$150.00	$165.00
Meter Test Over 1500 CFH	$225.00	$225.00	$200.00	$230.00
Orifice Meters	$200.00	$200.00	$200.00	$200.00
Payment Re-processing Fee (Returned Check Fee)	$25.00	$25.00	$25.00	$25.00
Collection Fee (All Classes)	$18.00	$18.00	$15.00	$20.00
Special Read	$20.00	$20.00	$18.00	$20.00
Meter Exchange (Customer Request)	$180.00	$180.00	$150.00	$200.00
Unauthorized Consumption (Plus Expenses)	$30.00	$30.00	$30.00	$32.00
Meter Removal Fee	$25.00	$25.00	$25.00	$28.00
Account Research per hour Fee	$20.00	$20.00	$20.00	$25.00
Excess Flow Valve Installation Fee	$400.00	$400.00	$400.00	$400.00
Minimum Deposit Residential	$75.00	$75.00	$75.00	$125.00
Minimum Non Residential Deposit	$250.00	$250.00	$250.00	$250.00
Meter Tampering (Residential)	$180.00	$180.00	$150.00	$200.00

[a] CFH: Cubic Feet per Hour.

[b] ERT: Electronic Radio Transponder. The Company only exchanges meters with ERT.

The proposed increases in Table 3 reflect a net increase of $546,729 in revenues.

TGS is requesting: (1) that rates be approved for TGS consistent with those proposed in the Statement of Intent, to become effective for meters read on and after August 19, 2025; (2) approval of the consolidation of the existing CGSA, RGVSA, and the WNSA; (3) the Commission approve new depreciation rates for Direct and Division distribution and general plant; (4) the Commission find that expenses for COVID-19 that

are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (5) that capital investment made through December 31, 2024, including capital investment in the Company's Interim Rate Adjustment filings made since the last rate cases in the CGSA, RGVSA, and the WNSA pursuant to Texas Utilities Code § 104.301, is deemed prudent; (6) that the form of notice for the proposed Rate Schedule PIT be approved; (7) approval of the proposed expansion of Customer Assistance Programs; and (8) that all reasonable rate case expenses incurred in connection with this Statement of Intent filing are authorized for recovery by the Company.

In addition, if new TGS tariffs are approved, TGS proposes to withdraw the existing CGSA, RGVSA, and WNSA tariffs to reflect the new TGS rates in Table 1 and/or related changes necessary to reflect consolidation, including revisions to reflect application of tariffs to all incorporated and unincorporated areas served by TGS.

For all proposed rate schedules for General Sales and Transportation customers, TGS proposes: (1) to use a Common Billing Pressure to calculate customer volume usage shown on customer bills; (2) a revision to the "Other Adjustments" section to remove references to: Rate Schedules URI-Rider, Conservation Adjustment Clause 1C and CAC, Energy Efficiency Program 1EE and EEP; and (3) add references to Rate Schedules EDR.

For Residential Rate Schedules Customer Assistance 16 and 1W, TGS proposes: to provide a reduced-price rate design for up to 30,000 customers who qualify.

For Commercial Rate Schedules, TGS proposes: to add Rate Schedules 20 and 2Z Small Commercial and 25 and 2Y Large Commercial for customers currently in the WNSA.

For Transportation Rate Schedules T-1, T-1-ENV and T-TERMS, TGS proposes: to combine the individual rates for Commercial Transportation, Industrial Transportation, Public Authority Transportation and CNG Transportation into a single general Transportation rate design; and, to include definitions for Compressed Natural Gas (CNG) Service and Public Authority Service under "Definitions."

For the Cost of Gas Clauses 1-INC and 1-ENV, TGS proposes: to add clarifying language to section B.2 to specify that the Customer Rate Relief Component is not applicable to some areas; that the "revenue associated fee" is applicable to Weatherford, Texas only; add clarifying language to section B.4 for the Customer Rate Relief definition to specify that this rate is not applicable to some areas (authorized by the Commission's Financing Order in Docket No. OS-21-00007061); add section B.5 to include a definition for FERC Intervention Costs; add section B.6 to include a definition for Non-Utility Transactions; add section B.12 to include a definition for Uncollectible Cost of Gas; add new Section G, Non-Utility Transactions; and, to add a reference to the FERC Intervention Costs to Section I. Annual Reconciliation Report.

For Rate Schedule WNA, TGS proposes: updated weather factors for each class consistent with weather normalization calculations in this case. Proposed Rate Schedules RCE-TGS and RCE-TGS-ENV provide 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 the Rules of Service, TGS proposes: revisions for consistency with the Commission's Quality of Service Rules; updating § 1.3, Definitions for the terms: Atmospheric Pressure, Common Billing Pressure, Compressed Natural Gas Service, Constant Factor, Public Authority Service, Safe Access and Standard Serving Pressure as well as expanded the definition for "electrical generation service" to apply to a larger group on non-residential customers, and removing the definition for "service area"; addition of § 4.2 to include language for the 'Use of Natural Gas Equipment' and 'Appliances'; revisions to § 5.5 to add clarifying language regarding to the Company's ability to provide Expedited Service at the customer's request; revisions to § 6.1 to add clarifying language regarding the Company's ability to refuse service in any situation that is unsafe for personnel, customers or the general public; revision to §§ 4.1, 6.1, 7.4, 7.9, 10.2, 12.3 and 12.7 to reflect the requirement that Company personnel have safe access to Company assets; revisions to § 9.3 to expand Company and Customer options for capturing meter reads when the meter is not accessible; revisions to §§ 10.2, 10.6, 10.7 and 10.8 to enhance language regarding: the prohibition against tampering, the requirement for reasonable precautions when engaging in activities near Company-owned facilities and clarify the responsibility for relocation expenses and replacement of Customer-owned piping; additions to § 11 to include language regarding cost justifications for line extensions and cost treatment for residential multi-family line extensions revisions to § 13 and the table in § 13.1 to add language

regarding ‘Common Billing Pressure’ and include the ‘Constant Factor’ for all incorporated and unincorporated jurisdictions; revision to § 14.1 to establish the systemwide pressure at 14.65 psi; revisions to § 15 to update service fees and deposits to reflect recent approvals among the Company’s service areas and to move fees closer to actual Company costs; and, addition of § 16 to expand the applicability of this option to the Company’s customers statewide, consistent with the approved Quality of Service Rules in the existing WNSA.

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/home. 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 September 18, 2025. Please reference Docket No. OS-25-000_____. Any affected person within an incorporated area may contact his or her city council.

Las personas que tengan preguntas específicas o deseen información adicional sobre esta presentación pueden comunicarse con TGS al 1-800-700-2443. Las copias completas de la Declaración de Intención presentada, incluidas todas las tarifas propuestas y los cambios de calendario, están disponibles para su inspección en el sitio web de la Compañía en: https://www.texasgasservice.com/rateinformation/home. Cualquier persona afectada puede presentar comentarios por escrito o una protesta con respecto al cambio de tarifa propuesto ante la Sección de Servicios de Expedientes de la Oficina de la División de Audiencias, Comisión de Ferrocarriles 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 ha entrado en vigencia, o el 18 de septiembre de 2025. Sírvase hacer referencia al Docket No. OS-25-000_____. Cualquier persona afectada dentro de un área incorporada puede comunicarse con su ayuntamiento.

CASE NO. _____

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, WEST NORTH, AND RIO GRANDE VALLEY SERVICE AREAS	**§**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

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. _____"** (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. _____.

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. _____, 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. _____."

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. _____ 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. _____, 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 Protective 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. _____, 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. _____. 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. _____.

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. _____ 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 _____ 2025.

_____

_____
Administrative Law Judge

EXHIBIT A

CERTIFICATIONS

Certification for protected materials only:

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. _____, 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. _____. 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

Additional certification for highly sensitive protected materials:

I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Order in Case No. _____.

Signature	Party Represented
Printed Name	Date

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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LINE NO.	SCHEDULE OR WORKPAPER	LINKED TAB NAME	DESCRIPTION	SPONSOR
	(a)	(b)	(c)	(d)
1	SCHEDULE A	SCH A Rev Rqmt	Summary of Revenue Requirement	Anthony Brown
2	WKP A.a	WKP A.a Proof	Proof of Revenue Requirement	Anthony Brown
3	WKP A.b	WKP A.b Alloc Factors	Customer Allocation Factors	Anthony Brown
4	SCHEDULE B	SCH B Rate Base	Rate Base	Anthony Brown / Eric Sanford
5	WKP B.a	WKP B.a Summary of Plant Adjs	Summary of Plant Adjustments	Anthony Brown / Eric Sanford
6	SCHEDULE B-1	SCH B-1 M&S	Materials and Supplies	Anthony Brown / Eric Sanford
7	SCHEDULE B-2	SCH B-2 Prepays	Prepayments	Anthony Brown / Eric Sanford
8	WKP B-2.a.1	WKP B-2.a.1 TGS Div Prepays	Prepayments - TGS Division	Eric Sanford
9	WKP B-2.b.1	WKP B-2.b.1 Corp Prepays	Prepayments - Corporate Allocated through Distrigas	Eric Sanford
10	SCHEDULE B-3	SCH B-3 8.209 Reg Asset	Rule 8.209 Regulatory Asset	Anthony Brown
11	WKP B-3.a	WKP B-3.a	Rule 8.209 Regulatory Asset	Anthony Brown
12	SCHEDULE B-4	SCH B-4 Pens-OPEB Reg Asset	Pension and OPEB Regulatory Asset	Anthony Brown
13	WKP B-4.a	WKP B-4.a	Pension and OPEB Regulatory Asset	Anthony Brown
14	SCHEDULE B-5	SCH B-5 Prepaid Pension Asset	Prepaid Pension Asset	Cyndi King / Anthony Brown
15	SCHEDULE B-6	SCH B-6 CWC	Cash Working Capital	Anthony Brown/ Timothy Lyons
16	SCHEDULE B-7	SCH B-7 Deposits	Customer Deposits	Anthony Brown
17	SCHEDULE B-8	SCH B-8 Advances	Customer Advances	Anthony Brown
18	SCHEDULE B-9	SCH B-9 ADIT	Accumulated Deferred Income Taxes	Janet Simpson / Anthony Brown
19	SCHEDULE B-10	SCH B-10 EDIT	Unamortized Excess Accumulated Deferred Income Taxes	Kenneth Eakens / Anthony Brown
20	SCHEDULE B-11	SCH B-11 Reg Assets	Regulatory Assets	Anthony Brown
21	SCHEDULE C	SCH C Plant	Total Plant in Service - Direct and Allocated	Anthony Brown / Eric Sanford
22	WKP C.a	WKP C.a. Direct Plant	Plant in Service - Service Area Direct	Anthony Brown
23	WKP Ca.1	WKP C.a.1 Fort Bliss	Plant in Service - Fort Bliss	Anthony Brown
24	WKP C.b	WKP C.b TGS Div Plant	Plant in Service - TGS Division	Eric Sanford
25	WKP C.c	WKP C.c Corp Plant	Plant in Service - Corporate	Eric Sanford
26	SCHEDULE C-1	SCH C-1 CCNC	Total Completed Construction Not Classified (CCNC) - Direct and Allocated	Anthony Brown / Eric Sanford
27	WKP C-1.a	WKP C-1.a Direct CCNC	CCNC - Service Area Direct	Anthony Brown
28	WKP C-1.a.1	WKP C-1.a.1 Fort Bliss	CCNC - Fort Bliss	Anthony Brown
29	WKP C-1.b	WKP C-1.b TGS Div CCNC	CCNC - TGS Division	Eric Sanford
30	WKP C-1.c	WKP C-1.c Corp CCNC	CCNC - Corporate	Eric Sanford
31	SCHEDULE D	SCH D Reserves	Total Accumulated Reserves for Depreciation and Amortization - Direct and Allocated	Anthony Brown / Eric Sanford
32	WKP D.a	WKP D.a Direct Reserves	Total Accumulated Reserves for Depreciation and Amortization - Direct	Anthony Brown
33	WKP D.a.1	WKP D.a.1 Fort Bliss	Total Accumulated Reserves for Depreciation and Amortization - Fort Bliss	Anthony Brown
34	WKP D.b	WKP D.b TGS Div Reserves	Total Accumulated Reserves for Depreciation and Amortization - TGS Division	Eric Sanford
35	WKP D.c	WKP D.c Corp Reserves	Total Accumulated Reserves for Depreciation and Amortization - Corporate	Eric Sanford
36	SCHEDULE E	SCH E Cost of Capital	Cost of Capital	Bruce Fairchild
37	SCHEDULE F	SCH F FIT	Federal Income Tax	Anthony Brown
38	SCHEDULE G	SCH Gp 1 Op Income	Summary of Operating Revenue and Expense Adjustments	Anthony Brown / Keara Downum / Zane Drummond
39	SCHEDULE G	SCH Gp 2 & 3 Op Income	Summary of Operating Revenue and Expenses	Anthony Brown / Keara Downum / Zane Drummond
40	WKP G.a.1	WKP G.a.1 Op Inc Adjs	Operating Revenue and Expense Adjustments	Anthony Brown / Keara Downum / Zane Drummond
41	WKP G.a.2	WKP G.a.2 Op Inc Per Book	Operating Revenue and Expense Per Book	Anthony Brown / Keara Downum
42	WKP G.a.2.a	WKP G.a.2.a	Supporting Workpaper for Operating Revenue and Expense Per Book, Including O& M Expense Factor for Shared Service, Including Costs Allocated Through Distrigas	Keara Downum
43	SCHEDULE G-1	SCH G-1 Gas Cost Related	Remove Gas Revenue, Cost of Gas and Related Taxes	Zane Drummond
44	SCHEDULE G-2	SCH G-2 Gas Sales Revenue	Normalize Gas Sales Revenue	Zane Drummond
45	SCHEDULE G-3	SCH G-3 Other Revenue	Normalize Other Utility Revenue	Zane Drummond
46	SCHEDULE G-4	SCH G-4 Base Payroll	Base Payroll Adjustment	Keara Downum

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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48	WKP G-4.b	WKP G-4.b Test Yr Payroll	Test Year Payroll	Keara Downum
49	WKP G-4.c	WKP G-4.c Dec Payroll	December Base Payroll	Keara Downum
50	SCHEDULE G-5	SCH G-5 Overtime Payroll	Overtime Payroll Adjustment	Keara Downum
51	WKP G-5.a	WKP G-5.a Distr of Overtime Adj	Overtime Payroll Expense	Keara Downum
52	SCHEDULE G-6	SCH G-6 Benefits & PR Taxes	Benefits and Payroll Tax Adjustment	Keara Downum
53	WKP G-6.a	WKP G-6.a Distri Ben & Tax	Benefits and Payroll Tax Expense	Keara Downum
54	WKP G-6.b	WKP G-6.b	Benefits and Taxes	Keara Downum
55	WKP G-6.c	WKP G-6.c Base Yr Pension OPEB	Base Level Pension and OPEB	Keara Downum
56	SCHEDULE G-7	SCH G-7 Pension OPEB	Pension and OPEB	Anthony Brown
57	SCHEDULE G-8	SCH G-8 Incentive Comp	Incentive Compensation	Keara Downum
58	WKP G-8.a STI ADJUSTMENT	WKP G-8.a STI Adjustment	STI Adjustment	Keara Downum
59	WKP G-8.b LTI ADJUSTMENT	WKP G-8.b LTI Adjustment	LTI Adjustment	Keara Downum
60	SCHEDULE G-9	SCH G-9 Misc Adj	Miscellaneous Adjustments	Anthony Brown / Keara Downum
61	WKP G-9.a	WKP G-9.a Direct	Miscellaneous Adjustments - Direct Service Area	Anthony Brown
62	WKP G-9.b	WKP G-9.b Shared Service	Miscellaneous Adjustments - Shared Services	Keara Downum
63	WKP G-9.c	WKP G-9.c Distrigas	Miscellaneous Adjustments - Distrigas	Keara Downum
64	SCHEDULE G-10	SCH G-10 Rent	Rents and Leases	Anthony Brown / Keara Downum
65	WKP G-10.a	WKP G-10.a Direct	Rents and Leases - Direct Service Area	Anthony Brown
66	WKP G-10.b	WKP G-10.b SS & Distr	Rents and Leases - Shared Services	Keara Downum
67	SCHEDULE G-11	SCH G-11 Cust Dep Int	Interest on Customer Deposits	Anthony Brown
68	SCHEDULE G-12	SCH G-12 Uncoll Exp	Uncollectible Expense	Anthony Brown
69	SCHEDULE G-13	SCH G-13 Inj & Dam	Injuries and Damages	Keara Downum
70	WKP G-13.a	WKP G-13.a	Injuries and Damages Workpaper	Keara Downum
71	SCHEDULE G-14	SCH G-14 Advertising	Advertising Expense	Anthony Brown / Keara Downum
72	SCHEDULE G-15	SCH G-15 Depr Amort	Depreciation and Amortization Expense	Anthony Brown / Eric Sanford
73	WKP G-15.a.1	WKP G-15.a.1 Direct	Depreciation and Amortization Expense - Direct Service Area	Anthony Brown
74	WKP G-15.a.2	WKP G-15.a.2 Direct Fully Depr	Fully Depreciated Plant - Direct Service Area	Anthony Brown
75	WKP G-15.a.1 Fort Bliss	WKP G-15.a.1 Fort Bliss	Depreciation and Amortization Expense - Fort Bliss	Anthony Brown
76	WKP G-15.a.2 Fort Bliss Fully Depr	WKP G-15.a.2 Ft Bliss Fully Dep	Fully Depreciated Plant - Fort Bliss Service Area	Anthony Brown
77	WKP G-15.b.1	WKP G-15.b.1 TGS Div	Depreciation and Amortization Expense - TGS Division	Eric Sanford
78	WKP G-15.b.2	WKP G-15.b.2 TGS Div Fully Depr	Fully Depreciated Plant - TGS Division	Eric Sanford
79	WKP G-15.c.1	WKP G-15.c.1 Corp	Depreciation and Amortization Expense - Corporate	Eric Sanford
80	WKP G-15.c.2	WKP G-15.c.2 Corp Fully Depr	Fully Depreciated Plant - Corporate	Eric Sanford
81	SCHEDULE G-16	SCH G-16 Ad Valorem	Ad Valorem Tax Expense	Anthony Brown
82	WKP G-16.a	WKP G-16.a	Plant in Service - Direct, Ad Valorem Tax Workpaper	Anthony Brown
83	WKP G-16.b	WKP G-16.b	CCNC - Direct, Ad Valorem Tax Workpaper	Anthony Brown
84	WKP G-16.c	WKP G-16.c	Accumulated Reserves for Depreciation and Amortization - Direct, Ad Valorem Tax Workpaper	Anthony Brown
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88	SCHEDULE G-20	SCH G-20 Reg Exp Amortization	Regulatory Expense Amortization	Anthony Brown
89	SCHEDULE G-21	SCH G-21 Distrigas Allocation	Distrigas Allocation Percentage	Keara Downum
90	WKP G-21.a	WKP G-21.a Distrigas Allocation	Distrigas Allocation Percentage Workpaper	Keara Downum
91	SCHEDULE G-22	SCH G-22 Causal Allocation	Causal Allocation Percentage	Keara Downum
92	WKP G-22.a	WKP G-22.a Causal Allocation	Causal Allocation Factor	Keara Downum
93	SCHEDULE G-23	SCH G-23 PIT	Pipeline Integrity Testing Expense	Anthony Brown

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95	SCHEDULE G-25	SCH G-25 CC Processing	Credit Card Processing Fees	Stacey McTaggart / Anthony Brown
96	SCHEDULE G-26	SCH G-26 Customer Assistance	Customer Assistance Programs	Stacey McTaggart / Anthony Brown
97	Study Summary	Study Summary	Class Cost of Service Study Summary	Teresa Serna
98	Classified Rate Base	Classified Rate Base	Classified Rate Base	Teresa Serna
99	Classified Cost of Service	Classified Cost of Service	Classified Cost of Service	Teresa Serna
100	Classification Factors	Classification Factors	Classification Factors	Teresa Serna
101	Allocated Rate Base	Allocated Rate Base	Allocated Rate Base	Teresa Serna
102	Allocated Cost of Service	Allocated Cost of Service	Allocated Cost of Service	Teresa Serna
103	Allocation Factors	Allocation Factors	Allocation Factors	Teresa Serna
104	WKP Plant	WKP Plant	Plant and Depreciation Workpaper	Teresa Serna
105	WKP Admin&Gen	WKP Admin&Gen	Administrative & General Workpaper	Teresa Serna
106	WKP Selected Data	WKP Selected Data	Selected Data Workpaper - Volumes, Bills, Margin, Odorization, Distrigas, Allocation Factors, Mains (Customer) Percentage	Teresa Serna
107	903 Factors	903 Factors	Account 903 Factors Summary for CCOSS	Teresa Serna
108	904 Factors	904 Factors	Account 904 Factors Summary for CCOSS	Teresa Serna
109	Billing Determinants Summary	Bill Determinants Summary	Billing Determinants Summary for CCOSS	Teresa Serna
110	Customer Deposit Factors	Customer Deposit Factors	Customer Deposit Factors Summary for CCOSS	Teresa Serna
111	Mains Study Summary	Mains Study Summary	Mains Study Summary for CCOSS	Teresa Serna
112	Meters & Regulator Factors	Meter & Regulator Factors	Meter & Regulator Factors Summar for COSS	Teresa Serna
113	Odorization Summary	Odorization Summary	Odorization Summary for COSS	Teresa Serna
114	Peak Demand	Peak Demand	Peak Demand Summary for COSS	Teresa Serna
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117	As Adj. Revenues Summary	As Adj. Revenues Summary	Summary of As Adjusted Revenues for CCOSS	Teresa Serna
118	Class Revenue Allocation	Class Revenue Allocation	Class Revenue Allocation	Teresa Serna
119	Proof of Revenue	Proof of Revenue	Proof of Revenue	Paul Raab
120	Current & Rec Rates	Current & Recommended Rates	Current and Recommended Rates	Paul Raab
121	WKP Current & Rec Rates	WKP Current & Rec Rates	Current and Recommended Rates Workpaper	Paul Raab
122	Customer Bill Impacts	Customer Bill Impacts	Customer Bill Impacts	Paul Raab
123	Residential Bill Impacts Existing Rates	Res Bill Impacts Existing Rates	Annual Residential Bill Impacts - Proposed A/B Rate Structure compared to Traditional Rate Structure	Paul Raab
124	Commercial Bill Impacts Existing Rates	Com Bill Impacts Existing Rates	Annual Bill Impacts of Small/Large Commercial Rate Relative to Existing Commercial Incorporated Rates	Paul Raab
125	Residential	Residential	Residential Rate Design	Paul Raab
126	Commercial	Commercial	Commercial Rate Design	Paul Raab
127	Industrial	Industrial	Industrial Rate Design	Paul Raab
128	Public Authority	Public Authority	Public Authority Rate Design	Paul Raab
129	Compressed Nat. Gas	CNG	Compressed Natural Gas Rate Design	Paul Raab
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

SUMMARY OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$1,934,529,098	$(47,616,761)	$1,886,912,337
2	Rate of Return	E	8.0162%	8.0162%	8.0162%
3	Required Return		$155,075,569	$(3,817,051)	$151,258,518
4	Cost of Gas	G	155,312,003	(155,312,003)	0
5	Depreciation and Amortization Expense	G	72,258,997	13,828,875	86,087,872
6	Taxes Other Than Income Taxes	G	23,392,468	2,529,506	25,921,974
7	Interest on Customer Deposits	G	911,925	(87,278)	824,647
8	Transmission and High-Pressure Distribution Expense	G	4,310,552	4,816,188	9,126,739.36
9	Distribution Expense	G	56,904,088	2,369,992	59,274,081
10	Customer Accounts Expense	G	14,845,619	5,031,894	19,877,513
11	Administrative and General Expense	G	79,463,578	(4,928,090)	74,535,487
12	Federal Income Tax	F	32,101,136	(788,725)	31,312,410
13	Revenue Requirement before Gross-up		$594,575,933	$(136,356,691)	$458,219,242
14	Test Year Adjusted Revenue	G	520,488,496	(102,729,111)	417,759,385
15	Revenue Deficiency		$74,087,437	$(33,627,580)	$40,459,857
	Gross-up for Revenue Related Expenses:	Factors:			
16	Uncollectible Expense	0.0073540			
17	Texas Franchise Tax	0.0075000			
18	Gross-Up Percentage	0.0148540	1,117,088	(507,036)	610,052
19	Total Revenue Deficiency		$75,204,525	$(34,134,615)	$41,069,909
20	Total Revenue Requirement (Line 13 + Line 18)		$595,693,021	$(136,863,727)	$458,829,294

WKP A.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

PROOF OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	AMOUNT (a)	AMOUNT (b)
1	Total Revenue Requirement		$458,829,294
	Less:		
2	Depreciation	$86,087,872	
3	Taxes	25,921,974	
4	Interest on Deposits	824,647	
5	Transmission Expense	9,126,739	
6	Distribution Expense	59,274,081	
7	Customer Accounting	19,877,513	
8	Administrative and General Expense	74,535,487	
9	Gross-Up Expenses	610,052	
10	Total Operating Expense	$276,258,366	276,258,366
11	Less Interest on Long-Term Debt		33,680,727
12	Taxable Income	$148,890,201	$148,890,201
13	Add back non-deductible parking expense		216,513
14	Tax Rate	21 %	
15	Income Taxes	$31,312,410	
16	Less Tax Adjustments		
17	Net Income Tax	$31,312,410	31,312,410
18	Net Income		$117,577,791
19	Rate Base	$1,886,912,337	
20	Wtd Cost of Equity (Common + Preferred)	6.23 %	
21	Required Return	$117,577,791	$117,577,791
22	Variance		0

WKP A.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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	328,534	46.7278%
3	West North Service Area	310,657	44.1852%
4	Rio Grande Valley Service Area	63,889	9.0870%
5	Total TGS	703,080	100.0000%
6	Service Area Factor for this Filing		100.0000%

Based on Test Year Average Total Billed Customers

SCHEDULE B

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$2,241,035,995	$(5,703,355)	$2,235,332,639
2	Completed Construction Not Classified	C-1	317,458,391	(1,736,052)	315,722,339
3	Accumulated Reserves for Depreciation and Amortization	D	(501,603,193)	4,872,379	(496,730,814)
4	Net Plant in Service		$2,056,891,193	$(2,567,029)	$2,054,324,164
	OTHER RATE BASE ITEMS				
5	Negative Acquisition Adjustment on OPC Assets		$0	$(1,949,023)	$(1,949,023)
6	Materials and Supplies Inventory	B-1	28,451,041	(1,811,049)	26,639,992
7	Prepayments	B-2	11,094,163	(13,860)	11,080,303
8	Rule 8.209 Regulatory Asset - DIMP Deferrals	B-3	4,757,745	0	4,757,745
9	Regulatory Assets	B-11	2,118,256	0	2,118,256
10	Pension & OPEB Regulatory Asset	B-4	(6,518,193)	0	(6,518,193)
11	Prepaid Pension Asset	B-5	44,728,624	0	44,728,624
12	Cash Working Capital	B-6	0	$(13,403,426)	(13,403,426)
	NON-INVESTOR SUPPLIED FUNDS				
13	Customer Deposits	B-7	(16,329,640)	0	(16,329,640)
14	Customer Advances	B-8	(6,534,399)	0	(6,534,399)
15	Accumulated Deferred Taxes	B-9	(184,129,691)	0	(184,129,691)
16	Excess Deferred Income Taxes	B-10	0	(27,872,376)	(27,872,376)
17	Total Rate Base		$1,934,529,098	$(47,616,761)	$1,886,912,337

Source: SCH B OPC Negative Acquisition Adjustment.xlsx

WKP B.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

SUMMARY OF PLANT ADJUSTMENTS

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	ADJUSTED TEST YEAR
			(a)	(b)	(c)
1	PLANT IN SERVICE	Schedule C	$2,241,035,995		$2,235,332,639
2	Meal & Hotel Adjustments	WKP C.a, C.a.1, C.b, C.c		$(34,959)	
3	Miscoded Additions & Transfers Adjustment	WKP C.a, C.a.1		(754,986)	
4	Miscoded Retirement Adjustment	WKP C.a, C.a.1		0	
5	FERC Reclass	WKP C.a, C.a.1		0	
6	Miscoded Project	WKP C.b, C.c		(25,155)	
7	Remove Duplicate Vertex Sales Tax	WKP C.b, C.c		(28,555)	
8	Miscoded Charges Adjustment	WKP C.b, C.c		92,683	
9	Adjustments from Prior Filings	WKP C.b, C.c		(114,802)	
10	Remove Insufficient Support	WKP C.b, C.c		(413,363)	
11	Remove Asset not used by Division	WKP C.b		(774)	
12	Remove ONE Gas Foundation Software	WKP C.c		(39,294)	
13	Remove ONE Gas Lease Incentive	WKP C.c		(175,107)	
14	Remove ONE Gas Aviation	WKP C.c		(4,194,119)	
15	Remove Artwork	WKP C.c		(14,924)	
16	Total		$2,241,035,995	$(5,703,355)	$2,235,332,639
17	COMPLETED CONSTRUCTION NOT CLASSIFIED	Schedule C-1	$317,458,391		$315,722,339
18	Meal & Hotel Adjustments	WKP C-1.a, C-1.a.1, C-1.c		$(2,639)	
19	Miscoded Additions & Transfers Adjustment	WKP C-1.a, C-1.a.1		(1,234,908)	
20	Miscoded Retirement Adjustment	WKP C-1.a, C-1.a.1		0	
21	FERC Reclass	WKP C-1.a, C-1.a.1		0	
22	Miscoded Charges Adjustment	WKP C-1.b		62,111	
23	Adjustments from Prior Filings	WKP C-1.b, C-1.c		(522,169)	
24	Miscoded Project	WKP C-1.c		(37,711)	
25	Remove Duplicate Vertex Sales Tax	WKP C-1.c		(680)	
26	Remove Insufficient Support	WKP C-1.c		(56)	
27	Total		$317,458,391	$(1,736,052)	$315,722,339
28	ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION	Schedule D	$(501,603,193)		$(496,730,814)
29	Meal & Hotel Adjustments	WKP D.b, D.c		$21,541	
30	Miscoded Additions & Transfers Adjustment	WKP D.a, D.a.1		(59,117)	
31	Miscoded Retirement Adjustment	WKP D.a, D.a.1		0	
32	FERC Reclass	WKP D.a, D.a.1		0	
33	Miscoded Project	WKP D.b, D.c		7,556	
34	Remove Duplicate Vertex Sales Tax	WKP D.b, D.c		6,263	
35	Miscoded Charges Adjustment	WKP D.b, D.c		(21,973)	
36	Adjustments from Prior Filings	WKP D.b, D.c		279,542	
37	Reserve Rebalance	WKP D.a, D.a.1, D.b, D.c		6,505	
38	Remove Insufficient Support	WKP D.b		406,116	
39	Remove Asset not used by Division	WKP D.b		774	
40	Remove Land Depreciation	WKP D.b		4,331	
41	Remove ONE Gas Foundation Software	WKP D.c		10,449	
42	Remove ONE Gas Lease Incentive	WKP D.c		90,333	
43	Remove ONE Gas Aviation	WKP D.c		4,112,942	
44	Remove Artwork	WKP D.c		7,116	
45	Total		$(501,603,193)	$4,872,379	$(496,730,814)

SCHEDULE B-1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

MATERIALS AND SUPPLIES

LINE NO.	DESCRIPTION	DIRECT INVENTORY	DIRECT STORES LOAD	OMA INVENTORY	TOTAL
		(a)	(b)	(c)	(d)
1	December 31, 2023	$20,733,666	-$46,415	$4,615,047	$25,302,298
2	January 30, 2024	20,730,952	(166,900)	4,198,457	24,762,509
3	February 28, 2024	20,694,656	(400,483)	4,053,198	24,347,372
4	March 31, 2024	20,933,150	(261,588)	4,938,013	25,609,575
5	April 30, 2024	20,617,542	(246,142)	4,534,284	24,905,684
6	May 31, 2024	20,830,570	15,769	4,471,282	25,317,621
7	June 30, 2024	21,693,530	336,898	5,058,128	27,088,556
8	July 31, 2024	21,780,154	236,834	4,602,854	26,619,842
9	August 31, 2024	22,002,609	224,517	5,250,472	27,477,598
10	September 30, 2024	22,348,038	450,940	6,200,580	28,999,558
11	October 31, 2024	22,480,563	168,618	6,208,291	28,857,472
12	November 30, 2024	22,222,080	(42,271)	6,400,961	28,580,770
13	December 31, 2024	22,436,443	28,176	5,986,422	28,451,041
14	13 Month Average	$21,500,304	$22,919	$5,116,768	$26,639,992

Source: SCH B-1 TGS Materials & Supplies.xlsx
Source: SCH B-1 Stores Balances.xlsx
Source: SCH B-1 OMA Inventory.xlsx

SCHEDULE B-2

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

PREPAYMENTS

LINE NO.	DESCRIPTION	DIRECT	TGS DIVISION	CORPORATE	TOTAL
		(a)	(b)	(c)	(d)
1	December 31, 2023	$0	$4,929,482	$25,318,550	
2	January 30, 2024	0	4,422,988	25,483,950	
3	February 28, 2024	0	3,919,486	27,811,674	
4	March 31, 2024	0	3,415,985	27,970,532	
5	April 30, 2024	0	2,911,094	27,692,491	
6	May 31, 2024	0	3,229,524	28,653,595	
7	June 30, 2024	0	2,716,895	29,001,449	
8	July 31, 2024	0	2,221,773	26,987,297	
9	August 31, 2024	0	1,707,463	25,923,937	
10	September 30, 2024	0	1,206,578	24,135,281	
11	October 31, 2024	0	693,981	23,787,451	
12	November 30, 2024	0	3,776,203	28,027,625	
13	December 31, 2024	0	3,473,106	27,700,002	
14	13 Month Average	$0	$2,971,120	$26,807,218	
15	Allocation Factor to TGS	100.00%	100.00%	30.25%	
16	Allocation Factor to Service Area	100.00%	100.00%	100.00%	
17	Total Allocated Prepayments	$0	$2,971,120	$8,109,183	$11,080,303

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

PREPAYMENTS - TGS DIVISION

LINE NO.	MONTH/YEAR ENDING	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
	(a)	(b)	(c)	(d) = (b)+(c)
1	December 31, 2023	$4,929,482	$0	$4,929,482
2	January 30, 2024	4,422,988	0	4,422,988
3	February 28, 2024	3,919,486	0	3,919,486
4	March 31, 2024	3,415,985	0	3,415,985
5	April 30, 2024	2,911,094	0	2,911,094
6	May 31, 2024	3,229,524	0	3,229,524
7	June 30, 2024	2,716,895	0	2,716,895
8	July 31, 2024	2,221,773	0	2,221,773
9	August 31, 2024	1,707,463	0	1,707,463
10	September 30, 2024	1,206,578	0	1,206,578
11	October 31, 2024	693,981	0	693,981
12	November 30, 2024	3,776,203	0	3,776,203
13	December 31, 2024	3,473,106	0	3,473,106
14	13-Month Average	$2,971,120	$0	$2,971,120
15	Allocation Factor to TGS	100.0000%	100.0000%	100.0000%
16	Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%
17	Total Allocated Prepayments	$2,971,120	$0	$2,971,120

Source: WKP B-2.a.1 Prepays - TGS Div (CONFIDENTIAL).xlsx

WKP B-2.b.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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, 2023	$25,460,971	$(142,421)	$25,318,550
2	January 30, 2024	25,600,420	(116,470)	25,483,950
3	February 28, 2024	27,902,193	(90,519)	27,811,674
4	March 31, 2024	28,035,100	(64,568)	27,970,532
5	April 30, 2024	27,731,108	(38,617)	27,692,491
6	May 31, 2024	28,685,019	(31,424)	28,653,595
7	June 30, 2024	29,025,680	(24,231)	29,001,449
8	July 31, 2024	27,004,335	(17,038)	26,987,297
9	August 31, 2024	25,933,782	(9,845)	25,923,937
10	September 30, 2024	24,137,933	(2,652)	24,135,281
11	October 31, 2024	23,787,451	0	23,787,451
12	November 30, 2024	28,057,919	(30,294)	28,027,625
13	December 31, 2024	27,727,542	(27,540)	27,700,002
14	13-Month Average	$26,853,035	$(45,817)	$26,807,218
15	Pro Forma, Q1 2025 Allocation Factor to TGS	30.2500%	30.2500%	30.2500%
16	13-Month Average Allocated to TGS	$8,123,043	$(13,860)	$8,109,183
17	Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%
18	Total Allocated Prepayments	$8,123,043	$(13,860)	$8,109,183

Source: WKP B-2.b.1 Prepays - Corporate (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

RULE 8.209 REGULATORY ASSET

LINE NO.	FERC ACCOUNT	TEST YEAR ACCRUAL	ADJUSTMENT TO ACCRUAL	TOTAL ACCRUAL
		(a)	(b)	(c)
1	(367) Mains	$1,134		$1,134
2	(371) Other Transmission System			0
3	(374.2) Land Rights	(2,418)	2,418	0
4	(376) Mains	1,457,628		1,457,628
5	(376.9) Cathodic Protection Anodes	82,457		82,457
6	(378) Meas & Reg Station -General	20,446		20,446
7	(379) Meas & Reg Station -City	3,011		3,011
8	(380) Services	3,179,741	(2,584)	3,177,157
9	(380.1) Ind Service Line Equip	21		21
10	(380.2) Comm Service Line Equip	(2,805.67)		(2,806)
11	(380.4) Yard Lines-Customer Svc	(12,918)		(12,918)
12	(381) Meters	(1,989)	(3,161)	(5,150)
13	(382) Meter Installations	(3,161)	3,161	0
14	(383) House Regulators	184		184
15	(385) Ind Meas & Reg Sta Equip	36,580		36,580
16	(390.1) Structures and Improvements	(1)	1	(0)
17	(394) Tools, Shop & Garage Equip	(177)	177	0
18	(394.1) Tools	13	(13)	0
19	(397) Communication Equipment			0
20	Total	$4,757,745	$0	$4,757,745

Source: SCH B-3 Rule 8.209 Accrual.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$53,541	$41,664	$229,560	$232,565	$557,331
2	091.053.7202.010563	CENTRAL-GULF	—	(0)	(0)	(0)	(0)
3	091.053.7202.010564	CENTRAL-GULF	—	(0)	(0)	(0)	(0)
4	091.053.7202.010568	CENTRAL-GULF	0	0	0	0	0
5	091.053.7202.010797	CENTRAL-GULF	(3)	0	—	—	(3)
6	091.053.7202.010798	CENTRAL-GULF	-14	-31	-261	-267	(573)
7	091.053.7202.010804	CENTRAL-GULF	(10)	40	333	340	703
8	091.053.7202.010827	CENTRAL-GULF	720	422	2,395	2,447	5,985
9	091.053.7202.010846	CENTRAL-GULF	(0)	24	129	132	285
10	091.053.7202.010863	CENTRAL-GULF	733	510	2,843	2,905	6,991
11	091.053.7202.010877	CENTRAL-GULF	304	(37)	(114)	(116)	36
12	091.053.7202.010879	CENTRAL-GULF	1,927	917	5,248	5,362	13,455
13	091.053.7202.010916	CENTRAL-GULF	135	77	438	448	1,097
14	091.053.7202.010925	CENTRAL-GULF	52	28	153	156	389
15	091.053.7202.010926	CENTRAL-GULF	351	186	1,030	1,052	2,619
16	091.053.7202.010927	CENTRAL-GULF	408	231	1,234	1,250	3,122
17	091.053.7202.010929	CENTRAL-GULF	(104)	(29)	(152)	(155)	(440)
18	091.053.7202.010932	CENTRAL-GULF	108	67	359	363	897
19	091.053.7202.010934	CENTRAL-GULF	803	451	2458	2415	6,127
20	091.053.7202.010938	CENTRAL-GULF	(92)	65	354	351	679
21	091.053.7202.010947	CENTRAL-GULF	165	89	481	481	1,216
22	091.053.7202.010952	CENTRAL-GULF	569	343	1839	1848	4,599
23	091.053.7202.010953	CENTRAL-GULF	12	8	41	42	102
24	091.053.7202.010965	CENTRAL-GULF	42	30	163	159	394
25	091.053.7202.010966	CENTRAL-GULF	8	-16	-86	-86	(180)
26	091.053.7202.010967	CENTRAL-GULF	101	63	343	338	844
27	091.053.7202.010970	CENTRAL-GULF	146	147	828	773	1,895
28	091.053.7202.010973	CENTRAL-GULF	4	5	26	25	60
29	091.053.7202.010975	CENTRAL-GULF	232	128	704	686	1,750
30	091.053.7202.010978	CENTRAL-GULF	(9)	(9)	(53)	(50)	(121)
31	091.053.7202.010980	CENTRAL-GULF	(2)	(2)	(14)	(13)	(32)
32	091.053.7292.005100	CENTRAL-GULF	-0	(0)	(0)	(0)	(0)
33	091.053.7300.010044	CENTRAL-GULF	30	19	104	105	259
34	091.053.7301.005100	CENTRAL-GULF	0	0	0	0	1
35	091.053.7302.005100	CENTRAL-GULF	-0	(0)	(0)	(0)	(0)
36	091.053.7303.005100	CENTRAL-GULF	(0)	(0)	(0)	(0)	(0)
37	091.053.7304.005100	CENTRAL-GULF	(0)	(0)	(0)	(0)	(0)
38	091.053.7306.005100	CENTRAL-GULF	(0)	(0)	(0)	(0)	(0)
39	091.053.7307.005100	CENTRAL-GULF	0	0	0	0	0
40	091.053.7308.005100	CENTRAL-GULF	(0)	(0)	(0)	(0)	(0)
41	091.053.7450.005100	CENTRAL-GULF	338	306	1683	1705	4,031
42	091.053.7550.005100	CENTRAL-GULF	585	493	2,723	2,761	6,561
43	091.053.7550.010082	CENTRAL-GULF	432	191	1,093	1,116	2,832
44	091.053.7610.005100	WEST-NORTH	0	0	0	0	0
45	091.053.7630.005100	WEST-NORTH	(0)	(0)	(0)	(0)	(0)
46	091.053.7640.005100	WEST-NORTH	0	0	0	0	0
47	091.053.7641.005100	WEST-NORTH	0	0	0	0	0
48	091.053.7645.005100	WEST-NORTH	8	15	67	57	147
49	091.053.7650.005100	WEST-NORTH	24,205	18,468	84,104	71,342	198,119
50	091.053.7650.010625	WEST-NORTH	0	—	—	—	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
51	091.053.7650.010718	WEST-NORTH	677	400	1,843	1,564	4,485
52	091.053.7650.010730	WEST-NORTH	1,625	876	4,064	3,447	10,012
53	091.053.7650.010736	WEST-NORTH	—	0	1	1	3
54	091.053.7650.010737	WEST-NORTH	346	161	746	633	1,886
55	091.053.7650.010738	WEST-NORTH	(12)	153	915	776	1,830
56	091.053.7650.010739	WEST-NORTH	(1)	4	17	14	34
57	091.053.7650.010741	WEST-NORTH	(2)	34	201	171	404
58	091.053.7650.010745	WEST-NORTH	1,880	1,289	5,944	5,042	14,155
59	091.053.7650.010749	WEST-NORTH	130	54	250	212	646
60	091.053.7650.010752	WEST-NORTH	188	80	370	314	951
61	091.053.7650.010754	WEST-NORTH	2,006	1,137	5,273	4,473	12,889
62	091.053.7650.010766	WEST-NORTH	699	555	2,540	2,155	5,948
63	091.053.7650.010777	WEST-NORTH	402	205	909	771	2,288
64	091.053.7650.010778	WEST-NORTH	3,133	1,985	8,805	7,469	21,391
65	091.053.7650.010790	WEST-NORTH	3,189	1,794	8,318	7,056	20,358
66	091.053.7650.010806	WEST-NORTH	2,283	1,358	6,293	5,338	15,271
67	091.053.7650.010809	WEST-NORTH	272	141	654	555	1,623
68	091.053.7650.010810	WEST-NORTH	4,793	3,198	14,181	12,029	34,200
69	091.053.7650.010812	WEST-NORTH	411	227	1,007	854	2,499
70	091.053.7650.010820	WEST-NORTH	1,376	799	3,700	3,138	9,013
71	091.053.7650.010823	WEST-NORTH	394	216	992	842	2,444
72	091.053.7650.010824	WEST-NORTH	682	400	1,774	1,505	4,361
73	091.053.7650.010826	WEST-NORTH	3,798	2,397	10,629	9,016	25,840
74	091.053.7650.010847	WEST-NORTH	275	128	596	505	1,504
75	091.053.7650.010852	WEST-NORTH	735	442	2,020	1,714	4,911
76	091.053.7650.010888	WEST-NORTH	2,045	1,475	6,543	5,550	15,612
77	091.053.7650.010889	WEST-NORTH	452	318	1,410	1,196	3,377
78	091.053.7650.010892	WEST-NORTH	754	594	2,632	2,233	6,212
79	091.053.7650.010894	WEST-NORTH	19	13	58	49	140
80	091.053.7650.010896	WEST-NORTH	443	312	1,385	1,175	3,315
81	091.053.7700.005100	RGV	26,880	9,147	100,496	86,678	223,201
82	091.053.7700.010147	RGV	(380)	47	524	452	642
83	091.053.7700.010149	RGV	(33)	37	412	356	772
84	091.053.7700.010154	RGV	(11)	9	105	91	194
85	091.053.7700.010157	RGV	(43)	34	384	331	707
86	091.053.7700.010158	RGV	(7)	—	—	—	(7)
87	091.053.7700.010162	RGV	(11)	21	238	205	454
88	091.053.7700.010174	RGV	3,857	988	10,701	9,230	24,776
89	091.053.7700.010180	RGV	(20)	58	492	424	954
90	091.053.7700.010186	RGV	(9)	8	92	80	171
91	091.053.7700.010190	RGV	(5)	16	181	156	348
92	091.053.7700.010191	RGV	76	26	288	248	639
93	091.053.7700.010194	RGV	185	32	350	302	869
94	091.053.7700.010195	RGV	297	91	988	852	2,227
95	091.053.7700.010198	RGV	129	19	219	189	556
96	091.053.7700.010202	RGV	206	47	504	435	1,192
97	091.053.7700.010239	RGV	35	11	120	103	269
98	091.053.7700.010240	RGV	54	14	163	141	372
99	091.053.7700.010241	RGV	114	31	352	303	801
100	091.053.7700.010244	RGV	65	22	245	211	542

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
101	091.053.7700.010246	RGV	58	11	124	107	299
102	091.053.7700.010247	RGV	142	34	378	326	879
103	091.053.7700.010249	RGV	127	32	360	310	829
104	091.053.7700.010260	RGV	47	24	271	234	576
105	091.053.7703.005100	RGV	1	0	2	2	4
106	091.053.7705.005100	RGV	0	0	0	0	0
107	091.053.7706.005100	RGV	0	0	0	0	0
108	091.053.7707.005100	RGV	0	0	0	0	0
109	091.053.7708.005100	RGV	0	0	0	0	0
110	091.053.7709.005100	RGV	0	0	0	0	0
111	091.053.7710.005100	RGV	0	0	0	0	1
112	091.053.7711.005100	RGV	1	0	1	1	3
113	091.053.7712.005100	RGV	0	0	1	0	1
114	091.053.7714.005100	RGV	0	0	0	0	0
115	091.053.7715.005100	RGV	0	0	0	0	0
116	091.053.7716.005100	RGV	0	0	0	0	1
117	091.053.7717.005100	RGV	0	0	0	0	0
118	091.053.7718.005100	RGV	0	0	0	0	0
119	091.053.7719.005100	RGV	4	0	0	0	4
120	091.053.7720.005100	RGV	0	0	0	0	0
121	091.053.7721.005100	RGV	0	0	0	0	0
122	091.053.7722.005100	RGV	0	0	0	0	0
123	091.053.7723.005100	RGV	0	0	0	0	1
124	091.053.7724.005100	RGV	0	0	1	1	2
125	091.053.7725.005100	RGV	0	0	0	0	0
126	091.053.7726.005100	RGV	0	0	1	0	1
127	091.053.7727.005100	RGV	—	—	—	—	0
128	091.053.7728.005100	RGV	0	0	0	0	0
129	091.053.7729.005100	RGV	0	0	0	0	1
130	091.053.7730.005100	RGV	0	0	0	0	0
131	091.053.7731.005100	RGV	0	0	0	0	0
132	091.053.7732.005100	RGV	0	0	0	0	0
133	091.053.7733.005100	RGV	0	0	0	0	0
134	091.053.7734.005100	RGV	0	0	0	0	0
135	091.053.7735.005100	RGV	0	0	1	1	3
136	091.053.7736.005100	RGV	0	0	1	1	2
137	091.053.7737.005100	RGV	0	0	0	0	0
138	091.053.7738.005100	RGV	0	0	0	0	0
139	091.053.7739.005100	RGV	0	0	0	0	0
140	091.053.7800.010030	WEST-NORTH	18	—	—	—	18
141	091.053.7800.010087	WEST-NORTH	(115)	(76)	(350)	(297)	(838)
142	091.053.7800.010097	WEST-NORTH	(14)	101	446	379	911
143	091.053.7800.010108	WEST-NORTH	607	396	1,837	1,559	4,400
144	091.053.7800.010109	WEST-NORTH	45	29	137	116	327
145	091.053.7800.010119	WEST-NORTH	9	5	24	20	58
146	091.053.7800.010124	WEST-NORTH	373	247	1,144	970	2,734
147	091.053.7800.010128	WEST-NORTH	0	0	1	1	2
148	091.053.7800.010133	WEST-NORTH	535	398	1,765	1,498	4,196
149	091.053.7810.005100	WEST-NORTH	0	0	0	0	0
150	091.053.7820.005100	WEST-NORTH	0	0	0	0	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
151	091.053.7825.005100	WEST-NORTH	0	0	0	0	0
152	091.053.7835.005100	WEST-NORTH	0	0	0	0	0
153	091.053.7850.005100	WEST-NORTH	89	67	304	258	719
154	091.053.7850.010037	WEST-NORTH	70	87	397	337	891
155	091.053.7850.010044	WEST-NORTH	33	21	100	85	238
156	091.054.7202.005100	CENTRAL-GULF	77,223	59,927	330,609	334,942	802,701
157	091.054.7202.011006	CENTRAL-GULF	(12)	105	557	569	1,220
158	091.054.7202.011311	CENTRAL-GULF	-6	77	408	417	896
159	091.054.7202.011345	CENTRAL-GULF	-0	78	417	426	920
160	091.054.7202.011346	CENTRAL-GULF	(5)	130	688	702	1,515
161	091.054.7202.011347	CENTRAL-GULF	(0)	55	293	299	647
162	091.054.7202.011359	CENTRAL-GULF	-8	163	1,358	1,387	2,900
163	091.054.7202.011369	CENTRAL-GULF	(27)	326	1,731	1,768	3,798
164	091.054.7202.011374	CENTRAL-GULF	-16	138	1149	1174	2,446
165	091.054.7202.011386	CENTRAL-GULF	(1)	48	255	261	563
166	091.054.7202.011402	CENTRAL-GULF	(0)	100	528	540	1,167
167	091.054.7202.011403	CENTRAL-GULF	(16)	191	1,586	1,620	3,380
168	091.054.7202.011405	CENTRAL-GULF	(1)	57	301	308	664
169	091.054.7202.011409	CENTRAL-GULF	(31)	412	2,188	2,235	4,804
170	091.054.7202.011412	CENTRAL-GULF	(0)	63	333	341	736
171	091.054.7202.011414	CENTRAL-GULF	(228)	132	1,098	1,121	2,123
172	091.054.7202.011416	CENTRAL-GULF	(80)	386	2,048	2,093	4,446
173	091.054.7202.011418	CENTRAL-GULF	(1)	44	233	238	514
174	091.054.7202.011419	CENTRAL-GULF	4,397	2,871	16,430	16,786	40,483
175	091.054.7202.011422	CENTRAL-GULF	(2)	49	263	268	578
176	091.054.7202.011424	CENTRAL-GULF	(18)	213	1,129	1,153	2,477
177	091.054.7202.011427	CENTRAL-GULF	(45)	345	1,830	1,870	3,999
178	091.054.7202.011429	CENTRAL-GULF	(0)	32	170	174	376
179	091.054.7202.011430	CENTRAL-GULF	906	456	2,613	2,669	6,645
180	091.054.7202.011434	CENTRAL-GULF	(0)	28	147	150	325
181	091.054.7202.011436	CENTRAL-GULF	(0)	68	362	370	801
182	091.054.7202.011440	CENTRAL-GULF	1,267	1,328	7,382	7,542	17,519
183	091.054.7202.011443	CENTRAL-GULF	(256)	10	52	53	(141)
184	091.054.7202.011444	CENTRAL-GULF	(0)	—	—	—	(0)
185	091.054.7202.011446	CENTRAL-GULF	1,736	1,228	7,744	7,912	18,621
186	091.054.7202.011451	CENTRAL-GULF	(2)	1	6	7	12
187	091.054.7202.011453	CENTRAL-GULF	2,473	2,057	11,471	11,720	27,721
188	091.054.7202.011457	CENTRAL-GULF	566	328	1,852	1,893	4,639
189	091.054.7202.011458	CENTRAL-GULF	(1)	46	245	251	541
190	091.054.7202.011461	CENTRAL-GULF	928	779	4,912	5,019	11,639
191	091.054.7202.011465	CENTRAL-GULF	72	8	44	45	169
192	091.054.7202.011468	CENTRAL-GULF	978	523	2,993	3,058	7,552
193	091.054.7202.011469	CENTRAL-GULF	2,570	571	3,689	3,769	10,600
194	091.054.7202.011472	CENTRAL-GULF	379	216	1,200	1,226	3,020
195	091.054.7202.011473	CENTRAL-GULF	(15)	59	312	319	674
196	091.054.7202.011475	CENTRAL-GULF	2,396	1,339	7,585	7,749	19,069
197	091.054.7202.011476	CENTRAL-GULF	(0)	19	101	103	223
198	091.054.7202.011477	CENTRAL-GULF	864	485	2,778	2,839	6,967
199	091.054.7202.011481	CENTRAL-GULF	710	147	839	857	2,554
200	091.054.7202.011482	CENTRAL-GULF	4,612	4,070	22,692	23,184	54,559

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LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
201	091.054.7202.011483	CENTRAL-GULF	931	468	2,680	2,738	6,818
202	091.054.7202.011485	CENTRAL-GULF	63	317	1,685	1,722	3,787
203	091.054.7202.011486	CENTRAL-GULF	283	105	597	610	1,594
204	091.054.7202.011488	CENTRAL-GULF	2,681	1,550	8,821	9,013	22,065
205	091.054.7202.011489	CENTRAL-GULF	376	115	645	659	1,794
206	091.054.7202.011491	CENTRAL-GULF	512	169	954	975	2,609
207	091.054.7202.011492	CENTRAL-GULF	1,437	1,346	7,477	7,639	17,899
208	091.054.7202.011493	CENTRAL-GULF	316	152	867	886	2,221
209	091.054.7202.011499	CENTRAL-GULF	314	116	650	664	1,745
210	091.054.7202.011501	CENTRAL-GULF	3,116	1,987	10,677	10,711	26,491
211	091.054.7202.011502	CENTRAL-GULF	366	159	909	928	2,362
212	091.054.7202.011503	CENTRAL-GULF	1,122	640	3,648	3,727	9,138
213	091.054.7202.011507	CENTRAL-GULF	442	250	1,433	1,464	3,589
214	091.054.7202.011508	CENTRAL-GULF	10	6	33	34	84
215	091.054.7202.011509	CENTRAL-GULF	180	80	458	468	1,186
216	091.054.7202.011511	CENTRAL-GULF	439	247	1,397	1,428	3,511
217	091.054.7202.011513	CENTRAL-GULF	429	257	1,443	1,474	3,603
218	091.054.7202.011514	CENTRAL-GULF	126	72	412	421	1,031
219	091.054.7202.011516	CENTRAL-GULF	353	201	1,147	1,172	2,873
220	091.054.7202.011517	CENTRAL-GULF	486	248	1,417	1,448	3,599
221	091.054.7202.011518	CENTRAL-GULF	7	4	24	24	59
222	091.054.7202.011521	CENTRAL-GULF	108	67	355	362	891
223	091.054.7202.011522	CENTRAL-GULF	45	24	135	138	342
224	091.054.7202.011523	CENTRAL-GULF	23	16	92	94	226
225	091.054.7202.011524	CENTRAL-GULF	117	63	353	360	893
226	091.054.7202.011528	CENTRAL-GULF	60	39	212	217	528
227	091.054.7202.011529	CENTRAL-GULF	104	33	192	196	525
228	091.054.7202.011531	CENTRAL-GULF	1,056	561	3,214	3,283	8,114
229	091.054.7202.011535	CENTRAL-GULF	4,291	2,639	14,101	14,266	35,297
230	091.054.7202.011536	CENTRAL-GULF	2,085	1,180	6,306	6,381	15,952
231	091.054.7202.011538	CENTRAL-GULF	638	320	1,810	1,849	4,617
232	091.054.7202.011539	CENTRAL-GULF	1,422	843	4,605	4,705	11,576
233	091.054.7202.011544	CENTRAL-GULF	47	27	153	156	383
234	091.054.7202.011547	CENTRAL-GULF	290	65	373	381	1,110
235	091.054.7202.011548	CENTRAL-GULF	40	9	50	51	149
236	091.054.7202.011549	CENTRAL-GULF	443	324	1,774	1,730	4,270
237	091.054.7202.011550	CENTRAL-GULF	488	286	1,619	1,654	4,047
238	091.054.7202.011552	CENTRAL-GULF	1,373	858	4,620	4,619	11,470
239	091.054.7202.011553	CENTRAL-GULF	11	7	38	39	95
240	091.054.7202.011555	CENTRAL-GULF	5,860	3,384	18,067	18,305	45,616
241	091.054.7202.011556	CENTRAL-GULF	5,788	3,511	18,827	18,948	47,074
242	091.054.7202.011557	CENTRAL-GULF	99	20	117	120	357
243	091.054.7202.011558	CENTRAL-GULF	461	209	1,117	1,131	2,918
244	091.054.7202.011559	CENTRAL-GULF	227	135	747	764	1,873
245	091.054.7202.011566	CENTRAL-GULF	591	357	1,916	1,930	4,794
246	091.054.7202.011567	CENTRAL-GULF	220	82	440	442	1,184
247	091.054.7202.011568	CENTRAL-GULF	1,149	746	3,996	4,027	9,918
248	091.054.7202.011570	CENTRAL-GULF	105	67	357	361	890
249	091.054.7202.011571	CENTRAL-GULF	315	146	778	794	2,033
250	091.054.7202.011572	CENTRAL-GULF	782	478	2,584	2,574	6,419

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
251	091.054.7202.011573	CENTRAL-GULF	313	164	876	886	2,240
252	091.054.7202.011574	CENTRAL-GULF	10	6	34	35	85
253	091.054.7202.011575	CENTRAL-GULF	452	337	1,847	1,800	4,436
254	091.054.7202.011576	CENTRAL-GULF	2,513	1,568	8,412	8,461	20,953
255	091.054.7202.011577	CENTRAL-GULF	340	206	1,103	1,116	2,766
256	091.054.7202.011581	CENTRAL-GULF	1,240	800	4,350	4,291	10,681
257	091.054.7202.011584	CENTRAL-GULF	1,918	1,217	6,506	6,575	16,217
258	091.054.7202.011586	CENTRAL-GULF	192	126	676	679	1,672
259	091.054.7202.011587	CENTRAL-GULF	1,197	791	4,305	4,241	10,534
260	091.054.7202.011588	CENTRAL-GULF	498	356	1,941	1,904	4,698
261	091.054.7202.011589	CENTRAL-GULF	2,062	565	3,020	3,055	8,702
262	091.054.7202.011591	CENTRAL-GULF	1,202	766	4,121	4,132	10,221
263	091.054.7202.011594	CENTRAL-GULF	407	249	1,336	1,341	3,332
264	091.054.7202.011596	CENTRAL-GULF	172	110	591	593	1,465
265	091.054.7202.011597	CENTRAL-GULF	200	120	642	647	1,609
266	091.054.7202.011600	CENTRAL-GULF	990	670	3,636	3,598	8,894
267	091.054.7202.011605	CENTRAL-GULF	288	235	1,305	1,244	3,072
268	091.054.7202.011606	CENTRAL-GULF	15	10	53	54	132
269	091.054.7202.011607	CENTRAL-GULF	1,249	794	4,295	4,268	10,605
270	091.054.7202.011608	CENTRAL-GULF	224	144	774	778	1,921
271	091.054.7202.011609	CENTRAL-GULF	135	97	529	516	1,277
272	091.054.7202.011612	CENTRAL-GULF	352	174	938	940	2,404
273	091.054.7202.011617	CENTRAL-GULF	92	36	196	191	515
274	091.054.7202.011620	CENTRAL-GULF	271	169	925	906	2,271
275	091.054.7202.011621	CENTRAL-GULF	2	2	10	9	23
276	091.054.7202.011622	CENTRAL-GULF	33	24	131	128	316
277	091.054.7202.011623	CENTRAL-GULF	2	1	7	7	17
278	091.054.7202.011625	CENTRAL-GULF	20	6	34	32	91
279	091.054.7202.011626	CENTRAL-GULF	11	7	38	37	93
280	091.054.7202.011627	CENTRAL-GULF	17	9	52	49	128
281	091.054.7202.011631	CENTRAL-GULF	52	38	210	203	503
282	091.054.7202.011632	CENTRAL-GULF	7	6	35	33	80
283	091.054.7202.011633	CENTRAL-GULF	43	30	161	158	391
284	091.054.7202.011635	CENTRAL-GULF	28	19	110	103	260
285	091.054.7202.011640	CENTRAL-GULF	18	20	113	105	256
286	091.054.7202.011642	CENTRAL-GULF	17	11	63	61	152
287	091.054.7202.011643	CENTRAL-GULF	3	3	17	16	38
288	091.054.7202.011644	CENTRAL-GULF	7	7	40	37	91
289	091.054.7202.011647	CENTRAL-GULF	3	3	16	15	37
290	091.054.7202.011650	CENTRAL-GULF	1	1	8	8	18
291	091.054.7300.010049	CENTRAL-GULF	(12)	(7)	(39)	(38)	(96)
292	091.054.7300.010051	CENTRAL-GULF	47	23	126	129	325
293	091.054.7300.010055	CENTRAL-GULF	(4)	6	34	34	70
294	091.054.7300.010058	CENTRAL-GULF	(9)	0	0	0	(9)
295	091.054.7300.010059	CENTRAL-GULF	974	545	3,118	3,185	7,822
296	091.054.7300.010061	CENTRAL-GULF	175	21	115	117	428
297	091.054.7300.010062	CENTRAL-GULF	(0)	0	2	2	5
298	091.054.7300.010063	CENTRAL-GULF	902	512	2,748	2,759	6,920
299	091.054.7300.010064	CENTRAL-GULF	102	58	331	338	830
300	091.054.7300.010066	CENTRAL-GULF	134	76	436	446	1,092

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
301	091.054.7300.010067	CENTRAL-GULF	36	10	55	55	157
302	091.054.7300.010068	CENTRAL-GULF	155	64	342	344	905
303	091.054.7300.010069	CENTRAL-GULF	357	142	763	768	2,030
304	091.054.7300.010070	CENTRAL-GULF	62	41	222	223	549
305	091.054.7300.010071	CENTRAL-GULF	26	20	110	104	259
306	091.054.7300.010073	CENTRAL-GULF	1	1	8	7	18
307	091.054.7301.005100	CENTRAL-GULF	(1)	(0)	(2)	(2)	(5)
308	091.054.7302.005100	CENTRAL-GULF	0	0	0	0	1
309	091.054.7303.005100	CENTRAL-GULF	2	2	8	8	20
310	091.054.7304.005100	CENTRAL-GULF	0	0	1	1	1
311	091.054.7306.005100	CENTRAL-GULF	0	0	0	0	1
312	091.054.7307.005100	CENTRAL-GULF	0	0	0	0	1
313	091.054.7308.005100	CENTRAL-GULF	0	0	0	0	0
314	091.054.7450.005100	CENTRAL-GULF	254	207	1,145	1,156	2,762
315	091.054.7450.010097	CENTRAL-GULF	6	132	703	718	1,559
316	091.054.7450.010098	CENTRAL-GULF	(33)	37	197	201	402
317	091.054.7450.010099	CENTRAL-GULF	41	23	132	135	331
318	091.054.7450.010100	CENTRAL-GULF	122	56	311	318	807
319	091.054.7501.005100	CENTRAL-GULF	0	0	2	2	6
320	091.054.7502.005100	CENTRAL-GULF	0	0	0	0	1
321	091.054.7503.005100	CENTRAL-GULF	0	0	0	0	1
322	091.054.7550.005100	CENTRAL-GULF	1,635	1,321	7,436	7,580	17,972
323	091.054.7550.010308	CENTRAL-GULF	0	0	0	0	0
324	091.054.7550.010379	CENTRAL-GULF	(8)	(1)	(8)	(9)	(26)
325	091.054.7550.010416	CENTRAL-GULF	(1)	14	73	75	160
326	091.054.7550.010420	CENTRAL-GULF	95	33	188	193	509
327	091.054.7550.010422	CENTRAL-GULF	137	81	452	461	1,131
328	091.054.7550.010423	CENTRAL-GULF	155	79	455	465	1,153
329	091.054.7550.010424	CENTRAL-GULF	293	85	480	490	1,347
330	091.054.7550.010425	CENTRAL-GULF	144	39	221	226	630
331	091.054.7550.010426	CENTRAL-GULF	243	134	768	784	1,930
332	091.054.7550.010427	CENTRAL-GULF	123	79	429	438	1,069
333	091.054.7550.010428	CENTRAL-GULF	43	8	46	47	144
334	091.054.7550.010429	CENTRAL-GULF	95	35	200	205	536
335	091.054.7550.010430	CENTRAL-GULF	75	35	201	206	517
336	091.054.7550.010431	CENTRAL-GULF	87	28	161	165	441
337	091.054.7550.010432	CENTRAL-GULF	280	131	748	764	1,923
338	091.054.7550.010435	CENTRAL-GULF	286	120	646	645	1,697
339	091.054.7550.010436	CENTRAL-GULF	124	76	412	419	1,030
340	091.054.7550.010437	CENTRAL-GULF	112	47	261	251	671
341	091.054.7550.010438	CENTRAL-GULF	59	48	265	251	623
342	091.054.7550.010439	CENTRAL-GULF	197	211	1,189	1,110	2,708
343	091.054.7550.010440	CENTRAL-GULF	46	25	142	132	345
344	091.054.7550.010441	CENTRAL-GULF	283	304	1,714	1,600	3,902
345	091.054.7550.010446	CENTRAL-GULF	4	2	9	9	23
346	091.054.7604.005100	WEST-NORTH	2	3	12	11	27
347	091.054.7605.005100	WEST-NORTH	0	0	0	0	0
348	091.054.7606.005100	WEST-NORTH	0	0	0	0	0
349	091.054.7608.005100	WEST-NORTH	21	59	266	225	571
350	091.054.7608.010012	WEST-NORTH	0	1	6	5	13

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
351	091.054.7608.010013	WEST-NORTH	64	50	231	196	540
352	091.054.7609.005100	WEST-NORTH	0	0	0	0	0
353	091.054.7610.005100	WEST-NORTH	(26)	0	0	0	(25)
354	091.054.7612.005100	WEST-NORTH	(19)	(12)	(55)	(47)	(133)
355	091.054.7614.005100	WEST-NORTH	0	0	0	0	0
356	091.054.7615.005100	WEST-NORTH	0	0	0	0	0
357	091.054.7616.005100	WEST-NORTH	0	0	0	0	0
358	091.054.7617.005100	WEST-NORTH	0	0	0	0	0
359	091.054.7630.005100	WEST-NORTH	0	0	0	0	1
360	091.054.7635.010048	WEST-NORTH	(2)	125	556	472	1,151
361	091.054.7635.010050	WEST-NORTH	(4)	153	677	575	1,401
362	091.054.7635.010053	WEST-NORTH	(5)	50	221	187	454
363	091.054.7635.010054	WEST-NORTH	(2)	42	188	159	388
364	091.054.7635.010055	WEST-NORTH	(2)	33	148	126	306
365	091.054.7635.010057	WEST-NORTH	433	450	2,049	1,738	4,671
366	091.054.7635.010059	WEST-NORTH	(3)	14	60	51	123
367	091.054.7635.010060	WEST-NORTH	120	92	426	362	1,000
368	091.054.7635.010061	WEST-NORTH	104	106	481	408	1,099
369	091.054.7635.010062	WEST-NORTH	137	121	555	470	1,283
370	091.054.7635.010063	WEST-NORTH	687	462	2,130	1,807	5,086
371	091.054.7635.010068	WEST-NORTH	(5)	27	120	102	244
372	091.054.7635.010070	WEST-NORTH	94	128	567	481	1,269
373	091.054.7635.010072	WEST-NORTH	32	42	187	159	420
374	091.054.7640.005100	WEST-NORTH	0	0	0	0	1
375	091.054.7641.005100	WEST-NORTH	(0)	(0)	(1)	(1)	(2)
376	091.054.7645.005100	WEST-NORTH	26	16	71	60	174
377	091.054.7650.005100	WEST-NORTH	101,521	82,455	374,057	317,297	875,331
378	091.054.7650.011418	WEST-NORTH	5,340	5,730	26,217	22,239	59,526
379	091.054.7650.011421	WEST-NORTH	(281)	1,927	10,220	8,669	20,534
380	091.054.7650.011472	WEST-NORTH	(14)	115	510	433	1,043
381	091.054.7650.011473	WEST-NORTH	3,018	1,904	8,815	7,477	21,214
382	091.054.7650.011485	WEST-NORTH	425	446	2,033	1,724	4,627
383	091.054.7650.011486	WEST-NORTH	(42)	59	263	223	503
384	091.054.7650.011491	WEST-NORTH	1,966	1,394	6,757	5,732	15,849
385	091.054.7650.011492	WEST-NORTH	(1)	88	392	332	811
386	091.054.7650.011496	WEST-NORTH	(22)	46	203	172	398
387	091.054.7650.011498	WEST-NORTH	(10)	63	279	237	568
388	091.054.7650.011503	WEST-NORTH	4,397	2,892	13,194	11,192	31,674
389	091.054.7650.011506	WEST-NORTH	373	135	628	533	1,669
390	091.054.7650.011512	WEST-NORTH	(13)	5	21	18	32
391	091.054.7650.011514	WEST-NORTH	41	29	129	110	309
392	091.054.7650.011519	WEST-NORTH	2,470	1,546	6,857	5,817	16,690
393	091.054.7650.011520	WEST-NORTH	18	117	524	445	1,104
394	091.054.7650.011521	WEST-NORTH	35	54	250	212	551
395	091.054.7650.011523	WEST-NORTH	355	343	1,566	1,329	3,593
396	091.054.7650.011526	WEST-NORTH	615	407	1,864	1,581	4,467
397	091.054.7650.011529	WEST-NORTH	66	29	135	114	345
398	091.054.7650.011533	WEST-NORTH	88	58	269	228	642
399	091.054.7650.011534	WEST-NORTH	101	37	171	145	455
400	091.054.7650.011538	WEST-NORTH	211	72	332	281	896

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LINE NO.	PROJECT NO.	SERVICE AREA	DEPRECIATION	PROPERTY TAX	ROE	ROI	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
401	091.054.7650.011539	WEST-NORTH	(0)	88	389	330	807
402	091.054.7650.011540	WEST-NORTH	84	55	254	216	608
403	091.054.7650.011543	WEST-NORTH	289	98	456	387	1,230
404	091.054.7650.011549	WEST-NORTH	108	71	329	279	788
405	091.054.7650.011551	WEST-NORTH	746	465	2,133	1,810	5,154
406	091.054.7650.011557	WEST-NORTH	251	38	176	149	614
407	091.054.7650.011562	WEST-NORTH	169	92	428	363	1,053
408	091.054.7650.011565	WEST-NORTH	66	43	201	170	480
409	091.054.7650.011567	WEST-NORTH	98	70	311	264	742
410	091.054.7650.011569	WEST-NORTH	40	17	79	67	204
411	091.054.7650.011570	WEST-NORTH	180	118	549	466	1,313
412	091.054.7650.011571	WEST-NORTH	1	1	3	2	7
413	091.054.7650.011572	WEST-NORTH	63	44	201	171	479
414	091.054.7650.011574	WEST-NORTH	640	247	1,144	970	3,001
415	091.054.7650.011578	WEST-NORTH	236	145	654	555	1,590
416	091.054.7650.011583	WEST-NORTH	2,317	1,466	6,499	5,513	15,796
417	091.054.7650.011587	WEST-NORTH	981	497	2,203	1,869	5,550
418	091.054.7650.011591	WEST-NORTH	2,503	1,728	7,664	6,501	18,395
419	091.054.7650.011592	WEST-NORTH	(0)	(0)	(1)	(1)	(2)
420	091.054.7650.011594	WEST-NORTH	2,077	1,406	6,234	5,288	15,004
421	091.054.7650.011595	WEST-NORTH	364	126	560	475	1,526
422	091.054.7650.011596	WEST-NORTH	122	88	389	330	929
423	091.054.7650.011601	WEST-NORTH	164	72	319	270	825
424	091.054.7650.011607	WEST-NORTH	66	48	211	179	503
425	091.054.7650.011609	WEST-NORTH	556	388	1,721	1,460	4,125
426	091.054.7650.011652	WEST-NORTH	42	37	166	141	386
427	091.054.7651.005100	WEST-NORTH	0	0	0	0	0
428	091.054.7700.010030	RGV	(0)	389	4,382	3,780	8,551
429	091.054.7700.010064	RGV	1	0	2	2	6
430	091.054.7700.010068	RGV	1,363	339	3,672	3,167	8,540
431	091.054.7700.010074	RGV	(0)	9	99	85	193
432	091.054.7700.010075	RGV	(19)	33	367	317	697
433	091.054.7700.010082	RGV	1,289	349	3,802	3,279	8,719
434	091.054.7700.010083	RGV	(10)	12	134	115	250
435	091.054.7700.010084	RGV	(212)	26	295	255	364
436	091.054.7700.010085	RGV	(18)	10	112	97	200
437	091.054.7700.010086	RGV	(5)	9	98	85	186
438	091.054.7700.010087	RGV	1,326	339	3,817	3,292	8,774
439	091.054.7700.010088	RGV	97	36	394	340	868
440	091.054.7700.010089	RGV	16	8	85	73	181
441	091.054.7700.010090	RGV	8	3	26	22	59
442	091.054.7700.010093	RGV	966	245	2,658	2,293	6,162
443	091.054.7700.010095	RGV	141	39	417	360	956
444	091.054.7700.010097	RGV	91	25	270	233	619
445	091.054.7700.010098	RGV	(17)	59	668	576	1,286
446	091.054.7700.010099	RGV	159	43	466	402	1,071
447	091.054.7700.010100	RGV	1,014	259	2,895	2,497	6,665
448	091.054.7700.010101	RGV	118	32	350	302	803
449	091.054.7700.010102	RGV	49	13	145	125	333
450	091.054.7700.010104	RGV	112	25	282	243	663

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
451	091.054.7700.010106	RGV	38	10	117	101	266
452	091.054.7700.010115	RGV	57	12	138	119	327
453	091.054.7703.005100	RGV	0	0	0	0	1
454	091.054.7709.005100	RGV	0	0	0	0	0
455	091.054.7710.005100	RGV	0	0	0	0	0
456	091.054.7711.005100	RGV	0	0	0	0	0
457	091.054.7716.005100	RGV	0	0	0	0	0
458	091.054.7717.005100	RGV	0	0	0	0	0
459	091.054.7719.005100	RGV	0	0	0	0	0
460	091.054.7720.005100	RGV	0	0	0	0	0
461	091.054.7723.005100	RGV	0	0	0	0	0
462	091.054.7724.005100	RGV	0	0	0	0	0
463	091.054.7734.005100	RGV	0	0	0	0	0
464	091.054.7735.005100	RGV	0	0	0	0	1
465	091.054.7736.005100	RGV	0	0	0	0	0
466	091.054.7800.010182	WEST-NORTH	(12)	390	2,337	1,983	4,698
467	091.054.7800.010224	WEST-NORTH	(28)	50	223	189	435
468	091.054.7800.010249	WEST-NORTH	(349)	131	580	492	853
469	091.054.7800.010256	WEST-NORTH	3	2	9	8	23
470	091.054.7800.010273	WEST-NORTH	(27)	2	10	9	(6)
471	091.054.7800.010278	WEST-NORTH	(54)	99	437	371	853
472	091.054.7800.010280	WEST-NORTH	(8)	18	81	69	160
473	091.054.7800.010283	WEST-NORTH	(56)	98	433	368	842
474	091.054.7800.010304	WEST-NORTH	(17)	70	312	265	630
475	091.054.7800.010305	WEST-NORTH	19	3	13	11	47
476	091.054.7800.010311	WEST-NORTH	(0)	0	0	0	(0)
477	091.054.7800.010316	WEST-NORTH	(0)	0	0	0	(0)
478	091.054.7800.010319	WEST-NORTH	1,719	1,105	5,123	4,346	12,293
479	091.054.7800.010321	WEST-NORTH	(150)	86	379	322	636
480	091.054.7800.010324	WEST-NORTH	1,108	655	3,036	2,575	7,375
481	091.054.7800.010325	WEST-NORTH	849	544	2,525	2,142	6,060
482	091.054.7800.010329	WEST-NORTH	(89)	10	46	39	6
483	091.054.7800.010331	WEST-NORTH	(0)	0	0	0	(0)
484	091.054.7800.010333	WEST-NORTH	(0)	3	11	9	23
485	091.054.7800.010334	WEST-NORTH	95	42	191	162	490
486	091.054.7800.010336	WEST-NORTH	3,287	1,966	9,115	7,732	22,101
487	091.054.7800.010339	WEST-NORTH	526	476	2,176	1,845	5,023
488	091.054.7800.010340	WEST-NORTH	3,017	1,830	8,480	7,194	20,521
489	091.054.7800.010341	WEST-NORTH	991	675	3,112	2,640	7,419
490	091.054.7800.010342	WEST-NORTH	2,184	1,384	6,412	5,439	15,419
491	091.054.7800.010343	WEST-NORTH	2,040	1,271	5,892	4,998	14,200
492	091.054.7800.010344	WEST-NORTH	(164)	16	70	60	(19)
493	091.054.7800.010345	WEST-NORTH	107	74	339	288	807
494	091.054.7800.010346	WEST-NORTH	285	176	815	691	1,968
495	091.054.7800.010347	WEST-NORTH	534	346	1,606	1,362	3,848
496	091.054.7800.010348	WEST-NORTH	411	420	1,915	1,624	4,369
497	091.054.7800.010349	WEST-NORTH	273	222	1,022	867	2,383
498	091.054.7800.010350	WEST-NORTH	809	491	2,277	1,932	5,509
499	091.054.7800.010351	WEST-NORTH	6	4	20	17	47
500	091.054.7800.010352	WEST-NORTH	920	564	2,616	2,219	6,320

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
501	091.054.7800.010354	WEST-NORTH	4,569	2,734	12,676	10,753	30,732
502	091.054.7800.010355	WEST-NORTH	11,861	6,688	31,008	26,302	75,859
503	091.054.7800.010356	WEST-NORTH	1,392	808	3,747	3,178	9,124
504	091.054.7800.010357	WEST-NORTH	871	544	2,521	2,138	6,074
505	091.054.7800.010359	WEST-NORTH	18	8	35	30	90
506	091.054.7800.010360	WEST-NORTH	306	164	759	644	1,873
507	091.054.7800.010361	WEST-NORTH	1,440	859	3,982	3,377	9,657
508	091.054.7800.010363	WEST-NORTH	4,227	2,717	12,508	10,610	30,063
509	091.054.7800.010364	WEST-NORTH	475	280	1,300	1,103	3,158
510	091.054.7800.010365	WEST-NORTH	852	533	2,473	2,098	5,956
511	091.054.7800.010366	WEST-NORTH	905	584	2,707	2,296	6,491
512	091.054.7800.010367	WEST-NORTH	853	382	1,770	1,501	4,505
513	091.054.7800.010370	WEST-NORTH	431	182	845	717	2,175
514	091.054.7800.010371	WEST-NORTH	27	9	42	35	114
515	091.054.7800.010373	WEST-NORTH	161	33	153	129	476
516	091.054.7800.010374	WEST-NORTH	256	140	648	550	1,594
517	091.054.7800.010375	WEST-NORTH	764	453	2,096	1,778	5,091
518	091.054.7800.010376	WEST-NORTH	1,100	664	3,081	2,613	7,459
519	091.054.7800.010377	WEST-NORTH	440	287	1,332	1,130	3,190
520	091.054.7800.010378	WEST-NORTH	11	12	55	47	125
521	091.054.7800.010379	WEST-NORTH	737	466	2,065	1,752	5,020
522	091.054.7800.010380	WEST-NORTH	553	355	1,618	1,373	3,899
523	091.054.7800.010381	WEST-NORTH	78	51	238	202	569
524	091.054.7800.010382	WEST-NORTH	147	97	449	381	1,073
525	091.054.7800.010383	WEST-NORTH	717	506	2,287	1,940	5,449
526	091.054.7800.010384	WEST-NORTH	44	29	134	114	321
527	091.054.7800.010385	WEST-NORTH	148	85	392	333	958
528	091.054.7800.010386	WEST-NORTH	425	284	1,314	1,115	3,138
529	091.054.7800.010388	WEST-NORTH	739	401	1,857	1,575	4,571
530	091.054.7800.010389	WEST-NORTH	49	22	101	86	257
531	091.054.7800.010390	WEST-NORTH	3,320	2,430	10,774	9,139	25,663
532	091.054.7800.010391	WEST-NORTH	1,911	1,194	5,533	4,693	13,330
533	091.054.7800.010392	WEST-NORTH	53	29	133	113	328
534	091.054.7800.010395	WEST-NORTH	55	36	168	142	402
535	091.054.7800.010396	WEST-NORTH	13	9	40	34	95
536	091.054.7800.010397	WEST-NORTH	7	2	9	8	27
537	091.054.7800.010398	WEST-NORTH	1,008	756	3,354	2,845	7,964
538	091.054.7800.010399	WEST-NORTH	718	510	2,262	1,919	5,408
539	091.054.7800.010400	WEST-NORTH	44	29	133	113	319
540	091.054.7800.010401	WEST-NORTH	212	129	596	506	1,443
541	091.054.7800.010402	WEST-NORTH	54	15	68	58	195
542	091.054.7800.010403	WEST-NORTH	1,019	818	3,628	3,078	8,543
543	091.054.7800.010404	WEST-NORTH	515	246	1,142	969	2,872
544	091.054.7800.010406	WEST-NORTH	818	401	1,796	1,524	4,539
545	091.054.7800.010407	WEST-NORTH	48	13	61	52	175
546	091.054.7800.010408	WEST-NORTH	697	566	2,510	2,129	5,901
547	091.054.7800.010409	WEST-NORTH	211	281	1,244	1,056	2,792
548	091.054.7800.010411	WEST-NORTH	3,274	2,401	10,648	9,032	25,356
549	091.054.7800.010415	WEST-NORTH	1,345	931	4,129	3,503	9,909
550	091.054.7800.010416	WEST-NORTH	1,801	1,204	5,341	4,530	12,876

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
551	091.054.7800.010417	WEST-NORTH	36	22	97	83	238
552	091.054.7800.010418	WEST-NORTH	249	174	771	654	1,849
553	091.054.7800.010419	WEST-NORTH	292	218	969	822	2,301
554	091.054.7800.010421	WEST-NORTH	10	7	32	27	76
555	091.054.7800.010422	WEST-NORTH	(7)	12	54	46	105
556	091.054.7800.010423	WEST-NORTH	872	645	2,860	2,426	6,802
557	091.054.7800.010424	WEST-NORTH	244	156	692	587	1,679
558	091.054.7800.010426	WEST-NORTH	343	165	731	620	1,858
559	091.054.7800.010428	WEST-NORTH	142	24	107	91	364
560	091.054.7800.010430	WEST-NORTH	189	139	619	525	1,472
561	091.054.7800.010431	WEST-NORTH	125	91	403	342	961
562	091.054.7800.010432	WEST-NORTH	977	540	2,397	2,033	5,947
563	091.054.7800.010433	WEST-NORTH	191	145	641	544	1,521
564	091.054.7800.010434	WEST-NORTH	151	111	493	418	1,173
565	091.054.7800.010437	WEST-NORTH	427	325	1,443	1,224	3,420
566	091.054.7800.010438	WEST-NORTH	309	253	1,123	952	2,637
567	091.054.7800.010439	WEST-NORTH	165	77	341	290	873
568	091.054.7800.010441	WEST-NORTH	542	397	1,763	1,495	4,197
569	091.054.7800.010442	WEST-NORTH	149	117	518	440	1,224
570	091.054.7800.010444	WEST-NORTH	98	116	513	435	1,161
571	091.054.7800.010447	WEST-NORTH	107	88	390	331	916
572	091.054.7800.010448	WEST-NORTH	117	120	530	450	1,217
573	091.054.7800.010449	WEST-NORTH	13	7	30	26	75
574	091.054.7800.010452	WEST-NORTH	12	7	33	28	79
575	091.054.7800.010459	WEST-NORTH	2	2	7	6	16
576	091.054.7800.010460	WEST-NORTH	2	2	10	8	22
577	091.054.7800.010461	WEST-NORTH	2	2	8	6	18
578	091.054.7810.005100	WEST-NORTH	1	0	1	1	3
579	091.054.7812.005100	WEST-NORTH	0	0	0	0	0
580	091.054.7813.005100	WEST-NORTH	0	0	0	0	0
581	091.054.7814.005100	WEST-NORTH	0	0	0	0	0
582	091.054.7815.005100	WEST-NORTH	0	0	0	0	0
583	091.054.7816.005100	WEST-NORTH	0	0	0	0	0
584	091.054.7820.005100	WEST-NORTH	0	0	1	1	2
585	091.054.7825.005100	WEST-NORTH	0	0	1	1	2
586	091.054.7830.005100	WEST-NORTH	0	0	0	0	1
587	091.054.7831.005100	WEST-NORTH	0	0	0	0	0
588	091.054.7832.005100	WEST-NORTH	0	0	0	0	0
589	091.054.7835.005100	WEST-NORTH	1	0	2	1	4
590	091.054.7837.005100	WEST-NORTH	0	0	0	0	0
591	091.054.7838.005100	WEST-NORTH	0	0	0	0	0
592	091.054.7839.005100	WEST-NORTH	0	0	0	0	0
593	091.054.7840.005100	WEST-NORTH	0	0	0	0	0
594	091.054.7841.005100	WEST-NORTH	0	0	0	0	0
595	091.054.7850.005100	WEST-NORTH	1,578	916	4,146	3,517	10,158
596	091.054.7850.010288	WEST-NORTH	(82)	26	115	97	155
597	091.054.7850.010289	WEST-NORTH	(1,710)	317	1,407	1,193	1,207
598	091.054.7850.010292	WEST-NORTH	(11)	10	11	9	18
599	091.054.7850.010294	WEST-NORTH	(1)	18	82	69	168
600	091.054.7850.010295	WEST-NORTH	(30)	156	692	587	1,405

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)
601	091.054.7850.010298	WEST-NORTH	(5)	28	124	105	252
602	091.054.7850.010300	WEST-NORTH	844	250	1,159	983	3,237
603	091.054.7850.010301	WEST-NORTH	931	289	1,338	1,135	3,692
604	091.054.7850.010302	WEST-NORTH	575	425	1,886	1,599	4,485
605	091.054.7850.010303	WEST-NORTH	176	197	875	742	1,990
606	091.054.7850.010304	WEST-NORTH	56	28	129	109	322
607	091.054.7850.010305	WEST-NORTH	103	67	310	263	742
608	091.054.7850.010306	WEST-NORTH	529	135	628	533	1,826
609	091.054.7850.010307	WEST-NORTH	90	59	274	232	655
610	091.054.7850.010308	WEST-NORTH	288	78	363	308	1,036
611	091.054.7850.010310	WEST-NORTH	1,337	425	1,885	1,599	5,245
612	091.054.7850.010311	WEST-NORTH	908	307	1,360	1,154	3,729
613	091.054.7850.010312	WEST-NORTH	704	204	906	768	2,582
614	091.054.7850.010313	WEST-NORTH	15	20	89	76	200
615	091.054.7850.010314	WEST-NORTH	658	208	921	781	2,568
616	091.054.7850.010316	WEST-NORTH	145	52	233	197	627
617	091.054.7850.010317	WEST-NORTH	19	19	83	71	191
618	091.054.7850.010321	WEST-NORTH	51	70	311	263	695
619	091.054.7850.010322	WEST-NORTH	53	72	321	272	718
620	091.054.7850.010324	WEST-NORTH	9	4	19	16	47
621	091.054.7850.010326	WEST-NORTH	17	3	15	13	48
622	091.054.7851.005100	WEST-NORTH	0	0	0	0	0
623	091.054.7852.005100	WEST-NORTH	4	3	12	10	29
							0
		Total	$544,095	$382,769	$1,989,882	$1,840,999	$4,757,745

SCHEDULE B-4

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$(2,493,687)
2	Deferred OPEB Regulatory Asset	1823	WKP B-4.a	(165,070)
3	Regulatory Assets Proforma Amortization January 2025 Through December 2025	4073		403,048
4	Deferred Pension and OPEB since last rate cases	1860		(4,262,484)
5	Total			$(6,518,193)

Source: SCH B-4 Pension OPEB Deferral.xlsx

WKP B-4.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PENSION AND OTHER POST EMPLOYMENT BENEFITS REGULATORY ASSET

PENSION

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2020	2021	2022	2023	2024	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	1823	January	Reg Assets Def Pension Recovery	$0	$(25,795)	$(25,795)	$(25,795)	$(38,430)	$(115,816)
2	1823	February	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	871,277	(38,430)	781,256
3	1823	March	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(38,430)	(38,430)	(128,451)
4	1823	April	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(38,430)	(38,430)	(128,451)
5	1823	May	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(38,430)	(38,430)	(128,451)
6	1823	June	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(38,430)	(38,430)	(128,451)
7	1823	July	Reg Assets Def Pension Recovery	0	(25,795)	(25,795)	(38,430)	(38,430)	(128,451)
8	1823	August	Reg Assets Def Pension Recovery	1,831,471	(25,795)	(25,795)	(38,430)	(38,430)	1,703,020
9	1823	September	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(38,430)	(38,430)	(154,247)
10	1823	October	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(38,430)	(38,430)	(154,247)
11	1823	November	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(38,430)	(38,430)	(154,247)
12	1823	December	Reg Assets Def Pension Recovery	(25,795)	(25,795)	(25,795)	(38,430)	(3,641,336)	(3,757,152)
13			Total	$1,728,290	$(309,544)	$(309,544)	$461,180	$(4,064,068)	$(2,493,687)

OPEB

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2020	2021	2022	2023	2024	GRAND TOTAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
14	1823	January	Reg Assets Def OPEB Recovery	$0	$100	$100	$100	$277	$576
15	1823	February	Reg Assets Def OPEB Recovery	0	100	100	(12,518)	277	(12,041)
16	1823	March	Reg Assets Def OPEB Recovery	0	100	100	277	277	754
17	1823	April	Reg Assets Def OPEB Recovery	0	100	100	277	277	754
18	1823	May	Reg Assets Def OPEB Recovery	0	100	100	277	277	754
19	1823	June	Reg Assets Def OPEB Recovery	0	100	100	277	277	754
20	1823	July	Reg Assets Def OPEB Recovery	0	100	100	277	277	754
21	1823	August	Reg Assets Def OPEB Recovery	(7,078)	100	100	277	277	(6,324)
22	1823	September	Reg Assets Def OPEB Recovery	100	100	100	277	277	854
23	1823	October	Reg Assets Def OPEB Recovery	100	100	100	277	277	854
24	1823	November	Reg Assets Def OPEB Recovery	100	100	100	277	277	854
25	1823	December	Reg Assets Def OPEB Recovery	100	100	100	277	(154,191)	(153,615)
26			Total	$(6,679)	$1,196	$1,196	$(9,644)	$(151,140)	$(165,070)
27			Total Pension and OPEB	$1,721,610	$(308,348)	$(308,348)	$451,536	$(4,215,207)	$(2,658,757)

SCHEDULE B-5

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

PREPAID PENSION ASSET

LINE NO.	DESCRIPTION	PREPAID PENSION BALANCE
	(a)	(b)
1	Prepaid Pension Asset - TGS	$44,728,624
2	Allocation to Service Area	100.00%
3	Prepaid Pension Asset - TGS	$44,728,624

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.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CASH WORKING CAPITAL

LINE NO.	DESCRIPTION	TEST YEAR AMOUNT	AVERAGE DAILY AMOUNT	REVENUE LAG DAYS	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	$155,312,003	$424,350	45.69	A	(41.69)	B	4.00	$1,698,205
3	Labor - Regular Payroll Expense	68,042,133	185,907	45.69	A	(22.50)	C	23.19	4,311,510
4	Labor - STI Expense	12,340,812	33,718	45.69	A	(243.79)	C	(198.10)	(6,679,502)
5	Non-Labor - Other O&M Expense	81,395,049	222,391	45.69	A	(48.10)	C	(2.41)	(535,584)
6	Total O&M Expenses	$317,089,996	$866,366						$(1,205,370)
7	Federal Income Taxes								
8	Current Income Taxes	$31,312,410	$85,553	45.69	A	(37.50)	D	8.19	$700,945
9	Deferred Income Taxes	0	0			0.00		0.00	0
10	Total Federal Income Taxes	$31,312,410	$85,553						$700,945
11	Taxes Other Than Income Taxes								
12	FICA	$4,587,666	$12,535	45.69	A	(12.89)	E	32.80	$411,134
13	Federal Unemployment	32,615	89	45.69	A	(29.33)	E	16.36	1,458
14	State Unemployment	116,134	317	45.69	A	(29.31)	E	16.39	5,199
15	State Gross Receipts	9,337,497	25,512	45.69	A	(75.12)	E	(29.43)	(750,804)
16	Local Franchise Tax	24,128,040	65,924	45.69	A	(103.94)	E	(58.25)	(3,840,024)
17	State Franchise Tax	1,023,024	2,795	45.69	A	47.58	E	93.28	260,721
18	Ad Valorem	19,470,082	53,197	45.69	A	(215.39)	E	(169.69)	(9,027,245)
19	Sales Tax	12,229,331	33,413	45.69	A	(35.82)	E	9.87	329,868
20	RRC Gas Utility Tax	99,205	271	45.69	A	(88.05)	E	(42.36)	(11,481)
21	Taxes Other Than Income Taxes	$71,023,595	$194,054		A				$(12,621,173)
22	Interest on Customer Deposits	$824,647	$2,253	45.69	A	(169.00)	F	(123.31)	$(277,827)
23	Labor - LTI Expense	$2,338,331	$6,389	0.00		0.00		0.00	$0
24	Depreciation Expense	$86,087,872	$235,213	0.00		0.00		0.00	$0
25	Return	$151,258,518	$413,275	0.00		0.00		0.00	$0
26	Total	$659,935,370	$1,803,102						$(13,403,426)

Source: SCH B-6 CWC Taxes.xlsx
Source: SCH B-6 Lead-Lag Study - TGS.xlsx

SCHEDULE B-7

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
1	7202 Austin - Incorporated	$4,512,906
2	7203 Sunset Valley - Incorporated	19,538
3	7204 Rollingwood - Incorporated	4,880
4	7205 West Lake Hills - Incorporated	13,405
5	7206 Cedar Park - Incorporated	22,225
6	7207 Aus Berg Intl Airport - Incorporated	7,530
7	7208 Austin - Environs	213,954
8	7209 West Lake Hills - Environs	2,455
9	7216 Cedar Park - Environs	10,921
10	7218 Mustang Ridge - Incorporated	250
11	7260 Lakeway - Incorporated	1,510
12	7262 Bee Cave - Incorporated	31,675
13	7263 Bee Cave - Environs	3,350
14	7264 Pflugerville - Incorporated	250
15	7267 Bastrop - Environs	927
16	7268 Marble Falls - Incorporated	379
17	7269 Marble Falls - Environs	38
18	7292 Kyle - Incorporated	15,182
19	7293 Kyle - Environs	300
20	7294 Dripping Springs - Incorporated	12,881
21	7295 Dripping Springs - Environs	41,253
22	7297 Buda - Environs	35,292
23	7301 Yoakum - Incorporated	33,427
24	7302 Shiner - Incorporated	12,419
25	7303 Cuero - Incorporated	38,315
26	7304 Gonzales - Incorporated	42,238

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
27	7306 Luling - Incorporated	24,728
28	7307 Lockhart - Incorporated	59,615
29	7308 Nixon - Incorporated	5,298
30	7309 Nixon - Environs	500
31	7310 Yoakum - Environs	1,020
32	7312 Shiner - Environs	4,715
33	7313 Cuero - Environs	3,389
34	7314 Gonzales - Environs	1,105
35	7316 Luling - Environs	225
36	7317 Lockhart - Environs	0
37	7401 Jamaica Beach - Incorporated	4,740
38	7402 Bayou Vista - Incorporated	5,380
39	7412 Bayou Vista - Environs	1,033
40	7450 Galveston - Incorporated	323,696
41	7452 Galveston - Environs	250
42	7501 Groves - Incorporated	106,939
43	7502 Nederland - Incorporated	96,985
44	7503 Port Neches - Incorporated	59,393
45	7509 Beaumont - Incorporated	250
46	7512 Nederland - Environs	11,317
47	7550 Port Arthur - Incorporated	410,954
48	7602 Fabens - Environs	47,524
49	7603 Vinton - Incorporated	16,388
50	7604 Clint - Incorporated	8,408
51	7605 Anthony - Incorporated	33,856
52	7606 Socorro - Incorporated	248,487

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
53	7607 Horizon City - Incorporated	170,041
54	7608 Dell City - Incorporated	9,655
55	7609 Dell City - Environs	197,620
56	7610 Pecos City - Incorporated	57,042
57	7611 Pecos City - Environs	2,480
58	7612 Barstow - Incorporated	600
59	7613 Andrews - Environs	9,990
60	7614 Wickett - Incorporated	2,332
61	7615 Wink - Incorporated	5,389
62	7616 Thorntonville - Incorporated	860
63	7617 Pyote - Incorporated	765
64	7618 Pyote - Environs	0
65	7619 San Elizario - Environs	34,574
66	7620 San Elizario - Incorporated	52,543
67	7623 Vinton - Environs	9,390
68	7624 Clint - Environs	16,048
69	7625 Anthony - Environs	0
70	7626 Socorro - Environs	3,951
71	7627 Horizon City - Environs	42,849
72	7630 Andrews - Incorporated	80,029
73	7639 Crane - Environs	995
74	7640 Crane - Incorporated	13,158
75	7641 McCamey - Incorporated	6,889
76	7642 McCamey - Environs	750
77	7645 Monahans - Incorporated	52,087
78	7646 Monahans - Environs	6,684

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
79	7650 El Paso - Incorporated	5,353,929
80	7651 El Paso - Environs	390,383
81	7662 Barstow - Environs	100
82	7665 Wink - Environs	2,375
83	7810 Mineral Wells - Incorporated	131,241
84	7811 Mineral Wells - Environs	2,385
85	7812 Palo Pinto - Environs	1,540
86	7813 Whitt - Environs	250
87	7814 Perrin - Environs	1,765
88	7815 Graford - Incorporated	2,395
89	7816 Millsap - Incorporated	741
90	7817 Graford - Environs	0
91	7818 Millsap - Environs	0
92	7820 Breckenridge - Incorporated	38,937
93	7821 Breckenridge - Environs	5,510
94	7825 Graham - Incorporated	57,225
95	7826 Graham - Environs	5,735
96	7830 Jacksboro - Incorporated	22,758
97	7831 Jermyn - Environs	200
98	7832 Bryson - Incorporated	3,073
99	7833 Jacksboro - Environs	375
100	7834 Bryson - Environs	100
101	7835 Weatherford - Incorporated	239,653
102	7836 Weatherford - Environs	2,105
103	7837 Punkin Center - Environs	656
104	7838 Aledo - Incorporated	16,832

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
105	7839 Hudson Oaks - Incorporated	13,320
106	7840 Willow Park - Incorporated	31,015
107	7841 Possum Kingdom - Environs	2,075
108	7842 Aledo-Rural - Environs	5,740
109	7843 Hudson Oaks - Environs	4,680
110	7844 Willow Park - Environs	250
111	7850 Borger - Incorporated	134,068
112	7851 Borger - Environs	10,610
113	7852 Skellytown - Incorporated	3,165
114	7701 Bayview - Environs	1,500
115	7703 Brownsville - Incorporated	532,247
116	7704 Rancho Viejo - Incorporated	4,140
117	7705 Laguna Heights - Environs	1,045
118	7706 Port Isabel - Incorporated	31,785
119	7707 Olmito - Environs	4,008
120	7708 Laguna Vista - Incorporated	1,520
121	7709 Los Fresnos - Incorporated	18,255
122	7710 San Benito - Incorporated	77,514
123	7711 Harlingen - Incorporated	212,122
124	7712 Mercedes - Incorporated	69,915
125	7713 Palm Valley - Incorporated	375
126	7714 Rio Hondo - Incorporated	7,926
127	7715 Santa Rosa - Incorporated	3,270
128	7716 Weslaco - Incorporated	112,381
129	7717 Primera - Incorporated	5,478
130	7718 Progreso - Incorporated	2,635

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
131	7719 Raymondville - Incorporated	40,360
132	7720 La Feria - Incorporated	18,514
133	7721 Combes - Incorporated	2,155
134	7722 Lyford - Incorporated	3,303
135	7723 Donna - Incorporated	57,870
136	7724 Pharr - Incorporated	196,858
137	7725 Edcouch - Incorporated	6,420
138	7726 Edinburgh - Incorporated	179,648
139	7727 Penitas - Incorporated	3,428
140	7728 Alton - Incorporated	6,835
141	7729 Alamo - Incorporated	40,222
142	7730 San Carlos - Environs	1,500
143	7731 San Juan - Incorporated	52,800
144	7732 Elsa - Incorporated	20,561
145	7733 Monte Alto - Environs	2,010
146	7734 La Villa - Incorporated	12,183
147	7735 McAllen - Incorporated	469,200
148	7736 Mission - Incorporated	149,127
149	7737 Hidalgo - Incorporated	14,065
150	7738 La Joya - Incorporated	5,945
151	7739 Palmview - Incorporated	14,825
152	7742 Los Fresnos - Environs	3,261
153	7743 Santa Rosa - Environs	0
154	7744 Penitas - Environs	1,250
155	7745 Rio Hondo - Environs	350
156	7753 Brownsville - Environs	51,401

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
157	7754 Rancho Viejo - Environs	75
158	7755 Port Isabel - Environs	735
159	7756 Palmhurst - Incorporated	10,135
160	7760 San Benito - Environs	2,875
161	7761 Harlingen - Environs	17,896
162	7762 Mercedes - Environs	2,625
163	7764 Weslaco - Environs	6,160
164	7765 Primera - Environs	0
165	7767 Raymondville - Environs	1,100
166	7768 La Feria - Environs	1,515
167	7774 Donna - Environs	5,675
168	7775 Pharr - Environs	0
169	7776 Edcouch - Environs	75
170	7777 Edinburgh - Environs	325
171	7778 Alton - Environs	125
172	7779 Alamo - Environs	1,990
173	7790 San Juan - Environs	150
174	7791 Elsa - Environs	1,180
175	7793 McAllen - Environs	2,515
176	7794 Mission - Environs	16,670
177	7797 Palmview - Environs	2,010
178	Total	$16,329,640

Source: SCH B-7 Customer Deposits.xlsx

SCHEDULE B-8

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER ADVANCES

LINE NO.	FERC ACCOUNT	DESCRIPTION	ENDING BALANCE
			(a)
1	2520	LINE EXT DEPOSITS FORFEITED	$65,648
2	2520	LINE EXT DEPOSITS RECEIVED	4,908,594
3	2520	LINE EXT DEPOSITS RECEIVED	(1,072)
4	2520	LINE EXT DEPOSITS RECEIVED	(14,424,879)
5	2520	LINE EXT DEPOSITS REIMBURSED	3,899,955
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	2520	LINE EXT DEPOSITS RECEIVED	(137,981)
21	2520	LINE EXT DEPOSITS RECEIVED	16,017
22	2520	LINE EXT DEPOSITS RECEIVED	(4,554)
23	2520	LINE EXT DEPOSITS FORFEITED	62,799
24	2520	LINE EXT DEPOSITS RECEIVED	(71,015)
25	2520	LINE EXT DEPOSITS RECEIVED	(8,412)
26	2520	LINE EXT DEPOSITS FORFEITED	162,354
27	2520	LINE EXT DEPOSITS RECEIVED	(432,390)
28	2520	LINE EXT DEPOSITS REIMBURSED	25,249
29	2520	LINE EXT DEPOSITS RECEIVED	(83,251)
30	2520	LINE EXT DEPOSITS RECEIVED	44,576
31	2520	LINE EXT DEPOSITS RECEIVED	(39,328)
32	2520	LINE EXT DEPOSITS RECEIVED	(120,676)
33	2520	LINE EXT DEPOSITS RECEIVED	(140,643)
34	2520	LINE EXT DEPOSITS RECEIVED	(20,564)
35	2520	LINE EXT DEPOSITS RECEIVED	10,113
36		Total	$(6,534,399)

Source: SCH B-8 Customer Advances.xlsx

SCHEDULE B-9

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DECSCRIPTION	TOTAL ALLOCATED ADIT TO TGS
		(a)
1	Plant Assets Depreciation	$(138,532,938)
2	Direct Plant Repairs	(101,911,370)
3	Subtotal Plant Assets Depreciation	$(240,444,309)
4	Other Rate Base Items	(9,468,151)
5	TGS Division Plant Assets Depreciation	(1,362,327)
6	Corporate Plant Assets Depreciation	(6,220,999)
7	Net Operating Loss	73,366,094
8	ADFIT - Accumulated Deferred Federal Income Taxes	$(184,129,691)

Source: SCH B-9 TGS ADIT WPs.xlsx

Source: SCH B-9 Reg NOL WPs.xlsx

SCHEDULE B-10

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	Plant Assets Depreciation	$(76,721,922)	$0	$0	$(76,721,922)	$0	$(76,721,922)
2	Repairs	0	(7,400,723)	(23,780,320)	(31,181,043)	0	(31,181,043)
3	Cost of Removal Asset	0	9,523,032	0	9,523,032	0	9,523,032
4	Other Nonprotected plant	0	0	(1,794,371)	(1,794,371)	0	(1,794,371)
5	Other Rate Base Items	0	0	(6,730,641)	(6,730,641)	0	(6,730,641)
6	TGS Division Plant Assets Depreciation	(571,323)	0	0	(571,323)	0	(571,323)
7	Corporate Plant Assets Depreciation	(3,364,068)	0	0	(3,364,068)	0	(3,364,068)
8	NOL	55,327,343	0	0	55,327,343	0	55,327,343
9	Total EDIT at December 31, 2017	$(25,329,970)	$2,122,309	$(32,305,333)	$(55,512,994)	$0	$(55,512,994)
10	Less 2018 Amortization				$5,099,737	$0	$5,099,737
11	Less 2019 Amortization				4,992,179	0	4,992,179
12	Less 2020 Amortization				4,867,589	0	4,867,589
13	Less 2021 Amortization				6,149,350	0	6,149,350
14	Less 2022 Amortization				1,971,033	0	1,971,033
15	Less 2023 Amortization				2,288,691	0	2,288,691
16	Less 2024 Amortization				2,272,038	0	2,272,038
17	Total EDIT at December 31, 2024				$(27,872,376)	$0	$(27,872,376)

Source: SCH B-10 EDIT.xlsx

SCHEDULE B-11

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

REG ASSETS

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Unamortized balance of Regulatory Assets from prior cases	$3,693,257
2	Less 12 mos. Amortization (line 24, January 2025 - December 2025) Note 1	(679,908)
3	Line Locating Expense Credit	(1,541,585)
4	Winter Storm Gerri	15,215
5	Expenses from GUD No. 14883	323,865
6	COVID related O&M (2022)	307,412
7	Regulatory Assets - Total	$2,118,256

Note 1: See data on SCH G-20

SCHEDULE C

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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	Direct Plant In Service	WKP C.a	$2,141,645,122	$(755,167)	$2,140,889,955
2	TGS Division Plant In Service	WKP C.b	11,817,307	(386,968)	11,430,339
3	Allocated Corporate Plant In Service	WKP C.c	87,573,566	(4,561,220)	83,012,346
4	Total Plant In Service		$2,241,035,995	$(5,703,355)	$2,235,332,639

WKP C.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	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)
		INTANGIBLE PLANT									
1	301	Organization	$186,679	$0	$0	$0	$0	$0	$186,679	$0	$186,679
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0
3	302	Franchises & Consents	402,970	0	0	0	0	0	402,970	0	402,970
4	303	Misc. Intangible	1,030,534	0	0	0	0	0	1,030,534	0	1,030,534
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	616,460	0	0	0	0	0	616,460	0	616,460
7		Total Intangible Plant	$2,236,642	$0	$0	$0	$0	$0	$2,236,642	$0	$2,236,642
		GATHERING AND TRANSMISSION PLANT									
8	325	Land & Land Rights	$0	$0	$0	$0	$0	0	$0	$0	$0
9	327	Field Comprss Station Strucutres	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
11	329	Other Structures	0	0	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	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
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0
18	365.1	Land - OPC	23,277	0	0	0	0	0	23,277	0	23,277
19	365.2	Rights-of-Way	228,423	0	0	0	0	0	228,423	0	228,423
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0
21	366.2	Meas/Reg Station Structures	27,231	0	0	0	0	0	27,231	0	27,231
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0
23	367	Mains	95,099,507	0	0	0	0	0	95,099,507	0	95,099,507
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0
25	368	Compressor Station Equip	88,467	0	0	0	0	0	88,467	0	88,467
26	369	Meas & Reg Stations Equip	16,055,478	(6)	0	0	0	(6)	16,055,472	0	16,055,472
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0
29	371	Other Equipment	52,349	0	0	0	0	0	52,349	0	52,349
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0
31		Total Gathering and Transmission Plant	$111,574,732	$(6)	$0	$0	$0	$(6)	$111,574,725	$0	$111,574,725
		DISTRIBUTION PLANT									
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	374.1	Land	203,003	0	0	0	0	0	203,003	0	203,003
34	374.2	Land Rights	1,642,956	0	0	0	0	0	1,642,956	0	1,642,956
35	375	Structures & Improvements		0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	495,192	0	0	0	0	0	495,192	0	495,192
37	375.2	Other System Structures	8,482	0	0	0	0	0	8,482	0	8,482
38	376	Mains	789,966,959	0	(492,760)	0	0	(492,760)	789,474,200	0	789,474,200

WKP C.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	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)
39	376.9	Mains - Cathodic Protection Anodes	70,706,739	0	(51,855)	0	0	(51,855)	70,654,884	0	70,654,884
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	41,311,066	0	(1,358)	0	0	(1,358)	41,309,708	0	41,309,708
42	379	Meas. & Reg. Station - C.G.	13,899,087	0	(9,290)	0	0	(9,290)	13,889,798	0	13,889,798
43	380	Services	657,551,966	0	(109,750)	0	0	(109,750)	657,442,217	0	657,442,217
44	380.1	Ind Service Line Equip	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)
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0
47	381	Meters	173,894,577	0	0	0	0	0	173,894,577	0	173,894,577
48	382	Meter Installations	0	0	0	0	0	0	0	0	0
49	383	House Regulators	34,290,909	0	0	0	0	0	34,290,909	0	34,290,909
50	385	Indust. Meas. & Reg. Stat. Equipment	36,951,604	0	0	0	0	0	36,951,604	0	36,951,604
51	386	Other Property on Customer Premises	1,707,620	0	0	0	0	0	1,707,620	0	1,707,620
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0
53		Total Distribution Plant	$1,822,630,160	$0	$(665,012)	$0	$0	$(665,012)	$1,821,965,148	$0	$1,821,965,148
		GENERAL PLANT									
54	389	Land & Land Rights	$10,192,918	$0	$0	$0	$0	$0	$10,192,918	$0	$10,192,918
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	37,918,181	(80)	(55,514)	0	0	(55,594)	37,862,587	0	37,862,587
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	3,939,640	(75)	(33,117)	0	0	(33,192)	3,906,448	0	3,906,448
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0
76	391.6	Concur Project	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
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0

WKP C.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	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)
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0
84	391.9	Computer & Equipment	3,474,008	(19)	0	0	0	(19)	3,473,989	0	3,473,989
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0
86	392	Transportation Equipment	39,327,484	0	(1,344)	0	0	(1,344)	39,326,140	0	39,326,140
87	392.2	Transport Equip Pickup Trucks& Vans	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
89	392.5	Trailers	0	0	0	0	0	0	0	0	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0
91	393	Stores Equipment	44,917	0	0	0	0	0	44,917	0	44,917
92	394	Tools, Shop & Garage	30,071,976	0	0	0	0	0	30,071,976	0	30,071,976
93	394.1	Tools	0	0	0	0	0	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0
96	396	Major Work Equipment	7,248,234	0	0	0	0	0	7,248,234	0	7,248,234
97	397	Communication Equipment	64,043,325	0	0	0	0	0	64,043,325	0	64,043,325
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	6,349	0	0	0	0	0	6,349	0	6,349
100		Total General Plant	$196,267,032	$(174)	$(89,975)	$0	$0	$(90,149)	$196,176,883	$0	$196,176,883
101		Total Orig Cost Plant in Service	$2,132,708,566	$(181)	$(754,986)	$0	$0	$(755,167)	$2,131,953,399	$0	$2,131,953,399

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - TGS.xlsx

WKP C.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010 AT	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT [1]	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		INTANGIBLE PLANT							
1	301	Organization	$0	$0	$0	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0	0	0	0
3	302	Franchises & Consents	0	0	0	0	0	0	0
4	303	Misc. Intangible	0	0	0	0	0	0	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	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	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0
11	329	Other Structures	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0
15	336	Purification Equipment	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0
18	365.1	Land - OPC	0	0	0	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0
23	367	Mains	0	0	0	0	0	0	0
24	367	Mains - OPC	0	0	0	0	0	0	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0
29	371	Other Equipment	0	0	0	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0

WKP C.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010 AT	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT [1]	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		DISTRIBUTION PLANT							
32	374	Land	$0	$0	$0	$0	$0	$0	$0
33	374.1	Land	0	0	0	0	0	0	0
34	374.2	Land Rights	19,533	0	0	0	0	0	19,533
35	375	Structures & Improvements	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0
37	375.2	Other System Structures	0	0	0	0	0	0	0
38	376	Mains	6,406,720	0	0		0	0	6,406,720
39	376.9	Mains - Cathodic Protection Anodes	135,856	0	0	0	0	0	135,856
40	377	Compressor Station Equipment	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	620,572	0	0	0	0	0	620,572
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0
43	380	Services	1,219,652	0	0	0	0	0	1,219,652
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0
47	381	Meters	108,468	0	0	0	0	0	108,468
48	382	Meter Installations	0	0	0	0	0	0	0
49	383	House Regulators	58,948	0	0	0	0	0	58,948
50	385	Indust. Meas. & Reg. Stat. Equipment	306,223	0	0	0	0	0	306,223
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0
53		Total Distribution Plant	$8,875,973	$0	$0	$0	$0	$0	$8,875,973
		GENERAL PLANT							
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0	0	0	$0
56	390.1	Structures & Improvements	0	0	0	0	0	0	0
57	390.17	Building Improv Plum	0	0	0	0	0	0	$0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	$0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	$0

WKP C.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010 AT	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT [1]	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	0	0	0	0	0	0	$0
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	$0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	$0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	$0
70	391.6	Purchased Software	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	$0
72	391.6	PowerPlant System	0	0	0	0	0	0	0
73	391.6	Riskworks	0	0	0	0	0	0	$0
74	391.6	Maximo	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	$0
76	391.6	Concur Project	0	0	0	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	$0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	$0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	$0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	$0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0
85	391.99	Cloud Computing	0	0	0	0	0	0	$0
86	392	Transportation Equipment	0	0	0	0	0	0	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	$0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0
89	392.5	Trailers	0	0	0	0	0	0	$0
90	392.6	Aircraft	0	0	0	0	0	0	0
91	393	Stores Equipment	0	0	0	0	0	0	$0
92	394	Tools, Shop & Garage	11,690	0	0	0	0	0	11,690
93	394.1	Tools	0	0	0	0	0	0	$0
94	394.2	Shop Equipment	0	0	0	0	0	0	0
95	395	CNG Equipment	0	0	0	0	0	0	$0

WKP C.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010 AT	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT [1]	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
96	396	Major Work Equipment	0	0	0	0	0	0	0
97	397	Communication Equipment	48,893	0	0	0	0	0	$48,893
98	397.2	Telephone Equipment	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0
100		Total General Plant	$60,583	$0	$0	$0	$0	$0	$60,583
101		Total Orig Cost Plant in Service	$8,936,556	$0	$0	$0	$0	$0	$8,936,556

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - TGS.xlsx

[1] Adjustments between service areas are not reflected in the TGS model since it incorporates all service areas

WKP C.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	REMOVE INSUFFICIENT SUPPORT	REMOVE ASSET NOT USED BY DIVISION	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		INTANGIBLE PLANT														
1	301	Organization	$127,437	$0	$0	$0	$0	$0	$(127,437)	$0	$(127,437)	$0	$0	$0	100.0000%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	$0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	$0
4	303	Misc. Intangible	278,560	0	0	0	0	0	(278,560)	0	(278,560)	0	0	0	100.0000%	$0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	$0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
7		Total Intangible Plant	$405,997	$0	$0	$0	$0	$0	$(405,997)	$0	$(405,997)	$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	100.0000%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
31		Total Gathering and Transmission Plant	$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	100.0000%	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
53		Total Distribution Plant	$0	$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	$0	$434,697	$0	$434,697	100.0000%	$434,697
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
56	390.1	Structures & Improvements	4,406,102	(53)	39,565	0	9	0	0	0	39,521	4,445,623	0	4,445,623	100.0000%	4,445,623
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0

WKP C.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	REMOVE INSUFFICIENT SUPPORT	REMOVE ASSET NOT USED BY DIVISION	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
59	390.2	Leasehold Improvement	235,077	0	0	0	0	0	0	(774)	(774)	234,303	0	234,303	100.0000%	234,303
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
63	391.1	Office Furniture & Equipment	2,550,064	(570)	6,303	(8,657)	26,814	0	(88)	0	23,802	2,573,867	0	2,573,867	100.0000%	2,573,867
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
84	391.9	Computer & Equipment	2,934,298	0	0	0	0	(113,513)	(201)	0.00	(113,714)	2,820,584	0	2,820,584	100.0000%	2,820,584
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
92	394	Tools, Shop & Garage	28,756	0	0	0	0	0	0	0	0	28,756	0	28,756	100.0000%	28,756
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
97	397	Communication Equipment	822,315	0	0	0	70,300	(107)	0	0	70,193	892,508	0	892,508	100.0000%	892,508
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
100		Total General Plant	$11,411,310	$(623)	$45,868	$(8,657)	$97,123	$(113,620)	$(289)	$(774)	$19,029	$11,430,339	$0	$11,430,339		$11,430,339
101		Total Orig Cost Plant in Service	$11,817,307	$(623)	$45,868	$(8,657)	$97,123	$(113,620)	$(406,286)	$(774)	$(386,968)	$11,430,339	$0	$11,430,339		$11,430,339
102		Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		
103		Total Allocated Plant In Service	$11,817,307	$(623)	$45,868	$(8,657)	$97,123	$(113,620)	$(406,286)	$(774)	$(386,968)	$11,430,339	$0	$11,430,339		

Source: WKP C.b C-1.b & D.b TGS Div PIS, CCNC & AR.xlxs

WKP C.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK Acct 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	REMOVE INSUFFICIENT SUPPORT	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE AVIATION	REMOVE ARTWORK	TOTAL ADJUSTMENTS	CORPORATE TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1010	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
		INTANGIBLE PLANT																			
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0	100.0000%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
7		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0.0000	$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	0.0000%	$0	100.0000%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0.0000	$0		$0
		DISTRIBUTION PLANT																			
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0	100.0000%	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0000%	0	100.0000%	0
53		Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0.0000	$0		$0
		GENERAL PLANT																			
54	389	Land & Land Rights	$43,763	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$43,763	$0	$43,763	30.2500%	$13,238	100.0000%	$13,238
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
56	390.1	Structures & Improvements	5,142,404	(796)	0	0	0	0	0	0	0	0	0	(796)	5,141,608	0	5,141,608	30.2500%	1,555,336	100.0000%	1,555,336
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
59	390.2	Leasehold Improvement	6,947,394	(183)	0	0	(9,201)	(123)	(18,335)	0	0	(93,620)	0	(121,462)	6,825,932	0	6,825,932	30.2500%	2,064,845	100.0000%	2,064,845
60	390.2	OGS Lease Incentive	579,787	0	0	0	0	0	0	0	(579,787)	0	0	(579,787)	0	0	0	30.2500%	0	100.0000%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
63	391.1	Office Furniture & Equipment	5,723,366	(257)	0	(896)	(5,439)	0	(1,544)	0	0	(55,418)	0	(63,554)	5,659,812	0	5,659,812	30.2500%	1,712,093	100.0000%	1,712,093
64	391.19	Airplane Hanger Furniture	59,246	0	0	0	0	0	0	0	0	(59,246)	0	(59,246)	0	0	0	30.2500%	0	100.0000%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
67	391.3	Office Machines	316,640	0	0	0	0	0	0	0	0	0	0	0	316,640	0	316,640	30.2500%	95,784	100.0000%	95,784
68	391.4	Audio Visual Equipment	197,525	0	0	0	(60)	0	(982)	0	0	0	0	(1,042)	196,483	0	196,483	30.2500%	59,436	100.0000%	59,436

WKP C.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK Acct 1010	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	REMOVE INSUFFICIENT SUPPORT	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE AVIATION	REMOVE ARTWORK	TOTAL ADJUSTMENTS	CORPORATE TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1010	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
69	391.5	Artwork	49,414	0	0	0	0	0	0	0	0	0	(49,414)	(49,414)	0	0	0	30.2500%	0	100.0000%	0
70	391.6	Purchased Software	136,787,977	(106,730)	0	(58,224)	0	(2,584)	(2,076)	(7,658)	0	0	0	(177,271)	136,610,707	0	136,610,707	30.2500%	41,324,739	100.0000%	41,324,739
71	391.6	Banner Software	11,396,597	(414)	0	0	0	0	0	0	0	0	0	(414)	11,396,183	0	11,396,183	30.9500%	3,527,119	100.0000%	3,527,119
72	391.6	PowerPlant System	2,448,925	0	0	0	0	0	0	0	0	0	0	0	2,448,925	0	2,448,925	28.6000%	700,393	100.0000%	700,393
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
74	391.6	Maximo	4,670,073	0	0	0	0	0	0	0	0	0	0	0	4,670,073	0	4,670,073	25.0000%	1,167,518	100.0000%	1,167,518
75	391.6	Foundation Software	70,872	0	0	0	0	0	0	(70,872)	0	0	0	(70,872)	0	0	0	30.2500%	0	100.0000%	0
76	391.6	Concur Project	71,646	0	0	0	0	0	0	0	0	0	0	0	71,646	0	71,646	30.1688%	21,615	100.0000%	21,615
77	391.6	Journey-Employee-ODC Distrigas	69,580,940	(4,661)	0	0	0	0	0	0	0	0	0	(4,661)	69,576,279	0	69,576,279	30.2500%	21,046,824	100.0000%	21,046,824
78	391.6	Journey-Employee Count	1,848,836	0	0	0	0	0	0	0	0	0	0	0	1,848,836	0	1,848,836	30.1688%	557,771	100.0000%	557,771
79	391.6	Payroll - Time Management	2,957,462	0	0	(6,762)	0	(1,210)	0	0	0	0	0	(7,972)	2,949,490	0	2,949,490	30.1688%	889,824	100.0000%	889,824
80	391.6	Accounts Payable Software	1,337,453	0	0	0	0	0	0	0	0	0	0	0	1,337,453	0	1,337,453	35.0750%	469,112	100.0000%	469,112
81	391.6	Customer Relations Software	1,905,984	0	0	0	0	0	0	0	0	0	0	0	1,905,984	0	1,905,984	30.9500%	589,902	100.0000%	589,902
82	391.8	Micro Computer Software	19,955,971	(50)	0	0	0	0	(498)	0	0	0	0	(548)	19,955,423	0	19,955,423	30.2500%	6,036,516	100.0000%	6,036,516
83	391.81	Aircraft Computer Equipment	36,559	0	0	0	0	0	0	0	0	(36,559)	0	(36,559)	0	0	0	30.2500%	0	100.0000%	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
85	391.99	Cloud Computing	2,442,443	0	0	0	0	0	0	(51,573)	0	0	0	(51,573)	2,390,869	0	2,390,869	30.2500%	723,238	100.0000%	723,238
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
87	392.2	Transport Equip Pickup Trucks& Vans	906,475	0	0	0	0	0	0	0	0	0	0	0	906,475	0	906,475	30.2500%	274,209	100.0000%	274,209
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
90	392.6	Aircraft	13,608,723	0	0	0	0	0	0	0	0	(13,608,723)	0	(13,608,723)	0	0	0	30.2500%	0	100.0000%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
92	394	Tools, Shop & Garage	535,247	0	0	0	0	0	0	0	0	(33,321)	0	(33,321)	501,926	0	501,926	30.2500%	151,833	100.0000%	151,833
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
97	397	Communication Equipment	337,647	0	(235,158)	0	0	0	0	0	0	0	0	(235,158)	102,489	0	102,489	30.2500%	31,003	100.0000%	31,003
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.2500%	0	100.0000%	0
100		Total General Plant	$289,959,368	$(113,090)	$(235,158)	$(65,882)	$(14,700)	$(3,917)	$(23,435)	$(130,104)	$(579,787)	$(13,886,886)	$(49,414)	$(15,102,372)	$274,856,996	$0	$274,856,996	30.2020%	$83,012,346		$83,012,346
101		Total Orig Cost Plant in Service	$289,959,368	$(113,090)	$(235,158)	$(65,882)	$(14,700)	$(3,917)	$(23,435)	$(130,104)	$(579,787)	$(13,886,886)	$(49,414)	$(15,102,372)	$274,856,996	$0	$274,856,996				
102		Allocation Factor to TGS	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%	30.2020%				
103		Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%				
104		Total Allocated Plant In Service	$87,573,566	$(34,155)	$(71,022)	$(19,898)	$(4,440)	$(1,183)	$(7,078)	$(39,294)	$(175,107)	$(4,194,119)	$(14,924)	$(4,561,220)	$83,012,346	$0	$83,012,346				

Source: WKP C.c C-1.c & D.c Corporate PIS, CCNC & AR.xlxs

SCHEDULE C-1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	Direct Completed Construction Not Classified	WKP C-1.a	$307,645,733	$(1,237,226)	$306,408,507
2	TGS Division Completed Construction Not Classified	WKP C-1.b	231,863	61,932	293,795
3	Allocated Corporate Completed Construction Not Classified	WKP C-1.c	9,580,795	(560,757)	9,020,038
4	Total Completed Construction Not Classified		$317,458,391	$(1,736,052)	$315,722,339

WKP C-1.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	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)
		INTANGIBLE PLANT									
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0
4	303	Misc. Intangible	261,178	0	0	0	0	0	261,178	0	261,178
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0
7		Total Intangible CCNC	$261,178	$0	$0	$0	$0	$0	$261,178	$0	$261,178
		GATHERING AND TRANSMISSION PLANT									
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
9	327	Field Comprss Station Strucutres	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
11	329	Other Structures	0	0	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	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
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0
19	365.2	Rights-of-Way	76	0	0	0	0	0	76	0	76
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0
21	366	Meas/Reg Station Structures	1,785,740	0	0	0	0	0	1,785,740	0	1,785,740
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0
23	367	Mains	17,325,674	(137)	(373)	0	0	(510)	17,325,164	0	17,325,164
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0
25	368	Compressor Station Equip	68,998	0	0	0	0	0	68,998	0	68,998
26	369	Meas & Reg Stations Equip	9,618,737	(38)	0	0	0	(38)	9,618,699	0	9,618,699
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0
29	371	Other Equipment	1,638	0	0	0	0	0	1,638	0	1,638
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0
31		Total Gathering and Transmission CCNC	$28,800,862	$(175)	$(373)	$0	$0	$(548)	$28,800,314	$0	$28,800,314
		DISTRIBUTION PLANT									
32	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0
33	374.1	Land	2,072	0	0	0	0	0	2,072	0	2,072
34	374.2	Land Rights	176,790	0	(5,864)	0	0	(5,864)	170,926	0	170,926
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	10,758	0	0	0	0	0	10,758	0	10,758
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0
38	376	Mains	183,239,964	(563)	(423,628)	0	0	(424,191)	182,815,773	0	182,815,773
39	376.9	Mains - Cathodic Protection Anodes	2,527,270	0	(8,460)	0	0	(8,460)	2,518,810	0	2,518,810

WKP C-1.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	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)
40	377	Compressor Station Equipment		0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	13,670,341	0	(5,602)	0	0	(5,602)	13,664,739	0	13,664,739
42	379	Meas. & Reg. Station - C.G.	7,205,108	(64)	0	0	0	(64)	7,205,044	0	7,205,044
43	380	Services	23,956,199	0	(332,886)	0	0	(332,886)	23,623,313	0	23,623,313
44	380.1	Ind Service Line Equip	71,032	0	(733)	0	0	(733)	70,299	0	70,299
45	380.2	Comm Service Line Equip	1,301,928	0	(399,738)	0	0	(399,738)	902,190	0	902,190
46	380.4	Yard Lines-Customer Svc	151,446	0	(5,610)	0	0	(5,610)	145,836	0	145,836
47	381	Meters	5,243,619	0	(471)	0	126,713	126,242	5,369,861	0	5,369,861
48	382	Meter Installations	126,713	0	0	0	(126,713)	(126,713)	0	0	0
49	383	House Regulators	1,407,940	0	(733)	0	0	(733)	1,407,207	0	1,407,207
50	385	Indust. Meas. & Reg. Stat. Equipment	1,980,942	0	0	0	0	0	1,980,942	0	1,980,942
51	386	Other Property on Customer Premises		0	0	0	0	0	0	0	0
52	387	Meas. & Reg. Stat. Equipment		0	0	0	0	0	0	0	0
53		Total Distribution CCNC	$241,072,121	$(627)	$(1,183,724)	$0	$0	$(1,184,351)	$239,887,770	$0	$239,887,770
		GENERAL PLANT									
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	10,836,329	(1,516)	-40,087	0	0	(41,603)	10,794,726	0	10,794,726
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	24,536	0	0	0	0	0	24,536	0	24,536
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
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

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	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)
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	115,555	—	0	0	0	0	115,555	0	115,555
85	391.99	Cloud Computing		0	0	0	0	0	0	0	0
86	392	Transportation Equipment	14,233,316	0	(10,724)	0	0	(10,724)	14,222,592	0	14,222,592
87	392.2	Transport Equip Pickup Trucks& Vans		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
89	392.5	Trailers		0	0	0	0	0	0	0	0
90	392.6	Aircraft		0	0	0	0	0	0	0	0
91	393	Stores Equipment	52,966	0	0	0	0	0	52,966	0	52,966
92	394	Tools, Shop & Garage	3,202,882	0	0	0	0	0	3,202,882	0	3,202,882
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	1,378,002	0	0	0	0	0	1,378,002	0	1,378,002
97	397	Communication Equipment	6,639,251	0	0	0	0	0	6,639,251	0	6,639,251
98	397.2	Telephone Equipment		0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant		0	0	0	0	0	0	0	0
100		Total General CCNC	$36,482,837	$(1,516)	$(50,811)	$0	$0	$(52,327)	$36,430,510	$0	$36,430,510
101		Total Orig Cost CCNC	$306,616,998	$(2,317)	$(1,234,908)	$0	$0	$(1,237,226)	$305,379,772	$0	$305,379,772

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - TGS.xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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COMPLETED CONSTRUCTION NOT CLASSIFIED - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		INTANGIBLE PLANT							
1	301	Organization	$0	$0	$0	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0	0	0	0
3	302	Franchises & Consents	0	0	0	0	0	0	0
4	303	Misc. Intangible	0	0	0	0	0	0	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	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	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0
11	329	Other Structures	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0
15	336	Purification Equipment	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0
18	365.1	Land - OPC	0	0	0	0	0	0	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0
23	367	Mains	0	0	0	0	0	0	0
24	367	Mains - OPC	0	0	0	0	0	0	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0
29	371	Other Equipment	0	0	0	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0
		DISTRIBUTION PLANT							

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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COMPLETED CONSTRUCTION NOT CLASSIFIED - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		INTANGIBLE PLANT							
1	301	Organization	$0	$0	$0	$0	$0	$0	$0
32	374	Land	$0	$0	$0	$0	$0	$0	$0
33	374.1	Land	0	0	0	0	0	0	0
34	374.2	Land Rights	0	0	0	0	0	0	0
35	375	Structures & Improvements	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0
37	375.2	Other System Structures	0	0	0	0	0	0	0
38	376	Mains	674,326	0	0	0	0	0	674,326
39	376.9	Mains - Cathodic Protection Anodes	15,227	0	0	0	0	0	15,227
40	377	Compressor Station Equipment	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	(295,036)	0	0	0	0	0	(295,036)
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0
43	380	Services	305,303	0	0	0	0	0	305,303
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0
47	381	Meters	44,343	0	0	0	0	0	44,343
48	382	Meter Installations	0	0	0	0	0	0	0
49	383	House Regulators	16,622	0	0	0	0	0	16,622
50	385	Indust. Meas. & Reg. Stat. Equipment	267,949	0	0	0	0	0	267,949
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0
53		Total Distribution Plant	$1,028,735	$0	$0	$0	$0	$0	$1,028,735
		GENERAL PLANT							
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	0	0	0	0	0	0	0
57	390.17	Building Improv Plum	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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COMPLETED CONSTRUCTION NOT CLASSIFIED - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		INTANGIBLE PLANT							
1	301	Organization	$0	$0	$0	$0	$0	$0	$0
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	0
70	391.6	Purchased Software	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0
73	391.6	Riskworks	0	0	0	0	0	0	0
74	391.6	Maximo	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	0
76	391.6	Concur Project	0	0	0	0	0	0	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0
85	391.99	Cloud Computing	0	0	0	0	0	0	0
86	392	Transportation Equipment	0	0	0	0	0	0	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0
89	392.5	Trailers	0	0	0	0	0	0	0
90	392.6	Aircraft	0	0	0	0	0	0	0
91	393	Stores Equipment	0	0	0	0	0	0	0
92	394	Tools, Shop & Garage	0	0	0	0	0	0	0
93	394.1	Tools	0	0	0	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0
95	395	CNG Equipment	0	0	0	0	0	0	0
96	396	Major Work Equipment	0	0	0	0	0	0	0
97	397	Communication Equipment	0	0	0	0	0	0	0
98	397.2	Telephone Equipment	0	0	0	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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COMPLETED CONSTRUCTION NOT CLASSIFIED - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		INTANGIBLE PLANT							
1	301	Organization	$0	$0	$0	$0	$0	$0	$0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0
100		Total General Plant	$0	$0	$0	$0	$0	$0	$0
101		Total Orig Cost Plant in Service	$1,028,735	$0	$0	$0	$0	$0	$1,028,735

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - TGS.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT									
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	100.0000%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	100.0000%	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	100.0000%	0
4	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	100.0000%	0
5	303	Misc. Intangible	0	0	0	0	0	0	0	100.0000%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	100.0000 %	0
7		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT									
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	100.0000%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	100.0000%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	100.0000%	0
11	329	Other Structures	0	0	0	0	0	0	0	100.0000%	0
12	332	Field Lines	0	0	0	0	0	0	0	100.0000%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	100.0000%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	100.0000%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	100.0000%	0
16	337	Other Equip	0	0	0	0	0	0	0	100.0000%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	100.0000%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	100.0000%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	100.0000%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	100.0000%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	100.0000%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	100.0000%	0
23	367	Mains	0	0	0	0	0	0	0	100.0000%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	100.0000%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	100.0000%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	100.0000%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	100.0000%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	100.0000%	0
29	371	Other Equipment	0	0	0	0	0	0	0	100.0000%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	100.0000 %	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT									
32	374	Land	$0	$0	$0	$0	$0	$0	$0	100.0000 %	$0
33	374.1	Land	0	0	0	0	0	0	0	100.0000 %	0
34	374.2	Land Rights	0	0	0	0	0	0	0	100.0000 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	100.0000 %	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	100.0000 %	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	100.0000 %	0
38	376	Mains	0	0	0	0	0	0	0	100.0000 %	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	100.0000 %	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	100.0000 %	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	100.0000 %	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	100.0000 %	0
43	380	Services	0	0	0	0	0	0	0	100.0000 %	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	100.0000 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	100.0000 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	100.0000 %	0
47	381	Meters	0	0	0	0	0	0	0	100.0000 %	0
48	382	Meter Installations	0	0	0	0	0	0	0	100.0000 %	0
49	383	House Regulators	0	0	0	0	0	0	0	100.0000 %	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	100.0000 %	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	100.0000 %	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	100.0000 %	0
53		Total Distribution CCNC	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT									
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	100.0000%	0
55	390	Structures & Improvements	0	0	0	0	0	0	0	100.0000%	0
56	390.1	Structures & Improvements	142,293	0	0	0	142,293	0	142,293	100.0000%	142,293
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	100.0000%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	100.0000%	0
59	390.2	Leasehold Improvement	18,181	0	0	0	18,181	0	18,181	100.0000%	18,181
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	100.0000%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	100.0000%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	100.0000%	0
63	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	100.0000%	0
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	100.0000%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	100.0000%	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	100.0000%	0
67	391.3	Office Machines	0	0	0	0	0	0	0	100.0000%	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	100.0000%	0
69	391.5	Artwork	0	0	0	0	0	0	0	100.0000%	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	100.0000%	0
71	391.6	Banner Software	0	0	0	0	0	0	0	100.0000%	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	100.0000%	0
73	391.6	Riskworks	0	0	0	0	0	0	0	100.0000%	0

WKP C-1.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
74	391.6	Maximo	0	0	0	0	0	0	0	100.0000%	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	100.0000%	0
76	391.6	Concur Project	0	0	0	0	0	0	0	100.0000%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	100.0000%	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	100.0000%	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	100.0000%	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	100.0000%	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	100.0000%	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	100.0000%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	100.0000%	0
84	391.9	Computer & Equipment	0	62,111	0	62,111	62,111	0	62,111	100.0000%	62,111
85	391.99	Cloud Computing	0	0	0	0	0	0	0	100.0000%	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	100.0000%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	100.0000%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	100.0000%	0
89	392.5	Trailers	0	0	0	0	0	0	0	100.0000%	0
90	392.6	Aircraft	0	0	0	0	0	0	0	100.0000%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	100.0000%	0
92	394	Tools, Shop & Garage	71,390	0	(180)	(180)	71,210	0	71,210	100.0000%	71,210
93	394.1	Tools	0	0	0	0	0	0	0	100.0000%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	100.0000%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	100.0000%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	100.0000%	0
97	397	Communication Equipment	0	0	0	0	0	0	0	100.0000%	0
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	100.0000%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	100.0000%	0
100		Total General plant	$231,863	$62,111	$(180)	$61,932	$293,795	$0	$293,795		$293,795
101		Total Orig Cost Plant in Service	$231,863	$62,111	$(180)	$61,932	$293,795	$0	$293,795		
102		Allocation Factor to Service Area	100.0000 %	100.0000 %	100.0000 %	100.0000 %	100.0000 %	100.0000 %	100.0000 %		
103		Total Allocated CCNC	$231,863	$62,111	$(180)	$61,932	$293,795	$0	$293,795		

Source: WKP C.b C-1.b & D.b TGS Div PIS, CCNC & AR.xlxs

WKP C-1.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	ADJUSTMENTS FROM PRIOR FILINGS	REMOVE INSUFFICIENT SUPPORT	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
		INTANGIBLE PLANT														
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	100.0000%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
7		Total Intangible Plant	$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	0.00%	$0	100.0000%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
31		Total Gathering and Transmission Plant	$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	0.00%	$0	100.0000%	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000%	0
53		Total Distribution CCNC	$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	30.25%	$0	100.0000%	0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
56	390.1	Structures & Improvements	52,832	0	0	0	0	0	0	52,832	0	52,832	30.25%	15,982	100.0000%	15,982
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
59	390.2	Leasehold Improvement	1,619,562	0	0	0	(1,223,619)	0	(1,223,619)	395,943	0	395,943	30.25%	119,773	100.0000%	119,773
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
63	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0

WKP C-1.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	ADJUSTMENTS FROM PRIOR FILINGS	REMOVE INSUFFICIENT SUPPORT	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
67	391.3	Office Machines	901,551	0	0	0	0	0	0	901,551	0	901,551	30.25%	272,719	100.0000%	272,719
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
70	391.6	Purchased Software	28,651,338	(1,065)	(124,966)	(2,252)	(506,132)	(68)	(634,483)	28,016,855	0	28,016,855	30.25%	8,475,099	100.0000%	8,475,099
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	30.95%	0	100.0000%	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	28.60%	0	100.0000%	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
74	391.6	Maximo	414,934	0	0	0	0	0	0	414,934	0	414,934	25.00%	103,734	100.0000%	103,734
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	30.17%	0	100.0000%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	30.17%	0	100.0000%	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	30.17%	0	100.0000%	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	35.08%	0	100.0000%	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	30.95%	0	100.0000%	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
92	394	Tools, Shop & Garage	108,323	0	0	0	0	(118)	(118)	108,204	0	108,204	30.25%	32,732	100.0000%	32,732
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
97	397	Communication Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000%	0
100		Total General plant	$31,748,541	$(1,065)	$(124,966)	$(2,252)	$(1,729,752)	$(186)	$(1,858,221)	$29,890,320	$0	$29,890,320	30.18%	$9,020,038		$9,020,038
101		Total Orig Cost Plant in Service	$31,748,541	$(1,065)	$(124,966)	$(2,252)	$(1,729,752)	$(186)	$(1,858,221)	$29,890,320	$0	$29,890,320				
102		Allocation Factor to TGS	30.1771%	30.1771%	30.1771%	30.1771%	30.1771%	30.1771%	30.1771%	30.1771%	30.1771%	30.1771%				
103		Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%				
104		Total Allocated CCNC	$9,580,795	$(321)	$(37,711)	$(680)	$(521,989)	$(56)	$(560,757)	$9,020,038	$0	$9,020,038				

Source: WKP C.c C-1.c & D.c Corporate PIS, CCNC & AR.xlxs

SCHEDULE D

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	Direct Accumulated Reserves	WKP D.a	$(447,357,983)	$(59,117)	$(447,417,100)
2	TGS Division Accumulated Reserves	WKP D.b	(3,906,441)	491,650	(3,414,791)
3	Allocated Corporate Accumulated Reserves	WKP D.c	(50,338,769)	4,439,846	(45,898,924)
4	Total Accumulated Reserves		$(501,603,193)	$4,872,379	$(496,730,814)

WKP D.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - 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 & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	RESERVE REBALANCE	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	$(182,357)	$0	$(182,357)	$0	$0	$0	$0	$0	$(182,357)	$0	$(182,357)
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0
3	302	Franchises & Consents	(393,609)	0	(393,609)	0	0	0	0	0	(393,609)	0	(393,609)
4	303	Misc. Intangible	0	(1,105,915)	(1,105,915)	0	0	0	0	0	(1,105,915)	0	(1,105,915)
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	0	(121,597)	(121,597)	0	0	0	0	0	(121,597)	0	(121,597)
7		Total Intangible Plant Reserves	$(575,966)	$(1,227,512)	$(1,803,478)	$0	$0	$0	$0	$0	$(1,803,478)	$0	$(1,803,478)
		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	(1,399)	0	(1,399)	0	0	0	0	0	(1,399)	0	(1,399)
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	(173,769)	0	(173,769)	0	0	0	30,297	30,297	(143,472)	0	(143,472)
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0
23	367	Mains	(6,682,614)	0	(6,682,614)	0	0	0	(698,855)	(698,855)	(7,381,469)	0	(7,381,469)
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0
25	368	Compressor Station Equip	(7,545)	0	(7,545)	0	0	0	(63)	(63)	(7,608)	0	(7,608)
26	369	Meas & Reg Stations Equip	(2,817,711)	0	(2,817,711)	0	0	0	665,710	665,710	(2,152,001)	0	(2,152,001)
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	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	(22,955)	0	(22,955)	0	0	0	2,911	2,911	(20,044)	0	(20,044)
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0
31		Total Gathering and Transmission Plant Reserves	$(9,705,994)	$0	$(9,705,994)	$0	$0	$0	$0	$0	$(9,705,994)	$0	$(9,705,994)
		DISTRIBUTION PLANT											
32	374	Land	$(286)	$0	$(286)	$0	$0	$0	$0	$0	$(286)	$0	$(286)
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0
34	374.2	Land Rights	(94,416)	0	(94,416)	0	0	0	0	0	(94,416)	0	(94,416)
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	(247,332)	0	(247,332)	0	0	0	109,132	109,132	(138,200)	0	(138,200)
37	375.2	Other System Structures	(197,408)	0	(197,408)	0	0	0	0	0	(197,408)	0	(197,408)
38	376	Mains	(143,765,391)	0	(143,765,391)	(44,256)	0	0	6,521,568	6,477,311	(137,288,079)	0	(137,288,079)
39	376.9	Mains - Cathodic Protection Anodes	(31,247,521)	0	(31,247,521)	(2,225)	0	0	(3,632,183)	(3,634,408)	(34,881,929)	0	(34,881,929)
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	(6,559,810)	0	(6,559,810)	(7)	0	0	831,204	831,198	(5,728,613)	0	(5,728,613)
42	379	Meas. & Reg. Station - C.G.	(2,734,807)	0	(2,734,807)	(295)	0	0	446,261	445,966	(2,288,841)	0	(2,288,841)
43	380	Services	(83,680,468)	0	(83,680,468)	(6,433)	0	0	(28,959,544)	(28,965,976)	(112,646,444)	0	(112,646,444)
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	(67,902,994)	0	(67,902,994)	0	0	126,713	20,482,150	20,608,862	(47,294,132)	0	(47,294,132)
48	382	Meter Installations	(37)	0	(37)	0	0	(126,713)	0	(126,713)	(126,749)	0	(126,749)
49	383	House Regulators	(12,998,990)	0	(12,998,990)	0	0	0	1,415,039	1,415,039	(11,583,951)	0	(11,583,951)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - 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 & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	RESERVE REBALANCE	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)
50	385	Indust. Meas. & Reg. Stat. Equipment	(9,990,964)	0	(9,990,964)	0	0	0	2,232,179	2,232,179	(7,758,786)	0	(7,758,786)
51	386	Other Property on Customer Premises	(1,691,660)	0	(1,691,660)	0	0	0	554,194	554,194	(1,137,465)	0	(1,137,465)
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
53		Total Distribution Plant Reserves	$(361,112,084)	$0	$(361,112,084)	$(53,216)	$0	$0	$(0)	$(53,216)	$(361,165,300)	$0	$(361,165,300)
		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	(6,463,783)	0	(6,463,783)	(48)	0	0	(2,993,055)	(2,993,103)	(9,456,886)	0	(9,456,886)
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	(1,849)	(1,849)	0	0	0	0	0	(1,849)	0	(1,849)
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	(1,657,634)	0	(1,657,634)	(5,363)	0	0	(151,409)	(156,772)	(1,814,406)	0	(1,814,406)
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	(2,464,461)	0	(2,464,461)	0	0	0	189,864	189,864	(2,274,597)	0	(2,274,597)
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0
86	392	Transportation Equipment	(19,149,982)	0	(19,149,982)	(490)	0	0	4,658,415	4,657,924	(14,492,058)	0	(14,492,058)
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	(21,501)	0	(21,501)	0	0	0	619	619	(20,882)	0	(20,882)
92	394	Tools, Shop & Garage	(11,372,009)	0	(11,372,009)	0	0	0	(337,848)	(337,848)	(11,709,857)	0	(11,709,857)
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	(2,817,191)	0	(2,817,191)	0	0	0	472,887	472,887	(2,344,303)	0	(2,344,303)
97	397	Communication Equipment	(29,801,957)	0	(29,801,957)	0	0	0	(1,838,468)	(1,838,468)	(31,640,425)	0	(31,640,425)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	(4,761)	0	(4,761)	0	0	0	(1,006)	(1,006)	(5,767)	0	(5,767)
100		Total General Plant Reserves	$(73,711,066)	$(1,849)	$(73,712,914)	$(5,901)	$0	$0	$0	$(5,901)	$(73,718,815)	$0	$(73,718,815)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - 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 & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	RESERVE REBALANCE	TOTAL ADJUSTMENTS	TEST YEAR ADJUSTED ACCTS 1080100 & 1110	MEASURABLE ADJUSTMENT TO INCLUDE RESERVE CHANGES	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
101		Total Accumulated Reserves For Depreciation	(445,105,109)	$(1,229,361)	$(446,334,470)	$(59,117)	$0	$0	$(0)	$(59,117)	$(446,393,587)	$0	$(446,393,587)

Source: WKP D.a Accum Depr - TGS.xlsx
Source: WKP D.a 1080100 1080500 Accum Depr.xlsx
Source: WKP D.a 1110100 1110500 Accum Amort.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	RESERVE REBALANCE	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT									
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0
7		Total Intangible Plant Reserves	$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
9	327	Field Comprss Station Strucutres	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
11	329	Other Structures	0	0	0	0	0	0	0	0	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0
13	333	Field Compressor Station Equip	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
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0
19	365.2	Rights-of-Way	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
21	366	Meas/Reg Station Structures	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
23	367	Mains	0	0	0	0	0	0	0	0	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0
31		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0
		DISTRIBUTION PLANT									
32	374	Land	$(8,660)	$0	$(8,660)	$0	$0	$0	$0	$0	$(8,660)
33	374.1	Land	0	0	0	0	0	0	0	0	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0
38	376	Mains	(600,313)	0	(600,313)		0	0	(36,532)	(36,532)	(636,844)
39	376.9	Mains - Cathodic Protection Anodes	(59,097)	0	(59,097)	0	0	0	(1,934)	(1,934)	(61,031)
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0
41	378	Meas. & Reg. Station - General	(60,179)	0	(60,179)	0	0	0	15,470	15,470	(44,709)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	RESERVE REBALANCE	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0
43	380	Services	(149,398)	0	(149,398)	0	0	0	(11,576)	(11,576)	(160,974)
44	380.1	Ind Service Line Equip	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
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0
47	381	Meters	(65,882)	0	(65,882)	0	0	0	26,387	26,387	(39,495)
48	382	Meter Installations	0	0	0	0	0	0	0	0	0
49	383	House Regulators	(23,792)	0	(23,792)	0	0	0	8,425	8,425	(15,367)
50	385	Indust. Meas. & Reg. Stat. Equipment	(39,539)	0	(39,539)	0	0	0	(241)	(241)	(39,779)
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0
53		Total Distribution Plant Reserves	$(1,006,859)	$0	$(1,006,859)	$0	$0	$0	$(0)	$(0)	$(1,006,859)
		GENERAL PLANT									
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0
56	390.1	Structures & Improvements	0	0	0	0	0	0	0	0	0
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0
63	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0
76	391.6	Concur Project	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
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0
84	391.9	Computer & Equipment	15,138	0	15,138	0	0	0	0	0	15,138
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0

WKP D.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS & TRANSFERS ADJUSTMENT	MISCODED RETIREMENT ADJUSTMENT	FERC RECLASS	RESERVE REBALANCE	TOTAL ADJUSTMENTS	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
87	392.2	Transport Equip Pickup Trucks& Vans	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
89	392.5	Trailers	0	0	0	0	0	0	0	0	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0
92	394	Tools, Shop & Garage	(3,503)	0	(3,503)	0	0	0	5	5	(3,498)
93	394.1	Tools	0	0	0	0	0	0	0	0	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0
97	397	Communication Equipment	(28,289)	0	(28,289)	0	0	0	(5)	(5)	(28,294)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0
100		Total General Plant Reserves	$(16,654)	$0	$(16,654)	$0	$0	$0	$0	$0	$(16,654)
101		Total Accumulated Reserves For Depreciation	$(1,023,513)	$0	$(1,023,513)	$0	$0	$0	$(0)	$(0)	$(1,023,513)

Source: WKP D.a Accum Depr - TGS.xlsx
Source: WKP D.a 1080100 1080500 Accum Depr.xlsx
Source: WKP D.a 1110100 1110500 Accum Amort.xlsx

WKP D.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	RESERVE REBALANCE	REMOVE INSUFFICIENT SUPPORT	REMOVE ASSET NOT USED BY DIVISION	REMOVE LAND DEPRECIATION	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		INTANGIBLE PLANT																
1	301	Organization	$(127,437)	$0	$0	$0	$0	$0	$0	$127,437	$0	$0	$127,437	$0	$0	$0	100.0000%	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
4	303	Misc. Intangible	(278,560)	0	0	0	0	0	0	278,560	0	0	278,560	0	0	0	100.0000%	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
7		Total Intangible Plant Reserves	$(405,997)	$0	$0	$0	$0	$0	$0	$405,997	$0	$0	$405,997	$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	100.0000%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000%	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
31		Total Gathering and Transmission Plant Reserves	$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	100.0000 %	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
53		Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT																
54	389	Land & Land Rights	$(4,331)	$0	$0	$0	$0	$0	$0	$0	0	4,331	$4,331	$0	$0	$0	100.0000 %	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
56	390.1	Structures & Improvements	(612,574)	0	(166)	0	(1)	0	36,722	0	0	0	36,555	(576,019)	0	(576,019)	100.0000 %	(576,019)
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
59	390.2	Leasehold Improvement	(253,258)	0	0	0	0	0	0	0	774	0	774	(252,484)	0	(252,484)	100.0000 %	(252,484)
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
63	391.1	Office Furniture & Equipment	(887,560)	0	(281)	2,887	(6,149)	0	(2,510)	0	0	0	(6,053)	(893,613)	0	(893,613)	100.0000 %	(893,613)
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
69	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	RESERVE REBALANCE	REMOVE INSUFFICIENT SUPPORT	REMOVE ASSET NOT USED BY DIVISION	REMOVE LAND DEPRECIATION	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
71	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
74	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
84	391.9	Computer & Equipment	(1,140,193)	0	0	0	(9,627)	102,699	(30,108)	0	0	0	62,964	(1,077,228)	0	(1,077,228)	100.0000 %	(1,077,228)
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	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	100.0000 %	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
92	394	Tools, Shop & Garage	(17,752)	0	0	0	0	0	0	0	0	0	0	(17,752)	0	(17,752)	100.0000 %	(17,752)
93	394.1	Tools	0	0	0	0	0	0	452	0	0	0	452	452	0	452	100.0000 %	452
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
97	397	Communication Equipment	(584,777)	0	0	0	(8,975)	42	(4,556)	120	0	0	(13,369)	(598,146)	0	(598,146)	100.0000 %	(598,146)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100.0000 %	0
100		Total General Plant Reserves	$(3,500,444)	$0	$(447)	$2,887	$(24,752)	$102,741	$0	$120	$774	$4,331	$85,653	$(3,414,791)	$0	$(3,414,791)		$(3,414,791)
101		Total Accumulated Reserves For Depreciation	$(3,906,441)	$0	$(447)	$2,887	$(24,752)	$102,741	$0	$406,116	$774	$4,331	$491,650	$(3,414,791)	$0	$(3,414,791)		
102		Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%		
103		Total Allocated Accumulated Reserves	$(3,906,441)	$0	$(447)	$2,887	$(24,752)	$102,741	$0	$406,116	$774	$4,331	$491,650	$(3,414,791)	$0	$(3,414,791)		

Source: WKP C.b C-1.b & D.b TGS Div PIS, CCNC & AR.xlxs

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	RESERVE REBALANCE	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE AVIATION	REMOVE ARTWORK	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
		INTANGIBLE PLANT																			
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	100.0000 %	$0
2	301	Organization - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
3	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
4	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
6	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
7		Total Intangible Plant Reserves	$0	$0	$0	$0	$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	$0	$0	$0	0.00%	$0	100.0000 %	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
11	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
12	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
16	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
18	365.1	Land - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
19	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
21	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
23	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
24	367	Mains - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
25	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
29	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
31		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$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	$0	$0	$0	0.00%	$0	100.0000 %	$0
33	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
34	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
37	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
38	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
41	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
43	380	Services	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
47	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
48	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
49	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	100.0000 %	0
53		Total Distribution Plant Reserves	$0	$0	$0	$0	$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	$0	$0	$0	0	30.25%	$0	100.0000 %	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
56	390.1	Structures & Improvements	(433,067)	19	0	0	0	0	0	0	0	0	0	19	(433,048)	0	(433,048)	30.25%	(130,997)	100.0000 %	(130,997)
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
59	390.2	Leasehold Improvement	(4,814,360)	128	0	0	7,345	472,159	18,323	0	0	20,760	0	518,715	(4,295,645)	0	(4,295,645)	30.25%	(1,299,433)	100.0000 %	(1,299,433)
60	390.2	OGS Lease Incentive	(299,650)	0	0	0	0	0	0	0	299,650	0	0	299,650	0	0	0	30.25%	0	100.0000 %	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
63	391.1	Office Furniture & Equipment	(2,388,242)	50	0	120	1,814	0	721	0	0	7,997	0	10,701	(2,377,540)	0	(2,377,540)	30.25%	(719,206)	100.0000 %	(719,206)
64	391.19	Airplane Hanger Furniture	(14,518)	0	0	0	0	0	0	0	0	14,518	0	14,518	0	0	0	30.25%	0	100.0000 %	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
67	391.3	Office Machines	(204,842)	0	0	0	0	0	0	0	0	0	0	0	(204,842)	0	(204,842)	30.25%	(61,965)	100.0000 %	(61,965)
68	391.4	Audio Visual Equipment	260,291	0	0	0	60	0	894	0	0	0	0	954	261,245	0	261,245	30.25%	79,027	100.0000 %	79,027
69	391.5	Artwork	(23,606)	0	0	0	0	0	0	0	0	0	23,606	23,606	0	0	0	30.25%	0	100.0000 %	0
70	391.6	Purchased Software	(73,864,903)	66,679	10,429	8,998	0	113,944	1,190	7,658	0	0	0	208,899	(73,656,005)	0	(73,656,005)	30.25%	(22,280,941)	100.0000 %	(22,280,941)
71	391.6	Banner Software	(3,296,912)	244	0	0	0	0	0	0	0	0	0	244	(3,296,668)	0	(3,296,668)	30.95%	(1,020,319)	100.0000 %	(1,020,319)
72	391.6	PowerPlant System	(1,131,510)	0	0	0	0	0	0	0	0	0	0	0	(1,131,510)	0	(1,131,510)	28.60%	(323,612)	100.0000 %	(323,612)
73	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
74	391.6	Maximo	(3,538,896)	0	0	0	0	0	0	0	0	0	0	0	(3,538,896)	0	(3,538,896)	25.00%	(884,724)	100.0000 %	(884,724)
75	391.6	Foundation Software	(24,946)	0	0	0	0	0	0	24,946	0	0	0	24,946	0	0	0	30.25%	0	100.0000 %	0
76	391.6	Concur Project	(62,722)	0	0	0	0	0	0	0	0	0	0	0	(62,722)	0	(62,722)	30.17%	(18,922)	100.0000 %	(18,922)
77	391.6	Journey-Employee-ODC Distrigas	(54,364,375)	4,305	0	0	0	0	0	0	0	0	0	4,305	(54,360,070)	0	(54,360,070)	30.25%	(16,443,921)	100.0000 %	(16,443,921)
78	391.6	Journey-Employee Count	(1,580,044)	0	0	0	0	0	0	0	0	0	0	0	(1,580,044)	0	(1,580,044)	30.17%	(476,679)	100.0000 %	(476,679)
79	391.6	Payroll - Time Management	(856,592)	0	0	2,081	0	372	0	0	0	0	0	2,453	(854,139)	0	(854,139)	30.17%	(257,683)	100.0000 %	(257,683)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110	MEAL & HOTEL ADJUSTMENTS	MISCODED PROJECT	REMOVE DUPLICATE VERTEX SALES TAX	MISCODED CHARGES ADJUSTMENT	ADJUSTMENTS FROM PRIOR FILINGS	RESERVE REBALANCE	REMOVE ONE GAS FOUNDATION SOFTWARE	REMOVE LEASE INCENTIVE	REMOVE AVIATION	REMOVE ARTWORK	TOTAL ADJUSTMENTS	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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
80	391.6	Accounts Payable Software	(505,961)	0	0	0	0	0	0	0	0	0	0	0	(505,961)	0	(505,961)	35.08%	(177,466)	100.0000 %	(177,466)
81	391.6	Customer Relations Software	(168,278)	0	0	0	0	0	0	0	0	0	0	0	(168,278)	0	(168,278)	30.95%	(52,082)	100.0000 %	(52,082)
82	391.8	Micro Computer Software	(5,391,797)	31	0	0	0	0	427	0	0	0	0	458	(5,391,339)	0	(5,391,339)	30.25%	(1,630,880)	100.0000 %	(1,630,880)
83	391.81	Aircraft Computer Equipment	18,476	0	0	0	0	0	0	0	0	(18,476)	0	(18,476)	0	0	0	30.25%	0	100.0000 %	0
84	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
85	391.99	Cloud Computing	(423,145)	0	0	0	0	0	0	2,057	0	0	0	2,057	(421,088)	0	(421,088)	30.25%	(127,379)	100.0000 %	(127,379)
86	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
87	392.2	Transport Equip Pickup Trucks& Vans	(102,798)	0	0	0	0	0	0	0	0	0	0	0	(102,798)	0	(102,798)	30.25%	(31,096)	100.0000 %	(31,096)
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
89	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
90	392.6	Aircraft	(13,608,723)	0	0	0	0	0	0	0	0	13,608,723	0	13,608,723	0	0	0	30.25%	0	100.0000 %	0
91	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
92	394	Tools, Shop & Garage	(108,994)	0	0	0	0	0	24	0	0	9,731	0	9,755	(99,239)	0	(99,239)	30.25%	(30,020)	100.0000 %	(30,020)
93	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
96	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
97	397	Communication Equipment	(51,240)	0	16,118	0	0	0	0	0	0	0	0	16,118	(35,123)	0	(35,123)	30.25%	(10,625)	100.0000 %	(10,625)
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30.25%	0	100.0000 %	0
100		Total General Plant Reserves	$(166,981,353)	$71,456	$26,547	$11,198	$9,219	$586,476	$21,579	$34,661	$299,650	$13,643,253	$23,606	$14,727,643	$(152,253,709)	$0	$(152,253,709)	30.15 %	$(45,898,924)		$(45,898,924)
101		Total Accumulated Reserves For Depreciation	$(166,981,353)	$71,456	$26,547	$11,198	$9,219	$586,476	$21,579	$34,661	$299,650	$13,643,253	$23,606	$14,727,643	$(152,253,709)	$0	$(152,253,709)				
102		Allocation Factor to TGS	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%	30.1463%				
103		Allocation Factor to Service Area	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%				
104		Total Allocated Accumulated Reserves	$(50,338,769)	$21,541	$8,003	$3,376	$2,779	$176,801	$6,505	$10,449	$90,333	$4,112,942	$7,116	$4,439,846	$(45,898,924)	$0	$(45,898,924)				

Source: WKP C.c C-1.c & D.c Corporate PIS, CCNC & AR.xlxs

SCHEDULE E

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

COST OF CAPITAL

LINE NO.	DESCRIPTION	RATIO	COST RATE %	COMPOSITE RATE %
		(a)	(b)	(c)
1	Long-Term Debt	40.08%	4.45%	1.78%
2	Common Equity	59.92%	10.40%	6.23%
3	Total	100.000%		8.02%

Source: SCH E Cost of Capital.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

FEDERAL INCOME TAX

LINE NO.	DESCRIPTION	REFERENCE	PER BOOKS	ADJUSTMENT	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$1,934,529,098	$(47,616,761)	$1,886,912,337
2	Rate of Return	E	8.0162%	8.0162%	8.0162%
3	Required Return		$155,075,569	$(3,817,051)	$151,258,518
4	Less: Interest on Long-Term Debt (1)		34,530,670	(849,943)	33,680,727
5	Net After Tax Income before parking adjustment		$120,544,900	$(2,967,108)	$117,577,791
6	Add: Parking Expense (2)		216,513		216,513
7	Net After Tax Income		$120,761,413	$(2,967,108)	$117,794,304
8	Gross-Up Factor [1 / (1-0.21)]		1.2658228	1.2658228	1.2658228
9	Net Taxable Income		$152,862,550	$(3,755,834)	$149,106,716
10	Tax Rate		21.0000%	21.0000%	21.0000%
11	Federal Income Tax		$32,101,136	$(788,725)	$31,312,410
12	Net Income Tax Expense		$32,101,136	$(788,725)	$31,312,410
	Note (1)				
13	Debt Component of Return	E	1.7850%		1.7850%
14	Total Rate Base	B	$1,934,529,098		$1,886,912,337
15	Interest on Long-Term Debt		$34,530,670		$33,680,727

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.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$520,488,496	$(102,729,111)	$417,759,385
	OPERATING EXPENSES				
2	Cost of Gas	G-1	$155,312,003	$(155,312,003)	$0
3	Base Payroll Expense	G-4	59,072,081	3,334,320	62,406,401
4	Overtime Payroll Expense	G-5	5,224,044	411,687	5,635,732
5	Employee Benefits and Payroll Taxes	G-6	19,322,206	901,213	20,223,419
6	Pension and Other Post Employment Benefits Regulatory Asset Amortization	G-7	386,093	(1,472,459)	(1,086,366)
7	Incentive Compensation	G-8	16,469,096	(1,789,953)	14,679,144
8	Miscellaneous Adjustments	G-9	8,871,220	(8,871,220)	0
9	Rents and Leases Adjustment	G-10	1,440,939	118,132	1,559,071
10	Interest on Customer Deposits	G-11	911,925	(87,278)	824,647
11	Uncollectible Expense	G-12	1,960,471	1,111,731	3,072,203
12	Injuries and Damages	G-13	257,212	206,096	463,308
13	Advertising Expense	G-14	135,305	0	135,305
14	Depreciation and Amortization Expense	G-15	71,626,713	17,466,520	89,093,233
15	Ad Valorem Tax Expense	G-16	17,854,051	1,616,031	19,470,082
16	Texas Franchise Tax Expense	G-17	0	715,000	715,000
17	Stores Load Clearing	G-18	481,627	7,568	489,196
18	Transportation & Work Equipment Clearing	G-19	7,005,620	(279,373)	6,726,247
19	Regulatory Asset Amortization	G-20	246,191	106,852	353,043
20	Distrigas % Adjustment	G-21	0	1,330,447	1,330,447
21	Causal % Adjustment - NOT USED	G-22	0	0	0
22	Pipeline Integrity Testing	G-23	0	4,699,556	4,699,556
23	Excess Deferred Income Tax Amortization	G-24	0	(2,272,038)	(2,272,038)
24	Credit Card Processing Fees	G-25	0	3,681,255	3,681,255
25	Customer Assistance Programs	G-26	0	2,627,000	2,627,000
24	Unadjusted Expenses		40,822,429	0	40,822,429
25	Total Operating Expense Adjustments		$407,399,228	$(131,750,915)	$275,648,313
26					
27	Net Operating Revenue & Expense Adjustments		$113,089,268	$29,021,804	$142,111,072

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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		$495,033,173	$(102,280,918)	$392,752,255
2	Forfeited Discounts	4870		0	0	0
3	Misc Fees	4880		4,221,356	546,729	4,768,085
4	Transportation	4893		20,137,876	101,169	20,239,045
5	Misc. Rent Revenue	4930		0	0	0
6	Other Utility Revenue	4950		1,096,091	(1,096,091)	0
7	Total Revenue			$520,488,496	$(102,729,111)	$417,759,385
8	COST OF GAS	805		$155,312,003	$(155,312,003)	$0
	DEPRECIATION & AMORTIZATION					
9	Depreciation and Amortization Expense	4030-4050		$71,626,713	$17,466,520	$89,093,233
10	Reg Asset Amortization Expense	4073		632,284	(1,365,607)	(733,323)
11	Total Depr. & Amort.			$72,258,997	$16,100,913	$88,359,910
	TAXES OTHER THAN INCOME					
12	Payroll	4081		$3,625,574	$198,475	$3,824,049
13	Ad Valorem	4081	190	17,854,051	1,616,031	19,470,082
14	Revenue Related	4081	133, 138 & 140	21,668	0	21,668
15	Other	4081	131, 233 & 995	1,891,175	715,000	2,606,175
16	Total Taxes Other Than Income			$23,392,468	$2,529,506	$25,921,974
17	Excess Deferred Income Tax Amortization	4101	102	$0	$(2,272,038)	$(2,272,038)
18	Interest on Customer Deposits	4310		$911,925	$(87,278)	$824,647
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION					
19	Underground Storage	8140-8360		$0	$0	$0
20	Operation Supervision and Engineering	8500		30,434	(180)	30,254
21	Transmission Communication Equip	8520		0	0	0
22	Compressor Station Labor and Expenses	8530		0	0	0
23	Mains Expenses	8560		2,661,451	4,774,193	7,435,644
24	Measuring and Regulating Station Expenses	8570		638,514	29,944	668,458
25	Trans/Compression of Gas by Others	8580		0	0	0
26	Other Expenses	8590		0	0	0
27	Rent	8600		95,251	0	95,251
28	Maintenance Supervision and Engineering	8610		2,549	0	2,549
29	Maintenance of Mains	8630		586,152	8,691	594,843
30	Maintenance of Compressor Station Equipment	8640		24	0	24
31	Maintenance of Measuring and Regulating Station Equipment	8650		296,176	3,539	299,715
32	Total Transmission			$4,310,552	$4,816,188	$9,126,739
	DISTRIBUTION OPERATIONS					
33	Supervision and Engineering	8700		$2,636,535	$97,839	$2,734,374
34	Distribution Load Dispatch	8710		589,938	(4,646)	585,292
35	Mains & Services	8740		15,260,865	464,245	15,725,110
36	Meas & Reg. Stat. Exp. - General	8750		1,309,744	51,007	1,360,751
37	Meas & Reg. Stat. Exp. - Ind.	8760		90,028	1,079	91,108
38	Meas & Reg. Stat. Exp. - City Gate	8770		96,496	2,247	98,743
39	Meter & House Reg. Exp.	8780		14,791,756	917,847	15,709,603
40	Customer Installation Exp	8790		10,401	343	10,745
41	Other Expense	8800		3,232,040	57,797	3,289,838
42	Rents	8810		117,124	0	117,124
43	Corporate & TGS Division Expenses	8820		0	0	0
44	Total Distribution Operations			$38,134,928	$1,587,760	$39,722,687

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024 **SCHEDULE G**

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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)
	DISTRIBUTION MAINTENANCE					
45	Supervision and Engineering	8850		$18,262	$730	$18,992
46	Struct. & Improv.	8860		2,374,120	87	2,374,207
47	Mains	8870		8,184,091	335,767	8,519,857
48	Meas. & Reg. Stat. Exp. - Gen	8890		3,018,730	128,129	3,146,858
49	Meas. & Reg. Stat. Exp. - Ind.	8900		1,461,516	98,128	1,559,644
50	Meas. & Reg. Stat. Exp. - City Gate	8910		68,559	805	69,364
51	Maintenance of Services	8920		3,617,041	217,408	3,834,449
52	Meters & House Reg.	8930		26,842	1,179	28,021
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			$18,769,161	$782,233	$19,551,393
57	Total Distribution Expense			$56,904,088	$2,369,992	$59,274,081
	CUSTOMER ACCOUNTING					
58	Supervision	9010		$645	$0	$645
59	Meter Reading	9020		1,359,103	64,602	1,423,705
60	Customer Accounting	9030		8,156,068	3,652,814	11,808,882
61	Bad Debts	9040		1,960,471	1,111,731	3,072,203
62	Miscellaneous	9050		868,780	616	869,396
63	Total Customer Accounting			$12,345,067	$4,829,763	$17,174,830
	CUSTOMER INFORMATION					
64	Supervision	9070		$0	$0	$0
65	Customer Assistance Expense	9080		2,198,571	150,160	2,348,730
66	Inform. & Instruct. Adver. Exp.	9090		160,487	0	160,487
67	Customer Svc and Informational Svc	9100		0	0	0
68	Total Customer Information			$2,359,058	$150,160	$2,509,218
	SALES					
69	Supervision	9110		$0	$0	$0
70	Demonstrating and Selling Expense	9120		6,630	(5,000)	1,630
71	Advertising	9130		134,863	56,972	191,835
72	Employee Sales Referrals	9140		0	0	0
73	Misc. Gas Sales Expense	9163		0	0	0
74	Total Sales			$141,493	$51,972	$193,465
75	Total Customer Accounts Expense			$14,845,619	$5,031,894	$19,877,513
	ADMINISTRATIVE & GENERAL					
76	Salaries	9200		$16,918,347	$125,506	$17,043,853
77	Office Supplies & Expenses	9210		2,355,401	1,938,462	4,293,863
78	Transferred Credit	9220		(15,292,445)	0	(15,292,445)
79	Outside Services	9230		970,825	463,000	1,433,825
80	Property Insurance	9240		792,906	38,438	831,344
81	Injuries & Damages	9250		4,148,162	(1,078,024)	3,070,138
82	Employee Pensions & Benefits	9260		11,107,674	1,964,076	13,071,750
83	A&G Franchise Elections	9270		0	0	0
84	Regulatory Commission Expenses	9280		681,122	(3)	681,119
85	Duplicate Charges- Credit	9290		0	0	0
86	General Advertising Expense	9301		57	0	57
87	Misc. General Expenses	9302		55,732,536	(8,586,674)	47,145,862
88	Rents	9310		1,440,939	207,129	1,648,068
89	Maintenance of General Plant	9320		608,053	0	608,053
90	Misc. General Expenses	9400's		0	0	0
91	Total Administrative & General Expense			$79,463,578	$(4,928,090)	$74,535,487
92	Total Operating Expense			$407,399,228	$(131,750,915)	$275,648,313
93	Earnings Before Income Tax & Interest Expense			$113,089,268	$29,021,804	$142,111,072

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
	REVENUE																			
1	Gas Sales Revenue	480-482		$495,033,173	$(155,312,003)	$53,031,084	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	Forfeited Discounts	4870		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Misc Fees	4880		4,221,356	0	0	546,729	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Transportation	4893		20,137,876	0	0	101,169	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Misc. Rent Revenue	4930		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Other Utility Revenue	4950		1,096,091	0	0	(1,096,091)	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Revenue			$520,488,496	$(155,312,003)	$53,031,084	$(448,193)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	COST OF GAS	805		$155,312,003	$(155,312,003)															
	DEPRECIATION & AMORTIZATION																			
9	Depreciation and Amortization Expense	4030-4050		$71,626,713	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,466,520	$0
10	Reg Asset Amortization Expense (Note 2)	4073		632,284	0	0	0	0	0	0	(1,472,459)	0	0	0	0	0	0	0	0	0
11	Total Depr. & Amort.			$72,258,997	$0	$0	$0	$0	$0	$0	$(1,472,459)	$0	$0	$0	$0	$0	$0	$0	$17,466,520	$0
	TAXES OTHER THAN INCOME																			
12	Payroll	4081		$3,625,574	$0	$0	$0	$0	$0	$209,235	$0	$(9,683)	$(1,077)	$0	$0	$0	$0	$0	$0	$0
13	Ad Valorem	4081	190	17,854,051	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,616,031
14	Revenue Related	4081	133, 138 & 140	21,668	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Other	4081	131, 233 & 995	1,891,175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Total Taxes Other Than Income			$23,392,468	$0	$0	$0	$0	$0	$209,235	$0	$(9,683)	$(1,077)	$0	$0	$0	$0	$0	$0	$1,616,031
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
18	Interest on Customer Deposits	4310		$911,925	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(87,278)	$0	$0	$0	$0	$0
19	Underground Storage	8140-8360		$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		30,434	$0	$0	$0	$(174)	$(6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Transmission Communication Equip	8520		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
23	Mains Expenses	8560		$2,661,451.48	0	0	0	74,173	11,638	0	0	0	(1,071)	0	0	0	0	0	0	0
24	Measuring and Regulating Station Expenses	8570		638,514.29	0	0	0	28,989	4,509	0	0	0	0	0	0	0	0	0	0	0
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
26	Other Expenses	8590		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Rent	8600		95,251	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Maintenance Supervision and Engineering	8610		2,549	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Maintenance of Mains	8630		586,152	0	0	0	7,930	1,448	0	0	0	(9)	0	0	0	0	0	0	0
30	Maintenance of Compressor Station Equipment	8640		24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Maintenance of Measuring and Regulating Station Equipment	8650		296,176	0	0	0	3,059	476	0	0	0	0	0	0	0	0	0	0	0
32	Total Transmission			$4,310,552	$0	$0	$0	$113,976	$18,065	$0	$0	$0	$(1,080)	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION OPERATIONS																			
33	Supervision and Engineering	8700		$2,636,535	$0	$0	$0	$87,441	$14,553	$0	$0	$0	$(2,316)	$0	$0	$0	$0	$0	$0	$0
34	Distribution Load Dispatch	8710		589,938	0	0	0	(4,492)	(154)	0	0	0	0	0	0	0	0	0	0	0
35	Mains & Services	8740		15,260,865	0	0	0	434,280	67,798	0	0	0	(339)	0	0	0	0	0	0	0
36	Meas & Reg. Stat. Exp. - General	8750		1,309,744	0	0	0	48,205	7,523	0	0	0	0	0	0	0	0	0	0	0
37	Meas & Reg. Stat. Exp. - Ind.	8760		90,028	0	0	0	876	204	0	0	0	0	0	0	0	0	0	0	0
38	Meas & Reg. Stat. Exp. - City Gate	8770		96,496	0	0	0	2,606	422	0	0	0	0	0	0	0	0	0	0	0
39	Meter & House Reg. Exp.	8780		14,791,756	0	0	0	886,601	137,890	0	0	0	0	0	0	0	0	0	0	0
40	Customer Installation Exp	8790		10,401	0	0	0	297	46	0	0	0	0	0	0	0	0	0	0	0
41	Other Expense	8800		3,232,040	0	0	0	64,281	10,415	0	0	0	(6,500)	0	0	0	0	0	0	0
42	Rents	8810		117,124	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Corporate & TGS Division Expenses	8820		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	Total Distribution Operations			$38,134,928	$0	$0	$0	$1,520,094	$238,698	$0	$0	$0	$(9,155)	$0	$0	$0	$0	$0	$0	$0
	DISTRIBUTION MAINTENANCE										0	0								
45	Supervision and Engineering	8850		$18,262	$0	$0	$0	$887	$138	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	Struct. & Improv.	8860		2,374,120	0	0	0	76	12	0	0	0	0	0	0	0	0	0	0	0
47	Mains	8870		8,184,091	0	0	0	326,838	50,832	0	0	0	(209)	0	0	0	0	0	0	0
48	Meas. & Reg. Stat. Exp. - Gen	8890		3,018,730	0	0	0	123,681	19,236	0	0	0	0	0	0	0	0	0	0	0
49	Meas. & Reg. Stat. Exp. - Ind.	8900		1,461,516	0	0	0	94,462	14,691	0	0	0	0	0	0	0	0	0	0	0
50	Meas. & Reg. Stat. Exp. - City Gate	8910		68,559	0	0	0	697	108	0	0	0	0	0	0	0	0	0	0	0
51	Maintenance of Services	8920		3,617,041	0	0	0	205,343	31,938	0	0	0	0	0	0	0	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	OVERTIME BASE PAYROLL ADJ G-4	BENEFITS & PAYROLL ADJ G-5	PAYROLL TAX ADJ G-6	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ G-7	INCENTIVE COMPENSATION ADJ G-8	CUSTOMER MISC. ADJ G-9	UNCOLLECTIBLE RENT ADJ G-10	INJURIES & DEPOSITS ADJ G-11	AD VALOREM EXPENSE ADJ G-12	DEPRECIATION DAMAGES ADJ G-13	TAX ADVERTISING ADJ G-14	DEPRECIATION ADJ G-15	TAX ADJ G-16
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
52	Meters & House Reg.	8930		26,842	0	0	0	1,020	159	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
54	Clearing - Meter Shop - Small Meters	8950		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
56	Total Distribution Maintenance			$18,769,161	$0	$0	$0	$753,003	$117,115	$0	$0	$0	$(209)	$0	$0	$0	$0	$0	$0	$0
57	Total Distribution Expense			$56,904,088	$0	$0	$0	$2,273,097	$355,812	$0	$0	$0	$(9,364)	$0	$0	$0	$0	$0	$0	$0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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
				(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
	CUSTOMER ACCOUNTING																			
58	Supervision	9010		$645	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
59	Meter Reading	9020		1,359,103	0	0	0	62,620	9,739	0	0	0	0	0	0	0	0	0	0	0
60	Customer Accounting	9030		8,156,068	0	0	0	(27,386)	(780)	0	0	0	(48)	0	0	0	0	0	0	0
61	Bad Debts	9040		1,960,471	0	0	0	0	0	0	0	0	0	0	0	1,111,731	0	0	0	0
62	Miscellaneous	9050		868,780	0	0	0	591	94	0	0	0	(69)	0	0	0	0	0	0	0
63	Total Customer Accounting			$12,345,067	$0	$0	$0	$35,825	$9,054	$0	$0	$0	$(116)	$0	$0	$1,111,731	$0	$0	$0	$0
	CUSTOMER INFORMATION																			
64	Supervision	9070		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
65	Customer Assistance Expense	9080		2,198,571	0	0	0	144,636	22,756	0	0	0	(17,232)	0	0	0	0	0	0	0
66	Inform. & Instruct. Adver. Exp.	9090		160,487	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Customer Svc and Informational Svc	9100		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
68	Total Customer Information			$2,359,058	$0	$0	$0	$144,636	$22,756	$0	$0	$0	$(17,232)	$0	$0	$0	$0	$0	$0	$0
	SALES																			
69	Supervision	9110		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
70	Demonstrating and Selling Expense	9120		$6,630	0	0	0	0	0	0	0	0	(5,000)	0	0	0	0	0	0	0
71	Advertising	9130		134,863	0	0	0	0	0	0	0	0	(3,028)	0	0	0	0	0	0	0
72	Employee Sales Referrals	9140		0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
74	Total Sales			$141,493	$0	$0	$0	$0	$0	$0	$0	$0	$(8,028)	$0	$0	$0	$0	$0	$0	$0
75	Total Customer Accounts Expense			$14,845,619	$0	$0	$0	$180,461	$31,809	$0	$0	$0	$(25,377)	$0	$0	$1,111,731	$0	$0	$0	$0
	ADMINISTRATIVE & GENERAL																			
76	Salaries	9200		$16,918,347	$0	$0	$0	$2,749	$6,044	$0	$0	$0	$12,713	$0	$0	$0	$0	$0	$0	$0
77	Office Supplies & Expenses	9210		2,355,401	0	0	0	0	0	0	0	0	(61,601)	0	0	0	0	0	0	0
78	Transferred Credit	9220		(15,292,445)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
79	Outside Services	9230		970,825	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
80	Property Insurance	9240		792,906	0	0	0	0	0	0	0	0	38,438	0	0	0	0	0	0	0
81	Injuries & Damages	9250		4,148,162	0	0	0	0	0	0	0	0	(1,284,120)	0	0	0	206,096	0	0	0
82	Employee Pensions & Benefits	9260		11,107,674	0	0	0	0	0	596,445	0	0	1,367,631	0	0	0	0	0	0	0
83	A&G Franchise Elections	9270		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
84	Regulatory Commission Expenses	9280		681,122	0	0	0	0	0	0	0	0	(3)	0	0	0	0	0	0	0
85	Duplicate Charges- Credit	9290		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
86	General Advertising Expense	9301		57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
87	Misc. General Expenses	9302		55,732,536	0	0	0	764,037	(43)	95,533	0	(1,780,270)	(8,996,766)	389	0	0	0	0	0	0
88	Rents	9310		1,440,939	0	0	0	0	0	0	0	0	89,386	117,743	0	0	0	0	0	0
89	Maintenance of General Plant	9320		608,053	0	0	0	0	0	0	0	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	0	0	0	0	0	0	0
91	Total Administrative & General Expense			$79,463,578	$0	$0	$0	$766,786	$6,001	$691,978	$0	$(1,780,270)	$(8,834,322)	$118,132	$0	$0	$206,096	$0	$0	$0
92	Total Operating Expense			$407,399,228	$(155,312,003)	$0	$0	$3,334,320	$411,687	$901,213	$(1,472,459)	$(1,789,953)	$(8,871,220)	$118,132	$(87,278)	$1,111,731	$206,096	$0	$17,466,520	$1,616,031
93	Earnings Before Income Tax & Interest Expense			$113,089,268	$(0)	$53,031,084	$(448,193)	$(3,334,320)	$(411,687)	$(901,213)	$1,472,459	$1,789,953	$8,871,220	$(118,132)	$87,278	$(1,111,731)	$(206,096)	$0	$(17,466,520)	$(1,616,031)

NOTE 2:

Account 4073	$632,284
Test Year 2024 Pension & OPEB Amortization	386,093
Test Year 2024 Amortization expense of regulatory asset	246,190.53
	$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	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)	CREDIT CARD PROCESSING FEES ADJ G-25 (z)	CUSTOMER ASSISTANCE PROGRAMS ADJ G-26 (aa)	TOTAL ADJUSTMENTS (ab)	TEST YEAR ADJUSTED (ac)
	REVENUE														
1	Gas Sales Revenue	480-482		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(102,280,918)	$392,752,255
2	Forfeited Discounts	4870		0	0	0	0	0	0	0	0	0	0	0	0
3	Misc Fees	4880		0	0	0	0	0	0	0	0	0	0	546,729	4,768,085
4	Transportation	4893		0	0	0	0	0	0	0	0	0	0	101,169	20,239,045
5	Misc. Rent Revenue	4930		0	0	0	0	0	0	0	0	0	0	0	0
6	Other Utility Revenue	4950		0	0	0	0	0	0	0	0	0	0	(1,096,091)	0
7	Total Revenue			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(102,729,111)	$417,759,385
8	COST OF GAS	805												$(155,312,003)	$0
	DEPRECIATION & AMORTIZATION														
9	Depreciation and Amortization Expense	4030-4050		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,466,520	$89,093,233
10	Reg Asset Amortization Expense (Note 2)	4073		0	0	0	106,852	0	0	0	0	0	0	$(1,365,607)	(733,323)
11	Total Depr. & Amort.			$0	$0	$0	$106,852	$0	$0	$0	$0	$0	$0	$16,100,913	$88,359,910
	TAXES OTHER THAN INCOME														
12	Payroll	4081		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$198,475	$3,824,049
13	Ad Valorem	4081	190	0	0	0	0	0	0	0	0	0	0	$1,616,031	19,470,082
14	Revenue Related	4081	133, 138 & 140	0	0	0	0	0	0	0	0	0	0	$0	21,668
15	Other	4081	131, 233 & 995	715,000	0	0	0	0	0	0	0	0	0	$715,000	2,606,175
16	Total Taxes Other Than Income			$715,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,529,506	$25,921,974
17	Excess Deferred Income Tax Amortization	4101	102	$0	$0	$0	$0	$0	$0	$0	$(2,272,038)	$0	$0	$(2,272,038)	$(2,272,038)
18	Interest on Customer Deposits	4310		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(87,278)	$824,647
19	Underground Storage	8140-8360		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION														
20	Operation Supervision and Engineering	8500		$0	$0	$0	$0	$0	0	0	0	0	0	(180)	30,254
21	Transmission Communication Equip	8520		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
23	Mains Expenses	8560		0	0	(10,103)	0	0	0	4,699,556	0	0	0	4,774,193	7,435,644
24	Measuring and Regulating Station Expenses	8570		0	0	(3,554)	0	0	0	0	0	0	0	29,944	668,458
25	Trans/Compression of Gas by Others	8580		0	0	0	0	0	0	0	0	0	0	0	0
26	Other Expenses	8590		0	0	0	0	0	0	0	0	0	0	0	0
27	Rent	8600		0	0	0	0	0	0	0	0	0	0	0	95,251
28	Maintenance Supervision and Engineering	8610		0	0	0	0	0	0	0	0	0	0	0	2,549
29	Maintenance of Mains	8630		0	0	(677)	0	0	0	0	0	0	0	8,691	594,843
30	Maintenance of Compressor Station Equipment	8640		0	0	0	0	0	0	0	0	0	0	0	24
31	Maintenance of Measuring and Regulating Station Equipment	8650		0	5	0	0	0	0	0	0	0	0	3,539	299,715
32	Total Transmission			$0	$5	$(14,334)	$0	$0	$0	$4,699,556	$0	$0	$0	$4,816,188	$9,126,739
	DISTRIBUTION OPERATIONS														
33	Supervision and Engineering	8700		$0	2	$(1,842)	$0	$0	$0	$0	$0	$0	$0	$97,839	$2,734,374
34	Distribution Load Dispatch	8710		0	0	0	0	0	0	0	0	0	0	(4,646)	585,292
35	Mains & Services	8740		0	2,464	(39,958)	0	0	0	0	0	0	0	464,245	15,725,110
36	Meas & Reg. Stat. Exp. - General	8750		0	0	(4,721)	0	0	0	0	0	0	0	51,007	1,360,751
37	Meas & Reg. Stat. Exp. - Ind.	8760		0	0	0	0	0	0	0	0	0	0	1,079	91,108
38	Meas & Reg. Stat. Exp. - City Gate	8770		0	1	(782)	0	0	0	0	0	0	0	2,247	98,743
39	Meter & House Reg. Exp.	8780		0	2,494	(109,137)	0	0	0	0	0	0	0	917,847	15,709,603
40	Customer Installation Exp	8790		0	0	0	0	0	0	0	0	0	0	343	10,745
41	Other Expense	8800		0	685	(11,084)	0	0	0	0	0	0	0	57,797	3,289,838
42	Rents	8810		0	0	0	0	0	0	0	0	0	0	0	117,124
43	Corporate & TGS Division Expenses	8820		0	0	0	0	0	0	0	0	0	0	0	0
44	Total Distribution Operations			$0	$5,647	$(167,524)	$0	$0	$0	$0	$0	$0	$0	$1,587,760	$39,722,687
	DISTRIBUTION MAINTENANCE														
45	Supervision and Engineering	8850		$0	$0	$(295)	$0	$0	$0	$0	$0	$0	$0	$730	$18,992
46	Struct. & Improv.	8860		0	0	0	0	0	0	0	0	0	0	87	2,374,207
47	Mains	8870		0	1,521	(43,215)	0	0	0	0	0	0	0	335,767	8,519,857
48	Meas. & Reg. Stat. Exp. - Gen	8890		0	7	(14,796)	0	0	0	0	0	0	0	128,129	3,146,858
49	Meas. & Reg. Stat. Exp. - Ind.	8900		0	0	(11,025)	0	0	0	0	0	0	0	98,128	1,559,644
50	Meas. & Reg. Stat. Exp. - City Gate	8910		0	0	0	0	0	0	0	0	0	0	805	69,364
51	Maintenance of Services	8920		0	319	(20,192)	0	0	0	0	0	0	0	217,408	3,834,449

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	TEXAS FRANCHISE TAX ADJ G-17	REGULATORY STORES LOAD ADJ G-18	TWE LOAD ADJ G-19	EXP ADJ G-20	DISTRIGAS % ADJ G-21	CAUSAL % ADJ G-22	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-23	EXCESS DEFERERED INCOME TAX AMORTIZATION ADJ G-24	CREDIT CARD PROCESSING FEES ADJ G-25	CUSTOMER ASSISTANCE PROGRAMS ADJ G-26	TOTAL ADJUSTMENTS	TEST YEAR ADJUSTED
				(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)
52	Meters & House Reg.	8930		0	0	0	0	0	0	0	0	0	0	1,179	28,021
53	Other Equipment	8940		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
55	Clearing - Meter Shop - Large Meters	8960		0	0	0	0	0	0	0	0	0	0	0	0
56	Total Distribution Maintenance			$0	$1,847	$(89,523)	$0	$0	$0	$0	$0	$0	$0	$782,233	$19,551,393
57	Total Distribution Expense			$0	$7,494	$(257,047)	$0	$0	$0	$0	$0	$0	$0	$2,369,992	$59,274,081

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	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)	CREDIT CARD PROCESSING FEES ADJ G-25 (z)	CUSTOMER ASSISTANCE PROGRAMS ADJ G-26 (aa)	TOTAL ADJUSTMENTS (ab)	TEST YEAR ADJUSTED (ac)
	CUSTOMER ACCOUNTING														
58	Supervision	9010		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$645
59	Meter Reading	9020		0	6	(7,764)	0	0	0	0	0	0	0	64,602	1,423,705
60	Customer Accounting	9030		0	0	(228)	0	0	0	0	0	3,681,255	0	3,652,814	11,808,882
61	Bad Debts	9040		0	0	0	0	0	0	0	0	0	0	1,111,731	3,072,203
62	Miscellaneous	9050		0	0	0	0	0	0	0	0	0	0	616	869,396
63	Total Customer Accounting			$0	$6	$(7,992)	$0	$0	$0	$0	$0	$3,681,255	$0	$4,829,763	$17,174,830
	CUSTOMER INFORMATION														
64	Supervision	9070		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
65	Customer Assistance Expense	9080		0	0	0	0	0	0	0	0	0	0	150,160	2,348,730
66	Inform. & Instruct. Adver. Exp.	9090		0	0	0	0	0	0	0	0	0	0	0	160,487
67	Customer Svc and Informational Svc	9100		0	0	0	0	0	0	0	0	0	0	0	0
68	Total Customer Information			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$150,160	$2,509,218
	SALES														
69	Supervision	9110		$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	(5,000)	1,630
71	Advertising	9130		0	0	0	0	0	0	0	0	0	60,000	56,972	191,835
72	Employee Sales Referrals	9140		0	0	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	0	0
74	Total Sales			$0	$0	$0	$0	$0	$0	$0	$0	$0	$60,000	$51,972	$193,465
75	Total Customer Accounts Expense			$0	$6	$(7,992)	$0	$0	$0	$0	$0	$3,681,255	$60,000	$5,031,894	$19,877,513
	ADMINISTRATIVE & GENERAL														
76	Salaries	9200		$0	$0	$0	$0	$0	$0	$0	$0	$0	$104,000	$125,506	$17,043,853
77	Office Supplies & Expenses	9210		0	63	0	0	0	0	0	0	0	2,000,000	1,938,462	4,293,863
78	Transferred Credit	9220		0	0	0	0	0	0	0	0	0	0	0	(15,292,445)
79	Outside Services	9230		0	0	0	0	0	0	0	0	0	463,000	463,000	1,433,825
80	Property Insurance	9240		0	0	0	0	0	0	0	0	0	0	38,438	831,344
81	Injuries & Damages	9250		0	0	0	0	0	0	0	0	0	0	(1,078,024)	3,070,138
82	Employee Pensions & Benefits	9260		0	0	0	0	0	0	0	0	0	0	1,964,076	13,071,750
83	A&G Franchise Elections	9270		0	0	0	0	0	0	0	0	0	0	0	0
84	Regulatory Commission Expenses	9280		0	0	0	0	0	0	0	0	0	0	(3)	681,119
85	Duplicate Charges- Credit	9290		0	0	0	0	0	0	0	0	0	0	0	0
86	General Advertising Expense	9301		0	0	0	0	0	0	0	0	0	0	0	57
87	Misc. General Expenses	9302		0	0	0	0	1,330,447	0	0	0	0	0	(8,586,674)	47,145,862
88	Rents	9310		0	0	0	0	0	0	0	0	0	0	207,129	1,648,068
89	Maintenance of General Plant	9320		0	0	0	0	0	0	0	0	0	0	0	608,053
90	Misc. General Expenses	9400's		0	0	0	0	0	0	0	0	0	0	0	0
91	Total Administrative & General Expense			$0	$63	$0	$0	$1,330,447	$0	$0	$0	$0	$2,567,000	$(4,928,090)	$74,535,487
92	Total Operating Expense			$715,000	$7,568	$(279,373)	$106,852	$1,330,447	$0	$4,699,556	$(2,272,038)	$3,681,255	$2,627,000	$(131,750,915)	$275,648,313
93	Earnings Before Income Tax & Interest Expense			$(715,000)	$(7,568)	$279,373	$(106,852	$(1,330,447)	$0	$(4,699,556)	$2,272,038	$(3,681,255)	$(2,627,000)	$29,021,804	$142,111,072

NOTE 2:

Account 4073	$632,284
Test Year 2024 Pension & OPEB Amortization	386,093
Test Year 2024 Amortization expense of regulatory asset	246,190.53
	$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NUMBER	SUB ACCOUNT	DIRECT PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL DIRECT AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
	REVENUE							
1	Gas Sales Revenue	480-482		$495,033,173	$0	$0	$0	$495,033,173
2	Forfeited Discounts	4870		0	0	0	0	0
3	Misc Fees	4880		4,221,356	0	0	0	4,221,356
4	Transportation	4893		20,137,876	0	0	0	20,137,876
5	Misc. Rent Revenue	4930		0	0	0	0	0
6	Other Utility Revenue	4950		1,096,091	0	0	0	1,096,091
7	Total Revenue			$520,488,496	$0	$0	$0	$520,488,496
8	COST OF GAS	805		$155,312,003	$0	$0	$0	$155,312,003
	DEPRECIATION & AMORTIZATION							
9	Depreciation and Amortization Expense	4030-4050		$63,312,870	$230,147	$8,083,697	$8,083,697	$71,626,713
10	Reg Asset Amortization Expense (Note 2)	4073		632,284	0	0	0	632,284
11	Total Depr. & Amort.			$63,945,154	$230,147	$8,083,697	$8,083,697	$72,258,997
	TAXES OTHER THAN INCOME							
12	Payroll	4081		$0	$0	$3,625,574	$3,625,574	$3,625,574
13	Ad Valorem	4081	190	17,854,051	0	0	0	17,854,051
14	Revenue Related	4081	133, 138 & 140	21,668	0	0	0	21,668
15	Other	4081	131, 233 & 995	0	0	1,891,175	1,891,175	1,891,175
16	Total Taxes Other Than Income			$17,875,719	$0	$5,516,749	$5,516,749	$23,392,468
17	Excess Deferred Income Tax Amortization	4101	102	$0		$0	$0	$0
18	Interest on Customer Deposits	4310		$911,925	$0	$0	$0	$911,925
19	Underground Storage	8140-8360		$0	$0	$0	$0	$0
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION							
20	Operation Supervision and Engineering	8500		$0	$0	$30,434	$30,434	$30,434
21	Transmission Communication Equip	8520		0	0	0	0	0
22	Compressor Station Labor and Expenses	8530		0	0	0	0	0
23	Mains Expenses	8560		2,163,646	0	497,806	497,806	2,661,451
24	Measuring and Regulating Station Expenses	8570		635,987	0	2,527	2,527	638,514
25	Trans/Compression of Gas by Others	8580		0	0	0	0	0
26	Other Expenses	8590		0	0	0	0	0
27	Rent	8600		92,805	0	2,446	2,446	95,251
28	Maintenance Supervision and Engineering	8610		0	0	2,549	2,549	2,549
29	Maintenance of Mains	8630		355,242	0	230,910	230,910	586,152
30	Maintenance of Compressor Station Equipment	8640		24	0	0	0	24
31	Maintenance of Measuring and Regulating Station Equipment	8650		296,176	0	0	0	296,176
32	Total Transmission			$3,543,880	$0	$766,672	$766,672	$4,310,552
	DISTRIBUTION OPERATIONS							
33	Supervision and Engineering	8700		$1,311,547	$0	$1,324,988	$1,324,988	$2,636,535
34	Distribution Load Dispatch	8710		0	0	589,938	589,938	589,938
35	Mains & Services	8740		14,964,956	0	295,909	295,909	15,260,865
36	Meas & Reg. Stat. Exp. - General	8750		1,278,756	0	30,988	30,988	1,309,744
37	Meas & Reg. Stat. Exp. - Ind.	8760		17,535	0	72,493	72,493	90,028
38	Meas & Reg. Stat. Exp. - City Gate	8770		78,295	0	18,201	18,201	96,496
39	Meter & House Reg. Exp.	8780		14,681,829	0	109,927	109,927	14,791,756
40	Customer Installation Exp	8790		10,283	0	118	118	10,401
41	Other Expense	8800		2,558,249	0	673,792	673,792	3,232,040
42	Rents	8810		117,124	0	0	0	117,124
43	Corporate & TGS Division Expenses	8820		0	0	0	0	0
44	Total Distribution Operations			$35,018,574	$0	$3,116,354	$3,116,354	$38,134,928
	DISTRIBUTION MAINTENANCE							
45	Supervision and Engineering	8850		$18,262	$0	$0	$0	$18,262
46	Struct. & Improv.	8860		2,371,209	0	2,911	2,911	2,374,120
47	Mains	8870		8,180,158	0	3,933	3,933	8,184,091
48	Meas. & Reg. Stat. Exp. - Gen	8890		3,009,398	0	9,331	9,331	3,018,730
49	Meas. & Reg. Stat. Exp. - Ind.	8900		1,455,329	0	6,187	6,187	1,461,516
50	Meas. & Reg. Stat. Exp. - City Gate	8910		68,559	0	0	0	68,559
51	Maintenance of Services	8920		3,615,437	0	1,604	1,604	3,617,041
52	Meters & House Reg.	8930		26,842	0	0	0	26,842
53	Other Equipment	8940		0	0	0	0	0
54	Clearing - Meter Shop - Small Meters	8950		0	0	0	0	0
55	Clearing - Meter Shop - Large Meters	8960		0	0	0	0	0
56	Total Distribution Maintenance			$18,745,194	$0	$23,967	$23,967	$18,769,161
57	Total Distribution Expense			$53,763,768	$0	$3,140,320	$3,140,320	$56,904,088
	CUSTOMER ACCOUNTING							
58	Supervision	9010		$0	$0	$645	$645	$645

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NUMBER	SUB ACCOUNT	DIRECT PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL DIRECT AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
59	Meter Reading	9020		1,359,103	0	0	0	1,359,103
60	Customer Accounting	9030		164,347	0	7,991,721	7,991,721	8,156,068
61	Bad Debts	9040		1,960,471	0	0	0	1,960,471
62	Miscellaneous	9050		58,151	0	810,628	810,628	868,780
63	Total Customer Accounting			$3,542,073	$0	$8,802,995	$8,802,995	$12,345,067
	CUSTOMER INFORMATION							
64	Supervision	9070		$0	$0	$0	$0	$0
65	Customer Assistance Expense	9080		1,868,028	0	330,543	330,543	2,198,571
66	Inform. & Instruct. Adver. Exp.	9090		0	0	160,487	160,487	160,487
67	Customer Svc and Informational Svc	9100		0	0	0	0	0
68	Total Customer Information			$1,868,028	$0	$491,030	$491,030	$2,359,058
	SALES							
69	Supervision	9110		$0	$0	$0	$0	$0
70	Demonstrating and Selling Expense	9120		6,630	0	0	0	6,630
71	Advertising	9130		134,458	0	406	406	134,863
72	Employee Sales Referrals	9140		0	0	0	0	0
73	Misc. Gas Sales Expense	9163		0	0	0	0	0
74	Total Sales			$141,088	$0	$406	$406	$141,493
75	Total Customer Accounts Expense			$5,551,188	$0	$9,294,431	$9,294,431	$14,845,619
	ADMINISTRATIVE & GENERAL							
76	Salaries	9200		$601,004	$0	$16,317,343	$16,317,343	$16,918,347
77	Office Supplies & Expenses	9210		(211,289)	0	2,566,690	2,566,690	2,355,401
78	Transferred Credit	9220		0	0	(15,292,445)	(15,292,445)	(15,292,445)
79	Outside Services	9230		83,715	0	887,110	887,110	970,825
80	Property Insurance	9240		0	0	792,906	792,906	792,906
81	Injuries & Damages	9250		(655,971)	0	4,804,133	4,804,133	4,148,162
82	Employee Pensions & Benefits	9260		2,474,027	0	8,633,646	8,633,646	11,107,674
83	A&G Franchise Elections	9270		0	0	0	0	0
84	Regulatory Commission Expenses	9280		621,333	0	59,789	59,789	681,122
85	Duplicate Charges- Credit	9290		0	0	0	0	0
86	General Advertising Expense	9301		0	0	57	57	57
87	Misc. General Expenses	9302		117,579	0	55,614,957	55,614,957	55,732,536
88	Rents	9310		54,412	0	1,386,527	1,386,527	1,440,939
89	Maintenance of General Plant	9320		5,895	0	602,158	602,158	608,053
90	Misc. General Expenses	9400's		0	0	0	0	0
91	Total Administrative & General Expense			$3,090,706	$0	$76,372,872	$76,372,872	$79,463,578
92	Total Operating Expense			$303,994,342	$230,147	$103,174,740	$103,174,740	$407,399,228
93	Earnings Before Income Tax & Interest Expense			$216,494,154	$(230,147)	$(103,174,740)	$(103,174,740)	$113,089,268

Note 1: Allocation Factor 100.00 %

Note 2: See "WKP G.a.1 Op Inc Adjs" for Account 4073 Reconcilation

Source: WKP G.a.2 Book Op Inc (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$770,228	$0	$0	$770,228
2	4030	4030300	DEPR EXP-TEXAS 8.209 ACCRUAL	0	0	0	0
3	4030	4030500	DEPRECIATION EXPENSE - NSC	(212)	0	0	(212)
4	4030	4030995	DEPR INDIRECT ALLOCATION	0	2,117,057	5,179,615	7,296,672
5	4043	4043100	AMORT OF GAS PLANT	17,001	0	0	17,001
6	4043	4043500	AMORT OF GAS PLANT - NSC	8	0	0	8
7	4081	4081100	GEN TAX O/H TRF TO CAPITAL	(2,980,795)	0	0	(2,980,795)
8	4081	4081101	GEN TAX FED UNEMPL INS TAX	44,622	0	0	44,622
9	4081	4081102	GEN TAX FICA	5,934,212	0	0	5,934,212
10	4081	4081103	GEN TAX FICA INCENTIVE	458,476	0	0	458,476
11	4081	4081104	GEN TAX FICA LTI	6,596	0	0	6,596
12	4081	4081131	GEN TAX SALES TAX ALLOWANCE	(61,453)	0	0	(61,453)
13	4081	4081132	GEN TAX STATE UNEMPL INS	162,464	0	0	162,464
14	4081	4081995	GEN TAX DISTRIGAS ALLOCATION	0	0	1,952,628	1,952,628
15	4091	4091100	CURRENT INCOME TAX ACCR	0	0	0	0
16	4101	4101100	DEFERRED INCOME TAX ACCR	0	0	0	0
17	4101	4101102	DEFERRED INCOME TAX AMORTIZATION EXCESS DTL	0	0	0	0
18	4140	4140230	MISC UTIL INCOME-DISTR	0	0	0	0
19	4170	4170110	MISC NON UTIL REV	0	0	0	0
20	4170	4170112	MISC NONUTIL REV CNG EXCISE TAX	0	0	0	0
21	4190	4190110	INTEREST INCOME TAXABLE	0	0	0	0
22	4191	4191120	INT CAP AFTER CONSTRUC	0	0	0	0
23	4210	4210100	MISC NONOPERATING INCOME	0	0	0	0
24	4210	4210995	MISC NONOP INCOME DISTRIGAS ALLOCATION	0	0	0	0
25	4261	4261210	CIVIC EXPENSES - CONTRIBUTIONS	0	0	0	0
26	4261	4261211	CIVIC EXPENSES - CHAMBER OF COMMERCE SPONSORSHIPS	0	0	0	0
27	4261	4261213	CIVIC EXPENSES - PROFESSIONAL ASSOCIATIONS SPONSORSHIPS	0	0	0	0
28	4261	4261225	DONATIONS-OTHER 501 (C)(3)	0	0	0	0
29	4264	4264102	GOVERNMENTAL AFFAIRS EXPENSE	0	0	0	0
30	4265	4265101	MISCELLANEOUS NONOPERATING EXPENSES	0	0	0	0
31	4265	4265116	WRITE-OFF DISALLOWED CAPITAL	0	0	0	0
32	4265	4265995	MISC NONOP DISTRIGAS ALLOCATION	0	0	0	0
33	4300	4300901	ALLOC INTERCO INTEREST	0	0	0	0
34	4310	4310901	ST DEBT INT EXP INTERCO	0	0	0	0
35	4320	4320100	INT CAP DURING CONSTRUC	0	0	0	0
36	4320	4320101	INT CAP AFTER CONSTRUC	0	0	0	0
37	4800	4800111	UTIL GAS SALES RES UNBILLED	0	0	0	0
38	4800	4800114	UTIL GAS SALES RES EST	0	0	0	0
39	4810	4810111	UTIL GAS SALES COMM UNBILLED	0	0	0	0
40	4810	4810211	UTIL GAS SALES IND UNBILLED	0	0	0	0
41	4820	4820111	UTIL GAS SALES CITY GATE UNBILLED	0	0	0	0
42	4880	4880100	SVC REVENUE MISC	0	0	0	0
43	4950	4950300	OTH GAS REV UTIL MISC	0	0	0	0
44	8040	8040100	NATURAL GAS CITY GATE PURCHASES	0	0	0	0
45	8050	8050108	OTH GAS PURCH RESIDENTIAL UNBILLED	0	0	0	0
46	8050	8050134	OTH GAS PURCH UNBILLED COMM	0	0	0	0
47	8050	8050144	OTH GAS PURCH UNBILLED IND	0	0	0	0
48	8050	8050208	OTH GAS PURCH PUBLIC AUTHORITY UNBILLED	0	0	0	0
49	8051	8051100	OTH GAS PURCH UNRECOV GAS ADJ	0	0	0	0
50	8500	8500100	TRANS GEN SUPERVISION	22,645	7,789	0	30,434
51	8560	8560100	TRANS MAINS MISC EXP	157,890	84	0	157,974
52	8560	8560207	TRANS MAINS TOOLS	398	0	0	398
53	8560	8560246	TRANS MAINS WEED CONTROL	308	0	0	308
54	8560	8560250	TRANS MAINS PIPELINE INTEGRITY MANAGEMENT	94,323	241,091	0	335,413
55	8560	8560402	TRANS MAINS CODE LEAK SURVEY	1,999	0	0	1,999
56	8560	8560405	TRANS MAINS MOBILE LEAK SURVEY	1,713	0	0	1,713
57	8570	8570100	TRANS MEAS & REG ST MISC EXP	882	0	0	882
58	8570	8570123	TRANS MEAS & REG ST - SCADA	1,102	0	0	1,102
59	8570	8570247	TRANS MEAS & REG ST PAINTING AND WRAPPING	543	0	0	543
60	8600	8600206	TRANS RENT VEHICLE	2,446	0	0	2,446
61	8610	8610100	TRANS MNT GEN SUPERVISION	0	2,549	0	2,549
62	8630	8630100	TRANS MNT MAINS	199,750	0	0	199,750
63	8630	8630115	TRANS MNT MAINS REPAIRS FR LEAKAGE	31,147	0	0	31,147
64	8630	8630250	TRANS MNT MAINS PIPELINE INTEGRITY MANAGEMENT	0	12	0	12
65	8700	8700100	DISTR GEN SUPERVISION	1,054,196	270,792	0	1,324,988
66	8710	8710100	DISTR LOAD DISPATCHING	589,883	0	0	589,883

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
67	8710	8710228	DISTR LOAD PERS USE AUTO	55	0	0	55
68	8740	8740100	DISTR MAINS & SVC MISC	882	249	0	1,131
69	8740	8740207	DISTR MAINS & SVC TOOLS	4,212	2,282	0	6,494
70	8740	8740225	DISTR MAINS & SVC UNIFORMS	0	175	0	175
71	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT PROGRAM	6,986	3,553	0	10,539
72	8740	8740302	DISTR MAINS & SVC CODE LINE LOCATE	25,886	0	0	25,886
73	8740	8740400	DISTR MAINS & SVC LEAK SURVEY MAINS	249,543	0	0	249,543
74	8740	8740404	DISTR MAINS & SVC RECHECK LEAK SURVEY	1,142	0	0	1,142
75	8740	8740405	DISTR MAINS & SVC MOBILE LEAK SURVEY	1,000	0	0	1,000
76	8750	8750100	DISTR MEAS & REG ST MISC	29,225	0	0	29,225
77	8750	8750114	DISTR MEAS & REG ST ODORIZATION	661	0	0	661
78	8750	8750123	DISTR MEAS & REG ST SCADA OPERATIONS	1,102	0	0	1,102
79	8760	8760100	DISTR IND MEAS & REG ST MISC	72,493	0	0	72,493
80	8770	8770100	DISTR C G MEAS & REG ST MISC	17,760	0	0	17,760
81	8770	8770104	DISTR C G METER INSPECTING/TESTING	441	0	0	441
82	8780	8780100	DISTR MEAS & HOUSE REG MISC	1,243	66,631	0	67,874
83	8780	8780112	DISTR MEAS & HOUSE REG TURN ON/OFFS & SVC ORDER	153	0	0	153
84	8780	8780139	DISTR MEAS & HOUSE MEAS SVC CTR	0	41,900	0	41,900
85	8790	8790100	DISTR CUST INSTALL MISC EXP	118	0	0	118
86	8800	8800100	DISTR OTHER EXPENSES	589,725	28,078	0	617,803
87	8800	8800120	DISTR OTH SVC BLDG	712	0	0	712
88	8800	8800209	DISTR OTH ENVIRONMENTAL EXP	15,647	0	0	15,647
89	8800	8800210	DISTR OTH OFFICE SUPPLIES	113	49	0	162
90	8800	8800221	DISTR OTH TRAINING & EDUCATION	39,226	0	0	39,226
91	8800	8800226	DISTR OTH POSTAGE	29	15	0	44
92	8800	8800400	DISTR OTH SAFETY	72	126	0	198
93	8860	8860120	DISTR MNT STRUC & IMPROV SVC BLDG	2,911	0	0	2,911
94	8870	8870100	DISTR MNT MAINS MISC	1,028	0	0	1,028
95	8870	8870101	DISTR MNT MAINS CATHODIC PROTECT	2,392	0	0	2,392
96	8870	8870120	DISTR MNT MAINS LEAK REPAIR	512	0	0	512
97	8890	8890100	DISTR MNT MEAS & REG ST MISC	9,331	0	0	9,331
98	8900	8900100	DISTR MNT IND MEAS & REG ST MISC	6,187	0	0	6,187
99	8920	8920100	DISTR MNT SERVICES MISC	1,604	0	0	1,604
100	9010	9010100	CUST ACCTG/COLL SUPERVISION	421	42	0	463
101	9010	9010220	CUST ACCTG/COLL SUPER MEMBERSHIP DUES	0	182	0	182
102	9030	9030100	CUST REC/COLLEC EXP MISC	1,752,670	15	0	1,752,685
103	9030	9030110	CUST RECORDS EXPENSE	3,589,103	333	0	3,589,436
104	9030	9030125	CUST REC/COLLEC LOCKBOX	203,394	0	0	203,394
105	9030	9030170	CUST COLLEC AGENCY FEE	194,858	0	0	194,858
106	9030	9030210	CUST REC/COLLEC OFFICE SUPPLIES	228,515	0	0	228,515
107	9030	9030226	CUST REC/COLLEC POSTAGE	2,022,833	0	0	2,022,833
108	9050	9050100	CUST ACCTS MISC EXP	554	601,076	0	601,629
109	9050	9050110	CUST ACCTS CUSTOMER PROTECTION PROGRAM	18	62	0	80
110	9050	9050120	CUST ACCTS SVC BLDG	206,197	0	0	206,197
111	9050	9050221	CUST ACCTS TRAINING & EDUCATION	2,721	0	0	2,721
112	9080	9080100	CUST ASST MISC EXP	330,543	0	0	330,543
113	9090	9090321	INFO/INSTRUC CORP COMM DIRECT	160,487	0	0	160,487
114	9130	9130100	ADVERTISING MISC EXP	406	0	0	406
115	9200	9200100	A&G SALARIES	6,052,147	3,263,893	0	9,316,040
116	9200	9200700	A&G SALARIES INCENTIVE PLAN	6,279,484	0	0	6,279,484
117	9200	9200712	A&G SALARIES ESPP	253,157	0	0	253,157
118	9200	9200713	A&G SALARIES LT INCENT-RESTRICTED	201,110	0	0	201,110
119	9200	9200714	A&G SALARIES LT INCENT-PERFORMANCE	267,552	0	0	267,552
120	9210	9210100	A&G SUPPLIES & EXPENSES MISC	726,468	97,962	0	824,430
121	9210	9210102	A&G S&E EMPL MISC	10,959	0	0	10,959
122	9210	9210106	A&G COVID 19 RESPONSE	3,300	0	0	3,300
123	9210	9210201	A&G S&E ASSOC MTGS	14,601	537	0	15,138
124	9210	9210202	A&G S&E SUBS/PUBLICATIONS	59,038	41	0	59,080
125	9210	9210205	A&G S&E AUTO	2,720	144	0	2,864
126	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	191,599	51,998	0	243,597
127	9210	9210209	A&G S&E ENVIRONMENTAL EXP	9,617	0	0	9,617
128	9210	9210210	A&G S&E OFFICE SUPPLIES	480	127	0	608
129	9210	9210220	A&G S&E MEMBERSHIP DUES	6,015	3,563	0	9,578
130	9210	9210221	A&G S&E TRAINING & ED	63,951	2,910	0	66,861
131	9210	9210222	A&G S&E LODGING	538	501	0	1,039
132	9210	9210223	A&G S&E AIRFARE	1,436	97	0	1,533

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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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)
133	9210	9210226	A&G S&E POSTAGE	1,368	9	0	1,377
134	9210	9210228	A&G S&E PERS USE AUTO	34	205	0	239
135	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	9,476	0	0	9,476
136	9210	9210301	A&G S&E TELE LONG DISTANCE	68,903	0	0	68,903
137	9210	9210303	A&G S&E TELE LOCAL LINES	137,285	0	0	137,285
138	9210	9210304	A&G S&E CELLULAR PHONES	387,708	0	0	387,708
139	9210	9210308	A&G S&E TELE DATA	306,524	0	0	306,524
140	9210	9210401	A&G S&E BLDG & GROUNDS	374	0	0	374
141	9210	9210402	A&G S&E OTH BLDG OPER	126,250	52,096	0	178,347
142	9210	9210404	A&G S&E MAIL ROOM	5,730	0	0	5,730
143	9210	9210411	A&G S&E TRAIN MGMT PROGRAM	1,420	0	0	1,420
144	9210	9210412	A&G S&E EMPL TRAINING PROGRAM	0	150	0	150
145	9210	9210413	A&G S&E TECH/CUST SVC TRAINING	205,246	0	0	205,246
146	9210	9210417	A&G S&E VISA/IMMIGRATION AND NATIONALITY COSTS	0	(513)	0	(513)
147	9210	9210807	A&G S&E TRANSITION COSTS	23,416	0	0	23,416
148	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	70	0	0	70
149	9210	9210880	A&G S&E Auto-NSC	(7,664)	0	0	(7,664)
150	9220	9220902	A&G TRF TO CONSTRUCTION	(15,292,445)	0	0	(15,292,445)
151	9230	9230110	A&G OUTSIDE SVC MISC	135,514	125,267	0	260,781
152	9230	9230115	A&G OUTSIDE SVC LEGAL REGULATORY	75,531	0	0	75,531
153	9230	9230120	A&G OUTSIDE SVC LEGAL	417,682	0	0	417,682
154	9230	9230130	A&G OUTSIDE SVC AUDIT FEES	65,000	0	0	65,000
155	9230	9230302	A&G OUTSIDE SVC IT APPLICATION SUPPORT	0	4,430	0	4,430
156	9230	9230307	A&G OUTSIDE SVC CLOUD COMPUTING ARRANGEMENTS	48,190	12,420	0	60,611
157	9230	9230810	A&G OUTSIDE SVC CONTRACT	3,075	0	0	3,075
158	9240	9240100	A&G PROPERTY INSURANCE PREMIUMS	792,906	0	0	792,906
159	9250	9250100	A&G INSURANCE	65,130	0	0	65,130
160	9250	9250120	A&G INJ & DAMAGES WORKERS COMP	304,064	0	0	304,064
161	9250	9250130	A&G INJ & DAMAGES 3RD PARTY GENERAL LIABILITY DAMAGES	(543,282)	0	0	(543,282)
162	9250	9250135	A&G INJ & DAMAGES PROPERTY	0	0	0	0
163	9250	9250140	A&G INJ & DAMAGES 3RD PARTY VEHICLE ACCIDENT DAMAGES	218,884	0	0	218,884
164	9250	9250180	A&G INJ & DAMAGES LIABILITY INSURANCE PREMIUMS	4,853,481	0	0	4,853,481
165	9250	9250200	A&G INJ & DAMAGES MISC SETTLEMENTS	(94,144)	0	0	(94,144)
166	9260	9260101	A&G EMPL BEN 401(K) CO MATCH	3,806,367	0	0	3,806,367
167	9260	9260102	A&G EMPL BEN 401(K) ADMIN	114,933	30,588	0	145,521
168	9260	9260112	A&G EMPL BEN SERP ADMIN	0	282	0	282
169	9260	9260115	A&G EMPL BEN PENSION ADMIN	31,419	5,275	0	36,695
170	9260	9260141	A&G EMPL BEN PROFIT SHARING	2,620,306	0	0	2,620,306
171	9260	9260190	A&G EMPL BEN RESERVE	10,530,975	0	0	10,530,975
172	9260	9260192	A&G EMPL BEN RESERVE IBNR	(761,433)	0	0	(761,433)
173	9260	9260197	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	314,357	0	0	314,357
174	9260	9260198	A&G EMPL BEN ACCR PSP ON STI	210,016	0	0	210,016
175	9260	9260302	A&G EMPL BEN TUITION LOANS	34,422	2,133	0	36,555
176	9260	9260307	A&G EMPL BEN EMPLOYEE EVENTS	20,951	8	0	20,959
177	9260	9260310	A&G EMPL BEN SVC RECOGNITION	59,200	0	0	59,200
178	9260	9260326	A&G EMPL BEN EMPL ASST PROGRAM	21,100	0	0	21,100
179	9260	9260328	A&G EMPL BEN DISABILITY	61,181	0	0	61,181
180	9260	9260337	A&G EMPL BEN WELLNESS PROGRAM	0	74	0	74
181	9260	9260413	A&G EMPL BEN ACTUARY ONE GAS PENSION-SC	1,204,699	0	0	1,204,699
182	9260	9260431	A&G EMPL BEN ACTUARY OPEB-SC	30,824	0	0	30,824
183	9260	9260511	A&G EMPL BEN ACTUARY SERP-NSC	3,362	0	0	3,362
184	9260	9260513	A&G EMPL BEN ACTUARY ONE GAS PENSION-NSC	(1,215,596)	0	0	(1,215,596)
185	9260	9260531	A&G EMPL BEN ACTUARY OPEB-NSC	127,641	0	0	127,641
186	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL	(9,481,479)	0	0	(9,481,479)
187	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC	668,122	0	0	668,122
188	9260	9260995	A&G EMPL BEN SERP DISTRIGAS ALLOC	0	0	240,966	240,966
189	9260	9260996	A&G EMPL BEN PENSION DISTRIGAS	0	0	(56,182)	(56,182)
190	9260	9260997	A&G EMPL BEN FAS 106 DISTRIGAS ALLOC	0	0	9,136	9,136
191	9280	9280100	A&G REG COMMISSION EXP	59,789	0	0	59,789
192	9301	9301140	A&G ADVERTISING BRANDING	57	0	0	57
193	9302	9302100	A&G MISC EXPENSES	648	514	0	1,162
194	9302	9302105	A&G MISC INDUSTRY DUES	8,100	312	0	8,412
195	9302	9302106	A&G MISC AGA INDUSTRY DUES	99,988	0	0	99,988
196	9302	9302120	A&G MISC EMPL MOVING	94,493	1,474	0	95,967
197	9302	9302310	A&G MISC UNITED WAY	6,800	0	0	6,800
198	9302	9302311	A&G MISC OGS VOLUNTEERS	6,624	0	0	6,624

WKP G.a.2.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
199	9302	9302320	A&G MISC DIVERSITY & INCLUSION	4,922	0	0	4,922
200	9302	9302409	A&G MISC	279	0	0	279
201	9302	9302800	A&G MISC PROCUREMENT CARD CLEARING	23,532	0	0	23,532
202	9302	9302901	A&G MISC O/H TRF TO AFFIL	1,548,081	0	0	1,548,081
203	9302	9302915	A&G MISC ROYALTY ALLOCATED	10,743,203	0	0	10,743,203
204	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	0	1,041,284	0	1,041,284
205	9302	9302995	A&G MISC DISTRIGAS ALLOC	0	0	42,034,702	42,034,702
206	9310	9310100	A&G RENTS LAND/FACILITY	1,331,550	0	0	1,331,550
207	9310	9310120	A&G RENTS EQUIPMENT	54,977	0	0	54,977
208	9320	9320140	A&G MNT AGREEMENT FEES	358,193	243,965	0	602,158
209				$45,487,984	$8,325,891	$49,360,865	$103,174,740
210							
211							

212	Calculation of O&M Expense Factor	
213		
214	Per Book Shared Services (net of the A&G transfer credit)	$103,174,740
215	Less: depreciation expense that does not get an O&M factor	(8,083,697)
216	Less: tax expense accounts	(5,516,749)
217	Total O&M Shared Service Expenses	$89,574,294
218		
219		
220		
221	Total O&M Shared Service Expenses	$89,574,294
222	Add back Account 9220902 A&G Transfer Credit/Construction Overhead	15,292,445
223	Grand Total Shared Service Expenses:	$104,866,739
224		
225	O&M effective expense factor	85.42%
226	Capitalization factor	14.58%
227		100.00%

Source: WKP G.a.2.a1 Shared Service per book (CONFIDENTIAL).xlsx

Source: WKP G.a.2.a2 Corporate Costs Allocated (CONFIDENTIAL).xlsx

SCHEDULE G-1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

REMOVE GAS REVENUE AND COST OF GAS

LINE NO.	DESCRIPTION	AMOUNT	
		(a)	
1	Remove Cost of Gas Revenue Collected through Cost of Gas Clause	$155,312,003	Source: SCH G-2 and G-3 Revenue Reconciliation.xlsx
2	Remove Test Year Cost of Gas Expense	(155,312,003)	Source: SCH G-2 and G-3 Revenue Reconciliation.xlsx
3	Net Adjustment	$0	

SCHEDULE G-2

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

NORMALIZE GAS SALES REVENUE

LINE NO.	DESCRIPTION	TOTAL # OF BILLS	CCF	REVENUE	
		(a)	(b)	(c)	
1	Operating Gas Sales Revenue (1):	8,409,315	363,185,533	$495,033,173	Source: SCH G-2 and G-3 Proof of Revenue.xlsx, SCH G-2 and G-3 Billing Determinants By Class.xlsx, SCH G-2 and G-3 Standard Pressure Base Adjustment.xlsx
2	Less: Test Year Gas Costs collected through Cost of Gas Clause			(155,312,003)	
3	Base Sales Revenue as Recorded	8,409,315	363,185,533	$339,721,171	
	Adjustments:				
4	Reclass and Annualization Adjustment			$53,727,427	Source: SCH G-2 and G-3 Reclass Annualization Adjustment.xlsx
5	Remove Test Year GRIP			(47,204,992)	Source: SCH G-2 and G-3 Proof of Revenue.xlsx
6	2025 GRIP Annualization			45,108,859	Source: SCH G-2 and G-3 2025 GRIP Annualization.xlsx
7	Remove Test Year WNA			(9,494,840)	Source: SCH G-2 and G-3 Proof of Revenue.xlsx
8	Weather Normalization		21,167,459	9,445,264	Source: SCH G-2 Weather Adjustment 10 Norm.xlsx, SCH G-2 HDD Detail.xlsx
9	Customer Growth (Loss)	35,657	938,217	1,449,367	Source: SCH G-2 Growth Adjustment.xlsx
10	Total Adjustments	35,657	22,105,676	53,031,084	
11	Base Revenue As Adjusted	8,444,972	385,291,209	$392,752,255	

Calculation of Normalized Gas Sales Revenue used for Advertising Limitation Calculation:

12	Calculation of Normalized Cost of Gas Revenue		
13	Normalized CCF		385,291,209
14	Test Year Cost of Gas Revenue	$155,312,003	
15	Test Year CCF	363,185,533	
16	Effective Rate	0.42764	0.42764
17	Normalized Cost of Gas Revenue		$164,765,933

Note 1: Operating gas sales revenue does not include franchise or gross receipt taxes.

SCHEDULE G-3

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

NORMALIZE OTHER UTILITY REVENUE

LINE NO.	DESCRIPTION	TOTAL BILLS (a)	TOTAL VOLUMES (b)	REVENUE (c)		
1	Test Year Transportation Revenue - Acct 4893	11,445	86,128,857	$20,137,876	Source:	SCH G-2 and G-3 Proof of Revenue.xlsx, SCH G-2 and G-3 Billing Determinants By Class.xlsx, SCH G-2 and G-3 Standard Pressure Base Adjustment
	Adjustments:					
2	Reclass and Annualization Adjustment			(15,822)	Source:	SCH G-2 and G-3 Reclass Annualization Adjustment.xlsx
3	Remove Test Year GRIP			(884,303)	Source:	SCH G-2 and G-3 Proof of Revenue.xlsx
4	2025 GRIP Annualization			699,129	Source:	SCH G-2 and G-3 2025 GRIP Annualization.xlsx
5	Fort Bliss CRC Annualization			71,733	Source:	SCH G-3 Fort Bliss CRC Annualization.xlsx
6	East Bliss Maintenance Agreement Annualization			300,000	Source:	SCH G-3 East Bliss Maint. Agreement Annualization.xlsx
7	Remove Estimated Revenue			(69,569)	Source:	SCH G-2 and G-3 Proof of Revenue.xlsx
8	Total Adjustments	0	0	$101,169		
9	Total Transportation Revenue As Adjusted	11,445	86,128,857	$20,239,045		
10	Test Year Service Fees - Acct 4880			$4,221,356	Source:	SCH G-2 and G-3 Revenue Reconciliation.xlsx
11	Service Fee Annualization			546,729	Source:	SCH G-3 Service Fee Annualization.xlsx
12	Total Service Fee Revenue As Adjusted			$4,768,085		
13	Test Year Other Utility Revenue - Acct 4950			$1,096,091	Source:	SCH G-2 and G-3 Revenue Reconciliation.xlsx
14	Remove Interest on Storage			(1,096,091)	Source:	SCH G-2 and G-3 Proof of Revenue.xlsx
15	Remove Estimated Revenue			$0		
16	Total Other Utility Revenue As Adjusted			$0		
17	Total Transportation, Service Fees, and Other Utility Revenue As Adjusted			$25,007,130		

SCHEDULE G-4

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

BASE PAYROLL ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)
1	Hourly Base Payroll for December 2024	WKP G-4.c	$3,159,011	$506,082	$429,880	
2	Salary Base Payroll for December 2024	WKP G-4.c	1,258,803	1,046,131	6,068,483	
3	Total Base Payroll for December 2024		$4,417,815	$1,552,213	$6,498,363	
4	Annualized Hourly Base Payroll		$41,067,145	$6,579,067	$5,588,444	
5	Annualized Salary Base Payroll		15,105,640	12,553,575	72,821,795	
6	Total Proforma Base Payroll		$56,172,785	$19,132,642	$78,410,239	
7	December Merit Increase Percent		0.00%	0.00%	0.00%	
8	Adjustment to include December Merit Increases		0	0	0	
9	Total Proforma Base Payroll		$56,172,785	$19,132,642	$78,410,239	
10	Total Test Year Base Payroll	WKP G-4.b	51,292,325	19,286,372	75,320,306	
11	Total Allocable Base Payroll Adjustment (Ln 9 minus Ln 10)		$4,880,460	$(153,730)	$3,089,933	
12	Allocation to TGS		100%	100%	30.25%	
13	Allocated Base Payroll Adjustment to TGS (Ln 11 times Ln 12)		$4,880,460	$(153,730)	$934,705	
14	Allocation to Service Area	WKP A.b	100%	100.00%	100.00%	
15	Allocated Base Payroll Adjustment to Service Area (Ln 13 times Ln 14)		$4,880,460	$(153,730)	$934,705	
16	Payroll Expense Factor	WKP G-4.b	54.69%	64.28%	81.74%	
17	Test Year Base Payroll O&M Expense Adjustment (Ln 15 times Ln 16)		$2,669,094.20	$(98,811)	$764,037	
18	Adjustment Summary:					
19	Account 9302		$0	$0	$764,037	$764,037
20	Other O&M Accounts (See WKP G-4.a for Distribution by FERC Account)		2,669,094	(98,811)	0	2,570,284
21	Total		$2,669,094	$(98,811)	$764,037	$3,334,320
22	Total Test Year Base Payroll Expense after Allocation		$28,051,462	$12,396,440	$18,624,179	$59,072,081
23	Total as Adjusted Base Payroll Expense after Allocation		$30,720,556	$12,297,630	$19,388,216	$62,406,401

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$22,645	0.18%	$(174)
2	8530	0	0.00%	0	8530	0	0.00%	0
3	8560	918,994	2.81%	75,017	8560	110,103	0.85%	(844)
4	8570	355,176	1.09%	28,993	8570	543	0.00%	(4)
5	8590	0	0.00%	0	8590	0	0.00%	0
6	8610	0	0.00%	0	8610	0	0.00%	0
7	8630	118,830	0.36%	9,700	8630	230,897	1.79%	(1,770)
8	8650	37,469	0.11%	3,059	8650	0	0.00%	0
9	8700	1,167,537	3.57%	95,305	8700	1,025,693	7.96%	(7,864)
10	8710	0	0.00%	0	8710	585,953	4.55%	(4,492)
11	8740	5,346,053	16.35%	436,393	8740	275,715	2.14%	(2,114)
12	8750	593,148	1.81%	48,418	8750	27,817	0.22%	(213)
13	8760	17,535	0.05%	1,431	8760	72,493	0.56%	(556)
14	8770	33,596	0.10%	2,742	8770	17,760	0.14%	(136)
15	8780	10,861,351	33.22%	886,602	8780	153	0.00%	(1)
16	8790	3,638	0.01%	297	8790	0	0.00%	0
17	8800	829,696	2.54%	67,727	8800	449,581	3.49%	(3,447)
18	8850	10,864	0.03%	887	8850	0	0.00%	0
19	8860	926	0.00%	76	8860	0	0.00%	0
20	8870	4,003,986	12.25%	326,842	8870	512	0.00%	(4)
21	8890	1,515,234	4.63%	123,687	8890	830	0.01%	(6)
22	8900	1,157,210	3.54%	94,462	8900	0	0.00%	0
23	8910	8,535	0.03%	697	8910	0	0.00%	0
24	8920	2,515,715	7.69%	205,355	8920	1,604	0.01%	(12)
25	8930	12,499	0.04%	1,020	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	0	0.00%	0
27	9020	767,131	2.35%	62,620	9020	0	0.00%	0
28	9030	15,968	0.05%	1,303	9030	3,742,110	29.03%	(28,689)
29	9050	7,490	0.02%	611	9050	2,721	0.02%	(21)
30	9080	1,798,250	5.50%	146,790	9080	280,867	2.18%	(2,153)
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	601,004	1.84%	49,059	9200	6,040,520	46.87%	(46,310)
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	$32,697,837	100.00%	$2,669,094	Total	$12,888,520	100.00%	$(98,811)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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TEST YEAR TOTAL PAYROLL

			BASE AND OVERTIME PAYROLL						BASE						OVERTIME					
			HOURLY			SALARY			HOURLY			SALARY			HOURLY			SALARY		
LINE NO.	DESCRIPTION		PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	Capital																			
1		1010	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2		1540	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3		1630	814,070	24	47,645	169,377	0	93,225	699,806	0	37,725	169,377	0	93,225	114,264	24	9,920	0	0	0
4		1840	18,146,365	3,044,934	1,014,238	7,509,974	4,118,470	12,646,277	15,113,355	2,496,610	894,752	7,509,205	4,118,414	12,646,268	3,033,010	548,324	119,486	769	56	9
5		1860	0	0	0	0	0	15,542	0	0	0	0	0	15,542	0	0	0	0	0	0
6		2530	139,266	0	0	311,372	0	0	132,076	0	0	311,372	0	0	7,190	0	0	0	0	0
7	Total Capital		$19,099,701	$3,044,959	$1,061,883	$7,990,722	$4,118,470	$12,755,044	$15,945,237	$2,496,610	$932,477	$7,989,953	$4,118,414	$12,755,034	$3,154,463	$548,348	$129,406	$769	$56	$9
	Expense																			
8		8500	$0	$0	$0	$0	$22,645	$71,557	$0	$0	$0	$0	$22,645	$71,557	$0	$0	$0	$0	$0	$0
9		8530	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10		8560	758,417	22,461	60,810	160,577	87,642	342,844	640,425	21,204	60,629	160,485	87,642	342,844	117,992	1,257	181	92	0	0
11		8570	345,196	543	0	9,980	0	0	287,842	507	0	9,980	0	0	57,354	36	0	0	0	0
12		8590	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13		8610	0	0	0	0	0	35,038	0	0	0	0	0	35,038	0	0	0	0	0	0
14		8630	118,830	230,897	0	0	0	0	97,232	213,060	0	0	0	0	21,599	17,838	0	0	0	0
15		8650	3,869	0	0	33,600	0	0	1,682	0	0	33,600	0	0	2,187	0	0	0	0	0
16		8700	20,737	12,726	88,855	1,146,800	1,012,968	1,778,132	20,481	12,715	76,694	1,146,732	1,012,968	1,778,132	256	11	12,161	68	0	0
17		8710	0	477,838	0	0	108,115	0	0	375,176	0	0	108,115	0	0	102,661	0	0	0	0
18		8740	4,562,986	68,911	27,851	783,067	206,805	384,079	3,626,947	59,320	27,695	782,751	206,802	384,079	936,038	9,590	155	316	3	0
19		8750	441,885	0	0	151,264	27,817	0	371,399	0	0	151,264	27,817	0	70,485	0	0	0	0	0
20		8760	16,766	0	0	769	72,493	0	14,065	0	0	769	72,491	0	2701.17	0	0	0	2	0
21		8770	31,600	0	0	1,996	17,760	0	26,757	0	0	1,996	17,760	0	4842.82	0	0	0	1	0
22		8780	10,130,000	153	214,340	731,351	0	67,595	8,098,960	0	178,796	731,106	0	67,595	2,031,040	153	35,544	245	0	0
23		8790	3,638	0	0	0	0	0	3,040	0	0	0	0	0	598	0	0	0	0	0
24		8800	565,708	11,950	57,096	263,988	437,630	68,431	483,462	11,238	57,062	263,945	437,617	68,431	82,246	712	35	43	13	0
25		8850	0	0	0	10,864	0	135,612	0	0	0	10,864	0	135,612	0	0	0	0	0	0
26		8860	926	0	0	0	0	0	0	0	0	0	0	0	926.09	0	0	0	0	0
27		8870	3,590,754	512	1,540	413,232	0	0	2,751,656	0	1,540	413,189	0	0	839,098	512	0	43	0	0
28		8890	1,441,689	830	0	73,545	0	0	1,212,934	180	0	73,545	0	0	228,755	650	0	0	0	0
29		8900	1,103,411	0	0	53,799	0	0	930,350	0	0	53,799	0	0	173,061	0	0	0	0	0
30		8910	8,535	0	0	0	0	0	7,021	0	0	0	0	0	1,514	0	0	0	0	0
31		8920	2,355,340	1,604	0	160,375	0	0	1,720,647	1,604	0	160,375	0	0	634,693	0	0	0	0	0
32		8930	12,499	0	0	0	0	0	9,578	0	0	0	0	0	2,921	0	0	0	0	0
33		9010	0	0	27,534	0	0	835,113	0	0	27,442	0	0	834,929	0	0	92	0	0	184
34		9020	660,728	0	0	106,403	0	0	586,464	0	0	106,403	0	0	74,264	0	0	0	0	0
35		9030	6,102	2,718,046	98,256	9,866	1,024,064	62,143	5,887	2,707,084	97,393	9,866	1,024,064	62,143	215	10,962	863	0	0	0
36		9050	7,490	2,721	773,921	0	0	2,082,697	4,999	2,200	764,055	0	0	2,082,662	2,491	521	9,867	0	0	35
37		9080	849,463	0	0	948,787	280,867	1,043,090	795,086	0	0	948,787	280,867	1,043,090	54,377	0	0	0	0	0
38		9120	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39		9130	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
40		9200	56,566	795,966	3,523,236	544,438	5,244,554	50,069,187	56,325	723,735	3,361,665	544,438	5,244,536	50,067,925	242	72,231	161,571	0	18	1,262
41		9210	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42		9230	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42		9280	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43		9302	0	0	5,786	0	0	0	0	0	5,786	0	0	0	0	0	0	0	0	0
44		9320	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
45	Total Expense		$27,093,134	$4,345,160	$4,879,225	$5,604,703	$8,543,360	$56,975,518	$21,753,240	$4,128,024	$4,658,758	$5,603,895	$8,543,323	$56,974,037	$5,339,894	$217,136	$220,467	$808	$37	$1,481
46	Total Test Year		$46,192,835	$7,390,118	$5,941,108	$13,595,425	$12,661,831	$69,730,562	$37,698,477	$6,624,634	$5,591,235	$13,593,848	$12,661,738	$69,729,071	$8,494,358	$765,484	$349,873	$1,577	$93	$1,491
47	Payroll Expense Factor		54.69%	64.28%	81.74%															
48	Overtime Factor		22.53%	11.56%	6.26%															

Source: WKP G-4.b and WKP G-4.c Payroll TGS (CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Payroll Corporate (CONFIDENTIAL).xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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TEST YEAR TOTAL PAYROLL

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	983,446	1.64%
1840 (non TWE)	25,654,369	42.91%
1840 (TWE 1840100-1840289)	1,970	0.00%
1860	0	0.00%
2530	450,637	0.75%
Total Non-Exp Mains	$27,090,423	45.31%
Total Expense Mains	32,697,837	54.69%
Total Payroll	$59,788,260	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	24	0.00%
1840 (non TWE)	7,019,730	35.01%
1840 (TWE 1840100-1840289)	155,302	0.77%
1860	0	0.00%
2530	0	0.00%
Total Non-Exp Mains	$7,175,056	35.78%
Total Expense Mains	12,888,520	64.28%
Total Payroll	$20,051,949	100.06%

Note: Average load rate for Stores during the test year	21.86 %
Note: Average load rate for TWE during the test year	60.45 %

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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BASE PAYROLL

			BASE PAYROLL					
			HOURLY			SALARY		
LINE NO.	DESCRIPTION		PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL
			(a)	(b)	(c)	(d)	(e)	(f)
	Capital							
1		1010	$0	$0	$0	$0	$0	$0
2		1540	0	0	0	0	0	0
3		1630	59,471	0	2,904	14,759	0	11,517
4		1840	1,264,031	185,790	50,845	706,462	356,622	1,064,683
5		1860	0	0	0	0	0	0
6		2530	10,976	0	0	21,703	0	0
7	Total Capital		$1,334,479	$185,790	$53,749	$742,924	$356,622	$1,076,200
	Expense							
8		8500	$0	$0	$0	$0	$2,019	$6,356
9		8530	0	0	0	0	0	0
10		8560	48,508	1,437	3,385	15,757	0	34,194
11		8570	23,050	0	0	0	0	0
12		8590	0	0	0	0	0	0
13		8610	0	0	0	0	0	3,109
14		8630	7,914	7,202	0	0	0	0
15		8650	0	0	0	3,043	0	0
16		8700	1,628	1,004	5,917	114,771	99,245	160,188
17		8710	0	30,490	0	0	9,339	0
18		8740	314,090	3,807	1,765	74,521	17,739	32,979
19		8750	28,950	0	0	12,228	1,018	0
20		8760	0	0	0	0	5,431	0
21		8770	0	0	0	0	1,370	0
22		8780	690,437	0	12,518	67,753	0	4,854
23		8790	0	0	0	0	0	0
24		8800	40,257	1,086	5,063	24,895	41,328	5,937
25		8850	0	0	0	0	0	12,221
26		8860	0	0	0	0	0	0
27		8870	220,271	0	0	37,229	0	0
28		8890	113,334	0	0	0	0	0
29		8900	80,786	0	0	0	0	0
30		8910	0	0	0	0	0	0
31		8920	140,384	0	0	14,350	0	0
32		8930	1,401	0	0	0	0	0
33		9010	0	0	0	0	0	73,729
34		9020	42,853	0	0	9,875	0	0
35		9030	465	212,748	14,010	917	82,473	10,825
36		9050	0	0	67,673	0	0	191,761
37		9080	66,108	0	0	88,654	27,045	62,491
38		9120	0	0	0	0	0	0
39		9130	0	0	0	0	0	0
40		9200	4,095	62,516	265,801	51,885	402,502	4,393,640
41		9210	0	0	0	0	0	0
42		9230	0	0	0	0	0	0
43		9280	0	0	0	0	0	0
44		9302	0	0	0	0	0	0
45		9320	0	0	0	0	0	0
46	Total Expense		$1,824,533	$320,292	$376,132	$515,879	$689,509	$4,992,283
47	Total Base Payroll		$3,159,011	$506,082	$429,880	$1,258,803	$1,046,131	$6,068,483

Source: WKP G-4.b and WKP G-4.c Payroll TGS (CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Payroll Corporate (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

OVERTIME PAYROLL ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	PAYROLL DIRECTLY CHARGED TO TGS	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO TGS	DISTRIGAS PAYROLL	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)
1	Total Proforma Hourly Base Payroll	G-4	$41,067,145	$6,579,067	$5,588,444	
2	Overtime as a % of Hourly Base Payroll (Actual for the Test Period)	WKP G-4.b	22.53%	11.56%	6.26%	
3	Total Annualized Overtime Payroll (Ln 1 times Ln 2)		$9,253,398	$760,219	$349,699	
4	Test Period Overtime Payroll	WKP G-4.b	8,494,358	765,484	349,873	
5	Overtime Payroll Adjustment Total (Ln 3 minus Ln 4)		$759,041	$(5,265)	$(175)	
6	Allocation to TGS		100%	100%	30.25%	
7	Allocated Base Payroll Adjustment to TGS (Ln 5 times Ln 6)		$759,041	$(5,265)	$(53)	
8	Allocation to Service Area	WKP A.b	100%	100.00%	100.00%	
9	Allocated Base Payroll Adjustment to Service Area (Ln 7 times Ln 8)		$759,041	$(5,265)	$(53)	
10	Payroll Expense Factor	WKP G-4.b	54.69%	64.28%	81.74%	
11	Test Year Base Payroll O&M Expense Adjustment (Ln 9 times Ln 10)		$415,115	$(3,384)	$(43)	
	Adjustment Summary:					
12	Account 9302		$0	$0	$(43)	$(43)
13	Other O&M Accounts (See WKP G-5.a for Distribution by FERC Account)		415,115	(3,384)	0	411,730
14	Total (Ln 12 plus Ln 13)		$415,115	$(3,384)	$(43)	$411,687
15	Total Test Year Overtime Expense after Allocation		$4,645,513	$492,020	$86,512	$5,224,044
16	Total As Adjusted Overtime Expense after Allocation		$5,060,627	$488,635	$86,469	$5,635,732

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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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	$22,645	0.18%	$(6)
2	8530	0	0.00%	0	8530	0	0.00%	0
3	8560	918,994	2.81%	11,667	8560	110,103	0.85%	(29)
4	8570	355,176	1.09%	4,509	8570	543	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	118,830	0.36%	1,509	8630	230,897	1.79%	(61)
8	8650	37,469	0.11%	476	8650	0	0.00%	0
9	8700	1,167,537	3.57%	14,822	8700	1,025,693	7.96%	(269)
10	8710	0	0.00%	0	8710	585,953	4.55%	(154)
11	8740	5,346,053	16.35%	67,871	8740	275,715	2.14%	(72)
12	8750	593,148	1.81%	7,530	8750	27,817	0.22%	(7)
13	8760	17,535	0.05%	223	8760	72,493	0.56%	(19)
14	8770	33,596	0.10%	427	8770	17,760	0.14%	(5)
15	8780	10,861,351	33.22%	137,890	8780	153	0.00%	(0)
16	8790	3,638	0.01%	46	8790	0	0.00%	0
17	8800	829,696	2.54%	10,533	8800	449,581	3.49%	(118)
18	8850	10,864	0.03%	138	8850	0	0.00%	0
19	8860	926	0.00%	12	8860	0	0.00%	0
20	8870	4,003,986	12.25%	50,833	8870	512	0.00%	(0)
21	8890	1,515,234	4.63%	19,237	8890	830	0.01%	(0)
22	8900	1,157,210	3.54%	14,691	8900	0	0.00%	0
23	8910	8,535	0.03%	108	8910	0	0.00%	0
24	8920	2,515,715	7.69%	31,938	8920	1,604	0.01%	(0)
25	8930	12,499	0.04%	159	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	0	0.00%	0
27	9020	767,131	2.35%	9,739	9020	0	0.00%	0
28	9030	15,968	0.05%	203	9030	3,742,110	29.03%	(983)
29	9050	7,490	0.02%	95	9050	2,721	0.02%	(1)
30	9080	1,798,250	5.50%	22,830	9080	280,867	2.18%	(74)
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	601,004	1.84%	7,630	9200	6,040,520	46.87%	(1,586)
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	$32,697,837	100.00%	$415,115	Total	$12,888,520	100.00%	$(3,384)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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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		$65,426,183		$19,892,861		$78,759,938	
2	BENEFITS COMPUTED PER PAYROLL $								
3	H&W BENEFITS*	WKP G-6.b	12.38%	$8,096,642	12.38%	$2,461,788	14.03%	$11,050,799	
4	PENSION	WKP G-6.b	0.77%	500,630	0.77%	152,217	1.23%	968,317	
5	OPEB	WKP G-6.b	0.15%	100,722	0.15%	30,625	0.00%	2,395	
6	SERP	WKP G-6.b	0.0039%	2,547	0.0039%	0	1.1806%	0	
7	401K & NQDC	WKP G-6.b	5.35%	3,501,124	5.35%	1,064,518	4.90%	3,858,186	
8	PROFIT SHARING	WKP G-6.b	3.40%	2,223,894	3.40%	676,176	2.84%	2,237,791	
				$14,425,560		$4,385,324		$18,117,489	
9	ADDITIONAL BENEFITS								
10	A&G EMPL BEN MISC ADMIN	WKP G-6.b		$0		$0		$(1,381)	
11	A&G EMPL BEN FAS 112	WKP G-6.b		0		0		2,241	
12	A&G EMPL BEN SCHOLARSHIPS	WKP G-6.b		0		0		116,500	
13	A&G EMPL BEN TUITION LOANS	WKP G-6.b		0		36,555		87,592	
14	A&G EMPL BEN ADOPTION ALLOW	WKP G-6.b		0		0		0	
15	A&G EMPL BEN SPR/SUMMER ACTIVITIES	WKP G-6.b		0		0		0	
16	A&G EMPL BEN EMPLOYEE EVENTS	WKP G-6.b		13,177		20,959		13,446	
17	A&G EMPL BEN SVC RECOGNITION	WKP G-6.b		0		59,200		63,400	
18	A&G EMPL BEN EMPLOYEE REFERRAL	WKP G-6.b		0		0		128,531	
19	A&G EMPL BEN DRUG & ALCOHOL TESTING	WKP G-6.b		0		0		114,381	
20	A&G EMPL BEN EMPL ASST PROGRAM	WKP G-6.b		0		21,100		17,046	
21	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	WKP G-6.b		0		0		0	
22	A&G EMPL BEN DISABILITY	WKP G-6.b		0		61,181		50,661	
23	A&G EMPL BEN ACCOMMODATIONS	WKP G-6.b		0		0		9,703	
24	A&G EMPL BEN WELLNESS PROGRAM	WKP G-6.b		0		74		61,341	
				$13,177		$199,069		$663,460	
25	Annualized Test Year Benefits			$14,438,738		$4,584,393		$18,780,949	
26	PAYROLL TAX RATE PER PAYROLL $	WKP G-6.b	7.16%	$4,683,819	7.16%	$1,424,117	6.47%	$5,093,707	
27	Total Annualized Benefits and Payroll Tax			$19,122,556		$6,008,510		$23,874,656	
28	Test Year Benefits and Payroll Tax			$17,560,486		$6,084,133		$23,488,299	
29	Allocable Adjustment to Benefits and Payroll Tax			$1,562,071		$(75,623)		$386,357	
30	Allocation to TGS			100%		100%		30.25%	
31	Allocated Benefits and Payroll Tax Adjustment to TGS			$1,562,071		$(75,623)		$116,873	
32	Allocation to Service Area	WKP A.b		100%		100.00%		100.00%	
33	Allocated Benefits and Payroll Tax Adjustment to Service Area			$1,562,071		$(75,623)		$116,873	
34	Payroll Expense Factor	WKP G-4.b		54.69%		64.28%		81.74%	
35	Test Year Benefits and Payroll Tax Adjustment			$854,287		$(48,607)		$95,533	
36	Adjustment Summary:								
37	Account 9302			$0		$0		$95,533	$95,533
38	Other O&M Accounts (See WKP G4a for Distribution by FERC Account)			854,287		(48,607)		0	805,680
39	Total			$854,287		$(48,607)		$95,533	$901,213

* Includes: Medical, Dental, Flexible Spending Plan Administration, Accidental Death & Dismemberment, Long Term Disability and Life Insurance

Total Test Year Benefits and Payroll Tax Expense after Allocation		$9,603,723	$3,910,616	$5,807,867	$19,322,206
Total As Adjusted Benefits and Payroll Tax Expense after Allocation		10,458,010	3,862,009	5,903,400	20,223,419
	Taxes only	$2,561,552	$915,361	$1,259,502	$4,736,415

Source: SCH G-6 Corp Benefits and Payroll Taxes (CONFIDENTIAL).xlsx
Source: SCH G-6 Benefits and Payroll Taxes - Direct & SS.xlsx

WKP G-6.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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			
		TEST YEAR				TEST YEAR		
LINE NO.	MAIN ACCOUNT	BEENFITS AND PAYROLL TAX ADJUSTMENT	RATIO OF PAYROLL BY ACCOUNT	TOTAL	MAIN ACCOUNT	BEENFITS AND PAYROLL TAX ADJUSTMENT	RATIO OF PAYROLL BY ACCOUNT	TOTAL
		(a)	(b)	(c)		(d)	(e)	(f)
1	4081	$4,598,905	25.97%	$221,858	4081	$1,542,393	25.97%	$(12,623)
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	12,961,581	74.03%	632,429	9260	4,541,740	74.03%	(35,984)
35	9302	0	0.00%	0	9302	0	0.00%	0
36	9320	0	0.00%	0	9320	0	0.00%	0
37	Total	$17,560,486	100.00%	$854,287	Total	$6,084,133	100.00%	$(48,607)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

BENEFITS AND TAXES

LINE NO.		DESCRIPTION	TEXAS EMPLOYEES		CORPORATE SHARED SERVICE AND DISTRIGAS EMPLOYEES	
			(a)	(b)	(c)	(d)
	Based on Known and Measurable for 2025					
		H&W Benefits				
1	9260190	A&G EMPL BEN RESERVE	$10,800,550		$11,791,235	
2			$10,800,550	12.38%	$11,791,235	14.03%
		Pension				
3	9260413	ONE GAS RETIREMENT PLAN SC	$1,027,207		$1,332,532	
4	9260513	ONE GAS RETIREMENT PLAN NSC	(417,325)		(345,967)	
5	9260115	EMPL BEN PENSION ADMIN	57,936		46,632	
			$667,818	0.77%	$1,033,197	1.23%
		OPEB				
6	9260431	OPEB SC	$24,058		$77,001	
7	9260531	OPEB NSC	110,301		(74,445)	
8	9260132	A&G EMPL BEN FAS 106 ADMIN	0		0	
			$134,359	0.15%	$2,556	0.00%
		SERP				
9	9260411	SERP SC	$0		$64,573	
10	9260511	SERP NSC	3,398		826,367	
11	9260112	A&G EMPL BEN SERP ADMIN	0		101,200	
			$3,398	0.00%	$992,140	1.18%
		401k & NQDC				
12	9260101	A&G EMPL BEN 401(K) CO MATCH	$4,523,207		$3,640,630	
13	9260102	A&G EMPL BEN 401(K) ADMIN	147,133		118,426	
14	9260103	A&G EMPL BEN DEF COMP CO MATCH	0		327,000	
15	9260104	A&G EMPL BEN DEF COMP ADMIN	0		30,640	
			$4,670,340	5.35%	$4,116,696	4.90%
		Profit Sharing Plan				
16	9260141	A&G EMPL BEN PROFIT SHARING	$2,966,573		$2,387,730	
17	9260140	A&G EMPL BEN PROFIT SHARING ADMIN	0		0	
			$2,966,573	3.40%	$2,387,730	2.84%
	Based on Test Year Data					
		Non - Payroll Related 9260 Expenditures				
18	9260118	A&G EMPL BEN MISC ADMIN	$0		$(1,381)	
19	9260119	A&G EMPL BEN FAS 112	0		2,241	
20	9260301	A&G EMPL BEN SCHOLARSHIPS	0		116,500	
21	9260302	A&G EMPL BEN TUITION LOANS	36,555		87,592	
22	9260303	A&G EMPL BEN ADOPTION ALLOW	0		0	
23	9260306	A&G EMPL BEN SPR/SUMMER ACTIVITIES	0		0	
24	9260307	A&G EMPL BEN EMPLOYEE EVENTS	34,137		13,446	
25	9260310	A&G EMPL BEN SVC RECOGNITION	59,200		63,400	
26	9260314	A&G EMPL BEN EMPLOYEE REFERRAL	0		128,531	
27	9260321	A&G EMPL BEN DRUG & ALCOHOL TESTING	0		114,381	
28	9260326	A&G EMPL BEN EMPL ASST PROGRAM	21,100		17,046	
29	9260327	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	0		0	
30	9260328	A&G EMPL BEN DISABILITY	61,181		50,661	
31	9260329	A&G EMPL BEN ACCOMMODATIONS	0		9,703	
32	9260337	A&G EMPL BEN WELLNESS PROGRAM	74		61,341	
			$212,247		$663,460	
	Based on Known and Measurable for 2025					
		Payroll Taxes				
33	4081102	GEN TAX FICA	$6,034,000	6.91%	$5,232,000	6.23%
34	4081101	GEN TAX FED UNEMPL INS TAX	41,700	0.05%	31,700	0.04%
35	4081132	GEN TAX STATE UNEMPL INS	172,300	0.20%	171,300	0.20%
			$6,248,000	7.16%	$5,435,000	6.47%
36		Total Benefit and Payroll Expense	$25,703,285		$26,422,014	
37		Total Labor*	$87,275,537	29.21%	$84,037,083	30.65%

38 * Total Labor used to calculate % is adjusted for known and measurable changes

Source: WKP G-6.b Benefits and Payroll Taxes.xlsx

WKP G-6.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

BASE YEAR LEVEL PENSION AND OPEB

LINE NO.	DESCRIPTION	REFERENCE	DIRECT	SHARED SERVICES	DISTRIGAS	TOTAL
			(a)	(b)	(c)	(d)
1	PENSION	SCH G-6	$500,630	$152,217	$968,317	
2	OPEB	SCH G-6	100,722	30,625	2,395	
3	TOTAL		$601,353	$182,842	$970,712	
4	Allocation to TGS	SCH G-6	100 %	100 %	30.25 %	
5	PENSION		$500,630	$152,217	$292,916	
6	OPEB		100,722	30,625	725	
7	TOTAL		$601,353	$182,842	$293,641	
8	Allocation to Service Area	SCH G-6	100 %	100.00 %	100.00 %	
9	PENSION		$500,630	$152,217	$292,916	
10	OPEB		100,722	30,625	725	
11	TOTAL		$601,353	$182,842	$293,641	
12	Payroll Expense Factor	SCH G-6	54.69 %	64.28 %	81.74 %	
13	PENSION		$273,792	$97,838	$239,432	$611,062
14	OPEB		55,084	19,684	592	75,361
15	TOTAL		$328,876	$117,523	$240,025	$686,423

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

AMORTIZATION OF PENSION & OTHER POST EMPLOYMENT BENEFITS REGULATORY ASSET

LINE NO.	YEAR ENDED DECEMBER 2024	BEGINNING OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION	END OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION
	(a)	(b)	(c)	(d)	(e)
1	2024			$(6,518,193)	
2	2025	$(6,518,193)		(6,518,193)	
3	2026	(6,518,193)	$(1,086,366)	(5,431,828)	
4	2027	(5,431,828)	(1,086,366)	(4,345,462)	
5	2028	(4,345,462)	(1,086,366)	(3,259,097)	
6	2029	(3,259,097)	(1,086,366)	(2,172,731)	
7	2030	(2,172,731)	(1,086,366)	(1,086,366)	
8	2031	(1,086,366)	(1,086,366)	0	
9	Annualized Amortization of Pension & Other Post Employment Benefits Reg Asset - Account 4073				$(1,086,366)
10	Test Year Pension & Other Post Employment Benefits Reg Asset Amortization Expense - Account 4073				386,093
11	Total Adjustment to Test Period Expense				$(1,472,459)

SCHEDULE G-8

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

INCENTIVE COMPENSATION

			CORPORATE ALLOCATED TO TGS							Allocated to TGS		
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 TGS	TOTAL ADJUSTMENT AS ALLOCATED TO TGS	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO TGS
										100.0000%		
1	GEN TAX FICA INCENTIVE	4081	$1,064,745	$(32,010)	$1,032,734	30.25%	$322,085	$(9,683)	$312,402	$322,085	$(9,683)	$312,402
2	A&G SALARIES INCENTIVE PLAN	9302	16,472,272	(1,937,734)	14,534,538	30.25%	4,982,862	(586,164)	4,396,698	4,982,862	(586,164)	4,396,698
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9302	773,256	(47,537)	725,719	30.25%	233,910	(14,380)	219,530	233,910	(14,380)	219,530
4	A&G EMPL BEN ACCR PSP ON STI	9302	500,295	(4,923)	495,372	30.25%	151,339	(1,489)	149,850	151,339	(1,489)	149,850
5	TOTAL SHORT-TERM INCENTIVE		$18,810,567	$(2,022,204)	$16,788,363		$5,690,197	$(611,717)	$5,078,480	$5,690,197	$(611,717)	$5,078,480
6	GEN TAX FICA INCENTIVE - RESTRICTED	4081	$121,889	$0	$121,889	30.25%	$36,871	$0	$36,871	$36,871	$0	$36,871
7	A&G SALARIES LT INCENT-RESTRICTED	9302	2,722,840	0	2,722,840	30.25%	823,659	0	823,659	823,659	0	823,659
8	GEN TAX FICA INCENTIVE- PERFORMANCE	4081	0	0	0	30.25%	0	0	0	0	0	0
9	A&G SALARIES LT INCENT-PERFORMANCE	9302	7,209,188	(3,894,995)	3,314,192	30.25%	2,180,779	(1,178,236)	1,002,543	2,180,779	(1,178,236)	1,002,543
10	TOTAL LONG-TERM INCENTIVE		$10,053,917	$(3,894,995)	$6,158,922		$3,041,310	$(1,178,236)	$1,863,074	$3,041,310	$(1,178,236)	$1,863,074

			TGS			Allocated to TGS		
LINE NO.	DESCRIPTION	ACCT. 'NO.	TGS PER BOOK	ADJUSTMENTS	TGS ADJUSTED TEST YEAR	TOTAL PER BOOK AS ALLOCATED TO TGS	TOTAL ADJUSTMENT AS ALLOCATED TO TGS	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO TGS
						100.0000%		
	Short-Term Incentive							
1	GEN TAX FICA INCENTIVE	4081	$458,476	$0	$458,476	$458,476	$0	$458,476
2	A&G SALARIES INCENTIVE PLAN	9200	6,279,484	0	6,279,484	6,279,484	0	6,279,484
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9260	314,357	0	314,357	314,357	0	314,357
4	A&G EMPL BEN ACCR PSP ON STI	9260	210,016	0	210,016	210,016	0	210,016
5	TOTAL SHORT-TERM INCENTIVE		$7,262,332	$0	$7,262,332	$7,262,332	$0	$7,262,332
6	GEN TAX FICA INCENTVIE - RESTRICTED	4081	$6,596	$0	$6,596	$6,596	$0	$6,596
7	A&G SALARIES LT INCENT-RESTRICTED	9200	201,110	0	201,110	201,110	0	201,110
8	GEN TAX FICA INCENTIVE - PERFORMANCE	4081	0	0	0	0	0	0
9	A&G SALARIES LT INCENT-PERFORMANCE	9200	267,552	0	267,552	267,552	0	267,552
10	TOTAL LONG-TERM INCENTIVE		$475,258	$0	$475,258	$475,258	$0	$475,258
11	Total Test Year Incentive Compensation after Allocation					$16,469,096		
12	Total As Adjusted Incentive Compensation after Allocation					$14,679,144		

Source: SCH G-8 Incentive Compensation (CONFIDENTIAL).xlsx

WKP G-8.a STI
ADJUSTMENT
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	1,110,000	16,660	12,305	2,030	76.56 %	44.24 %	12,755	849,816	9,421	1,554
2	Sighinolfi	361,000	9,523	16,815	2,030	76.56 %	44.24 %	7,291	276,382	12,874	1,554
3	Dinan	451,500	6,547	16,254	—	76.56 %	44.24 %	5,012	345,668	12,444	—
4	McCormick	371,500	5,559	16,718	—	76.56 %	44.24 %	4,256	284,420	12,799	—
5	Bender	237,000	3,521	—	2,370	76.56 %	44.24 %	2,696	181,447	—	1,814
6	**Total**							**32,010**	**1,937,734**	**47,537**	**4,923**

WKP G-8.b LTI ADJUSTMENT

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	Corporate	9302	*NEO*	282,253	303,838	330,890	330,890	330,890	330,890	330,890	330,890	330,890	330,890	330,890	330,890	3,894,995
2	Corporate	9302	Non NEO's	253,690	273,188	315,625	237,942	282,645	282,645	282,645	277,659	277,659	277,659	276,645	276,195	3,314,192
3	TOTAL Corporate PSU			535,943	577,026	646,515	568,832	613,535	613,535	613,535	608,549	608,549	608,549	607,535	607,085	7,209,188
4	TGS	9200	Non NEO's	16,435	19,225	24,851	21,041	23,250	23,250	23,250	23,250	23,250	23,250	23,250	23,250	267,552
5	TOTAL TGS PSU			16,435	19,225	24,851	21,041	23,250	23,250	23,250	23,250	23,250	23,250	23,250	23,250	267,552
6	GRAND TOTAL			552,378	596,251	671,366	589,873	636,785	636,785	636,785	631,799	631,799	631,799	630,785	630,335	7,476,740

LINE NO.	COMPANY	ACCT. 'NO.	NAMED EXECUTIVE OFFICERS (NEO)	TOTAL PSU TAX
7	Corporate	4081	NEO	—
8	Corporate	4081	Non NEO's	—
9	TOTAL Corporate PSU TAXES			—
10	TGS		Non NEO's	—
11	TOTAL TGS PSU TAXES			—
12	GRAND TOTAL			—

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

MISCELLANEOUS ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT	DIRECT	SHARED SERVICES ALLOCATION TO TGS	DISTRIGAS ALLOCATION TO TGS	TOTAL ADJUSTMENT TO TGS
			(a)	(b)	(c)	(d)
1	Payroll Taxes	4081	$2,366,740	$(2,366,740)	$(1,077)	$(1,077)
2	Transmission O & M - Mains Expenses	8560	(928)	(143)	0	(1,071)
3	Transmission Other Misc Expenses	8590	0	0	0	0
4	Maintenance of Mains	8630	(9)	0	0	(9)
5	Distr. Operations- General Supervision	8700	(925)	(1,391)	0	(2,316)
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0
7	Distr. Operations - Mains & Services	8740	(339)	0	0	(339)
8	Distr Meas & Reg St Misc	8750	0	0	0	0
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0
10	Distr. Operations - Other Expense	8800	(6,300)	(199)	0	(6,500)
11	Distr. Operations - Rents	8810	0	0	0	0
12	Distr. Operations - Struct. & Improv.	8860	0	0	0	0
13	Distr. Maintenance - Mains	8870	(209)	0	0	(209)
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	(48)	0	(48)
19	Customer Accounting - Bad Debt	9040	0	0	0	0
20	Customer Accounting - Misc. Expense	9050	0	(69)	0	(69)
21	Customer Assistance-Misc. Expense	9080	(2,409)	(14,824)	0	(17,232)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0
23	Demo/Sell- Misc. Expenses	9120	(5,000)	0	0	(5,000)
24	Advertising-Misc. Expense	9130	(3,028)	0	0	(3,028)
25	Salaries	9200	0	12,713	0	12,713
26	Admin & Gen - Office Supp & Exp	9210	(53,562)	(8,038)	0	(61,601)
27	Admin & Gen - Outside Services	9230	0	0	0	0
28	Property Insurance	9240	0	38,438	0	38,438
29	Admin & Gen - Injuries & Damages	9250	0	(1,284,120)	0	(1,284,120)
30	Admin & Gen - Employee Pensions & Benefits	9260	6,345,803	(4,772,345)	(205,827)	1,367,631
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0
32	Admin & Gen - Regulatory Commission Expense	9280	(3)	0	0	(3)
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	(107,266)	(9,188,153)	298,653	(8,996,766)
36	Admin & Gen - Rents	9310	0	89,386	0	89,386
37	Totals		$8,532,564	$(17,495,533)	$91,749	$(8,871,220)

WKP G-9.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

MISCELLANEOUS ADJUSTMENTS
DIRECT

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF CLUBS AND CIVIC EXPENSE (a)	REMOVAL OF MEAL/HOTEL COSTS OVER RRC THRESHOLD AND REMOVAL OF SPOUSE AND ALCOHOL ACTIVITY (b)	ADJUSTMENT TO INCLUDE DIRECT BENEFITS AND PAYROLL RELATED TAXES (c)	ADJUSTMENT TO INCLUDE DIRECT O/H FOR PAYROLL RELATED TAXES AND BENEFITS (d)	DIRECT SERP WITH PAYROLL FACTOR APPLIED SCH G-6 BENEFITS & PAYROLL (e)	OTHER ADJUSTMENTS (f)	TOTAL ADJUSTMENT TO TGS (g)
1	Payroll Taxes	4081	$0	$0	$4,598,905	$(2,232,165)	$0	$0	$2,366,740
2	Transmission O & M - Mains Expenses	8560	(142)	(786)	0	0	0	0	(928)
3	Transmission Other Misc Expenses	8590	0	0	0	0	0	0	0
4	Maintenance of Mains	8630	0	(9)	0	0	0	0	(9)
5	Distr. Operations- General Supervision	8700	(908)	(17)	0	0	0	0	(925)
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0	0	0
7	Distr. Mains & Services	8740	(312)	(27)	0	0	0	0	(339)
8	Distr Meas & Reg St Misc	8750	0	0	0	0	0	0	0
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0	0	0	0
10	Distr. Operations - Other Expense	8800	(1,581)	(4,719)	0	0	0	0	(6,300)
11	Distr. Operations - Rents	8810	0	0	0	0	0	0	0
12	Distr. Structuctures & Improvements	8860	0	0	0	0	0	0	0
13	Distr. Maintenance - Mains	8870	0	(209)	0	0	0	0	(209)
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	0	0
15	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	0	0
16	Customer Accounting - Supervision	9010	0	0	0	0	0	0	0
17	Customer Accounting - Meter Reading	9020	0	0	0	0	0	0	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	0	0	0	0	0	0	0
19	Customer Accounting - Bad Debts	9040	0	0	0	0	0	0	0
20	Customer Accounting - Misc. Expense	9050	0	0	0	0	0	0	0
21	Customer Asst.- Misc. Expenses	9080	(1,928)	(481)	0	0	0	0	(2,409)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0	0	0	0
23	Demo/Sell- Misc. Expenses	9120	(5,000)	0	0	0	0	0	(5,000)
24	Advertising-Misc. Expense	9130	(3,028)	0	0	0	0	0	(3,028)
25	Advertising-Misc. Expense	9200	0	0	0	0	0	0	0
26	Admin & Gen - Office Supp & Exp	9210	(51,064)	(2,498)	0	0	0	0	(53,562)
27	Admin & Gen - Outside Services	9230	0	0	0	0	0	0	0
28	Property Insurance	9240	0	0	0	0	0	0	0
29	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0	0	0
30	Admin & Gen - Employee Pensions & Benefits	9260	(2,727)	0	12,948,404	(6,599,874)	0	0	6,345,803
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0	0	0	0
32	Admin & Gen - Regulatory Commission Expense	9280	0	(3)	0	0	0	0	(3)
33	Admin & Gen - Labor Attends Credit	9290	0	0	0	0	0	0	0
34	Admin & Gen - Advertising	9301	0	0	0	0	0	0	0
35	Admin & Gen - Misc General	9302	(107,266)	0	0	0	0	0	(107,266)
36	Admin & Gen - Rents	9310	0	0	0	0	0	0	0
37	Totals		$(173,958)	$(8,748)	$17,547,308	$(8,832,038)	$0	$0	$8,532,564

Source: SCH G-6 Benefits and Payroll Taxes - Direct & SS.xlsx
Source: WKP G-9.a Direct Misc Adj.xlsx
Source: WKP G-9.c Meal and Hotel Adj (CONFIDENTIAL).xlsx

WKP G-9.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

MISCELLANEOUS ADJUSTMENTS

SHARED SERVICES

LINE NO.	DESCRIPTION	ACCT	ADJUSTMENT FOR KNOWN AND MEASURABLE CHANGE IN INSURANCE PREMIUMS (a)	REMOVE URI RECLASSIFICATION ENTRY (b)	ADJUSTMENT TO REMOVE COSTS ASSOCIATED WITH ROYALTY FEES (c)	REMOVE MEAL/HOTEL COSTS OVER RRC THRESHOLD AND REMOVAL OF SPOUSE AND ALCOHOL ACTIVITY (d)	REMOVE MANAGEMENT DECISION TO NOT SEEK RECOVERY (e)	REMOVE - RULE 7.5414 CONTRIBUTIONS, DONATIONS TO CHARITABLE, RELIGIOUS, OR OTHER NONPROFIT ORGANIZATIONS (f)	REMOVE LEGISLATIVE/GOVERNMENTAL ACTIVITY (g)	PRIOR PERIOD ADJUSTMENT (h)	ADJUSTMENT TO REMOVE PAYROLL RELATED TAXES AND BENEFITS (i)	ADJUSTMENT TO INCLUDE SHARED SERVICE PAYROLL RELATED TAXES AND BENEFITS (j)	ADJUSTMENT TO REMOVE TOTAL O/H FOR PAYROLL RELATED TAXES AND BENEFITS (k)	ADJUSTMENT TO INCLUDE SHARED SERVICES PORTION OF O/H FOR PAYROLL RELATED TAXES AND BENEFITS (l)	TOTAL (m) = sum(a:l)	O&M EXPENSE FACTOR (n)	ALLOCATION TO SERVICE AREA (o)	AMOUNT ALLOCATED TO TGS BY FERC ACCT (p) = (m) x (n) x (o)
1	Payroll Taxes	4081	$0	$0	$0	$0	$0	$0	$0	$0	$(6,141,298)	$1,542,393	$2,980,795	$(748,630)	$(2,366,740)	100.00%	100.0000%	$(2,366,740)
2	Transmission O & M - Mains Expenses	8560	0	0	0	(167)	0	0	0	0	0	0	0	0	(167)	85.42%	100.0000%	(143)
3	Transmission Other Misc Expenses	8590	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
4	Maintenance of Mains	8630	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
5	Distr. Operations- General Supervision	8700	0	0	0	(73)	(1,556)	0	0	0	0	0	0	0	(1,629)	85.42%	100.0000%	(1,391)
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
7	Distr. Mains & Services	8740	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
8	Distr Meas & Reg St Misc	8750	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
10	Distr. Operations - Other Expense	8800	0	0	0	(190)	0	(44)	0	0	0	0	0	0	(234)	85.42%	100.0000%	(199)
11	Distr. Operations - Rents	8810	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
12	Distr. Structuctures & Improvements	8860	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
13	Distr. Maintenance - Mains	8870	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
15	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
16	Customer Accounting - Supervision	9010	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
17	Customer Accounting - Meter Reading	9020	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
18	Customer Records and Collections	9030	0	0	0	(56)	0	0	0	0	0	0	0	0	(56)	85.42%	100.0000%	(48)
19	Customer Accounting - Bad Debts	9040	0	0	0	0	0	0	0	0	0	0	0	0	0	100.00%	100.0000%	—
20	Customer Accounting - Misc. Expense	9050	0	0	0	0	(80)	0	0	0	0	0	0	0	(80)	85.42%	100.0000%	(69)
21	Customer Asst.- Misc. Expenses	9080	0	0	0	(125)	(892)	(13,988)	(2,350)	0	0	0	0	0	(17,355)	85.42%	100.0000%	(14,824)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
24	Advertising-Misc. Expense	9130	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
25	Administrative and General Salaries	9200	0	14,883	0	0	0	0	0	0	0	0	0	0	14,883	85.42%	100.0000%	12,713
26	Admin & Gen - Office Supp & Exp	9210	0	0	0	(5,331)	(908)	(2,912)	(260)	0	0	0	0	0	(9,411)	85.42%	100.0000%	(8,038)
27	Admin & Gen - Outside Services	9230	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
28	Property Insurance	9240	45,000	0	0	0	0	0	0	0	0	0	0	0	45,000	85.42%	100.0000%	38,438
29	Admin & Gen - Injuries & Damages	9250	(1,503,350)	0	0	0	0	0	0	0	0	0	0	0	(1,503,350)	85.42%	100.0000%	(1,284,120)
30	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	0	0	0	0	761,433	(17,490,144)	4,541,740	8,813,357	(2,213,484)	(5,587,097)	85.42%	100.0000%	(4,772,345)
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
32	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
33	Admin & Gen - Labor Attends Credit	9290	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
34	Admin & Gen - Advertising	9301	0	0	0	0	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	—
35	Admin & Gen - Misc General	9302	0	0	(10,743,203)	0	0	(13,424)	(160)	0	0	0	0	0	(10,756,787)	85.42%	100.0000%	(9,188,153)
36	Admin & Gen - Rents	9310	0	0	0	0	(11,632)	0	0	116,279	0	0	0	0	104,646	85.42%	100.0000%	89,386
37	Totals		$(1,458,350)	$14,883	$(10,743,203)	$(5,941)	$(15,069)	$(30,368)	$(2,770)	$877,712	$(23,631,442)	$6,084,133	$11,794,152	$(2,962,113)	$(20,078,375)			$(17,495,533)

Source: SCH G-6 Benefits and Payroll Taxes - Direct & SS.xlsx

Source: WKP G-9.b Insurance Adj.xlsx

Source: WKP G-9.c Meal and Hotel Adj (CONFIDENTIAL).xlsx

WKP G-9.c

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

MISCELLANEOUS ADJUSTMENTS
DISTRIGAS AMOUNT ALLOCATED TO TGS

LINE NO.	DESCRIPTION	ACCT	WKP G-9.c Remove Meal & Hotel per AP file (a)	WKP G-9.b SS & Distr Adjustment for Known and measurable change in Insurance premiums (b)	WKP G-9.b SS & Distr Remove SERP (GUD 10506) (c)	WKP G-9.b SS & Distr Remove Gov / Legis (Rule 7.5414) (d)	WKP G-9.b SS & Distr Remove Aviation (e)	WKP G-9.b SS & Distr Exclude Costs (f)	WKP G-9.b SS & Distr Remove Contributions / Donations / Civic / Religious / Nonprofit Organizations (Rule 7.5414) (g)	WKP G-9.b SS & Distr Prior Period Adjustment (h)	TOTAL (i) = sum(a:g)	O&M EXPENSE FACTOR (j)	ALLOCATION TO SERVICE AREA (k)	AMOUNT ALLOCATED TO TGS BY FERC ACCT (l) = (i) x (j) x (k)
1	Payroll Taxes	4081	$0	$0	$(1,260)	$0	$0	$0	$0	$0	$(1,260)	85.42%	100.0000%	$(1,077)
2	Transmission O & M - Mains Expenses	8560	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
3	Transmission Other Misc Expenses	8590	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
4	Maintenance of Mains	8630	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
5	Distr. Operations- General Supervision	8700	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
7	Distr. Mains & Services	8740	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
8	Distr Meas & Reg St Misc	8750	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
10	Distr. Operations - Other Expense	8800	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
11	Distr. Operations - Rents	8810	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
12	Distr. Structuctures & Improvements	8860	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
13	Distr. Maintenance - Mains	8870	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
15	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
16	Customer Accounting - Supervision	9010	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
17	Customer Accounting - Meter Reading	9020	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
19	Customer Accounting - Bad Debts	9040	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
20	Customer Accounting - Misc. Expense	9050	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
21	Customer Asst.- Misc. Expenses	9080	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
24	Advertising-Misc. Expense	9130	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
25	Advertising-Misc. Expense	9200	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
26	Admin & Gen - Office Supp & Exp	9210	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
27	Admin & Gen - Outside Services	9230	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
28	Property Insurance	9240	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
29	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
30	Admin & Gen - Employee Pensions & Benefits	9260	0	0	(240,966)	0	0	0	0	0	(240,966)	85.42%	100.0000%	(205,827)
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
32	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
33	Admin & Gen - Labor Attends Credit	9290	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
34	Admin & Gen - Advertising	9301	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
35	Admin & Gen - Misc General	9302	(28,610)	803,877	(22,665)	(10,936)	(464,829)	(59,517)	(44,529)	176,848	349,640	85.42%	100.0000%	298,653
36	Admin & Gen - Rents	9310	0	0	0	0	0	0	0	0	0	85.42%	100.0000%	0
37	Totals		$(28,610)	$803,877	$(264,891)	$(10,936)	$(464,829)	$(59,517)	$(44,529)	$176,848	$107,413			$91,749

Source: WKP G-9.c.2 Misc Adj.xlsx
Source: WKP G-9.b Insurance Adj.xlsx
Source: WKP G-9.c Meal and Hotel Adj (CONFIDENTIAL).xlsx

SCHEDULE G-10

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

RENTS AND LEASES ADJUSTMENT

LINE NO.	DESCRIPTION	ACCT	DIRECT TGS	SHARED SERVICES ALLOCATION TO TGS	DISTRIGAS ALLOCATION TO TGS	TOTAL ADJUSTMENT TO TGS
			(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	389	389
21	Admin & Gen - Rents	9310	0	117,743	0	117,743
22	Totals		$0	$117,743	$389	$118,132

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

RENTS AND LEASES ADJUSTMENTS
DIRECT

LINE NO.	DESCRIPTION	ACCT	ANNUALIZE LEASE PAYMENTS (a)	TOTAL ADJUSTMENT TO TGS (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

WKP G-10.b

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

RENTS AND LEASES ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ANNUALIZE LEASE PAYMENTS (a)	ANNUALIZE IMAGENET LEASE PAYMENTS (b)	GRAND TOTAL (c)	O&M EXPENSE FACTOR (d)	ALLOCATION TO SERVICE AREA (e)	AMOUNT ALLOCATED TO TGS BY FERC ACCT (f)
1	Shared Service	Transmission O & M - Mains Expenses	8560	$0	$0	$0	85.42%	100.0000%	$0
2	Shared Service	Distr. Operations - Supervision and Engineering	8700	0	0	0	85.42%	100.0000%	0
3	Shared Service	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	85.42%	100.0000%	0
4	Shared Service	Distr. Operations - Mains & Services	8740	0	0	0	85.42%	100.0000%	0
5	Shared Service	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	85.42%	100.0000%	0
6	Shared Service	Distr. Operations - Other Expense	8800	0	0	0	85.42%	100.0000%	0
7	Shared Service	Distr. Operations - Rents	8810	0	0	0	85.42%	100.0000%	0
8	Shared Service	Distr. Maintenance - Mains	8870	0	0	0	85.42%	100.0000%	0
9	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	85.42%	100.0000%	0
10	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0	0	85.42%	100.0000%	0
11	Shared Service	Customer Accounting - Supervision	9010	0	0	0	85.42%	100.0000%	0
12	Shared Service	Customer Accounting - Customer Accounting	9030	0	0	0	85.42%	100.0000%	0
13	Shared Service	Customer Accounting - Miscellaneous	9050	0	0	0	85.42%	100.0000%	0
14	Shared Service	Customer Accounting - Customer Assistance Expense	9080	0	0	0	85.42%	100.0000%	0
15	Shared Service	Admin & Gen - Office Supp & Exp	9210	0	0	0	85.42%	100.0000%	0
16	Shared Service	Admin & Gen - Outside Services	9230	0	0	0	85.42%	100.0000%	0
17	Shared Service	Admin & Gen - Injuries & Damages	9250	0	0	0	85.42%	100.0000%	0
18	Shared Service	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	85.42%	100.0000%	0
19	Shared Service	Admin & Gen - General Advertising Expense	9301	0	0	0	85.42%	100.0000%	0
20	Shared Service	Admin & Gen - Misc General	9302	0	0	0	85.42%	100.0000%	0
21	Shared Service	Admin & Gen - Rents	9310	158,214	(20,370)	137,844	85.42%	100.0000%	117,743
22	Grand Total Shared Services			$158,214	$(20,370)	$137,844			$117,743
23									
24		O&M Expense Factor		85.42%	85.42%	85.42%			
25		Adjustment to TGS O&M		$135,142	$(17,399)	$117,743			
26									
27		Allocation to Service Area		100.00%	100.00%	100.00%			
28									
29		Adjustment to Service Area O&M		$135,142	$(17,399)	$117,743			

DISTRIGAS

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ANNUALIZE LEASE PAYMENTS (a)	ANNUALIZE IMAGENET LEASE PAYMENTS (b)	GRAND TOTAL (c)	DISTRIGAS ALLOCATION FACTOR (d)	O&M EXPENSE FACTOR (e)	ALLOCATION TO SERVICE AREA (f)	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT (g)
30	OGS Corporate Allocated through Distrigas (1007)	Admin & Gen - Misc General	9302	$0	$1,505	$1,505	30.25%	85.42%	100.0000%	$389
31	Grand Total Distrigas			$0	$1,505	$1,505				$389
32										
33		Distrigas Allocation Percent		30.25%	30.25%	30.25%				
34		Corporate Adjustment Allocated to TGS		$0	$455	$455				
35										
36		O&M Expense Factor		85.42%	85.42%	85.42%				
37		Adjustment to TGS O&M		$0	$389	$389				
38										
39		Allocation to Service Area		100.00%	100.00%	100.00%				
40										
41		Adjustment to Service Area O&M		$0	$389	$389				

Source: WKP G-10.b Rent Adj.xlsx

SCHEDULE G-11

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

INTEREST ON CUSTOMER DEPOSITS

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	TGS Active Customer Deposits		$16,329,640
2	Interest Rate on Customer Deposits		5.05%
3	Annualized Interest on Customer Deposits		$824,647
4	Test Year Interest on Customer Deposits - Acct 4310	WKP G.a.2	911,925
5	Adjustment to Test Year Expense		$(87,278)

Source: SCH G-11 Interest on Customer Deposits.pdf

SCHEDULE G-12

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

UNCOLLECTIBLE EXPENSE

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT
		(a)	(b)	(c)
1	As Adjusted Base (Non-Gas) Revenue	G-2		$392,752,255
2	As Adjusted Transportation, Fees & Other Utility Revenue	G-3		25,007,130
3	Total Adjusted Base and Other Revenue (Note 2)			$417,759,385
4	Uncollectible Expense Ratio (Note 1)			0.007354
5	Adjusted Uncollectible Expense			$3,072,203
6	Test Year Uncollectible Expense - Acct 9040			1,960,471
7	Adjustment to Test Year Expense			$1,111,731

Note 1: Calculation of Uncollectible Ratio		Base Revenue Write Offs	Base Revenue	Uncollectible Ratio
8	Twelve Months Ended December 2022	$2,369,668	$304,741,476	0.00778
9	Twelve Months Ended December 2023	2,512,140	332,471,197	0.00756
10	Twelve Months Ended December 2024	2,491,471	365,446,212	0.00682
11	Average	$2,457,760	$334,219,628	0.00735

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.xlsx

SCHEDULE G-13

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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. 2021 - Dec. 2021		$163,140	$8,834	$152,762	$324,736
2	Jan. 2022 - Dec. 2022		102,671	17,705	142,584	262,959
3	Jan. 2023 - Dec. 2023		384,399	96,813	154,421	635,633
4	Jan. 2024 - Dec. 2024		164,226	570,230	36,190	770,646
5	Total		$814,436	$693,582	$485,956	$1,993,975
6	Average Claims for TGS Division		$203,609	$173,396	$121,489	$498,494
7	Per Book	Acct 9250	82,738	217,677	(43,203)	257,212
8	Adjustment					$241,281
9	Allocation to TGS					100.0000%
10	Adjustment to Employee Injury, Auto, and General Liability Claims					$241,281
11	O&M Expense Factor					85.42%
12	Adjustment to Employee Injury, Auto, and General Liability Claims with O&M factor applied					$206,096

Source: SCH G-13 Inj & Damages (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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.

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

INJURIES AND DAMAGES

Employee Injuries

Period Reporting: January 1, 2021 through December 31, 2024

Employee Injuries	2024 $ Paid	2023 $ Paid	2022 $ Paid	2021 $ Paid
January	$1,707	$8,417	$8,970	$14,253
February	3,607	21,647	11,622	18,962
March	17,305	58,365	8,116	9,353
April	11,347	22,930	7,888	16,695
May	7,488	35,944	5,669	7,068
June	4,136	54,685	4,422	11,697
July	7,684	53,924	10,792	22,311
August	5,811	25,485	5,499	12,090
September	10,968	17,168	7,732	12,261
October	24,278	26,110	8,900	4,753
November	27,168	45,559	10,716	13,882
December	42,726	14,165	12,344	19,816
Sub Total	$164,226	$384,399	$102,671	$163,140
4 Year Average	$203,609			

Auto Accidents

Period Reporting: January 1, 2021 through December 31, 2024

Auto Accidents	2024 $ Paid	2023 $ Paid	2022 $ Paid	2021 $ Paid
January	$0	$34,237	$13,854	$0
February	1,653	965	0	0
March	1,150	0	0	0
April	157,486	100	0	1,641
May	65,223	0	3,851	0
June	11,052	0	0	0
July	0	0	0	0
August	157,195	20,500	0	0
September	3,441	0	0	7,193
October	1,096	0	0	0
November	151,275	20,000	0	0
December	20,658	21,011	0	0
Sub Total	$570,230	$96,813	$17,705	$8,834
4 Year Average	$173,396			

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

INJURIES AND DAMAGES

General Liability

Period Reporting: January 1, 2021 through December 31, 2024

General Liability	2024 $ Paid	2023 $ Paid	2022 $ Paid	2021 $ Paid
January	$5,993	$17,267	$27,697	$27,456
February	700	15,570	2,622	2,139
March	1,252	1,597	8,158	2,797
April	2,067	5,435	19,571	9,609
May	537	52,254	3,813	20,052
June	0	39,480	12,840	25,712
July	831	3,202	11,752	9,161
August	4,699	5,487	5,916	13,695
September	3,633	6,724	34,724	8,519
October	2,552	140	2,603	19,448
November	829	700	8,290	5,028
December	13,096	6,566	4,597	9,145
Sub Total	$36,190	$154,421	$142,584	$152,762
4 Year Average	$121,489			

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$134,863	$0	$0	$0	$134,863
2	Advertising - Misc. Adm & Gen. Expense	WKP G.a.1	9301	57	0	0	0	57
3	Distrigas Allocated Advertising	WKP G.a.2	9302	385	0	0	0	385
4	Total Adjusted Advertising Expense			$135,305	$0	$0	$0	$135,305

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:

6	Revenue Requirement	A			$458,829,294
7	Normalized CCF	G-2		385,291,209	
8	Test Year Cost of Gas Revenue	G-2	$155,312,003		
9	Test Year CCF	G-2	363,185,533		
10	Effective Rate		0.427638186	0.427638186	
11	Normalized Cost of Gas Revenue			$164,765,234	164,765,234
12	Total Revenue				$623,594,528
13	Allowed Rate				0.50 %
14	Allowable Advertising (Note 1)				$3,117,973

Source: WKP G.a.2 Book Op Inc (CONFIDENTIAL).xlsx
Source: WKP G.a.2.a1 Shared Service per book (CONFIDENTIAL).xlsx
Source: WKP G.a.2.a2 Corporate Costs Allocated (CONFIDENTIAL).xlsx

Actual Advertising expense represents in gross receipts	0.022 %

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT DEPR & AMORT EXP	TGS DIVISION ALLOCATED DEPR & AMORT EXP	CORPORATE ALLOCATED DEPR & AMORT EXP	TOTAL DEPR & AMORT EXP
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$7,467	$0	$0	$7,467
2	301	Organization - OPC	0	0	0	0
3	302	Franchises & Consents	16,199	0	0	16,199
4	303	Misc. Intangible	52,444	0	0	52,444
5	303	Misc. Intangible - OPC	0	0	0	0
6	303.1	Misc. Intangible	11,220	0	0	11,220
7		Total Intangible Plant	$87,330	$0	$0	$87,330
		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	49,857	0	0	49,857
22	366.1	Compressor Station Structure - OPC	0	0	0	0
23	367	Mains	3,282,834	0	0	3,282,834
24	367	Mains - OPC	0	0	0	0
25	368	Compressor Station Equip	3,937	0	0	3,937
26	369	Meas & Reg Stations Equip	890,894	0	0	890,894
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	2,818	0	0	2,818
30	371	Other Equipment	0	0	0	0
31		Total Gathering and Transmission Plant	$4,230,339	$0	$0	$4,230,339
		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	19,226	0	0	19,226
37	375.2	Other System Structures	0	0	0	0
38	376	Mains	24,226,468	0	0	24,226,468
39	376.9	Mains - Cathodic Protection Anodes	4,896,263	0	0	4,896,263
40	377	Compressor Station Equipment	0	0	0	0
41	378	Meas. & Reg. Station - General	1,433,157	0	0	1,433,157
42	379	Meas. & Reg. Station - C.G.	459,933	0	0	459,933
43	380	Services	25,921,102	0	0	25,921,102
44	380.1	Ind Service Line Equip	2,658	0	0	2,658
45	380.2	Comm Service Line Equip	33,997	0	0	33,997
46	380.4	Yard Lines-Customer Svc	5,024	0	0	5,024
47	381	Meters	7,356,843	0	0	7,356,843
48	382	Meter Installations	0	0	0	0
49	383	House Regulators	1,513,401	0	0	1,513,401
50	385	Indust. Meas. & Reg. Stat. Equipment	940,499	0	0	940,499
51	386	Other Property on Customer Premises	355,527	0	0	355,527
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0
53		Total Distribution Plant	$67,164,097	$0	$0	$67,164,097
		GENERAL PLANT				
54	389	Land & Land Rights	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT DEPR & AMORT EXP	TGS DIVISION ALLOCATED DEPR & AMORT EXP	CORPORATE ALLOCATED DEPR & AMORT EXP	TOTAL DEPR & AMORT EXP
			(a)	(b)	(c)	(d)
56	390.1	Leasehold Improvements	1,172,641	111,945	31,583	1,316,170
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	391,274	391,274
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	262,197	171,677	114,140	548,013
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	18,425	18,425
68	391.4	Audio Visual Equipment	0	0	11,887	11,887
69	391.5	Artwork	0	0	0	0
70	391.6	Purchased Software	0	0	3,830,757	3,830,757
71	391.6	Banner Software	0	0	271,317	271,317
72	391.6	PowerPlant System	0	0	53,876	53,876
73	391.6	Riskworks	0	0	0	0
74	391.6	Maximo	0	0	97,789	97,789
75	391.6	Dynamic Risk Assessment	0	0	0	0
76	391.6	Concur Project	0	0	1,663	1,663
77	391.6	Journey-Employee-ODC Distrigas	0	0	1,618,986	1,618,986
78	391.6	Journey-Employee Count	0	0	42,905	42,905
79	391.6	Ariba Software	0	0	68,448	68,448
80	391.6	Accounts Payable Software	0	0	36,086	36,086
81	391.6	Customer Relations Software	0	0	45,377	45,377
82	391.8	Micro Computer Software	0	0	1,207,303	1,207,303
83	391.81	Aircraft Computer Equipment	0	0	0	0
84	391.9	Computer & Equipment	512,946	411,937	0	924,883
85	391.99	Cloud Computing	0	0	55,634	55,634
86	392	Transportation Equipment	0	0	0	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	45,701	45,701
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	6,529	0	0	6,529
92	394	Tools, Shop & Garage	2,220,213	6,664	12,304	2,239,181
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	4,717,789	59,501	1,550	4,778,840
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	423	0	0	423
100		Total General Plant	$8,892,738	$761,724	$7,957,005	$17,611,467
101		Total	$80,374,503	$761,724	$7,957,005	$89,093,233
102		Total Annualized Depreciation & Amortization Expense	$80,374,503	$761,724	$7,957,005	$89,093,233
103		Test Year Depreciation & Amortization Expense Accts 403 & 404	63,543,016	787,025	7,296,672	71,626,713
104		Adjustment to Test Year	$16,831,487	$(25,300)	$660,333	$17,466,520

WKP G-15.a.1

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE - 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	$186,679	$0	$0	$0	0	$0	$186,679	4.0000 %	$7,467
2	301	Organization - OPC	0	0	0	0	0	0	0	6.6700 %	0
3	302	Franchises & Consents	402,970	0	0	0	0	0	402,970	4.0200 %	16,199
4	303	Misc. Intangible	1,030,534	261,178	0	0	0	0	1,291,712	4.0600 %	52,444
5	303	Misc. Intangible - OPC	0	0	0	0	0	0	0	0.0000 %	0
6	303.1	Misc. Intangible	616,460	0	0	0	0	0	616,460	1.8200 %	11,220
7		Total Intangible Plant	$2,236,642	$261,178	$0	$0	$0	$0	$2,497,821		$87,330
		GATHERING AND TRANSMISSION PLANT									
8	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000 %	$0
9	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0.0000 %	0
10	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000 %	0
11	329	Other Structures	0	0	0	0	0	0	0	0.0000 %	0
12	332	Field Lines	0	0	0	0	0	0	0	0.0000 %	0
13	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0.0000 %	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0.0000 %	0
15	336	Purification Equipment	0	0	0	0	0	0	0	0.0000 %	0
16	337	Other Equip	0	0	0	0	0	0	0	0.0000 %	0
17	365	Land & Land Rights	0	0	0	0	0	0	0	0.0000 %	0
18	365.1	Land - OPC	23,277	0	(23,277)	0	0	0	0	0.0000 %	0
19	365.2	Rights-of-Way	228,423	76	0	0	0	0	228,499	0.0000 %	0
20	365.2	Rights-of-Way - OPC	0	0	0	0	0	0	0	— %	0
21	366	Meas/Reg Station Structures	27,231	1,785,740	0	0	0	0	1,812,971	2.7500 %	49,857
22	366.1	Compressor Station Structure - OPC	0	0	0	0	0	0	0	2.7500 %	0
23	367	Mains	95,099,507	17,325,164	0	0	0	1,134	112,425,805	2.9200 %	3,282,834
24	367	Mains - OPC	0	0	0	0	0	0	0	0.0000 %	0
25	368	Compressor Station Equip	88,467	68,998	0	0	0	0	157,464	2.5000 %	3,937
26	369	Meas & Reg Stations Equip	16,055,472	9,618,699	0	0	0	0	25,674,171	3.4700 %	890,894
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0	0.0000 %	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0	0.0000 %	0
29	371	Other Equipment	52,349	1,638	0	0	0	0	53,986	5.2200 %	2,818
30	371	Other Equipment - OPC	0	0	0	0	0	0	0	5.2200 %	0
31		Total Gathering and Transmission Plant	$111,574,725	$28,800,314	$(23,277)	$0	$0	$1,134	$140,352,897		$4,230,339
		DISTRIBUTION PLANT									
32	374	Land	$0	$0	$0	$0	$0	$0	$0	0.0000 %	$0
33	374.1	Land	203,003	2,072	(205,076)	0	0	0	0	0.0000 %	0
34	374.2	Land Rights	1,642,956	170,926	(1,813,882)	0	0	0	0	0.0000 %	0
35	375	Structures & Improvements	0	0	0	0	0	0	0	0.0000 %	0
36	375.1	Structures & Improvements	495,192	10,758	0	0	0	0	505,950	3.8000 %	19,226
37	375.2	Other System Structures	8,482	0	0	0	(8,482)	0	0	4.1300 %	0
38	376	Mains	789,474,200	182,815,773	0	0	0	1,457,628	973,747,600	2.4700 %	24,051,566
39	376.9	Mains - Cathodic Protection Anodes	70,654,884	2,518,810	0	0	0	82,457	73,256,151	6.6700 %	4,886,185
40	377	Compressor Station Equipment	0	0	0	0	0	0	0	0.0000 %	0
41	378	Meas. & Reg. Station - General	41,309,708	13,664,739	0	0	0	20,446	54,994,893	2.5900 %	1,424,368
42	379	Meas. & Reg. Station - C.G.	13,889,798	7,205,044	0	0	0	3,011	21,097,852	2.1800 %	459,933

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE - 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)
43	380	Services	657,442,217	23,623,313	0	0	0	3,177,157	684,242,687	3.7800 %	25,864,374
44	380.1	Ind Service Line Equip	0	70,299	0	0	0	21	70,320	3.7800 %	2,658
45	380.2	Comm Service Line Equip	(0)	902,190	0	0	0	(2,806)	899,384	3.7800 %	33,997
46	380.4	Yard Lines-Customer Svc	0	145,836	0	0	0	(12,918)	132,918	3.7800 %	5,024
47	381	Meters	173,894,577	5,369,861	0	0	0	(5,150)	179,259,288	4.1000 %	7,349,631
48	382	Meter Installations	0	0	0	0	0	0	0	4.2600 %	0
49	383	House Regulators	34,290,909	1,407,207	0	0	0	184	35,698,301	4.2300 %	1,510,038
50	385	Indust. Meas. & Reg. Stat. Equipment	36,951,604	1,980,942	0	0	0	36,580	38,969,126	2.3800 %	927,465
51	386	Other Property on Customer Premises	1,707,620	0	0	0	0	0	1,707,620	20.8200 %	355,527
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0.0000 %	0
53		Total Distribution Plant	$1,821,965,148	$239,887,770	$(2,018,957)	$0	$(8,482)	$4,756,611	$2,064,582,089		$66,889,991
		GENERAL PLANT									
54	389	Land & Land Rights	$10,192,918	$0	$(10,192,918)	$0	$0	$0	$0	0.0000 %	$0
55	390	Structures & Improvements	0	0	0	0	0	0	0	0.0000 %	0
56	390.1	Structures & Improvements	37,862,587	10,794,726	0	0	0	0	48,657,313	2.4100 %	1,172,641
57	390.17	Building Improv Plum	0	0	0	0	0	0	0	0.0000 %	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0.0000 %	0
59	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0.0000 %	0
60	390.2	OGS Lease Incentive	0	0	0	0	0	0	0	0.0000 %	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0.0000 %	0
62	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0.0000 %	0
63	391.1	Office Furniture & Equipment	3,906,448	24,536	0	0	0	0	3,930,984	6.6700 %	262,197
64	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0.0000 %	0
65	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0.0000 %	0
66	391.2	Oracle Equipment	0	0	0	0	0	0	0	0.0000 %	0
67	391.3	Office Machines	0	0	0	0	0	0	0	0.0000 %	0
68	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0.0000 %	0
69	391.5	Artwork	0	0	0	0	0	0	0	0.0000 %	0
70	391.6	Purchased Software	0	0	0	0	0	0	0	0.0000 %	0
71	391.6	Banner Software	0	0	0	0	0	0	0	0.0000 %	0
72	391.6	PowerPlant System	0	0	0	0	0	0	0	0.0000 %	0
73	391.6	Riskworks	0	0	0	0	0	0	0	0.0000 %	0
74	391.6	Maximo	0	0	0	0	0	0	0	0.0000 %	0
75	391.6	Foundation Software	0	0	0	0	0	0	0	0.0000 %	0
76	391.6	Concur Project	0	0	0	0	0	0	0	0.0000 %	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0.0000 %	0
78	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0.0000 %	0
79	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0.0000 %	0
80	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0.0000 %	0
81	391.6	Customer Relations Software	0	0	0	0	0	0	0	0.0000 %	0
82	391.8	Micro Computer Software	0	0	0	0	0	0	0	0.0000 %	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0.0000 %	0
84	391.9	Computer & Equipment	3,473,989	115,555	0	0	0	0	3,589,544	14.2900 %	512,946
85	391.99	Cloud Computing	0	0	0	0	0	0	0	0.0000 %	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE - 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)
86	392	Transportation Equipment	39,326,140	14,222,592	0	(53,548,732)	0	0	0	6.5600 %	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0.0000 %	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0.0000 %	0
89	392.5	Trailers	0	0	0	0	0	0	0	0.0000 %	0
90	392.6	Aircraft	0	0	0	0	0	0	0	0.0000 %	0
91	393	Stores Equipment	44,917	52,966	0	0	0	0	97,883	6.6700 %	6,529
92	394	Tools, Shop & Garage	30,071,976	3,202,882	0	0	0	0	33,274,859	6.6700 %	2,219,433
93	394.1	Tools	0	0	0	0	0	0	0	0.0000 %	0
94	394.2	Shop Equipment	0	0	0	0	0	0	0	0.0000 %	0
95	395	CNG Equipment	0	0	0	0	0	0	0	0.0000 %	0
96	396	Major Work Equipment	7,248,234	1,378,002	0	(8,626,236)	0	0	0	4.5100 %	0
97	397	Communication Equipment	64,043,325	6,639,251	0	0	0	0	70,682,576	6.6700 %	4,714,528
98	397.2	Telephone Equipment	0	0	0	0	0	0	0	0.0000 %	0
99	398	Miscellaneous General Plant	6,349	0	0	0	0	0	6,349	6.6700 %	423
100		Total General Plant	$196,176,883	$36,430,510	$(10,192,918)	$(62,174,968)	$0	$0	$160,239,508		$8,888,697
101		Total Plant in Service	$2,131,953,399	$305,379,772	$(12,235,152)	$(62,174,968)	$(8,482)	$4,757,745	$2,367,672,314		$80,096,356
102		Total Annualized Depreciation & Amortization Expense									$80,096,356
103		Test Year Depreciation & Amortization Expense (Accts. 403 & 404)									63,312,870
104		Adjustment to Test Year									$16,783,487

Note: Depreciation Related to Transportation Work Equipment:		Vehicles (392)	Work Equip (396)	Total	
105		Plant in Service + CCNC	$53,548,732	$8,626,236	$62,174,968	
106		Less Fully Depreciated Plant	0	0	0	
107		Net Depreciable Plant	$53,548,732	$8,626,236	$62,174,968	
108		Depreciation Rate	6.5600%	4.510%		
109		Proforma Depreciation Expense	$3,512,797	$389,043	$3,901,840	(to Schedule G-19)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - 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	$186,679	$(182,357)	$4,322	$0
2	301	Organization - OPC	0	0	0	0
3	302	Franchises & Consents	402,970	(393,609)	9,361	0
4	303	Misc. Intangible	1,291,712	(1,105,915)	185,797	0
5	303	Misc. Intangible - OPC	0	0	0	0
6	303.1	Misc. Intangible	616,460	(121,597)	494,863	0
7		Total Intangible Plant	$2,497,821	$(1,803,478)	$694,342	$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	(1,399)	(1,399)	0
18	365.1	Land - OPC	23,277	0	23,277	0
19	365.2	Rights-of-Way	228,499	0	228,499	0
20	365.2	Rights-of-Way - OPC	0	0	0	0
21	366	Meas/Reg Station Structures	1,812,971	(143,472)	1,669,498	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0
23	367	Mains	112,424,671	(7,381,469)	105,043,202	0
24	367	Mains - OPC	0	0	0	0
25	368	Compressor Station Equip	157,464	(7,608)	149,856	0
26	369	Meas & Reg Stations Equip	25,674,171	(2,152,001)	23,522,170	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	53,986	(20,044)	33,943	0
30	371	Other Equipment - OPC	0	0	0	0
31		Total Gathering and Transmission Plant	$140,375,039	$(9,705,994)	$130,669,046	$0
		DISTRIBUTION PLANT				
32	374	Land	$0	$(286)	$(286)	$0
33	374.1	Land	205,076	0	205,076	0
34	374.2	Land Rights	1,813,882	(94,416)	1,719,465	0
35	375.1	Structures & Improvements	0	0	0	0
36	375.1	Structures & Improvements	505,950	(138,200)	367,750	0
37	375.2	Other System Structures	8,482	(197,408)	(188,926)	(8,482)
38	376	Mains	972,289,972	(137,288,079)	835,001,893	0
39	376.9	Mains - Cathodic Protection Anodes	73,173,694	(34,881,929)	38,291,765	0
40	377	Compressor Station Equipment	0	0	0	0
41	378	Meas. & Reg. Station - General	54,974,447	(5,728,613)	49,245,834	0
42	379	Meas. & Reg. Station - C.G.	21,094,842	(2,288,841)	18,806,001	0
43	380	Services	681,065,529	(112,646,444)	568,419,085	0
44	380.1	Ind Service Line Equip	70,299	0	70,299	0
45	380.2	Comm Service Line Equip	902,190	0	902,190	0
46	380.4	Yard Lines-Customer Svc	145,836	0	145,836	0
47	381	Meters	179,264,438	(47,294,132)	131,970,305	0
48	382	Meter Installations	0	(126,749)	(126,749)	0
49	383	House Regulators	35,698,116	(11,583,951)	24,114,165	0
50	385	Indust. Meas. & Reg. Stat. Equipment	38,932,546	(7,758,786)	31,173,760	0
51	386	Other Property on Customer Premises	1,707,620	(1,137,465)	570,155	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT	FULLY DEPREICATED PLANT
			(a)	(b)	(c)	(d)
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0
53		Total Distribution Plant	$2,061,852,918	$(361,165,300)	$1,700,687,618	$(8,482)
		GENERAL PLANT				
54	389	Land & Land Rights	$10,192,918	$4,733	$10,197,651	$0
55	390	Structures & Improvements	0	0	0	0
56	390.1	Structures & Improvements	48,657,313	(9,456,886)	39,200,427	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	(1,849)	(1,849)	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	3,930,984	(1,814,406)	2,116,578	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	3,589,544	(2,274,597)	1,314,947	0
85	391.99	Cloud Computing	0	0	0	0
86	392	Transportation Equipment	53,548,732	(14,492,058)	39,056,674	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	97,883	(20,882)	77,002	0
92	394	Tools, Shop & Garage	33,274,859	(11,709,857)	21,565,002	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	8,626,236	(2,344,303)	6,281,933	0
97	397	Communication Equipment	70,682,576	(31,640,425)	39,042,151	0
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	6,349	(5,767)	582	0
100		Total General Plant	$232,607,394	$(73,718,815)	$158,888,579	$0
101		Total Orig Cost Plant in Service	$2,437,333,171	$(446,393,587)	$1,990,939,584	$(8,482)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE - FORT BLISS

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	$0	$0	$0	$0	$0	$0	$0		$0
2	301	Organization - OPC	0	0	0	0	0	0	0		0
3	302	Franchises & Consents	0	0	0	0	0	0	0		0
4	303	Misc. Intangible	0	0	0	0	0	0	0		0
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		0
7		Total Intangible Plant	$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
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		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		0
23	367	Mains	0	0	0	0	0	0	0		0
24	367	Mains - OPC	0	0	0	0	0	0	0		0
25	368	Compressor Station Equip	0	0	0	0	0	0	0		0
26	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0		0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0	0	0	0		0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0	0	0	0		0
29	371	Other Equipment	0	0	0	0	0	0	0		0
30	371	Other Equipment - OPC	0	0	0	0	0	0	0		0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT									
32	374	Land	$0	$0	$0	$0	$0	$0	$0		$0
33	374.1	Land	0	0	0	0	0	0	0		0
34	374.2	Land Rights	19,533	0	(19,533)	0	0	0	0		0
35	375	Structures & Improvements	0	0	0	0	0	0	0		0
36	375.1	Structures & Improvements	0	0	0	0	0	0	0		0
37	375.2	Other System Structures	0	0	0	0	0	0	0		0
38	376	Mains	6,406,720	674,326	0	0	0	0	7,081,047	2.4700 %	174,902
39	376.9	Mains - Cathodic Protection Anodes	135,856	15,227	0	0	0	0	151,083	6.6700 %	10,077
40	377	Compressor Station Equipment	0	0	0	0	0	0	0		0
41	378	Meas. & Reg. Station - General	620,572	(295,036)	0	0	0	0	325,537	2.7000 %	8,789
42	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	— %	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE - FORT BLISS

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)
43	380	Services	1,219,652	305,303	0	0	0	0	1,524,955	3.7200 %	56,728
44	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	3.7200 %	0
45	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	3.7200 %	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	3.7200 %	0
47	381	Meters	108,468	44,343	0	0	0	0	152,811	4.7200 %	7,213
48	382	Meter Installations	0	0	0	0	0	0	0	0.0000 %	0
49	383	House Regulators	58,948	16,622	0	0	0	0	75,571	4.4500 %	3,363
50	385	Indust. Meas. & Reg. Stat. Equipment	306,223	267,949	0	0	0	0	574,172	2.2700 %	13,034
51	386	Other Property on Customer Premises	0	0	0	0	0	0	0		0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0		0
53		Total Distribution Plant	$8,875,973	$1,028,735	$(19,533)	$0	$0	$0	$9,885,174		$274,106
		GENERAL PLANT									
54	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0		$0
55	390	Structures & Improvements	0	0	0	0	0	0	0		0
56	390.1	Structures & Improvements	0	0	0	0	0	0	0		0
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	0	0	0	0	0	0	0		0
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
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	0	0	0	0	0	0	0		0
85	391.99	Cloud Computing	0	0	0	0	0	0	0		0
86	392	Transportation Equipment	0	0	0	0	0	0	0		0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0		0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DEPRECIATION AND AMORTIZATION EXPENSE - FORT BLISS

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)
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0		0
89	392.5	Trailers	0	0	0	0	0	0	0		0
90	392.6	Aircraft	0	0	0	0	0	0	0		0
91	393	Stores Equipment	0	0	0	0	0	0	0		0
92	394	Tools, Shop & Garage	11,690	0	0	0	0	0	11,690	6.6700 %	780
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	0	0	0	0	0	0	0		0
97	397	Communication Equipment	48,893	0	0	0	0	0	48,893	6.6700 %	3,261
98	397.2	Telephone Equipment	0	0	0	0	0	0	0		0
99	398	Miscellaneous General Plant	0	0	0	0	0	0	0		0
100		Total General Plant	$60,583	$0	$0	$0	$0	$0	$60,583		$4,041
101		Total Plant in Service	$8,936,556	$1,028,735	$(19,533)	$0	$0	$0	$9,945,757		$278,147
102		Total Annualized Depreciation & Amortization Expense									$278,147
103		Test Year Depreciation & Amortization Expense (Accts. 403 & 404)									230,147
104		Adjustment to Test Year									$48,001

Note: Depreciation Related to Transportation Work Equipment:		Vehicles (392)	Work Equip (396)	Total	
105		Plant in Service + CCNC	$0	$0	$0	
106		Less Fully Depreciated Plant	0	0	0	
107		Net Depreciable Plant	$0	$0	$0	
108		Depreciation Rate	0.0000%	0.000%		
109		Proforma Depreciation Expense	$0	$0	$0	(to Schedule G-19)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - FORT BLISS

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	$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	$(8,660)	$(8,660)	$0
33	374.1	Land	0	0	0	0
34	374.2	Land Rights	19,533	0	19,533	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	7,081,047	(636,844)	6,444,202	0
39	376.9	Mains - Cathodic Protection Anodes	151,083	(61,031)	90,053	0
40	377	Compressor Station Equipment	0	0	0	0
41	378	Meas. & Reg. Station - General	325,537	(44,709)	280,828	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0
43	380	Services	1,524,955	(160,974)	1,363,980	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	152,811	(39,495)	113,316	0
48	382	Meter Installations	0	0	0	0
49	383	House Regulators	75,571	(15,367)	60,204	0
50	385	Indust. Meas. & Reg. Stat. Equipment	574,172	(39,779)	534,392	0
51	386	Other Property on Customer Premises	0	0	0	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT	FULLY DEPREICATED PLANT
			(a)	(b)	(c)	(d)
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0
53		Total Distribution Plant	$9,904,708	$(1,006,859)	$8,897,849	$0
		GENERAL PLANT				
54	389	Land & Land Rights	$0	$0	$0	$0
55	390	Structures & Improvements	0	0	0	0
56	390.1	Structures & Improvements	0	0	0	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	0	0	0	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	0	15,138	15,138	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
91	393	Stores Equipment	0	0	0	0
92	394	Tools, Shop & Garage	11,690	(3,498)	8,192	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	48,893	(28,294)	20,599	0
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	0	0	0	0
100		Total General Plant	$60,583	$(16,654)	$43,929	$0
101		Total Orig Cost Plant in Service	$9,965,290	$(1,023,513)	$8,941,778	$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0		0	100.0000%	$0
2	301	Organization - OPC	0	0	0	0		0	100.0000%	0
3	302	Franchises & Consents	0	0	0	0		0	100.0000%	0
4	303	Misc. Intangible	0	0	0	0		0	100.0000%	0
5	303	Misc. Intangible - OPC	0	0	0	0		0	100.0000%	0
6	303.1	Misc. Intangible	0	0	0	0		0	100.0000%	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	100.0000%	$0
9	327	Field Comprss Station Strucutres	0	0	0	0		0	100.0000%	0
10	328	Field Meas/Reg Station Structures	0	0	0	0		0	100.0000%	0
11	329	Other Structures	0	0	0	0		0	100.0000%	0
12	332	Field Lines	0	0	0	0		0	100.0000%	0
13	333	Field Compressor Station Equip	0	0	0	0		0	100.0000%	0
14	334	Field Meas/Reg Station Equipment	0	0	0	0		0	100.0000%	0
15	336	Purification Equipment	0	0	0	0		0	100.0000%	0
16	337	Other Equip	0	0	0	0		0	100.0000%	0
17	365	Land & Land Rights	0	0	0	0		0	100.0000%	0
18	365.1	Land - OPC	0	0	0	0		0	100.0000%	0
19	365.2	Rights-of-Way	0	0	0	0		0	100.0000%	0
20	365.2	Rights-of-Way - OPC	0	0	0	0		0	100.0000%	0
21	366	Meas/Reg Station Structures	0	0	0	0		0	100.0000%	0
22	366.1	Compressor Station Structure - OPC	0	0	0	0		0	100.0000%	0
23	367	Mains	0	0	0	0		0	100.0000%	0
24	367	Mains - OPC	0	0	0	0		0	100.0000%	0
25	368	Compressor Station Equip	0	0	0	0		0	100.0000%	0
26	369	Meas & Reg Stations Equip	0	0	0	0		0	100.0000%	0
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0		0	100.0000%	0
28	369.1	Measuring Stations Equip - OPC	0	0	0	0		0	100.0000%	0
29	371	Other Equipment	0	0	0	0		0	100.0000%	0
30	371	Other Equipment - OPC	0	0	0	0		0	100.0000%	0
31		Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
		DISTRIBUTION PLANT								

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
32	374	Land	$0	$0	$0	$0		0	100.0000%	$0
33	374.1	Land	0	0	0	0		0	100.0000%	0
34	374.2	Land Rights	0	0	0	0		0	100.0000%	0
35	375.1	Structures & Improvements	0	0	0	0		0	100.0000%	0
36	375.1	Structures & Improvements	0	0	0	0		0	100.0000%	0
37	375.2	Other System Structures	0	0	0	0		0	100.0000%	0
38	376	Mains	0	0	0	0		0	100.0000%	0
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0		0	100.0000%	0
40	377	Compressor Station Equipment	0	0	0	0		0	100.0000%	0
41	378	Meas. & Reg. Station - General	0	0	0	0		0	100.0000%	0
42	379	Meas. & Reg. Station - C.G.	0	0	0	0		0	100.0000%	0
43	380	Services	0	0	0	0		0	100.0000%	0
44	380.1	Ind Service Line Equip	0	0	0	0		0	100.0000%	0
45	380.2	Comm Service Line Equip	0	0	0	0		0	100.0000%	0
46	380.4	Yard Lines-Customer Svc	0	0	0	0		0	100.0000%	0
47	381	Meters	0	0	0	0		0	100.0000%	0
48	382	Meter Installations	0	0	0	0		0	100.0000%	0
49	383	House Regulators	0	0	0	0		0	100.0000%	0
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0		0	100.0000%	0
51	386	Other Property on Customer Premises	0	0	0	0		0	100.0000%	0
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0		0	100.0000%	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	100.0000%	$0
55	390	Structures & Improvements	0	0	0	0		0	100.0000%	0
56	390.1	Structures & Improvements	4,445,623	142,293	0	4,587,916	2.4400%	111,945	100.0000%	111,945
57	390.17	Building Improv Plum	0	0	0	0		0	100.0000%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0		0	100.0000%	0
59	390.2	Leasehold Improvement	234,303	18,181	(252,484)	0		0	100.0000%	0
60	390.2	OGS Lease Incentive	0	0	0	0		0	100.0000%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0		0	100.0000%	0
62	391	Office Furniture & Equipment	0	0	0	0		0	100.0000%	0
63	391.1	Office Furniture & Equipment	2,573,867	0	0	2,573,867	6.6700%	171,677	100.0000%	171,677
64	391.19	Airplane Hanger Furniture	0	0	0	0		0	100.0000%	0
65	391.2	Data Processing Equipment	0	0	0	0		0	100.0000%	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
66	391.2	Oracle Equipment	0	0	0	0		0	100.0000%	0
67	391.3	Office Machines	0	0	0	0		0	100.0000%	0
68	391.4	Audio Visual Equipment	0	0	0	0		0	100.0000%	0
69	391.5	Artwork	0	0	0	0		0	100.0000%	0
70	391.6	Purchased Software	0	0	0	0		0	100.0000%	0
71	391.6	Banner Software	0	0	0	0		0	100.0000%	0
72	391.6	PowerPlant System	0	0	0	0		0	100.0000%	0
73	391.6	Riskworks	0	0	0	0		0	100.0000%	0
74	391.6	Maximo	0	0	0	0		0	100.0000%	0
75	391.6	Foundation Software	0	0	0	0		0	100.0000%	0
76	391.6	Concur Project	0	0	0	0		0	100.0000%	0
77	391.6	Journey-Employee-ODC Distrigas	0	0	0	0		0	100.0000%	0
78	391.6	Journey-Employee Count	0	0	0	0		0	100.0000%	0
79	391.6	Payroll - Time Management	0	0	0	0		0	100.0000%	0
80	391.6	Accounts Payable Software	0	0	0	0		0	100.0000%	0
81	391.6	Customer Relations Software	0	0	0	0		0	100.0000%	0
82	391.8	Micro Computer Software	0	0	0	0		0	100.0000%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0		0	100.0000%	0
84	391.9	Computer & Equipment	2,820,584	62,111	0	2,882,696	14.2900%	411,937	100.0000%	411,937
85	391.99	Cloud Computing	0	0	0	0		0	100.0000%	0
86	392	Transportation Equipment	0	0	0	0		0	100.0000%	0
87	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0		0	100.0000%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0		0	100.0000%	0
89	392.5	Trailers	0	0	0	0		0	100.0000%	0
90	392.6	Aircraft	0	0	0	0		0	100.0000%	0
91	393	Stores Equipment	0	0	0	0		0	100.0000%	0
92	394	Tools, Shop & Garage	28,756	71,210	0	99,966	6.6667%	6,664	100.0000%	6,664
93	394.1	Tools	0	0	0	0		0	100.0000%	0
94	394.2	Shop Equipment	0	0	0	0		0	100.0000%	0
95	395	CNG Equipment	0	0	0	0		0	100.0000%	0
96	396	Major Work Equipment	0	0	0	0		0	100.0000%	0
97	397	Communication Equipment	892,508	0	0	892,508	6.6667%	59,501	100.0000%	59,501
98	397.2	Telephone Equipment	0	0	0	0		0	100.0000%	0
99	398	Miscellaneous General Plant	0	0	0	0		0	100.0000%	0
100		Total General Plant	$11,430,339	$293,795	$(252,484)	$11,471,650		$761,724		$761,724

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
101		Total Plant in Service	$11,430,339	$293,795	$(252,484)	$11,471,650		$761,724		$761,724
102		Total Annualized Depreciation & Amortization Expense						$761,724	100.0000%	$761,724
103		Test Year Depreciation & Amortization Expense Accts 403 & 404						787,025	100.0000%	787,025
104		Adjustment to Test Year						$(25,300)	100.0000%	$(25,300)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION AS ADJUSTED 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
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

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION AS ADJUSTED PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
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	4,587,916	(576,019)	4,011,897	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	(252,484)	0	(252,484)
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	2,573,867	(893,613)	1,680,253	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	2,882,696	(1,077,228)	1,805,467	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
91	393	Stores Equipment	0	0	0	0
92	394	Tools, Shop & Garage	99,966	(17,752)	82,214	0
93	394.1	Tools	0	452	452	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	892,508	(598,146)	294,362	0
98	397.2	Telephone Equipment	0	0	0	0
99	398	Miscellaneous General Plant	0	0	0	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

FULLY DEPRECIATED PLANT - TGS DIVISION

LINEN O.	ACCOUNT	DESCRIPTION	TGS DIVISION AS ADJUSTED PLANT 1010 & 1060	RESERVES 1080100 & 1110	NET PLANT	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
100		Total General Plant	$11,724,133	$(3,414,791)	$8,309,343	$(252,484)
101		Total Orig Cost Plant in Service	$11,724,133	$(3,414,791)	$8,309,343	$(252,484)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0		$0		
2	301	Organization - OPC	0	0	0	0		0		
3	302	Franchises & Consents	0	0	0	0		0		
4	303	Misc. Intangible	0	0	0	0		0		
5	303	Misc. Intangible - OPC	0	0	0	0		0		
6	303.1	Misc. Intangible	0	0	0	0		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		
9	327	Field Comprss Station Strucutres	0	0	0	0		0		
10	328	Field Meas/Reg Station Structures	0	0	0	0		0		
11	329	Other Structures	0	0	0	0		0		
12	332	Field Lines	0	0	0	0		0		
13	333	Field Compressor Station Equip	0	0	0	0		0		
14	334	Field Meas/Reg Station Equipment	0	0	0	0		0		
15	336	Purification Equipment	0	0	0	0		0		
16	337	Other Equip	0	0	0	0		0		
17	365	Land & Land Rights	0	0	0	0		0		
18	365.1	Land - OPC	0	0	0	0		0		
19	365.2	Rights-of-Way	0	0	0	0		0		
20	365.2	Rights-of-Way - OPC	0	0	0	0		0		
21	366	Meas/Reg Station Structures	0	0	0	0		0		
22	366.1	Compressor Station Structure - OPC	0	0	0	0		0		
23	367	Mains	0	0	0	0		0		
24	367	Mains - OPC	0	0	0	0		0		
25	368	Compressor Station Equip	0	0	0	0		0		
26	369	Meas & Reg Stations Equip	0	0	0	0		0		
27	369	Meas & Reg Stations Equip - OPC	0	0	0	0		0		
28	369.1	Measuring Stations Equip - OPC	0	0	0	0		0		
29	371	Other Equipment	0	0	0	0		0		
30	371	Other Equipment - OPC	0	0	0	0		0		
31		Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
		DISTRIBUTION PLANT								
32	374	Land	$0	$0	$0	$0		$0		
33	374.1	Land	0	0	0	0		0		
34	374.2	Land Rights	0	0	0	0		0		
35	375.1	Structures & Improvements	0	0	0	0		0		
36	375.1	Structures & Improvements	0	0	0	0		0		

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
37	375.2	Other System Structures	0	0	0	0		0		
38	376	Mains	0	0	0	0		0		
39	376.9	Mains - Cathodic Protection Anodes	0	0	0	0		0		
40	377	Compressor Station Equipment	0	0	0	0		0		
41	378	Meas. & Reg. Station - General	0	0	0	0		0		
42	379	Meas. & Reg. Station - C.G.	0	0	0	0		0		
43	380	Services	0	0	0	0		0		
44	380.1	Ind Service Line Equip	0	0	0	0		0		
45	380.2	Comm Service Line Equip	0	0	0	0		0		
46	380.4	Yard Lines-Customer Svc	0	0	0	0		0		
47	381	Meters	0	0	0	0		0		
48	382	Meter Installations	0	0	0	0		0		
49	383	House Regulators	0	0	0	0		0		
50	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0		0		
51	386	Other Property on Customer Premises	0	0	0	0		0		
52	387	Meas. & Reg. Stat. Equipment	0	0	0	0		0		
53		Total Distribution Plant	$0	$0	$0	$0		$0		$0
		GENERAL PLANT								
54	389	Land & Land Rights	$13,238	$0	$0	$13,238	0.0000%	$0	100.0000%	$0
55	390	Structures & Improvements	0	0	0	0	0.0000%	0	100.0000%	0
56	390.1	Structures & Improvements	1,555,336	15,982	0	1,571,318	2.0100%	31,583	100.0000%	31,583
57	390.17	Building Improv Plum	0	0	0	0		0	100.0000%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0		0	100.0000%	0
59	390.2	Leasehold Improvement	2,064,845	119,773	0	2,184,617	17.9104%	391,274	100.0000%	391,274
60	390.2	OGS Lease Incentive	0	0	0	0		0	100.0000%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0		0	100.0000%	0
62	391	Office Furniture & Equipment	0	0	0	0		0	100.0000%	0
63	391.1	Office Furniture & Equipment	1,712,093	0	0	1,712,093	6.6667%	114,140	100.0000%	114,140
64	391.19	Airplane Hanger Furniture	0	0	0	0	6.6667%	0	100.0000%	0
65	391.2	Data Processing Equipment	0	0	0	0		0	100.0000%	0
66	391.2	Oracle Equipment	0	0	0	0		0	100.0000%	0
67	391.3	Office Machines	95,784	272,719	0	368,503	5.0000%	18,425	100.0000%	18,425
68	391.4	Audio Visual Equipment	59,436	0	0	59,436	20.0000%	11,887	100.0000%	11,887
69	391.5	Artwork	0	0	0	0		0	100.0000%	0
70	391.6	Purchased Software	41,324,739	8,475,099	0	49,799,837	7.6923%	3,830,757	100.0000%	3,830,757
71	391.6	Banner Software	3,527,119	0	0	3,527,119	7.6923%	271,317	100.0000%	271,317
72	391.6	PowerPlant System	700,393	0	0	700,393	7.6923%	53,876	100.0000%	53,876
73	391.6	Riskworks	0	0	0	0	7.6923%	0	100.0000%	0
74	391.6	Maximo	1,167,518	103,734	0	1,271,252	7.6923%	97,789	100.0000%	97,789
75	391.6	Foundation Software	0	0	0	0	7.6923%	0	100.0000%	0
76	391.6	Concur Project	21,615	0	0	21,615	7.6923%	1,663	100.0000%	1,663

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 TGS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
77	391.6	Journey-Employee-ODC Distrigas	21,046,824	0	0	21,046,824	7.6923%	1,618,986	100.0000%	1,618,986
78	391.6	Journey-Employee Count	557,771	0	0	557,771	7.6923%	42,905	100.0000%	42,905
79	391.6	Payroll - Time Management	889,824	0	0	889,824	7.6923%	68,448	100.0000%	68,448
80	391.6	Accounts Payable Software	469,112	0	0	469,112	7.6923%	36,086	100.0000%	36,086
81	391.6	Customer Relations Software	589,902	0	0	589,902	7.6923%	45,377	100.0000%	45,377
82	391.8	Micro Computer Software	6,036,516	0	0	6,036,516	20.0000%	1,207,303	100.0000%	1,207,303
83	391.81	Aircraft Computer Equipment	0	0	0	0		0	100.0000%	0
84	391.9	Computer & Equipment	0	0	0	0		0	100.0000%	0
85	391.99	Cloud Computing	723,238	0	0	723,238	7.6923%	55,634	100.0000%	55,634
86	392	Transportation Equipment	0	0	0	0		0	100.0000%	0
87	392.2	Transport Equip Pickup Trucks& Vans	274,209	0	0	274,209	16.6667%	45,701	100.0000%	45,701
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0		0	100.0000%	0
89	392.5	Trailers	0	0	0	0		0	100.0000%	0
90	392.6	Aircraft	0	0	0	0	6.2800%	0	100.0000%	0
91	393	Stores Equipment	0	0	0	0		0	100.0000%	0
92	394	Tools, Shop & Garage	151,833	32,732	0	184,564	6.6667%	12,304	100.0000%	12,304
93	394.1	Tools	0	0	0	0		0	100.0000%	0
94	394.2	Shop Equipment	0	0	0	0		0	100.0000%	0
95	395	CNG Equipment	0	0	0	0		0	100.0000%	0
96	396	Major Work Equipment	0	0	0	0		0	100.0000%	0
97	397	Communication Equipment	31,003	0	0	31,003	5.0000%	1,550	100.0000%	1,550
98	397.2	Telephone Equipment	0	0	0	0		0	100.0000%	0
99	398	Miscellaneous General Plant	0	0	0	0		0	100.0000%	0
100		Total General Plant	$83,012,346	$9,020,038	$0	$92,032,383		$7,957,005		$7,957,005
101		Total Plant in Service	$83,012,346	$9,020,038	$0	$92,032,383		$7,957,005		$7,957,005
102		Total Annualized Depreciation & Amortization Expense						$7,957,005	100.0000%	$7,957,005
103		Test Year Depreciation & Amortization Expense Accts 403 & 404						7,296,672	100.0000%	7,296,672
104		Adjustment to Test Year						$660,333	100.0000%	$660,333

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	30.25%	$0
55	390	Structures & Improvements	0	0	0	0	30.25%	0
56	390.1	Structures & Improvements	5,194,440	(433,048)	4,761,392	0	30.25%	0
57	390.17	Building Improv Plum	0	0	0	0	30.25%	0
58	390.19	Airplane Hanger Furniture	0	0	0	0	30.25%	0
59	390.2	Leasehold Improvement	7,221,875	(4,295,645)	2,926,230	0	30.25%	0
60	390.2	OGS Lease Incentive	0	0	0	0	30.25%	0
61	390.21	Leasehold Equipment EOL	0	0	0	0	30.25%	0
62	391	Office Furniture & Equipment	0	0	0	0	30.25%	0
63	391.1	Office Furniture & Equipment	5,659,812	(2,377,540)	3,282,272	0	30.25%	0
64	391.19	Airplane Hanger Furniture	0	0	0	0	30.25%	0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
65	391.2	Data Processing Equipment	0	0	0	0	30.25%	0
66	391.2	Oracle Equipment	0	0	0	0	30.25%	0
67	391.3	Office Machines	1,218,191	(204,842)	1,013,349	0	30.25%	0
68	391.4	Audio Visual Equipment	196,483	261,245	457,728	0	30.25%	0
69	391.5	Artwork	0	0	0	0	30.25%	0
70	391.6	Purchased Software	164,627,562	(73,656,005)	90,971,557	0	30.25%	0
71	391.6	Banner Software	11,396,183	(3,296,668)	8,099,515	0	30.95%	0
72	391.6	PowerPlant System	2,448,925	(1,131,510)	1,317,415	0	28.60%	0
73	391.6	Riskworks	0	0	0	0	30.25%	0
74	391.6	Maximo	5,085,007	(3,538,896)	1,546,111	0	25.00%	0
75	391.6	Foundation Software	0	0	0	0	30.25%	0
76	391.6	Concur Project	71,646	(62,722)	8,924	0	30.17%	0
77	391.6	Journey-Employee-ODC Distrigas	69,576,279	(54,360,070)	15,216,209	0	30.25%	0
78	391.6	Journey-Employee Count	1,848,836	(1,580,044)	268,792	0	30.17%	0
79	391.6	Payroll - Time Management	2,949,490	(854,139)	2,095,351	0	30.17%	0
80	391.6	Accounts Payable Software	1,337,453	(505,961)	831,493	0	35.08%	0
81	391.6	Customer Relations Software	1,905,984	(168,278)	1,737,706	0	30.95%	0
82	391.8	Micro Computer Software	19,955,423	(5,391,339)	14,564,085	0	30.25%	0
83	391.81	Aircraft Computer Equipment	0	0	0	0	30.25%	0
84	391.9	Computer & Equipment	0	0	0	0	30.25%	0
85	391.99	Cloud Computing	2,390,869	(421,088)	1,969,781	0	30.25%	0
86	392	Transportation Equipment	0	0	0	0	30.25%	0
87	392.2	Transport Equip Pickup Trucks& Vans	906,475	(102,798)	803,677	0	30.25%	0
88	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	30.25%	0
89	392.5	Trailers	0	0	0	0	30.25%	0
90	392.6	Aircraft	0	0	0	0	30.25%	0
91	393	Stores Equipment	0	0	0	0	30.25%	0
92	394	Tools, Shop & Garage	610,130	(99,239)	510,891	0	30.25%	0
93	394.1	Tools	0	0	0	0	30.25%	0
94	394.2	Shop Equipment	0	0	0	0	30.25%	0
95	395	CNG Equipment	0	0	0	0	30.25%	0
96	396	Major Work Equipment	0	0	0	0	30.25%	0
97	397	Communication Equipment	102,489	(35,123)	67,366	0	30.25%	0
98	397.2	Telephone Equipment	0	0	0	0	30.25%	0
99	398	Miscellaneous General Plant	0	0	0	0	30.25%	0
100		Total General Plant	$304,747,316	$(152,253,709)	$152,493,607	$0		$0
101		Total Orig Cost Plant in Service	$304,747,316	$(152,253,709)	$152,493,607	$0		$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

AD VALOREM TAX EXPENSE

LINE NO.	DESCRIPTION	AMOUNT	AMOUNT	AMOUNT
		(a)	(b)	(c)
	DIRECT PLANT @ 12/31/2024			
1	Plant In Service - Gathering/Transmission/Distribution		$1,942,415,846	
2	Plant In Service - General		196,237,466	
3	CCNC - Gathering/Transmission/Distribution		269,716,819	
4	CCNC - General		36,430,510	
5	Accumulated Depreciation - Gathering/Transmission/Distribution		(371,878,153)	
6	Accumulated Depreciation - General		(73,735,469)	
7	Net Plant - Direct 12/31/2024		$1,999,187,020	$1,999,187,020
	CALCULATION OF EFFECTIVE RATE			
8	Ad Valorem Taxes Paid TYE 2024 for Service Area Direct Plant at 1/1/2024		$17,535,497	
	DIRECT PLANT @ 1/1/2024			
9	Plant In Service - Gathering/Transmission/Distribution	$1,803,360,163		
10	Plant In Service - General	171,721,838		
11	CCNC - Gathering/Transmission/Distribution	184,241,142		
12	CCNC - General	41,898,466		
13	Accumulated Depreciation - Gathering/Transmission/Distribution	(337,530,879)		
14	Accumulated Depreciation - General	(63,111,790)		
		$1,800,578,940	1,800,578,940	
15	Effective Tax Rate		0.009739	0.009739
16	Annualized Ad Valorem Tax Expense			$19,470,082
17	Test Year Ad Valorem Tax Expense - Acct 4081190			17,854,051
18	Adjustment to Test Year Expense			$1,616,031

Source: SCH G-16 Ad Valorem Tax (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PLANT IN SERVICE - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/23	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization	$186,679	$0	$186,679
2	(302) Franchises & Consents	402,970	0	402,970
3	(303) Misc. Intangible	1,646,993	0	1,646,993
4	Total Intangible Plant - Direct	$2,236,642	$0	$2,236,642
	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	112,914	0	112,914
15	(365.2) Rights-of-Way	235,382	0	235,382
16	(366) Meas/Reg Station Structures	29,577	0	29,577
17	(367) Mains	104,208,074	0	104,208,074
18	(368) Compressor Station Equip	88,467	0	88,467
19	(369) Measure/Reg. Station Equipment	16,871,183	0	16,871,183
20	(371) Other Equipment	52,349	0	52,349
21	Total Gathering and Transmission Plant - Direct	$121,597,945	$0	$121,597,945
	DISTRIBUTION PLANT			
22	(374) Land	$113,367	$0	$113,367
23	(374.2) Land & Land Rights	1,655,530	-	1,655,530
24	(375) Structures & Improvements	470,640	0	470,640
25	(376) Mains	736,022,388	0	736,022,388
26	(376.9) Cathodic Protection Anodes	69,641,696	0	69,641,696
27	(377) Compressor Station Equipment	0	0	0
28	(378) Meas. & Reg. Station - General	36,504,147	0	36,504,147
29	(379) Meas. & Reg. Station - C.G.	11,956,744	0	11,956,744
30	(380) Services	590,737,019	0	590,737,019
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	164,514,967	0	164,514,967
35	(382) Meter Installations	0	0	0
36	(383) House Regulators	32,202,548	0	32,202,548
37	(385) Indust. Meas. & Reg. Stat. Equipment	36,235,552	0	36,235,552
38	(386) Other Property on Customer Premises	1,707,620	0	1,707,620
39	(387) Meas. & Reg. Stat. Equipment	0	0	0
40	Total Distribution Plant - Direct	$1,681,762,218	$0	$1,681,762,218
	GENERAL PLANT			
41	(389) Land & Land Rights	$10,193,160	$0	$10,193,160
42	(390) Structures & Improvements	35,893,501	0	35,893,501
43	(391) Office Furniture & Equipment	3,813,735	0	3,813,735
44	(391.9) Computer & Equipment	4,200,305	0	4,200,305
45	(392) Transportation Equipment	37,825,947	0	37,825,947
46	(393) Stores Equipment	32,034	0	32,034
47	(394) Tools, Shop & Garage	24,287,134	0	24,287,134
48	(395) CNG Equipment	0	0	0
49	(396) Major Work Equipment	6,445,360	0	6,445,360
50	(397) Communication Equipment	49,024,313	0	49,024,313
51	(398) Miscellaneous General Plant	6,349	0	6,349
52	Total General Plant - Direct	$171,721,838	$0	$171,721,838
53	Total Orig Cost Plant in Service - Direct	$1,977,318,643	$0	$1,977,318,643

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT

AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/23 (a)	ADJUSTMENTS (b)	ADJUSTED BALANCE (c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization			$0
2	(302) Franchises & Consents			0
3	(303) Misc. Intangible	260,537		260,537
4	Total Intangible CCNC - Direct	$260,537	$0	$260,537
	GATHERING AND TRANSMISSION PLANT			
5	(325) Land & Land Rights			$0
6	(327) Field Comprss Station Strucutres			0
7	(328) Field Meas/Reg Station Structures			0
8	(329) Other Structures			0
9	(332) Field Lines			0
10	(333) Field Compressor Station Equip			0
11	(334) Field Meas/Reg Station Equipment			0
12	(336) Purification Equipment			0
13	(337) Other Equip			0
14	(365) Land & Land Rights			0
15	(365.2) Rights-of-Way	15,696		15,696
16	(366) Meas/Reg Station Structures	1,785,740		1,785,740
17	(367) Mains	15,822,924		15,822,924
18	(368) Compressor Station Equip			0
19	(369) Measure/Reg. Station Equipment	8,049,649		8,049,649
20	(371) Other Equipment	1,638		1,638
21	Total Gathering and Transmission CCNC - Direct	$25,675,646	$0	$25,675,646
	DISTRIBUTION PLANT			
22	(374) Land	$1,674		$1,674
23	(374.2) Land & Land Rights	72,664		72,664
24	(375) Structures & Improvements	1,988,673		1,988,673
25	(376) Mains	112,839,477		112,839,477
26	(376.9) Cathodic Proteciton Anodes	1,408,310		1,408,310
27	(377) Compressor Station Equipment			0
28	(378) Meas. & Reg. Station - General	14,510,996		14,510,996
29	(379) Meas. & Reg. Station - C.G.	3,944,041		3,944,041
30	(380) Services	17,876,529		17,876,529
31	(380.1) Ind Service Line Equip	26,499		26,499
32	(380.2) Comm Service Line Equip	84,507		84,507
33	(380.4) Yard Lines-Customer Svc	246,089		246,089
34	(381) Meters	4,133,653		4,133,653
35	(382) Meter Installations	102,607		102,607
36	(383) House Regulators	187,285		187,285
37	(385) Indust. Meas. & Reg. Stat. Equipment	1,142,491		1,142,491
38	(386) Other Property on Customer Premises			0
39	(387) Meas. & Reg. Stat. Equipment			0
40	Total Distribution CCNC - Direct	$158,565,496	$0	$158,565,496
	GENERAL PLANT			
41	(389) Land & Land Rights			$0
42	(390) Structures & Improvements	9,447,604.18		9,447,604
43	(391) Office Furniture & Equipment	42,589		42,589
44	(391.9) Computer & Equipment	479,472		479,472
45	(392) Transportation Equipment	8,716,739		8,716,739
46	(393) Stores Equipment	155,828		155,828
47	(394) Tools, Shop & Garage	5,640,189		5,640,189
48	(395) CNG Equipment			0
49	(396) Major Work Equipment	1,288,308		1,288,308
50	(397) Communication Equipment	16,127,737		16,127,737
51	(398) Miscellaneous General Plant			0
52	Total General CCNC - Direct	$41,898,466	$0	$41,898,466
53	Total Orig Cost CCNC - Direct	$226,400,145	$0	$226,400,145

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION- DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/23 1080100	YTD BALANCE 12/31/23 1110000	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)	(d)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)				
1	(301) Organization	$(178,665)			$(178,665)
2	(302) Franchises & Consents	(393,229)			(393,229)
3	(303) Misc. Intangible		(1,175,626)		(1,175,626)
4	Total Intangible Plant Reserves - Direct	$(571,894)	$(1,175,626)	$0	$(1,747,520)
	GATHERING AND TRANSMISSION PLANT				
5	(325) Land & Land Rights				$0
6	(327) Field Comprss Station Strucutres				0
7	(328) Field Meas/Reg Station Structures				0
8	(329) Other Structures				0
9	(332) Field Lines				0
10	(333) Field Compressor Station Equip				0
11	(334) Field Meas/Reg Station Equipment				0
12	(336) Purification Equipment				0
13	(337) Other Equip				0
14	(365) Land & Land Rights	(1,399)			(1,399)
15	(365.2) Rights-of-Way	(2,462)			(2,462)
16	(366) Meas/Reg Station Structures	(153,289)			(153,289)
17	(367) Mains	(5,515,511)			(5,515,511)
18	(368) Compressor Station Equip	(8,108)			(8,108)
19	(369) Measure/Reg. Station Equipment	(3,355,805)			(3,355,805)
20	(371) Other Equipment	(26,248)			(26,248)
21	Total Gathering and Transmission Plant Reserves - Direct	$(9,062,822)	$0	$0	$(9,062,822)
	DISTRIBUTION PLANT				
22	(374) Land	(286)			$(286)
23	(374.2) Land & Land Rights	(99,749)			(99,749)
24	(375) Structures & Improvements	(416,066)			(416,066)
25	(376) Mains	(130,443,473)			(130,443,473)
26	(376.9) Cathodic Protection Anodes	(29,003,142)			(29,003,142)
27	(377) Compressor Station Equipment				0
28	(378) Meas. & Reg. Station - General	(6,704,934)			(6,704,934)
29	(379) Meas. & Reg. Station - C.G.	(1,425,410)			(1,425,410)
30	(380) Services	(71,583,552)			(71,583,552)
31	(380.1) Ind Service Line Equip				0
32	(380.2) Comm Service Line Equip				0
33	(380.4) Yard Lines-Customer Svc				0
34	(381) Meters	(65,300,172)			(65,300,172)
35	(382) Meter Installations	(18,906)			(18,906)
36	(383) House Regulators	(12,622,372)			(12,622,372)
37	(385) Indust. Meas. & Reg. Stat. Equipment	(9,240,905)			(9,240,905)
38	(386) Other Property on Customer Premises	(1,609,090)			(1,609,090)
39	(387) Meas. & Reg. Stat. Equipment	0			0
40	Total Distribution Plant Reserves - Direct	$(328,468,057)	$0	$0	$(328,468,057)
	GENERAL PLANT				
41	(389) Land & Land Rights	4,733			$4,733
42	(390) Structures & Improvements	(4,677,456)	(59,753)		(4,737,209)
43	(391) Office Furniture & Equipment	(1,475,043)			(1,475,043)
44	(391.9) Computer & Equipment	(2,356,334)			(2,356,334)
45	(392) Transportation Equipment	(16,438,359)			(16,438,359)
46	(393) Stores Equipment	(31,258)			(31,258)
47	(394) Tools, Shop & Garage	(9,666,206)			(9,666,206)
48	(395) CNG Equipment	37,479			37,479
49	(396) Major Work Equipment	(2,593,508)			(2,593,508)
50	(397) Communication Equipment	(25,851,747)			(25,851,747)
51	(398) Miscellaneous General Plant	(4,338)			(4,338)
52	Total General Plant Reserves - Direct	$(63,052,037)	$(59,753)	$0	$(63,111,790)
53	Total Accumulated Reserves - Direct	$(401,154,810)	$(1,235,379)	$0	$(402,390,189)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

TEXAS FRANCHISE ("GROSS MARGIN") TAX EXPENSE

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	Total Texas Franchise Tax in calendar year ended 12/31/2024		$715,000
2	Allocation to Texas Gas Service	WKP A.b Alloc Factors	100.00 %
3	Texas Franchise Tax		$715,000
4	Test Year Expense - Acct 4091100		0
5	Adjustment to Test Year		$715,000
6	Texas Franchise Tax Rate	0.7500 %	

Source: SCH G-17 Texas Franchise Tax (CONFIDENTIAL).pdf

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

STORES LOAD CLEARING

LINE NO.	DESCRIPTION	(a)	(b)	(c)	(d)
1	Test Year Charges into Stores Account 1630 for direct and allocated charges:		$6,463,794		
2	Test Year Amounts Cleared Out of Account 1630 to TGS		6,389,288		
3	Test Year Amount Under/(Over) Cleared		$74,506		$74,506

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)	$1,046,218	$1,025,938	$20,280	
5	Benefits & Payroll Taxes	331,608	325,991	5,617	
6	Other	5,111,865	5,111,865	0	
7	Total Other Adjustments	$6,489,692	$6,463,794	$25,898	25,898
8	Total Adjusted Amount Under/(Over) Cleared				$100,404

Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:

9	Adjustment to Test Year Expense Accounts (See account breakdown below)	$7,568
10	Adjustment to Test Year Non-Expense Accounts	92,835
11	Total Adjustment to Test Year Clearing Acct 1630	$100,404

Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:

		Acct.	Amount	Percentage	Amount Under/ (Over) Cleared
12					
13		8040	$0	0.00 %	$0
14		8650	317	0.00 %	5
15		8700	158	0.00 %	2
16		8740	156,830	2.45 %	2,464
17		8750	0	0.00 %	0
18		8770	85	0.00 %	1
19		8780	158,689	2.48 %	2,494
20		8800	43,604	0.68 %	685
21		8870	96,759	1.51 %	1,521
22		8890	463	0.01 %	7
23		8920	20,307	0.32 %	319
24		9020	412	0.01 %	6
25		9210	4,002	0.06 %	63
26	Total Adjustment to Test Year Expense Accounts		$481,627	0.075380	$7,568
27	Total Adjustment to Test Year Non-Expense Accounts		5,907,661	0.924620	92,835.43
	Adjustment to Test Year Clearing		$6,389,288	1.000000	$100,404

Source: SCH G-18 TGS Stores Clearing (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

TRANSPORTATION AND WORK EQUIPMENT CLEARING

LINE NO.	DESCRIPTION				AMOUNT
		(a)	(b)	(c)	(d)
1	Test Year Charges into TWE Clearing Accounts 1840100-1840289		$12,052,364		
2	Test Year Amounts Cleared Out of TWE Accounts 1840100-1840289		12,087,557		
3	Test Year Amount Under/(Over) Cleared		$(35,193)		$(35,193)

Plus/Minus Adjustments To Test Year Amounts Charged into TWE Acct 1840100-1840289:

		Adjusted Test Year	Recorded Test Year	Adjustment	
4	Depreciation	$3,901,840	$4,347,581	$(445,741)	
5	Lease Costs			0	
6	Payroll	241,435	242,180	(744)	
7	Benefits & Payroll Taxes	64,619	64,973	(354)	
8	Other (gasoline, maintenance, etc)	7,397,630	7,397,630	0	
9	Total	$11,605,525	$12,052,364	$(446,839)	(446,839)
10	Total Adjusted Amount Under/(Over) Cleared				$(482,033)

Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:

11	Adjustment to Test Year Expense Accounts (See account breakdown below)	$(279,373)
12	Adjustment to Test Year Non-Expense Accounts	(202,660)
13	Total Adjustment to Test Year TWE Clearing Acct 1840	$(482,033)

Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:

		Acct.	Amount	Percentage	Amount Under/ (Over) Cleared
14					
15		8560	$253,347	2.10 %	$(10,103)
16		8570	89,109	0.74 %	(3,554)
17		8630	16,979	0.14 %	(677)
18		8700	46,182	0.38 %	(1,842)
19		8740	1,001,997	8.29 %	(39,958)
20		8750	118,381	0.98 %	(4,721)
21		8760		0.00 %	—
22		8770	19,620	0.16 %	(782)
23		8780	2,736,750	22.64 %	(109,137)
24		8790		0.00 %	—
25		8800	277,939	2.30 %	(11,084)
26		8850	7,398	0.06 %	(295)
27		8870	1,083,676	8.97 %	(43,215)
28		8890	371,016	3.07 %	(14,796)
29		8900	276,474	2.29 %	(11,025)
30		8910		0.00 %	—
31		8920	506,343	4.19 %	(20,192)
32		8930		0.00 %	—
33		9020	194,697	1.61 %	(7,764)
34		9030	5,714	0.05 %	(228)
35		9050		0.00 %	—
36		9210		0.00 %	—
37	Total Adjustment to Test Year Expense Accounts		$7,005,620	57.96 %	$(279,373)
38	Total Adjustment to Test Year Non-Expense Accounts		5,081,937	0.420427	(202,660)
39	Adjustment to Test Year Clearing		$12,087,557	1.000000	$(482,033)

Source: SCH G-19 TWE Clearing (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

REGULATORY EXPENSE AMORTIZATION

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Unamortized balance of Regulatory Assets from prior cases	$3,693,257
2	Less 12 mos. Amortization (line 24, January 2025 - December 2025) Note 1	(679,908)
3	Line Locating Expense Credit	(1,541,585)
4	Winter Storm Gerri	15,215
5	Expenses from GUD No. 14883	323,865
6	COVID related O&M (2022)	307,412
7	Regulatory Assets - Total	$2,118,256
8	Amortization Period (in years)	6
9	Annual Regulatory Asset Amortization Expense	$353,043
10	Test Year Regulatory Asset Amortization Expense - Acct 407.3	246,191
11	Adjustment to Test Year Expense	$106,852

Note 1: Amortization of Regulatory Asset between end of Test Year and beginning of effective rates.

	MONTH	2025	GRAND TOTAL
12	January	$(56,659)	$(56,659)
13	February	(56,659)	(56,659)
14	March	(56,659)	(56,659)
15	April	(56,659)	(56,659)
16	May	(56,659)	(56,659)
17	June	(56,659)	(56,659)
18	July	(56,659)	(56,659)
19	August	(56,659)	(56,659)
20	September	(56,659)	(56,659)
21	October	(56,659)	(56,659)
22	November	(56,659)	(56,659)
23	December	(56,659)	(56,659)
24			$(679,908)

Source: SCH G-20 Regulatory Expenses (CONFIDENTIAL).xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

DISTRIGAS ALLOCATION PERCENTAGE

							ADJUSTMENT FOR Q1 2025 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	2024	1	$728,856	28.74%	$209,473			
2		2024	2	776,775	28.74%	223,245			
3		2024	3	628,332	28.74%	180,583			
4		2024	4	493,169	29.01%	143,068			
5		2024	5	463,177	29.01%	134,368			
6		2024	6	509,947	29.01%	147,936			
7		2024	7	524,079	29.22%	153,136			
8		2024	8	471,623	29.22%	137,808			
9		2024	9	474,008	29.22%	138,505			
10		2024	10	522,469	29.63%	154,807			
11		2024	11	541,404	29.63%	160,418			
12		2024	12	571,315	29.63%	169,281			
13	4081 Total			$6,705,154		$1,952,628			
14	9260	2024	1	$55,123	28.74%	$15,842			
15		2024	2	55,139	28.74%	15,847			
16		2024	3	55,139	28.74%	15,847			
17		2024	4	(444,064)	29.01%	(128,823)			
18		2024	5	55,139	29.01%	15,996			
19		2024	6	55,139	29.01%	15,996			
20		2024	7	554,342	29.22%	161,979			
21		2024	8	55,139	29.22%	16,112			
22		2024	9	55,139	29.22%	16,112			
23		2024	10	55,139	29.63%	16,338			
24		2024	11	55,139	29.63%	16,338			
25		2024	12	55,139	29.63%	16,338			
26	9260 Total			$661,652		$193,920			
27	9302	2024	1	$12,933,487	28.74%	$3,717,084			
28		2024	2	12,665,523	28.74%	3,640,071			
29		2024	3	11,205,426	28.74%	3,220,439			
30		2024	4	10,000,865	29.01%	2,901,251			
31		2024	5	10,957,860	29.01%	3,178,875			
32		2024	6	11,107,213	29.01%	3,222,203			
33		2024	7	11,319,889	29.22%	3,307,672			
34		2024	8	10,834,834	29.22%	3,165,939			
35		2024	9	11,444,161	29.22%	3,343,984			
36		2024	10	12,131,233	29.63%	3,594,484			
37		2024	11	14,374,005	29.63%	4,259,018			
38		2024	12	15,132,238	29.63%	4,483,682			
39	9302 Total			$144,106,735		$42,034,702	30.25%	$43,592,287	$1,557,585
40	Total			$151,473,541		$44,181,250		$43,592,287	$1,557,585
41								O&M Expense Factor	85.42%
42								Adjustment to TGS O&M	1,330,447
43								Allocation to Service Area	100.0000%
44								Adjustment to Service Area after O&M	$1,330,447

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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 2024 - based on 12 months Ended Dec 2023							
1	Oklahoma Natural Gas Company	$3,408,887,578	41.87%	$156,066,534	42.96%	$63,216,648	38.39%	41.08%
2	Kansas Gas Service Company	2,474,943,803	30.40%	99,012,329	27.25%	54,184,004	32.90%	30.18%
3	Texas Gas Service Company	2,257,856,066	27.73%	108,228,998	29.79%	47,270,550	28.71%	28.74%
4	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
5	Total	$8,141,687,446	100.00%	$363,307,861	100.00%	$164,671,202	100.00%	100.00%
	2nd Quarter 2024 - based on 12 months Ended Mar 2024							
6	Oklahoma Natural Gas Company	$3,453,659,872	41.74%	$155,649,302	43.13%	$64,791,772	38.65%	41.17%
7	Kansas Gas Service Company	2,506,633,727	30.29%	95,622,574	26.49%	54,798,681	32.68%	29.82%
8	Texas Gas Service Company	2,314,940,329	27.97%	109,659,185	30.38%	48,074,901	28.67%	29.01%
9	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
10	Total	$8,275,233,928	100.00%	$360,931,061	100.00%	$167,665,353	100.00%	100.00%
	3rd Quarter 2024 - based on 12 months Ended Jun 2024							
11	Oklahoma Natural Gas Company	$3,520,712,093	41.77%	$156,607,138	42.87%	$65,680,296	38.85%	41.17%
12	Kansas Gas Service Company	2,541,559,761	30.16%	96,008,672	26.28%	54,771,318	32.40%	29.61%
13	Texas Gas Service Company	2,365,886,087	28.07%	112,649,070	30.84%	48,600,272	28.75%	29.22%
14	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
15	Total	$8,428,157,941	100.00%	$365,264,881	99.99%	$169,051,887	100.00%	100.00%
	4th Quarter 2024 - based on 12 months Ended Sep 2024							
16	Oklahoma Natural Gas Company	$3,590,601,758	41.81%	$157,805,700	43.01%	$67,262,044	39.17%	41.33%
17	Kansas Gas Service Company	2,573,158,139	29.96%	92,613,220	25.25%	54,790,524	31.91%	29.04%
18	Texas Gas Service Company	2,424,657,381	28.23%	116,424,564	31.74%	49,646,920	28.92%	29.63%
19	Utility Insurance Company	0	0.00%	0	0.00%	0	0.00%	0.00%
20	Total	$8,588,417,278	100.00%	$366,843,484	100.00%	$171,699,487	100.00%	100.00%
	1st Quarter 2025 - based on 12 months Ended Dec 2024							
21	Oklahoma Natural Gas Company	$3,658,425,025	41.73%	$157,279,205	40.88%	$68,711,947	39.31%	40.64%
22	Kansas Gas Service Company	2,601,570,418	29.67%	97,644,548	25.38%	55,356,084	31.67%	28.91%
23	Texas Gas Service Company	2,507,580,685	28.60%	127,520,942	33.15%	50,708,340	29.01%	30.25%
24	Utility Insurance Company	0	0.00%	2,252,778	0.59%	14,448	0.01%	0.20%
25	Total	$8,767,576,128	100.00%	$384,697,472	100.00%	$174,790,819	100.00%	100.00%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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	2024	1	$25,306	25.00 %	$6,326
2	Invoice Count	2024	2	25,953	25.00%	6,488
3	Invoice Count	2024	3	24,618	25.00%	6,155
4	Invoice Count	2024	4	27,795	25.00%	6,949
5	Invoice Count	2024	5	22,743	25.00%	5,686
6	Invoice Count	2024	6	24,678	25.00%	6,169
7	Invoice Count	2024	7	24,433	25.00%	6,108
8	Invoice Count	2024	8	24,375	25.00%	6,094
9	Invoice Count	2024	9	24,311	25.00%	6,078
10	Invoice Count	2024	10	24,356	25.00%	6,089
11	Invoice Count	2024	11	24,447	25.00%	6,112
12	Invoice Count	2024	12	25,519	25.00%	6,380
13	**Invoice Count Total**			**$298,535**		**$74,634**
14	Employee Count	2024	1	$1,051,266	24.09 %	$253,250
15	Employee Count	2024	2	1,063,394	24.09%	256,172
16	Employee Count	2024	3	1,037,118	24.09%	249,842
17	Employee Count	2024	4	1,096,748	24.09%	264,207
18	Employee Count	2024	5	1,234,753	24.09%	297,452
19	Employee Count	2024	6	1,168,026	24.09%	281,377
20	Employee Count	2024	7	1,286,466	24.09%	309,910
21	Employee Count	2024	8	1,197,675	24.09%	288,520
22	Employee Count	2024	9	1,210,663	24.09%	291,649
23	Employee Count	2024	10	1,198,000	24.09%	288,598
24	Employee Count	2024	11	932,189	24.09%	224,564
25	Employee Count	2024	12	1,334,269	24.09%	321,425
26	**Employee Count Total**			**$13,810,568**		**$3,326,966**
27	Property Accounting Gross PP&E	2024	1	$0	27.75 %	$0
28	Property Accounting Gross PP&E	2024	2	419	27.75%	116
29	Property Accounting Gross PP&E	2024	3	0	27.75%	0
30	Property Accounting Gross PP&E	2024	4	174	27.75%	48
31	Property Accounting Gross PP&E	2024	5	148	27.75%	41
32	Property Accounting Gross PP&E	2024	6	320	27.75%	89
33	Property Accounting Gross PP&E	2024	7	209	27.75%	58
34	Property Accounting Gross PP&E	2024	8	32	27.75%	9
35	Property Accounting Gross PP&E	2024	9	1,702	27.75%	472
36	Property Accounting Gross PP&E	2024	10	1,004	27.75%	279
37	Property Accounting Gross PP&E	2024	11	565	27.75%	157
38	Property Accounting Gross PP&E	2024	12	0	27.75%	0
39	**Property Accounting Gross PP&E Total**			**$4,573**		**$1,269**
40	Administrative Cost for SERP	2024	1	$4,281	0.30 %	13
41	Administrative Cost for SERP	2024	2	12,474	0.30%	37
42	Administrative Cost for SERP	2024	3	9,959	0.30%	30
43	Administrative Cost for SERP	2024	4	2,276	0.30%	7
44	Administrative Cost for SERP	2024	5	8,650	0.30%	26
45	Administrative Cost for SERP	2024	6	10,387	0.30%	31
46	Administrative Cost for SERP	2024	7	5,529	0.30%	17
47	Administrative Cost for SERP	2024	8	10,270	0.30%	31
48	Administrative Cost for SERP	2024	9	16,769	0.30%	50
49	Administrative Cost for SERP	2024	10	2,456	0.30%	7
50	Administrative Cost for SERP	2024	11	2,640	0.30%	8
51	Administrative Cost for SERP	2024	12	8,176	0.30%	25
52	**Administrative Cost for SERP Total**			**$93,866**		**$282**
53	Administrative Cost for Pension	2024	1	$2,946	19.42 %	$572

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CAUSAL ALLOCATION PERCENTAGE

LINE NO.	CAUSAL METHOD	YEAR	MONTH	CORPORATE ALLOCABLE $	CAUSAL ALLOCATION %	$ ALLOCATED TO TGS
		(a)	(b)	(c)	(d)	(e) = (c) x (d)
54	Administrative Cost for Pension	2024	2	3,804	19.42%	739
55	Administrative Cost for Pension	2024	3	3,284	19.42%	638
56	Administrative Cost for Pension	2024	4	1,245	19.42%	242
57	Administrative Cost for Pension	2024	5	2,968	19.42%	576
58	Administrative Cost for Pension	2024	6	989	19.42%	192
59	Administrative Cost for Pension	2024	7	989	19.42%	192
60	Administrative Cost for Pension	2024	8	1,978	19.42%	384
61	Administrative Cost for Pension	2024	9	4,710	19.42%	915
62	Administrative Cost for Pension	2024	10	989	19.42%	192
63	Administrative Cost for Pension	2024	11	989	19.42%	192
64	Administrative Cost for Pension	2024	12	2,271	19.42%	441
65	**Administrative Costs for Pension Total**			**$27,164**		**$5,275**
66	Customer Count	2024	1	$537,948	30.85 %	$165,957
67	Customer Count	2024	2	548,209	30.85%	169,122
68	Customer Count	2024	3	541,753	30.85%	167,131
69	Customer Count	2024	4	631,812	30.85%	194,914
70	Customer Count	2024	5	595,206	30.85%	183,621
71	Customer Count	2024	6	451,274	30.85%	139,218
72	Customer Count	2024	7	485,444	30.85%	149,760
73	Customer Count	2024	8	499,163	30.85%	153,992
74	Customer Count	2024	9	524,086	30.85%	161,681
75	Customer Count	2024	10	510,782	30.85%	157,576
76	Customer Count	2024	11	521,118	30.85%	160,765
77	Customer Count	2024	12	568,833	30.85%	175,485
78	**Customer Count Total**			**$6,415,629**		**$1,979,222**
79	Miles of Pipe	2024	1	$216,325	25.00 %	$54,081
80	Miles of Pipe	2024	2	232,355	25.00%	58,089
81	Miles of Pipe	2024	3	209,957	25.00%	52,489
82	Miles of Pipe	2024	4	575,401	25.00%	143,850
83	Miles of Pipe	2024	5	204,350	25.00%	51,087
84	Miles of Pipe	2024	6	206,413	25.00%	51,603
85	Miles of Pipe	2024	7	233,178	25.00%	58,295
86	Miles of Pipe	2024	8	252,055	25.00%	63,014
87	Miles of Pipe	2024	9	304,957	25.00%	76,239
88	Miles of Pipe	2024	10	291,349	25.00%	72,837
89	Miles of Pipe	2024	11	260,286	25.00%	65,072
90	Miles of Pipe	2024	12	298,118	25.00%	74,529
91	**Miles of Pipe Total**			**$3,284,745**		**$821,186**
92	**Total**			**$23,935,080**		**$6,208,833**

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CAUSAL ALLOCATION FACTORS

	2024			2025		
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	56,046	28.00%	Oklahoma Natural Gas Company	53,372	27.00%
2	Kansas Gas Service Company	37,032	18.00%	Kansas Gas Service Company	34,266	17.00%
3	Texas Gas Service Company	50,510	25.00%	Texas Gas Service Company	51,852	26.00%
4	ONE Gas Inc.	57,312	29.00%	ONE Gas Inc.	61,047	30.00%
5	Total	200,900	100.00%	Total	200,537	100.00%
		Employee Count			Employee Count	
6	Oklahoma Natural Gas Company	1,250	32.13%	Oklahoma Natural Gas Company	1,256	32.06%
7	Kansas Gas Service Company	967	24.86%	Kansas Gas Service Company	947	24.17%
8	Texas Gas Service Company	937	24.09%	Texas Gas Service Company	951	24.27%
9	ONE Gas Inc.	736	18.92%	ONE Gas Inc.	764	19.50%
10	Total	3,890	100.00%	Total	3,918	100.00%
		Powerplant			Powerplant	
11	Oklahoma Natural Gas Company	$3,408,887,578	41.87%	Oklahoma Natural Gas Company	$3,658,425,025	41.73%
12	Kansas Gas Service Company	2,474,943,803	30.40%	Kansas Gas Service Company	2,601,570,418	29.67%
13	Texas Gas Service Company	2,257,856,066	27.73%	Texas Gas Service Company	2,507,580,685	28.60%
14	Total	$8,141,687,446	100.00%	Total	$8,767,576,128	100.00%
		Miles of Pipe			Miles of Pipe	
15	Oklahoma Natural Gas Company	20,100	45.00%	Oklahoma Natural Gas Company	20,300	45.00%
16	Kansas Gas Service Company	13,300	30.00%	Kansas Gas Service Company	13,400	30.00%
17	Texas Gas Service Company	11,400	25.00%	Texas Gas Service Company	11,600	25.00%
18	Total	44,800	100.00%	Total	45,300	100.00%
		Customer Count			Customer Count	
19	Oklahoma Natural Gas Company	919,000	40.55%	Oklahoma Natural Gas Company	924,000	40.51%
20	Kansas Gas Service Company	648,000	28.60%	Kansas Gas Service Company	651,000	28.54%
21	Texas Gas Service Company	699,000	30.85%	Texas Gas Service Company	706,000	30.95%
22	Total	2,266,000	100.00%	Total	2,281,000	100.00%
		Admistrative costs for SERP			Admistrative costs for SERP	
23	Oklahoma Natural Gas Company	$98,112	8.86%	Oklahoma Natural Gas Company	$91,263	7.82%
24	Kansas Gas Service Company	179,757	16.23%	Kansas Gas Service Company	181,483	15.55%
25	Texas Gas Service Company	3,362	0.30%	Texas Gas Service Company	3,398	0.29%
26	ONE Gas Inc.	826,500	74.61%	ONE Gas Inc.	890,940	76.34%
27	Total	$1,107,731	100.00%	Total	$1,167,084	100.00%

WKP G-22.a

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CAUSAL ALLOCATION FACTORS

		2024			2025	
LINE NO.	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR
		(a)	(b)		(c)	(d)
		Property Accounting Gross PP&E			Property Accounting Gross PP&E	
28	Oklahoma Natural Gas Company	$3,408,887,578	41.89%	Oklahoma Natural Gas Company	3,658,425,025	41.74%
29	Kansas Gas Service Company	2,470,509,863	30.36%	Kansas Gas Service Company	2,597,136,478	29.64%
30	Texas Gas Service Company	2,257,856,066	27.75%	Texas Gas Service Company	2,507,580,685	28.62%
31	Total	$8,137,253,507	100.00%	Total	8,763,142,188	100.00%
		Administrative cost for Pension			Administrative cost for Pension	
32	Oklahoma Natural Gas Company	$1,830,050	29.50%	Oklahoma Natural Gas Company	$1,681,597	31.82%
33	Kansas Gas Service Company	1,543,178	24.87%	Kansas Gas Service Company	1,243,765	23.53%
34	Texas Gas Service Company	1,204,699	19.42%	Texas Gas Service Company	1,027,207	19.44%
35	ONE Gas Inc.	1,626,303	26.21%	ONE Gas Inc.	1,332,532	25.21%
36	Total	$6,204,230	100.00%	Total	$5,285,101	100.00%

SCHEDULE G-23

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PIPELINE INTEGRITY EXPENSE

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Total Expense for Planned Testing 2023 through 2029	$32,896,891
2	Number of Years to Levelize Expense	7
3	Levelized Pipeline Integrity Expense	$4,699,556
4	Test Year Pipeline Integrity Expense[(1)]	0
5	Adjustment to Test Year	$4,699,556

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.

SCHEDULE G-24

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

AMORTIZATION OF EXCESS DEFERRED INCOME TAXES

LINE NO.	MONTH	MONTHLY AMMORTIZATION
	(a)	(b)
1	January 2024	$(440,614)
2	Febuary 2024	(354,484)
3	March 2024	(256,936)
4	April 2024	(99,986)
5	May 2024	(81,143)
6	June 2024	(97,454)
7	July 2024	(77,311)
8	August 2024	(85,973)
9	September 2024	(64,862)
10	October 2024	(94,454)
11	November 2024	(281,572)
12	December 2024	(337,249)
13	Test Year EDIT Amortization - Account 4101110	$(2,272,038)

Source: SCH B-10 EDIT.xlsx

SCHEDULE G-25

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CREDIT CARD PROCESSING FEES

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	Annual Credit Card Payments		2,470,641
2	Per payment Processing Fee		$1.49
3	Annualized Credit Card Processing Fees		3,681,255
4	Test Year Credit Card Processing Fees	WKP G.a.2	0
5	Adjustment to Test Year Expense	9030	$3,681,255

Source: SCH G-25 Credit Card Pricing (CONFIDENTIAL).xlsx
Source: SCH G-25 TGS Credit Card Transactions.xlsx

SCHEDULE G-26

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER ASSISTANCE PROGRAMS

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
	PROGRAM 1: SHARE THE WARMTH FUNDING		
1	Annual funding amount	9210	$2,000,000
2	Donation Management Platform	9230	120,000
3	One employee salary, taxes and benefits	9200	104,000
4	Outreach	9130	60,000
5	Total		2,284,000
	PROGRAM 2: CUSTOMER ASSISTANCE TARIFF PILOT PROGRAM		
6	Third Party Qualifier	9230	343,000
7	One employee salary, taxes and benefits	9200	104,000
8	Outreach	9130	60,000
9	Total		507,000
	SAVINGS IF BOTH PROGRAMS ADOPTED		
10	One employee salary, taxes and benefits	9200	(104,000)
11	Outreach	9130	(60,000)
12	Total		(164,000)
13	GRAND TOTAL		2,627,000
14	Test Year Expense	WKP G.a.2	0
15	Adjustment to Test Year Expense		$2,627,000

Study Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Costs	$347,226,026	$324,517,516	$19,239,537	$86,351	$1,663,055	$962	$0	$329,760	$74,220	$321,574	$8,303	$1,105	$983,643
2	Demand Costs	109,466,318	70,138,757	21,487,572	511,190	5,569,300	0	0	3,511,998	2,800,810	2,648,169	384,142	324,509	2,089,871
3	Commodity Costs	2,136,950	1,078,495	528,560	20,996	87,854	0	0	131,184	146,429	67,114	29,116	19,527	27,673
4	Cost of Service Before Revenue Credits	$458,829,294	$395,734,768	$41,255,670	$618,538	$7,320,209	$962	$0	$3,972,943	$3,021,458	$3,036,857	$421,561	$345,141	$3,101,187
5	Revenues Credited to Cost of Service (1)	$10,229,085	$9,262,295	$704,389	$7,773	$88,889	$11	$0	$47,399	$36,074	$36,218	$5,017	$4,108	$36,910
6	Total Cost of Service	$448,600,209	$386,472,473	$40,551,280	$610,765	$7,231,321	$951	$0	$3,925,544	$2,985,384	$3,000,639	$416,543	$341,033	$3,064,276
7	Revenue at Current Rates	$407,530,300	$317,492,536	$62,686,696	$2,225,175	$9,464,406	$4,533	$0	$4,655,868	$4,778,368	$2,887,898	$658,287	$197,869	$2,478,665
8	Revenue Deficiency	$41,069,909	$68,979,937	-$22,135,415	-$1,614,410	-$2,233,085	-$3,582	$0	-$730,324	-$1,792,984	$112,741	-$241,743	$143,164	$585,611
9	Revenue-to-Cost Ratios:													
10	Current Revenue	0.9105	0.8257	1.5365	3.6100	1.3051	4.7222	0.0000	1.1838	1.5934	0.9629	1.5734	0.5852	0.8112
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge revenue including Company recommended changes, special contract (other than Fort Bliss), irrigation, unmetered gas service, and other 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:

Classified Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	$ 186,679	$ 135,677	$ 50,724	$ 278
2	302	Franchises and Consents	NONINTPLT	$ 402,970	$ 292,876	$ 109,495	$ 599
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 1,908,172	$ 1,386,845	$ 518,488	$ 2,838
4		Total Intangible Plant		$ 2,497,821	$ 1,815,397	$ 678,708	$ 3,715
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ 251,776	$ —	$ 251,776	$ —
8	366	Meas. and Reg. Station Structures	DEM	$ 1,812,971	$ —	$ 1,812,971	$ —
9	367	Transmission Mains	DEM	$ 112,424,671	$ —	$ 112,424,671	$ —
10	368	Compression Station Equipment	DEM	$ 157,464	$ —	$ 157,464	$ —
11	369	Measuring and Reg. Station Equipment	DEM	$ 24,967,021	$ —	$ 24,967,021	$ —
12	369	Odorization	COM	$ 707,150	$ —	$ —	$ 707,150
13	371	Other Equipment	DEM	$ 53,986	$ —	$ 53,986	$ —
14		Total Transmission Plant		$ 140,375,039	$ —	$ 139,667,889	$ 707,150
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 2,018,957	$ 1,201,536	$ 817,421	$ —
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ 19,533	$ 10,458	$ 9,076	$ —
19	375	Structures and Improvements	DIS376-379-ALL	$ 514,432	$ 306,153	$ 208,280	$ —
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 1,045,319,513	$ 665,916,824	$ 379,402,689	$ —
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
22	376	Odorization	COM	$ 144,153	$ —	$ —	$ 144,153
23	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
24	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 53,871,432	$ —	$ 53,871,432	$ —
25	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ 325,537	$ —	$ 325,537	$ —
26	378	Odorization Tank	COM	$ 1,103,014	$ —	$ —	$ 1,103,014
27	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 19,757,746	$ —	$ 19,757,746	$ —
28	379	Odorization	COM	$ 1,337,096	$ —	$ —	$ 1,337,096
29	380	Services - Allocated	CUS	$ 682,183,854	$ 682,183,854	$ —	$ —
30	380	Services - Directly Assigned	CUS	$ 1,524,955	$ 1,524,955	$ —	$ —
31	381	Meters - Allocated	CUS	$ 179,264,438	$ 179,264,438	$ —	$ —
32	381	Meters - Directly Assigned	CUS	$ 152,811	$ 152,811	$ —	$ —
33	382	Meter Installations	CUS	$ —	$ —	$ —	$ —
34	383	House Regulators - Allocated	CUS	$ 35,698,116	$ 35,698,116	$ —	$ —
35	383	House Regulators - Directly Assigned	CUS	$ 75,571	$ 75,571	$ —	$ —
36	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 38,880,705	$ —	$ 38,880,705	$ —
37	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ 574,172	$ —	$ 574,172	$ —
38	385	Odorization	COM	$ 51,841	$ —	$ —	$ 51,841
39	386	Other Property - Customer Premises	CUS	$ 1,707,620	$ 1,707,620	$ —	$ —
40	387	Other Equipment	DIS376-379-ALL	$ —	$ —	$ —	$ —
41		Total Distribution Plant		$ 2,071,757,626	$ 1,572,088,582	$ 497,032,940	$ 2,636,104
42							
43		**General Plant**					
44	389	Land & Land Rights	GENPLT	$ 10,640,853	$ 8,182,513	$ 2,445,371	$ 12,969
45	390	Structures & Improvements	GENPLT	$ 57,253,648	$ 45,518,418	$ 11,673,319	$ 61,912
46	391	Office Furniture and Equipment	GENPLT	$ 100,750,525	$ 98,936,714	$ 1,804,241	$ 9,569
47	392	Transportation Equipment	GENPLT	$ 53,822,941	$ 40,907,992	$ 12,846,813	$ 68,135
48	393	Stores Equipment	GENPLT	$ 97,883	$ 74,276	$ 23,483	$ 125
49	394	Tools, Shop & Garage - Allocated	GENPLT	$ 33,407,511	$ 25,418,870	$ 7,946,495	$ 42,146
50	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ 11,690	$ 6,857	$ 4,833	$ —
51	394	Odorization	COM	$ 151,878	$ —	$ —	$ 151,878
52	395	CNG Equipment	GENPLT	$ —	$ —	$ —	$ —
53	396	Major Work Equipment	GENPLT	$ 8,626,236	$ 6,545,750	$ 2,069,510	$ 10,976
54	397	Communication Equipment - Allocated	GENPLT	$ 71,606,087	$ 54,558,777	$ 16,957,374	$ 89,937
55	397	Communication Equipment - Dir. Assn.	GENPLT	$ 48,893	$ 28,680	$ 20,212	$ —
56	398	Miscellaneous General Plant	GENPLT	$ 6,349	$ 4,818	$ 1,523	$ 8
57		Total General Plant		$ 336,424,493	$ 280,183,664	$ 55,793,175	$ 447,655
58							
59		Total Plant in Service		$ 2,551,054,979	$ 1,854,087,642	$ 693,172,712	$ 3,794,624
60							
61		**Depreciation & Amortization Reserve**					
62	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (1,803,478)	$ (1,409,488)	$ (392,042)	$ (1,948)
63	325-371	Transmission Plant	DEM	$ (9,635,404)	$ —	$ (9,635,404)	$ —
64	369	Odorization	COM	$ (70,589)	$ —	$ —	$ (70,589)
65	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (361,205,079)	$ (282,295,641)	$ (78,519,194)	$ (390,244)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
66	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ (8,660)	$ (4,636)	$ (4,023)	$ —
67	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ (697,875)	$ (390,448)	$ (307,426)	$ —
68	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ (44,709)	$ —	$ (44,709)	$ —
69	380	Services - Directly Assigned	CUS	$ (160,974)	$ (160,974)	$ —	$ —
70	381	Meters - Directly Assigned	CUS	$ (39,495)	$ (39,495)	$ —	$ —
71	383	House Regulators - Directly Assigned	CUS	$ (15,367)	$ (15,367)	$ —	$ —
72	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ —	$ —	$ —	$ —
73	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (123,017,392)	$ (105,219,590)	$ (17,675,252)	$ (122,550)
74	389-398	General Plant - Directly Assigned	GEN-DARES	$ (31,792)	$ (18,649)	$ (13,143)	$ —
75		Total Depreciation & Amortization Reserve		$ (496,730,814)	$ (389,554,288)	$ (106,591,194)	$ (585,332)
76							
77		Net Plant in Service		$ 2,054,324,164	$ 1,464,533,354	$ 586,581,518	$ 3,209,292
78							
79		Customer Deposits	CUS	$ (16,329,640)	$ (16,329,640)	$ —	$ —
80							
81		Customer Advances	MAINS/SVCS	$ (6,534,399)	$ (5,094,531)	$ (1,439,868)	$ —
82							
83		Accumulated Deferred Income Taxes	TOTPLT	$ (184,129,691)	$ (133,824,080)	$ (50,031,724)	$ (273,888)
84							
85		Excess Deferred Income Taxes	TOTPLT	$ (27,872,376)	$ (20,257,434)	$ (7,573,483)	$ (41,459)
86							
87		Negative Acquisition Adjustment on OPC Assets	MAINS-ALLOC	$ (1,949,023)	$ (1,241,617)	$ (707,405)	$ —
88							
89		Materials and Supplies	TOTPLT	$ 26,639,992	$ 19,361,746	$ 7,238,619	$ 39,626
90							
91		Prepayments	OPEXP	$ 11,080,303	$ 8,807,394	$ 2,155,797	$ 117,112
92							
93		Pension & FAS 106 Regulatory Asset	OPEXP	$ 38,210,431	$ 30,372,303	$ 7,434,266	$ 403,862
94							
95		DIMP Deferrals	OPEXP	$ 4,757,745	$ 3,781,786	$ 925,672	$ 50,287
96							
97		Regulatory Assets	OPEXP	$ 2,118,256	$ 1,683,737	$ 412,130	$ 22,389
98							
99		Cash Working Capital	OPEXP	$ (13,403,426)	$ (10,653,973)	$ (2,607,786)	$ (141,666)
100							
101		Total Rate Base		$ 1,886,912,337	$ 1,341,139,045	$ 542,387,737	$ 3,385,554

Classified Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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	814-865	Transmission Expenses	DEM	$ 9,124,268	$ —	$ 9,124,268	$ —
3	8650	Odorization	COM	$ 2,471	$ —	$ —	$ 2,471.13
4	8700	Operation Supervision & Engineering	DIS871-879	$ 2,734,374	$ 2,296,831	$ 389,559	$ 47,984
5	8710	Distribution Load Dispatch	COM	$ 585,292	$ —	$ —	$ 585,292
6	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 15,691,623	$ 12,245,352	$ 3,446,270	$ —
7	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ 79,312	$ 50,458	$ 28,854	$ —
8	8740	Odorization	COM	$ (45,825)	$ —	$ —	$ (45,825)
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 1,078,584	$ —	$ 1,078,584	$ —
10	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ 8,173	$ —	$ 8,173	$ —
11	8750	Odorization	COM	$ 273,994	$ —	$ —	$ 273,994
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 89,782	$ —	$ 89,782	$ —
13	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ 1,326	$ —	$ 1,326	$ —
14	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 98,743	$ —	$ 98,743	$ —
15	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 15,692,849	$ 15,692,849	$ —	$ —
16	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ 16,673	$ 16,673	$ —	$ —
17	8780	Odorization	COM	$ 81	$ —	$ —	$ 81
18	8790	Customer Installation Expenses	CUS	$ 10,745	$ 10,745	$ —	$ —
19	8800	Other Expenses	DIS871-879	$ 3,288,333	$ 2,762,147	$ 468,481	$ 57,705
20	8800	Odorization	COM	$ 1,505	$ —	$ —	$ 1,505
21	8810	Rents	DIS871-879	$ 117,124	$ 98,383	$ 16,686	$ 2,055
22	8820	Corporate & Div. Exp.	DEM	$ —	$ —	$ —	$ —
23		Total Transmission & Distribution Oper. Exp.		$ 48,849,427	$ 33,173,437	$ 14,750,728	$ 925,262
24							
25		**Distribution Maintenance Expenses**					
26	8850	Maintenance Supervision and Engineering	DIS887-893	$ 18,992	$ 10,488	$ 8,504	$ —
27	8860	Structures and Improvements	DIS887-893	$ 2,374,207	$ 1,311,078	$ 1,063,129	$ —
28	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 8,461,317	$ 5,390,250	$ 3,071,067	$ —
29	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ 58,540	$ 32,752	$ 25,788	$ —
30	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 2,784,748	$ —	$ 2,784,748	$ —
31	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ 18,902	$ —	$ 18,902	$ —
32	8890	Odorization	COM	$ 343,209	$ —	$ —	$ 343,209
33	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 1,536,947	$ —	$ 1,536,947	$ —
34	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ 22,697	$ —	$ 22,697	$ —
35	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 69,264	$ —	$ 69,264	$ —
36	8910	Odorization	COM	$ 100	$ —	$ —	$ 100
37	8920	Maintenance of Services - Allocated	CUS	$ 3,825,896	$ 3,825,896	$ —	$ —
38	8920	Maintenance of Services - Directly Assn.	CUS	$ 8,552	$ 8,552	$ —	$ —
39	8930	Main. of Meters & House Reg. - Allocated	CUS	$ 27,992	$ 27,992	$ —	$ —
40	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ 30	$ 30	$ —	$ —
41	8940	Maintenance of Other Equipment	DIS887-893	$ —	$ —	$ —	$ —
42	8950	Clearing - Meter Shop - Small Meters	CUS	$ —	$ —	$ —	$ —
43	8960	Clearing - Meter Shop - Large Meters	CUS	$ —	$ —	$ —	$ —
44		Total Distribution Maintenance Expenses		$ 19,551,393	$ 10,607,039	$ 8,601,046	$ 343,309
45							
46		Total Operations & Maintenance Expenses		$ 68,400,820	$ 43,780,476	$ 23,351,773	$ 1,268,571
47							
48		**Customer Accounting Expenses**					
49	9010	Supervision	CUS	$ 645	$ 645	$ —	$ —
50	9020	Meter Reading Expense	CUS	$ 1,423,705	$ 1,423,705	$ —	$ —
51	9030	Customer Accounting	CUS	$ 11,808,882	$ 11,808,882	$ —	$ —
52	9040	Bad Debts (includes gross up)	CUS	$ 3,374,231	$ 3,374,231	$ —	$ —
53	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 869,396	$ 869,396	$ —	$ —
54		Total Customer Accounts Expenses		$ 17,476,858	$ 17,476,858	$ —	$ —
55							
56		**Customer Information Expenses**					
57	9070	Supervision	CUS	$ —	$ —	$ —	$ —
58	9080	Customer Assistance	CUS	$ 2,348,730	$ 2,348,730	$ —	$ —
59	9090	Informational and Instructional Advertising	CUS	$ 160,487	$ 160,487	$ —	$ —
60	9100	Customer Service & Informational Svc.	CUS	$ —	$ —	$ —	$ —
61		Total Customer Information Expenses		$ 2,509,218	$ 2,509,218	$ —	$ —
62							
63		**Sales and Advertising Expenses**					
64	9110	Supervision	CUS	$ —	$ —	$ —	$ —

Classified Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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)
65	9120	Demonstrating and Selling	CUS	$ 1,630	$ 1,630	$ —	$ —
66	9130	Advertising	CUS	$ 191,835	$ 191,835	$ —	$ —
67	9140	Employee Sales Referrals	CUS	$ —	$ —	$ —	$ —
68	9163	Misc. Gas Sales Expense	CUS	$ —	$ —	$ —	$ —
69		Total Sales and Advertising Expenses		$ 193,465	$ 193,465	$ —	$ —
70							
71		**Administrative & General Expenses**					
72	920-940	Administrative & General Expenses	ADMINGEN	$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
73		Total Administrative & General Expenses		$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
74							
75		**Depreciation and Amortization Expense**					
76	301-303	Intangible Plant - Allocated	PLT301-03	$ 87,330	$ 63,471	$ 23,729	$ 130
77	301-303	Intangible Plant - Directly Assigned	PLT301-03	$ —	$ —	$ —	$ —
78	365	Land and Land Rights	DEM	$ —	$ —	$ —	$ —
79	366	Meas. and Reg. Station Structures	PLT366	$ 49,857	$ —	$ 49,857	$ —
80	367	Transmission Mains	PLT367	$ 3,282,834	$ —	$ 3,282,834	$ —
81	368	Compression Station Equipment	PLT368	$ 3,937	$ —	$ 3,937	$ —
82	369	Measuring and Reg. Station Equipment	PLT369	$ 890,894	$ —	$ 890,894	$ —
83	371	Other Equipment	PLT371	$ 2,818	$ —	$ 2,818	$ —
84	375	Structures and Improvements	PLT375	$ 19,226	$ 11,442	$ 7,784	$ —
85	376	Mains - Allocated	MAINS-ALLOC	$ 28,937,751	$ 18,434,684	$ 10,503,067	$ —
86	376	Mains - Directly Assigned	MAINS-DA	$ 184,979	$ 103,492	$ 81,487	$ —
87	377	Compressor Station Equipment	DEM	$ —	$ —	$ —	$ —
88	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 1,415,814	$ —	$ 1,415,814	$ —
89	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ 7,213	$ —	$ 7,213	$ —
90	378	Odorization	COM	$ 10,130	$ —	$ —	$ 10,130
91	379	Meas. & Reg. Sta. Equipment - City Gate - Alloc.	PLT379	$ 459,933	$ —	$ 459,933	$ —
92	379	Meas. & Reg. Sta. Equipment - City Gate - Dir. Assn.	PLT379	$ —	$ —	$ —	$ —
93	379	Odorization	COM	$ —	$ —	$ —	$ —
94	380	Services - Allocated	PLT380	$ 25,906,053	$ 25,906,053	$ —	$ —
95	380	Services - Directly Assigned	PLT380	$ 56,728	$ 56,728	$ —	$ —
96	381	Meters - Allocated	PLT381	$ 7,349,631	$ 7,349,631	$ —	$ —
97	381	Meters - Directly Assigned	PLT381	$ 7,213	$ 7,213	$ —	$ —
98	382	Meter Installations	PLT382	$ —	$ —	$ —	$ —
99	383	House Regulators - Allocated	PLT383	$ 1,510,038	$ 1,510,038	$ —	$ —
100	383	House Regulators - Directly Assigned	PLT383	$ 3,363	$ 3,363	$ —	$ —
101	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 940,499	$ —	$ 940,499	$ —
102	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ —	$ —	$ —	$ —
103	386	Other Property - Customer Premises	PLT386	$ 355,527	$ 355,527	$ —	$ —
104	387	Other Equipment	PLT387	$ —	$ —	$ —	$ —
105	389-398	General Plant - Allocated	GENDEP	$ 17,598,856	$ 15,397,496	$ 2,179,682	$ 21,678
106	389-398	General Plant - Directly Assigned	GENDEP	$ 2,481	$ 2,171	$ 307	$ 3
107	389-398	General Plant - Odorization	COM	$ 10,130	$ —	$ —	$ 10,130
108	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ (733,323)	$ (582,896)	$ (142,676)	$ (7,751)
109		Total Depreciation and Amortization Expense		$ 88,359,910	$ 68,618,412	$ 19,707,177	$ 34,321
110							
111		**Taxes Other Than Income**					
112	4080	Payroll and Other	OPEXP	$ 6,430,224	$ 5,111,189	$ 1,251,072	$ 67,964
113	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 19,394,025	$ 14,106,095	$ 5,258,969	$ 28,961
114	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ 76,057	$ 44,614	$ 31,442	$ —
115	4080	Revenue Related (includes gross up)	CUS	$ 329,692	$ 329,692	$ —	$ —
116		Total Taxes Other Than Income		$ 26,229,998	$ 19,591,590	$ 6,541,483	$ 96,925
117							
118	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ (9,917)	$ (5,769)	$ (4,148)	$ —
119	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (2,262,121)	$ (1,613,973)	$ (644,598)	$ (3,549)
120							
121	4310	Interest on Customer Deposits	CUS	$ 824,647	$ 824,647	$ —	$ —
122							
123		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 150,598,327	$ 107,448,563	$ 42,913,466	$ 236,298
124		Required Return - Directly Assigned	RB-DA	$ 660,191	$ 384,051	$ 276,140	$ —
125		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 31,175,742	$ 22,243,200	$ 8,883,626	$ 48,917
126		Income Taxes - Directly Assigned	RB-DA	$ 136,668	$ 79,503	$ 57,164	$ —
127		Total Cost of Service Before Revenue Credits		$ 458,829,294	$ 347,226,026	$ 109,466,318	$ 2,136,950

Classification Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	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			Total Transmission Plant	$ 140,375,039	$ —	$ 139,667,889	$ 707,150
8			Total Distribution Plant	$ 2,071,757,626	$ 1,572,088,582	$ 497,032,940	$ 2,636,104
9			Total General Plant	$ 336,424,493	$ 280,183,664	$ 55,793,175	$ 447,655
10			Total Non-Intangible Plant	$ 2,548,557,158	$ 1,852,272,245	$ 692,494,004	$ 3,790,909
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.72679	0.27172	0.00149
12							
13	376		Distribution Mains-Allocated	$ 1,045,319,513	$ 665,916,824	$ 379,402,689	$ —
14	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 53,871,432	$ —	$ 53,871,432	$ —
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 19,757,746	$ —	$ 19,757,746	$ —
17			Total Accounts 376-379	$ 1,118,948,691	$ 665,916,824	$ 453,031,867	$ —
18		DIS376-379-ALL	Accounts 376-379 Allocated Factor	1.00000	0.59513	0.40487	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ 325,537	$ —	$ 325,537	$ —
22			Total Accounts 376-379 Directly Assigned	$ 7,557,666	$ 4,046,246	$ 3,511,420	$ —
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	1.00000	0.53538	0.46462	0.00000
24							
25	376		Mains-Allocated	$ 1,045,319,513	$ 665,916,824	$ 379,402,689	$ —
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.63705	0.36295	0.00000
27							
28	376		Mains-Directly Assigned	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.55948	0.44052	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ 8,757,084	$ 5,571,201	$ 3,185,884	$ —
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	1.00000	0.63619	0.36381	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 1,727,503,367	$ 1,348,100,678	$ 379,402,689	$ —
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.78038	0.21962	0.00000
36							
37	376/380		Mains and Services	$ 1,736,260,452	$ 1,353,671,879	$ 382,588,573	$ —
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.77965	0.22035	0.00000
39							
40	374-387		Total Distribution Plant	$ 2,071,757,626	$ 1,572,088,582	$ 497,032,940	$ 2,636,104
41		DISPLT	Distribution Plant Factor	1.00000	0.75882	0.23991	0.00127
42							
43	374		Land & Land Rights - Directly Assigned	$ 19,533	$ 10,458	$ 9,076	$ —
44	376		Mains - Directly Assigned	$ 7,232,130	$ 4,046,246	$ 3,185,884	$ —
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ 325,537	$ —	$ 325,537	$ —
46	380		Service - Directly Assigned	$ 1,524,955	$ 1,524,955	$ —	$ —
47	381		Meters - Directly Assigned	$ 152,811	$ 152,811	$ —	$ —
48	383		House Regulators - Directly Assigned	$ 75,571	$ 75,571	$ —	$ —
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ 574,172	$ —	$ 574,172	$ —
50			Total Distribution Plant - Directly Assigned	$ 9,904,708	$ 5,810,040	$ 4,094,668	$ —
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	1.00000	0.58659	0.41341	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (94,703)	$ (56,360)	$ (38,343)	$ —
54	375		Structures and Improvements	$ (335,608)	$ (199,729)	$ (135,878)	$ —
55	376		Distribution Mains - Allocated	$ (172,170,008)	$ (109,680,250)	$ (62,489,759)	$ —
56	377		Compressor Station Equipment	$ —	$ —	$ —	$ —
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (5,542,020)	$ —	$ (5,542,020)	$ —
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (2,085,232)	$ —	$ (2,085,232)	$ —
59	378-379		Odorization Tank	$ (390,202)	$ —	$ —	$ (390,202)
60	380		Services - Allocated	$ (112,646,444)	$ (112,646,444)	$ —	$ —
61	381		Meters - Allocated	$ (47,294,132)	$ (47,294,132)	$ —	$ —
62	382		Meter Installations	$ (126,749)	$ (126,749)	$ —	$ —
63	383		House Regulators - Allocated	$ (11,583,951)	$ (11,583,951)	$ —	$ —
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (7,758,786)	$ —	$ (7,758,786)	$ —
65	386		Other Property-Customer Premises	$ (1,137,465)	$ (676,937)	$ (460,529)	$ —
66	387		Other Equipment	$ —	$ —	$ —	$ —
67			Total Distribution Plant - Allocated Reserve	$ (361,165,300)	$ (282,264,552)	$ (78,510,546)	$ (390,202)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.78154	0.21738	0.00108
69							
70	376		Distribution Mains - Directly Assigned	$ (697,875)	$ (390,448)	$ (307,426)	$ —
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	1.00000	0.55948	0.44052	0.00000

Classification Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
72							
73			General Plant - Allocated Reserve	$ (123,017,392)	$ (105,219,590)	$ (17,675,252)	$ (122,550)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.85532	0.14368	0.00100
75							
76			General Plant - Directly Assigned Reserve	$ (31,792)	$ (18,649)	$ (13,143)	$ —
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	1.00000	0.58659	0.41341	0.00000
78							
79			Total Plant - Allocated	$ 2,541,089,688	$ 1,848,242,065	$ 689,052,999	$ 3,794,624
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.72734	0.27116	0.00149
81							
82			Total Plant - Directly Assigned	$ 9,965,290	$ 5,845,578	$ 4,119,713	$ —
83		TPLT-DA	Total Plant Directly Assigned Factor	$ 1.00000	$ 0.58659	$ 0.41341	$ —
84							
85			Total Plant	$ 2,551,054,979	$ 1,854,087,642	$ 693,172,712	$ 3,794,624
86		TOTPLT	Total Plant Factor	1.00000	0.72679	0.27172	0.00149
87							
88			Total Operations and Maintenance Expenses	$ 68,400,820	$ 43,780,476	$ 23,351,773	$ 1,268,571
89			Total Customer Accounts Expenses	$ 17,476,858	$ 17,476,858	$ —	$ —
90			Total Customer Information Expenses	$ 2,509,218	$ 2,509,218	$ —	$ —
91			Total Sales and Advertising Expenses	$ 193,465	$ 193,465	$ —	$ —
92			Administrative and General Expenses	$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
93			Total Operating Expenses	$ 163,115,848	$ 129,655,800	$ 31,736,009	$ 1,724,039
94		OPEXP	Operating Expense Factor	1.00000	0.79487	0.19456	0.01057
95							
96	8710		Distribution Load Dispatch	$ 585,292	$ —	$ —	$ 585,292
97	8740		Mains and Services Expenses - Allocated	$ 15,691,623	$ 12,245,352	$ 3,446,270	$ —
98	8740		Mains and Services Expenses - Dir. Assn.	$ 79,312	$ 50,458	$ 28,854	$ —
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 1,078,584	$ —	$ 1,078,584	$ —
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ 8,173	$ —	$ 8,173	$ —
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 89,782	$ —	$ 89,782	$ —
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ 1,326	$ —	$ 1,326	$ —
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 98,743	$ —	$ 98,743	$ —
104	8780		Meter and House Regulator Exp.- Allocated	$ 15,692,849	$ 15,692,849	$ —	$ —
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ 16,673	$ 16,673	$ —	$ —
106	8790		Customer Installation Expenses	$ 10,745	$ 10,745	$ —	$ —
107			Total Accounts 871-879	$ 33,353,101	$ 28,016,076	$ 4,751,733	$ 585,292
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.83998	0.14247	0.01755
109							
110	8870		Maintenance of Mains-Allocated	$ 8,461,317	$ 5,390,250	$ 3,071,067	$ —
111	8870		Maintenance of Mains - Directly Assn.	$ 58,540	$ 32,752	$ 25,788	$ —
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 2,784,748	$ —	$ 2,784,748	$ —
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ 18,902	$ —	$ 18,902	$ —
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 1,536,947	$ —	$ 1,536,947	$ —
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ 22,697	$ —	$ 22,697	$ —
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 69,264	$ —	$ 69,264	$ —
117	8920		Maintenance of Services - Allocated	$ 3,825,896	$ 3,825,896	$ —	$ —
118	8920		Maintenance of Services - Directly Assn.	$ 8,552	$ 8,552	$ —	$ —
119	8930		Main. of Meters & House Reg. - Allocated	$ 27,992	$ 27,992	$ —	$ —
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ 30	$ 30	$ —	$ —
121			Total Accounts 887-893	$ 16,814,886	$ 9,285,473	$ 7,529,413	$ —
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.55222	0.44778	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 68,400,820	$ 43,780,476	$ 23,351,773	$ 1,268,571
125			Total Customer Accounts Expenses	$ 17,476,858	$ 17,476,858	$ —	$ —
126			Total Customer Service Expenses	$ 2,509,218	$ 2,509,218	$ —	$ —
127			Total Sales and Advertising Expenses	$ 193,465	$ 193,465	$ —	$ —
128			Total Operating Exp. Without A&G Expenses	$ 88,580,361	$ 63,960,017	$ 23,351,773	$ 1,268,571
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.72206	0.26362	0.01432
130							
131	920-932		Administrative and General Expenses	$ 74,535,487	$ 65,695,784	$ 8,384,235	$ 455,468
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.88140	0.11249	0.00611
133							
134	366		Meas. and Reg. Station Structures	$ 1,812,971	$ —	$ 1,812,971	$ —
135		PLT366	Measuring and Reg. Station Structures Factor	1.00000	0.00000	1.00000	0.00000
136							
137	367		Transmission Mains	$ 112,424,671	$ —	$ 112,424,671	$ —
138		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
139							
140	368		Compression Station Equipment	$ 157,464	$ —	$ 157,464	$ —
141		PLT368	Compression Station Equipment Factor	0.00000	0.00000	1.00000	0.00000
142							

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCOUNT	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
143	369		Measuring and Reg. Station Equipment	$ 24,967,021	$ —	$ 24,967,021	$ —
144		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
145							
146	371		Other Equipment	$ 53,986	$ —	$ 53,986	$ —
147		PLT371	Other Equipment Factor	1.00000	0.00000	1.00000	0.00000
148							
149	375		Structures and Improvements	$ 514,432	$ 306,153	$ 208,280	$ —
150		PLT375	Structures and Improvements Factor	1.00000	0.59513	0.40487	0.00000
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 53,871,432	$ —	$ 53,871,432	$ —
153		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
154							
155	379		Meas. & Reg. Sta. Equip.- City Gate	$ 19,757,746	$ —	$ 19,757,746	$ —
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services - Allocated	$ 682,183,854	$ 682,183,854	$ —	$ —
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters - Allocated	$ 179,264,438	$ 179,264,438	$ —	$ —
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
163							
164	382		Meter Installations	$ —	$ —	$ —	$ —
165		PLT382	Meter Installations Factor	—	0.00000	0.00000	0.00000
166							
167	383		House Regulators - Allocated	$ 35,698,116	$ 35,698,116	$ —	$ —
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 38,880,705	$ —	$ 38,880,705	$ —
171		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
172							
173	386		Other Property - Customer Premises	$ 1,707,620	$ 1,707,620	$ —	$ —
174		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
175							
176	387		Other Equipment	$ —	$ —	$ —	$ —
177		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
178							
179	301-303		Intangible Plant	$ 2,497,821	$ 1,815,397	$ 678,708	$ 3,715
180		PLT301-03	Intangible Plant	1.00000	0.72679	0.27172	0.00149
181							
182	389-398		General Plant Depreciation Expense	$ 17,611,467	$ 15,408,530	$ 2,181,244	$ 21,693
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.87491	0.12385	0.00123
184							
185			Net Plant Directly Assigned	$ 8,966,419	$ 5,216,008	$ 3,750,411	$ —
186		NETPLT-DA	Net Plant Directly Assigned Factor	1.00000	0.58173	0.41827	0.00000
187							
188			Net Plant Allocated	$ 2,045,357,745	$ 1,459,317,346	$ 582,831,107	$ 3,209,292
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.71348	0.28495	0.00157
190							
191			Rate Base Directly Assigned	$ 8,235,724	$ 4,790,943	$ 3,444,781	$ —
192		RB-DA	Rate Base Directly Assigned Factor	1.00000	0.58173	0.41827	0.00000
193							
194			Rate Base Allocated	$ 1,878,676,612	$ 1,340,394,058	$ 535,334,795	$ 2,947,759
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.71348	0.28495	0.00157
196							
197			Required Return	$ 151,258,518	$ 107,832,614	$ 43,189,606	$ 236,298
198		REQRET	Required Return Factor	1.00000	0.71290	0.28554	0.00156
199							
200			Non-Plant Rate Base	$ (167,411,828)	$ (123,394,309)	$ (44,193,781)	$ 176,262
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.73707	0.26398	-0.00105

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	301-303	**Intangible Plant**														
2		Customer	NONINCUS	$ 1,815,397	$ 1,717,061	$ 88,586	$ 236	$ 7,029	$ 3	$ —	$ 915	$ 190	$ 1,306	$ 21	$ 3	$ 49
3		Demand	NONINDEM	$ 678,708	$ 452,400	$ 125,632	$ 2,989	$ 32,562	$ —	$ —	$ 20,534	$ 16,376	$ 15,483	$ 2,246	$ 1,897	$ 8,589
4		Commodity	COM	$ 3,715	$ 1,875	$ 919	$ 37	$ 153	$ —	$ —	$ 228	$ 255	$ 117	$ 51	$ 34	$ 48
5		Total Intangible Plant		$ 2,497,821	$ 2,171,336	$ 215,137	$ 3,261	$ 39,744	$ 3	$ —	$ 21,677	$ 16,820	$ 16,905	$ 2,317	$ 1,934	$ 8,686
6	365-371	**Transmission Plant**														
7		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
8		Demand	DEM	$ 139,667,889	$ 93,097,051	$ 25,853,282	$ 615,050	$ 6,700,835	$ —	$ —	$ 4,225,544	$ 3,369,861	$ 3,186,208	$ 462,190	$ 390,441	$ 1,767,428
9		Commodity	COM	$ 707,150	$ 356,891	$ 174,909	$ 6,948	$ 29,072	$ —	$ —	$ 43,411	$ 48,456	$ 22,209	$ 9,635	$ 6,462	$ 9,157
10		Total Transmission Plant		$ 140,375,039	$ 93,453,942	$ 26,028,191	$ 621,998	$ 6,729,908	$ —	$ —	$ 4,268,955	$ 3,418,317	$ 3,208,417	$ 471,825	$ 396,903	$ 1,776,584
11		**Distribution Plant**														
12	374	**Land & Land Rights - Allocated**														
13		Customer	376-379CUS	$ 1,201,536	$ 1,129,588	$ 58,277	$ 155	$ 4,624	$ 2	$ —	$ 602	$ 125	$ 859	$ 14	$ 2	$ 7,289
14		Demand	DEM	$ 817,421	$ 544,860	$ 151,309	$ 3,600	$ 39,217	$ —	$ —	$ 24,730	$ 19,722	$ 18,648	$ 2,705	$ 2,285	$ 10,344
15		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
16		Total Land & Land Rights - Allocated		$ 2,018,957	$ 1,674,448	$ 209,586	$ 3,755	$ 43,841	$ 2	$ —	$ 25,333	$ 19,847	$ 19,507	$ 2,719	$ 2,287	$ 17,633
17	374	**Land & Land Rights - DA**														
18		Customer	CUS-DA	$ 10,458	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 10,458
19		Demand	DEM-DA	$ 9,076	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 9,076
20		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
21		Total Land & Rights - DA		$ 19,533	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 19,533
22	375	**Structures and Improvements**														
23		Customer	376-379CUS	$ 306,153	$ 287,820	$ 14,849	$ 39	$ 1,178	$ 0	$ —	$ 153	$ 32	$ 219	$ 3	$ 0	$ 1,857
24		Demand	DEM	$ 208,280	$ 138,831	$ 38,554	$ 917	$ 9,993	$ —	$ —	$ 6,301	$ 5,025	$ 4,751	$ 689	$ 582	$ 2,636
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Structures and Improvements		$ 514,432	$ 426,651	$ 53,403	$ 957	$ 11,171	$ 0	$ —	$ 6,455	$ 5,057	$ 4,970	$ 693	$ 583	$ 4,493
27	376	**Distribution Mains-Allocated**														
28		Customer	CUS	$ 665,916,824	$ 629,845,609	$ 32,494,688	$ 86,433	$ 2,578,333	$ 945	$ —	$ 335,816	$ 69,706	$ 478,908	$ 7,561	$ 945	$ 17,879
29		Demand	DEM	$ 379,402,689	$ 252,894,719	$ 70,229,490	$ 1,670,762	$ 18,202,572	$ —	$ —	$ 11,478,534	$ 9,154,104	$ 8,655,217	$ 1,255,521	$ 1,060,618	$ 4,801,152
30		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Distribution Mains - Allocated		$ 1,045,319,513	$ 882,740,328	$ 102,724,179	$ 1,757,195	$ 20,780,905	$ 945	$ —	$ 11,814,350	$ 9,223,809	$ 9,134,125	$ 1,263,082	$ 1,061,563	$ 4,819,031
32	376	**Odorization**														
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ 144,153	$ 72,753	$ 35,655	$ 1,416	$ 5,926	$ —	$ —	$ 8,849	$ 9,878	$ 4,527	$ 1,964	$ 1,317	$ 1,867
36		Total Odorization		$ 144,153	$ 72,753	$ 35,655	$ 1,416	$ 5,926	$ —	$ —	$ 8,849	$ 9,878	$ 4,527	$ 1,964	$ 1,317	$ 1,867
37		**Distribution Mains - Directly Assn.**														
38		Customer	CUS-DA	$ 4,046,246	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 4,046,246
39		Demand	DEM-DA	$ 3,185,884	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,185,884
40		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Distribution Mains - Dir. Assn.		$ 7,232,130	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7,232,130
42	377	**Compressor Station Equipment**														
43		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
45		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
47	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**														
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ 53,871,432	$ 35,908,551	$ 9,971,894	$ 237,232	$ 2,584,585	$ —	$ —	$ 1,629,838	$ 1,299,792	$ 1,228,955	$ 178,272	$ 150,597	$ 681,716
50		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
51		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 53,871,432	$ 35,908,551	$ 9,971,894	$ 237,232	$ 2,584,585	$ —	$ —	$ 1,629,838	$ 1,299,792	$ 1,228,955	$ 178,272	$ 150,597	$ 681,716
52	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**														
53		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	DEM-DA	$ 325,537	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 325,537
55		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 325,537	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 325,537
57	378	**Odorization**														
58		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
60		Commodity	COM	$ 1,103,014	$ 556,680	$ 272,824	$ 10,838	$ 45,347	$ —	$ —	$ 67,713	$ 75,581	$ 34,642	$ 15,029	$ 10,079	$ 14,282

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
61		Total Odorization		$ 1,103,014	$ 556,680	$ 272,824	$ 10,838	$ 45,347	$ —	$ —	$ 67,713	$ 75,581	$ 34,642	$ 15,029	$ 10,079	$ 14,282
62	379	**Meas. & Reg. Station - City Gate**														
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 19,757,746	$ 13,169,726	$ 3,657,266	$ 87,006	$ 947,916	$ —	$ —	$ 597,755	$ 476,708	$ 450,728	$ 65,382	$ 55,233	$ 250,024
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Equip.-City Gate		$ 19,757,746	$ 13,169,726	$ 3,657,266	$ 87,006	$ 947,916	$ —	$ —	$ 597,755	$ 476,708	$ 450,728	$ 65,382	$ 55,233	$ 250,024
67	379	**Odorization**														
68		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ 1,337,096	$ 674,818	$ 330,722	$ 13,137	$ 54,971	$ —	$ —	$ 82,083	$ 91,621	$ 41,994	$ 18,218	$ 12,218	$ 17,313
71		Total Odorization		$ 1,337,096	$ 674,818	$ 330,722	$ 13,137	$ 54,971	$ —	$ —	$ 82,083	$ 91,621	$ 41,994	$ 18,218	$ 12,218	$ 17,313
72	380	**Services - Allocated**														
73		Customer	SERCUS-ALL	$ 682,183,854	$ 639,603,935	$ 38,061,699	$ 123,174	$ 3,028,852	$ 1,110	$ —	$ 513,349	$ 107,906	$ 731,131	$ 11,255	$ 1,444	$ —
74		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Services - Allocated		$ 682,183,854	$ 639,603,935	$ 38,061,699	$ 123,174	$ 3,028,852	$ 1,110	$ —	$ 513,349	$ 107,906	$ 731,131	$ 11,255	$ 1,444	$ —
77	380	**Services-Directly Assigned**														
78		Customer	CUS-DA	$ 1,524,955	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 1,524,955
79		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
81		Total Services - Directly Assigned		$ 1,524,955	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 1,524,955
82	381	**Meters - Allocated**														
83		Customer	METCUS-ALL	$ 179,264,438	$ 162,975,157	$ 13,618,098	$ 94,279	$ 1,673,901	$ 1,518	$ —	$ 470,261	$ 110,307	$ 307,238	$ 12,161	$ 1,518	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Meters - Allocated		$ 179,264,438	$ 162,975,157	$ 13,618,098	$ 94,279	$ 1,673,901	$ 1,518	$ —	$ 470,261	$ 110,307	$ 307,238	$ 12,161	$ 1,518	$ —
87	381	**Meters-Directly Assigned**														
88		Customer	CUS-DA	$ 152,811	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 152,811
89		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
90		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
91		Total Meters - Directly Assigned		$ 152,811	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 152,811
92	382	**Meter Installations**														
93		Customer	METCUS-ALL	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
96		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
97	383	**House Regulators - Allocated**														
98		Customer	REGCUS-ALL	$ 35,698,116	$ 30,642,573	$ 3,793,501	$ 48,556	$ 744,024	$ 1,004	$ —	$ 262,929	$ 60,196	$ 136,058	$ 8,274	$ 1,004	$ —
99		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
100		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
101		Total House Regulators - Allocated		$ 35,698,116	$ 30,642,573	$ 3,793,501	$ 48,556	$ 744,024	$ 1,004	$ —	$ 262,929	$ 60,196	$ 136,058	$ 8,274	$ 1,004	$ —
102	383	**House Regulators - Directly Assigned**														
103		Customer	CUS-DA	$ 75,571	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 75,571
104		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total House Regulators - Dir. Assigned		$ 75,571	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 75,571
107	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**														
108		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
109		Demand	NRDEM	$ 38,880,705	$ —	$ 21,584,190	$ 513,489	$ 5,594,342	$ —	$ —	$ 3,527,790	$ 2,813,404	$ 2,660,077	$ 385,869	$ 325,968	$ 1,475,576
110		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
111		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 38,880,705	$ —	$ 21,584,190	$ 513,489	$ 5,594,342	$ —	$ —	$ 3,527,790	$ 2,813,404	$ 2,660,077	$ 385,869	$ 325,968	$ 1,475,576
112	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**														
113		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
114		Demand	DEM-DA	$ 574,172	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 574,172
115		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
116		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ 574,172	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 574,172
117	385	**Odorization**														
118		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
119		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
120		Commodity	COM	$ 51,841	$ 26,164	$ 12,823	$ 509	$ 2,131	$ —	$ —	$ 3,182	$ 3,552	$ 1,628	$ 706	$ 474	$ 671
121		Total Odorization		$ 51,841	$ 26,164	$ 12,823	$ 509	$ 2,131	$ —	$ —	$ 3,182	$ 3,552	$ 1,628	$ 706	$ 474	$ 671

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
122	386	**Other Prop.-Customer Premises**														
123		Customer	CUS	$ 1,707,620	$ 1,615,122	$ 83,327	$ 222	$ 6,612	$ 2	$ —	$ 861	$ 179	$ 1,228	$ 19	$ 2	$ 46
124		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
125		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
126		Total Other Prop.- Cust. Premises		$ 1,707,620	$ 1,615,122	$ 83,327	$ 222	$ 6,612	$ 2	$ —	$ 861	$ 179	$ 1,228	$ 19	$ 2	$ 46
127	387	**Other Equipment**														
128		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
129		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
130		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
131		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		**Total Distribution Plant**														
133		Customer		$ 1,572,088,582	$ 1,466,099,805	$ 88,124,439	$ 352,858	$ 8,037,523	$ 4,581	$ —	$ 1,583,972	$ 348,449	$ 1,655,640	$ 39,287	$ 4,915	$ 5,837,111
134		Demand		$ 497,032,940	$ 302,656,687	$ 105,632,702	$ 2,513,006	$ 27,378,625	$ —	$ —	$ 17,264,949	$ 13,768,756	$ 13,018,376	$ 1,888,438	$ 1,595,283	$ 11,316,116
135		Commodity		$ 2,636,104	$ 1,330,414	$ 652,024	$ 25,901	$ 108,376	$ —	$ —	$ 161,827	$ 180,632	$ 82,791	$ 35,917	$ 24,089	$ 34,134
136		Total Distribution Plant		$ 2,071,757,626	$ 1,770,086,906	$ 194,409,165	$ 2,891,765	$ 35,524,524	$ 4,581	$ —	$ 19,010,749	$ 14,297,838	$ 14,756,808	$ 1,963,643	$ 1,624,287	$ 17,187,361
137		**General Plant**														
138		**General Plant - Allocated**														
139		Customer	GENPTCUS	$ 280,148,126	$ 263,261,462	$ 14,607,972	$ 48,589	$ 1,244,964	$ 591	$ —	$ 206,283	$ 44,434	$ 244,614	$ 4,942	$ 618	$ 483,656
140		Demand	DISPLTDEM	$ 55,768,130	$ 33,958,710	$ 11,852,209	$ 281,964	$ 3,071,939	$ —	$ —	$ 1,937,163	$ 1,544,883	$ 1,460,689	$ 211,887	$ 178,994	$ 1,269,692
141		Commodity	COM	$ 447,655	$ 225,927	$ 110,725	$ 4,398	$ 18,404	$ —	$ —	$ 27,481	$ 30,674	$ 14,059	$ 6,099	$ 4,091	$ 5,796
142		Total General Plant - Allocated		$ 336,363,911	$ 297,446,099	$ 26,570,906	$ 334,952	$ 4,335,307	$ 591	$ —	$ 2,170,927	$ 1,619,991	$ 1,719,362	$ 222,928	$ 183,703	$ 1,759,144
143		**Total General Plant - Directly Assigned**														
144		Customer	CUS-DA	$ 35,537	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 35,537
145		Demand	DEM-DA	$ 25,045	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 25,045
146		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
147		Total General Plant - Directly Assigned		$ 60,583	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 60,583
148		**Total General Plant**														
149		Customer		$ 280,183,664	$ 263,261,462	$ 14,607,972	$ 48,589	$ 1,244,964	$ 591	$ —	$ 206,283	$ 44,434	$ 244,614	$ 4,942	$ 618	$ 519,193
150		Demand		$ 55,793,175	$ 33,958,710	$ 11,852,209	$ 281,964	$ 3,071,939	$ —	$ —	$ 1,937,163	$ 1,544,883	$ 1,460,689	$ 211,887	$ 178,994	$ 1,294,737
151		Commodity		$ 447,655	$ 225,927	$ 110,725	$ 4,398	$ 18,404	$ —	$ —	$ 27,481	$ 30,674	$ 14,059	$ 6,099	$ 4,091	$ 5,796
152		Total General Plant		$ 336,424,493	$ 297,446,099	$ 26,570,906	$ 334,952	$ 4,335,307	$ 591	$ —	$ 2,170,927	$ 1,619,991	$ 1,719,362	$ 222,928	$ 183,703	$ 1,819,727
153		**Total Plant in Service**														
154		Customer		$ 1,854,087,642	$ 1,731,078,328	$ 102,820,997	$ 401,683	$ 9,289,516	$ 5,175	$ —	$ 1,791,171	$ 393,073	$ 1,901,560	$ 44,250	$ 5,535	$ 6,356,354
155		Demand		$ 693,172,712	$ 430,164,848	$ 143,463,826	$ 3,413,009	$ 37,183,962	$ —	$ —	$ 23,448,190	$ 18,699,876	$ 17,680,756	$ 2,564,760	$ 2,166,616	$ 14,386,869
156		Commodity		$ 3,794,624	$ 1,915,107	$ 938,576	$ 37,284	$ 156,005	$ —	$ —	$ 232,947	$ 260,017	$ 119,176	$ 51,702	$ 34,675	$ 49,135
157		Total Plant in Service		$ 2,551,054,979	$ 2,163,158,283	$ 247,223,399	$ 3,851,976	$ 46,629,483	$ 5,175	$ —	$ 25,472,308	$ 19,352,966	$ 19,701,492	$ 2,660,713	$ 2,206,826	$ 20,792,358
158		**Depreciation & Amort. Reserve**														
159		**Intangible Plant**														
160		Customer	NONINCUS	$ (1,409,488)	$ (1,333,139)	$ (68,779)	$ (183)	$ (5,457)	$ (2)	$ —	$ (711)	$ (148)	$ (1,014)	$ (16)	$ (2)	$ (38)
161		Demand	NONINDEM	$ (392,042)	$ (261,320)	$ (72,569)	$ (1,726)	$ (18,809)	$ —	$ —	$ (11,861)	$ (9,459)	$ (8,944)	$ (1,297)	$ (1,096)	$ (4,961)
162		Commodity	COM	$ (1,948)	$ (983)	$ (482)	$ (19)	$ (80)	$ —	$ —	$ (120)	$ (134)	$ (61)	$ (27)	$ (18)	$ (25)
163		Total Intangible Plant		$ (1,803,478)	$ (1,595,442)	$ (141,830)	$ (1,929)	$ (24,346)	$ (2)	$ —	$ (12,691)	$ (9,740)	$ (10,018)	$ (1,340)	$ (1,116)	$ (5,024)
164		**Transmission Plant**														
165		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Demand	DEM	$ (9,635,404)	$ (6,422,577)	$ (1,783,565)	$ (42,431)	$ (462,277)	$ —	$ —	$ (291,512)	$ (232,480)	$ (219,810)	$ (31,886)	$ (26,936)	$ (121,931)
167		Commodity	COM	$ (70,589)	$ (35,626)	$ (17,460)	$ (694)	$ (2,902)	$ —	$ —	$ (4,333)	$ (4,837)	$ (2,217)	$ (962)	$ (645)	$ (914)
168		Total Transmission Plant		$ (9,705,994)	$ (6,458,202)	$ (1,801,025)	$ (43,125)	$ (465,179)	$ —	$ —	$ (295,845)	$ (237,317)	$ (222,027)	$ (32,847)	$ (27,581)	$ (122,845)
169		**Distribution Plant - Allocated**														
170		Customer	DISPLTCUS	$ (282,295,641)	$ (263,263,527)	$ (15,824,264)	$ (63,362)	$ (1,443,276)	$ (823)	$ —	$ (284,430)	$ (62,570)	$ (297,299)	$ (7,055)	$ (882)	$ (1,048,154)
171		Demand	DISPLTDEM	$ (78,519,194)	$ (47,812,443)	$ (16,687,414)	$ (396,994)	$ (4,325,161)	$ —	$ —	$ (2,727,445)	$ (2,175,131)	$ (2,056,589)	$ (298,328)	$ (252,016)	$ (1,787,673)
172		Commodity	COM	$ (390,244)	$ (196,952)	$ (96,525)	$ (3,834)	$ (16,044)	$ —	$ —	$ (23,957)	$ (26,741)	$ (12,256)	$ (5,317)	$ (3,566)	$ (5,053)
173		Total Distribution Plant - Allocated		$ (361,205,079)	$ (311,272,922)	$ (32,608,203)	$ (464,190)	$ (5,784,481)	$ (823)	$ —	$ (3,035,831)	$ (2,264,441)	$ (2,366,144)	$ (310,699)	$ (256,465)	$ (2,840,880)
174		**Distribution Plant - Dir. Assn.**														
175		Customer	CUS-DA	$ (610,921)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (610,921)
176		Demand	DEM-DA	$ (356,159)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (356,159)
177		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
178		Total Distribution Plant - Dir. Assn.		$ (967,079)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (967,079)
179		**General Plant - Allocated**														
180		Customer	GENPTCUS	$ (105,219,590)	$ (98,877,203)	$ (5,486,543)	$ (18,249)	$ (467,591)	$ (222)	$ —	$ (77,477)	$ (16,689)	$ (91,873)	$ (1,856)	$ (232)	$ (181,654)
181		Demand	DISPLTDEM	$ (17,675,252)	$ (10,762,935)	$ (3,756,461)	$ (89,366)	$ (973,626)	$ —	$ —	$ (613,968)	$ (489,638)	$ (462,953)	$ (67,156)	$ (56,731)	$ (402,418)
182		Commodity	COM	$ (122,550)	$ (61,850)	$ (30,312)	$ (1,204)	$ (5,038)	$ —	$ —	$ (7,523)	$ (8,397)	$ (3,849)	$ (1,670)	$ (1,120)	$ (1,587)
183		Total General Plant - Allocated		$ (123,017,392)	$ (109,701,987)	$ (9,273,316)	$ (108,820)	$ (1,446,255)	$ (222)	$ —	$ (698,968)	$ (514,724)	$ (558,676)	$ (70,682)	$ (58,083)	$ (585,659)

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
184		**General Plant - Directly Assigned**														
185		Customer	CUS-DA	$ (18,649)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (18,649)
186		Demand	DEM-DA	$ (13,143)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (13,143)
187		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
188		Total General Plant - Directly Assn.		$ (31,792)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (31,792)
189		**Total Depr. & Amort. Reserve**														
190		Customer		$ (389,554,288)	$ (363,473,869)	$ (21,379,586)	$ (81,794)	$ (1,916,324)	$ (1,047)	$ —	$ (362,617)	$ (79,406)	$ (390,186)	$ (8,927)	$ (1,117)	$ (1,859,416)
191		Demand		$ (106,591,194)	$ (65,259,274)	$ (22,300,009)	$ (530,518)	$ (5,779,873)	$ —	$ —	$ (3,644,785)	$ (2,906,708)	$ (2,748,296)	$ (398,666)	$ (336,779)	$ (2,686,285)
192		Commodity		$ (585,332)	$ (295,411)	$ (144,778)	$ (5,751)	$ (24,064)	$ —	$ —	$ (35,933)	$ (40,108)	$ (18,383)	$ (7,975)	$ (5,349)	$ (7,579)
193		Total Depr. & Amortization Reserve		$ (496,730,814)	$ (429,028,554)	$ (43,824,374)	$ (618,063)	$ (7,720,261)	$ (1,047)	$ —	$ (4,043,336)	$ (3,026,222)	$ (3,156,865)	$ (415,568)	$ (343,244)	$ (4,553,280)
194		**Net Plant in Service**														
195		Customer		$ 1,464,533,354	$ 1,367,604,460	$ 81,441,411	$ 319,889	$ 7,373,192	$ 4,128	$ —	$ 1,428,554	$ 313,667	$ 1,511,374	$ 35,323	$ 4,419	$ 4,496,938
196		Demand		$ 586,581,518	$ 364,905,574	$ 121,163,816	$ 2,882,491	$ 31,404,088	$ —	$ —	$ 19,803,405	$ 15,793,168	$ 14,932,460	$ 2,166,094	$ 1,829,837	$ 11,700,584
197		Commodity		$ 3,209,292	$ 1,619,696	$ 793,798	$ 31,532	$ 131,941	$ —	$ —	$ 197,014	$ 219,909	$ 100,793	$ 43,727	$ 29,326	$ 41,555
198		Total Net Plant in Service		$ 2,054,324,164	$ 1,734,129,729	$ 203,399,026	$ 3,233,913	$ 38,909,221	$ 4,128	$ —	$ 21,428,973	$ 16,326,744	$ 16,544,627	$ 2,245,144	$ 1,863,582	$ 16,239,077
199		**Customer Deposits**														
200		Customer	DEPCUS	$ (16,329,640)	$ (7,757,745)	$ (8,199,802)	$ (103,027)	$ (84,295)	$ —	$ —	$ (145,892)	$ (38,879)	$ —	$ —	$ —	$ —
201		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Commodity	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		Total Customer Deposits		$ (16,329,640)	$ (7,757,745)	$ (8,199,802)	$ (103,027)	$ (84,295)	$ —	$ —	$ (145,892)	$ (38,879)	$ —	$ —	$ —	$ —
204		**Customer Advances**														
205		Customer	MSCUS-ALL	$ (5,094,531)	$ (4,797,305)	$ (266,636)	$ (792)	$ (21,190)	$ (8)	$ —	$ (3,209)	$ (671)	$ (4,573)	$ (71)	$ (9)	$ (68)
206		Demand	DEM	$ (1,439,868)	$ (959,759)	$ (266,527)	$ (6,341)	$ (69,080)	$ —	$ —	$ (43,562)	$ (34,741)	$ (32,847)	$ (4,765)	$ (4,025)	$ (18,221)
207		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
208		Total Customer Advances		$ (6,534,399)	$ (5,757,064)	$ (533,163)	$ (7,133)	$ (90,270)	$ (8)	$ —	$ (46,771)	$ (35,412)	$ (37,420)	$ (4,836)	$ (4,034)	$ (18,288)
209		**Accum. Deferred Income Taxes**														
210		Customer	TPLTCUS	$ (133,824,080)	$ (124,945,531)	$ (7,421,400)	$ (28,993)	$ (670,497)	$ (373)	$ —	$ (129,283)	$ (28,371)	$ (137,251)	$ (3,194)	$ (400)	$ (458,788)
211		Demand	TPLTDEM	$ (50,031,724)	$ (31,048,379)	$ (10,354,912)	$ (246,344)	$ (2,683,859)	$ —	$ —	$ (1,692,440)	$ (1,349,717)	$ (1,276,159)	$ (185,119)	$ (156,382)	$ (1,038,413)
212		Commodity	COM	$ (273,888)	$ (138,228)	$ (67,744)	$ (2,691)	$ (11,260)	$ —	$ —	$ (16,814)	$ (18,767)	$ (8,602)	$ (3,732)	$ (2,503)	$ (3,546)
213		Total Accum. Deferred Inc. Taxes		$ (184,129,691)	$ (156,132,138)	$ (17,844,056)	$ (278,027)	$ (3,365,616)	$ (373)	$ —	$ (1,838,537)	$ (1,396,856)	$ (1,422,012)	$ (192,045)	$ (159,284)	$ (1,500,748)
214		**Excess Deferred Income Taxes**														
215		Customer	TPLTCUS	$ (20,257,434)	$ (18,913,456)	$ (1,123,404)	$ (4,389)	$ (101,496)	$ (57)	$ —	$ (19,570)	$ (4,295)	$ (20,776)	$ (483)	$ (60)	$ (69,448)
216		Demand	TPLTDEM	$ (7,573,483)	$ (4,699,905)	$ (1,567,460)	$ (37,290)	$ (406,265)	$ —	$ —	$ (256,191)	$ (204,312)	$ (193,177)	$ (28,022)	$ (23,672)	$ (157,188)
217		Commodity	COM	$ (41,459)	$ (20,924)	$ (10,255)	$ (407)	$ (1,704)	$ —	$ —	$ (2,545)	$ (2,841)	$ (1,302)	$ (565)	$ (379)	$ (537)
218		**Total Excess Deferred Income Taxes**		$ (27,872,376)	$ (23,634,285)	$ (2,701,119)	$ (42,086)	$ (509,465)	$ (57)	$ —	$ (278,306)	$ (211,447)	$ (215,255)	$ (29,070)	$ (24,111)	$ (227,174)
219		**Negative Acquisition Adjustment on OPC Assets**														
220		Customer	DISPLTCUS	$ (1,241,617)	$ (1,157,909)	$ (69,600)	$ (279)	$ (6,348)	$ (4)	$ —	$ (1,251)	$ (275)	$ (1,308)	$ (31)	$ (4)	$ (4,610)
221		Demand	DISPLTDEM	$ (707,405)	$ (430,758)	$ (150,342)	$ (3,577)	$ (38,967)	$ —	$ —	$ (24,572)	$ (19,596)	$ (18,528)	$ (2,688)	$ (2,270)	$ (16,106)
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		**Total Negative Acquisition Adjustment on OPC Assets**		$ (1,949,023)	$ (1,588,667)	$ (219,942)	$ (3,855)	$ (45,315)	$ (4)	$ —	$ (25,823)	$ (19,872)	$ (19,836)	$ (2,719)	$ (2,274)	$ (20,716)
224		**Materials and Supplies**														
225		Customer	TPLTCUS	$ 19,361,746	$ 18,077,193	$ 1,073,732	$ 4,195	$ 97,008	$ 54	$ —	$ 18,705	$ 4,105	$ 19,857	$ 462	$ 58	$ 66,378
226		Demand	TPLTDEM	$ 7,238,619	$ 4,492,098	$ 1,498,155	$ 35,641	$ 388,302	$ —	$ —	$ 244,863	$ 195,278	$ 184,635	$ 26,783	$ 22,625	$ 150,238
227		Commodity	COM	$ 39,626	$ 19,999	$ 9,801	$ 389	$ 1,629	$ —	$ —	$ 2,433	$ 2,715	$ 1,245	$ 540	$ 362	$ 513
228		Total Materials and Supplies		$ 26,639,992	$ 22,589,289	$ 2,581,689	$ 40,225	$ 486,939	$ 54	$ —	$ 266,001	$ 202,098	$ 205,737	$ 27,785	$ 23,045	$ 217,129
229		**Prepayments**														
230		Customer	OPEXPCUS	$ 8,807,394	$ 8,201,853	$ 511,963	$ 2,610	$ 47,551	$ 33	$ —	$ 10,739	$ 2,365	$ 9,425	$ 273	$ 34	$ 20,548
231		Demand	OPEXPDEM	$ 2,155,797	$ 1,331,140	$ 451,887	$ 10,750	$ 117,123	$ —	$ —	$ 73,858	$ 58,902	$ 55,691	$ 8,079	$ 6,824	$ 41,542
232		Commodity	COM	$ 117,112	$ 59,105	$ 28,967	$ 1,151	$ 4,815	$ —	$ —	$ 7,189	$ 8,025	$ 3,678	$ 1,596	$ 1,070	$ 1,516
233		Total Prepayments		$ 11,080,303	$ 9,592,098	$ 992,817	$ 14,511	$ 169,489	$ 33	$ —	$ 91,787	$ 69,291	$ 68,795	$ 9,947	$ 7,929	$ 63,606
234		**Pension & FAS 106 Reg. Asset**														
235		Customer	OPEXPCUS	$ 30,372,303	$ 28,284,095	$ 1,765,505	$ 9,001	$ 163,979	$ 113	$ —	$ 37,035	$ 8,155	$ 32,502	$ 942	$ 118	$ 70,859
236		Demand	OPEXPDEM	$ 7,434,266	$ 4,590,436	$ 1,558,333	$ 37,073	$ 403,900	$ —	$ —	$ 254,699	$ 203,122	$ 192,052	$ 27,859	$ 23,534	$ 143,257
237		Commodity	COM	$ 403,862	$ 203,825	$ 99,893	$ 3,968	$ 16,604	$ —	$ —	$ 24,793	$ 27,674	$ 12,684	$ 5,503	$ 3,690	$ 5,229
238		Total Pen. & FAS 106 Reg. Asset		$ 38,210,431	$ 33,078,356	$ 3,423,731	$ 50,042	$ 584,482	$ 113	$ —	$ 316,526	$ 238,951	$ 237,238	$ 34,304	$ 27,342	$ 219,346
239		**DIMP Deferrals**														
240		Customer	TPLTCUS	$ 3,781,786	$ 3,530,884	$ 209,724	$ 819	$ 18,948	$ 11	$ —	$ 3,653	$ 802	$ 3,879	$ 90	$ 11	$ 12,965
241		Demand	TPLTDEM	$ 925,672	$ 574,448	$ 191,584	$ 4,558	$ 49,656	$ —	$ —	$ 31,313	$ 24,972	$ 23,611	$ 3,425	$ 2,893	$ 19,212
242		Commodity	COM	$ 50,287	$ 25,379	$ 12,438	$ 494	$ 2,067	$ —	$ —	$ 3,087	$ 3,446	$ 1,579	$ 685	$ 460	$ 651
243		Total DIMP Deferrals		$ 4,757,745	$ 4,130,711	$ 413,746	$ 5,871	$ 70,671	$ 11	$ —	$ 38,054	$ 29,220	$ 29,069	$ 4,200	$ 3,364	$ 32,829
244		**Regulatory Asset**														
245		Customer	TPLTCUS	$ 1,683,737	$ 1,572,029	$ 93,374	$ 365	$ 8,436	$ 5	$ —	$ 1,627	$ 357	$ 1,727	$ 40	$ 5	$ 5,772
246		Demand	TPLTDEM	$ 412,130	$ 255,757	$ 85,297	$ 2,029	$ 22,108	$ —	$ —	$ 13,941	$ 11,118	$ 10,512	$ 1,525	$ 1,288	$ 8,554
247		Commodity	COM	$ 22,389	$ 11,299	$ 5,538	$ 220	$ 920	$ —	$ —	$ 1,374	$ 1,534	$ 703	$ 305	$ 205	$ 290
248		**Total Regulatory Asset**		$ 2,118,256	$ 1,839,086	$ 184,209	$ 2,614	$ 31,464	$ 5	$ —	$ 16,942	$ 13,009	$ 12,942	$ 1,870	$ 1,498	$ 14,616
249		**Cash Working Capital**														
250		Customer	OPEXPCUS	$ (10,653,973)	$ (9,921,473)	$ (619,302)	$ (3,157)	$ (57,520)	$ (40)	$ —	$ (12,991)	$ (2,861)	$ (11,401)	$ (330)	$ (41)	$ (24,856)
251		Demand	OPEXPDEM	$ (2,607,786)	$ (1,610,230)	$ (546,631)	$ (13,004)	$ (141,680)	$ —	$ —	$ (89,343)	$ (71,251)	$ (67,368)	$ (9,772)	$ (8,255)	$ (50,252)

Allocated Rate Base

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
252		Commodity	COM	$ (141,666)	$ (71,498)	$ (35,040)	$ (1,392)	$ (5,824)	$ —	$ —	$ (8,697)	$ (9,707)	$ (4,449)	$ (1,930)	$ (1,295)	$ (1,834)
253		Total Cash Working Capital		$ (13,403,426)	$ (11,603,200)	$ (1,200,974)	$ (17,554)	$ (205,024)	$ (40)	$ —	$ (111,031)	$ (83,819)	$ (83,218)	$ (12,033)	$ (9,591)	$ (76,942)
254		**Total Rate Base**														
255		Customer		$ 1,341,139,045	$ 1,259,777,095	$ 67,395,566	$ 196,242	$ 6,767,768	$ 3,862	$ —	$ 1,188,116	$ 254,099	$ 1,403,456	$ 33,021	$ 4,130	$ 4,115,689
256		Demand		$ 542,387,737	$ 337,400,422	$ 112,063,199	$ 2,665,987	$ 29,045,327	$ —	$ —	$ 18,315,970	$ 14,606,943	$ 13,810,883	$ 2,003,399	$ 1,692,398	$ 10,783,208
257		Commodity		$ 3,385,554	$ 1,708,654	$ 837,395	$ 33,264	$ 139,187	$ —	$ —	$ 207,835	$ 231,986	$ 106,329	$ 46,129	$ 30,937	$ 43,838
258		Total Rate Base		$ 1,886,912,337	$ 1,598,886,171	$ 180,296,161	$ 2,895,494	$ 35,952,282	$ 3,862	$ —	$ 19,711,921	$ 15,093,028	$ 15,320,668	$ 2,082,548	$ 1,727,465	$ 14,942,735

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1		**Transmission and Distribution Op. Exp.**														
2	814-865	**Transmission Expenses**														
3		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
4		Demand	DEM	$ 9,124,268	$ 6,081,874	$ 1,688,951	$ 40,180	$ 437,754	$ —	$ —	$ 276,048	$ 220,147	$ 208,150	$ 30,194	$ 25,507	$ 115,463
5		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
6		Total Transmission Expense		$ 9,124,268	$ 6,081,874	$ 1,688,951	$ 40,180	$ 437,754	$ —	$ —	$ 276,048	$ 220,147	$ 208,150	$ 30,194	$ 25,507	$ 115,463
7	8650	**Odorization**														
8		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
9		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
10		Commodity	COM	$ 2,471	$ 1,247	$ 611	$ 24	$ 102	$ —	$ —	$ 152	$ 169	$ 78	$ 34	$ 23	$ 32
11		Total Odorization		$ 2,471	$ 1,247	$ 611	$ 24	$ 102	$ —	$ —	$ 152	$ 169	$ 78	$ 34	$ 23	$ 32
12	8700	**Operation Supervision & Engineering**														
13		Customer	871-879CUS	$ 2,296,831	$ 2,108,716	$ 157,948	$ 1,032	$ 18,937	$ 17	$ —	$ 5,190	$ 1,185	$ 3,634	$ 141	$ 18	$ 13
14		Demand	DEM	$ 389,559	$ 259,665	$ 72,110	$ 1,715	$ 18,690	$ —	$ —	$ 11,786	$ 9,399	$ 8,887	$ 1,289	$ 1,089	$ 4,930
15		Commodity	COM	$ 47,984	$ 24,217	$ 11,868	$ 471	$ 1,973	$ —	$ —	$ 2,946	$ 3,288	$ 1,507	$ 654	$ 438	$ 621
16		Total Supervision & Engineering		$ 2,734,374	$ 2,392,598	$ 241,926	$ 3,219	$ 39,599	$ 17	$ —	$ 19,922	$ 13,872	$ 14,028	$ 2,084	$ 1,545	$ 5,564
17	8710	**Distribution Load Dispatch**														
18		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
19		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
20		Commodity	COM	$ 585,292	$ 295,390	$ 144,768	$ 5,751	$ 24,063	$ —	$ —	$ 35,930	$ 40,106	$ 18,382	$ 7,975	$ 5,348	$ 7,579
21		Total Distribution Load Dispatch		$ 585,292	$ 295,390	$ 144,768	$ 5,751	$ 24,063	$ —	$ —	$ 35,930	$ 40,106	$ 18,382	$ 7,975	$ 5,348	$ 7,579
22	8740	**Mains & Services - Allocated**														
23		Customer	MSCUS-ALL	$ 12,245,352	$ 11,530,932	$ 640,893	$ 1,904	$ 50,932	$ 19	$ —	$ 7,713	$ 1,613	$ 10,991	$ 171	$ 22	$ 162
24		Demand	DEM	$ 3,446,270	$ 2,297,147	$ 637,923	$ 15,176	$ 165,341	$ —	$ —	$ 104,264	$ 83,150	$ 78,619	$ 11,404	$ 9,634	$ 43,611
25		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
26		Total Mains & Services - Allocated		$ 15,691,623	$ 13,828,078	$ 1,278,816	$ 17,080	$ 216,274	$ 19	$ —	$ 111,978	$ 84,764	$ 89,610	$ 11,575	$ 9,656	$ 43,773
27	8740	**Mains & Services - Dir. Assn.**														
28		Customer	MSCUS-DA	$ 50,458	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 50,458
29		Demand	DEM-DA	$ 28,854	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 28,854
30		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
31		Total Mains & Services - Dir. Assn.		$ 79,312	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 79,312
32	8740	**Odorization**														
33		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
34		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
35		Commodity	COM	$ (45,825)	$ (23,127)	$ (11,334)	$ (450)	$ (1,884)	$ —	$ —	$ (2,813)	$ (3,140)	$ (1,439)	$ (624)	$ (419)	$ (593)
36		Total Odorization		$ (45,825)	$ (23,127)	$ (11,334)	$ (450)	$ (1,884)	$ —	$ —	$ (2,813)	$ (3,140)	$ (1,439)	$ (624)	$ (419)	$ (593)
37	8750	**Meas. & Reg. Station - Gen. - Allocated**														
38		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
39		Demand	DEM	$ 1,078,584	$ 718,941	$ 199,652	$ 4,750	$ 51,747	$ —	$ —	$ 32,632	$ 26,024	$ 24,605	$ 3,569	$ 3,015	$ 13,649
40		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
41		Total Meas. & Reg. Station - Gen. - Allocated		$ 1,078,584	$ 718,941	$ 199,652	$ 4,750	$ 51,747	$ —	$ —	$ 32,632	$ 26,024	$ 24,605	$ 3,569	$ 3,015	$ 13,649
42		**Meas. & Reg. Station - Gen. - DA**														
43	8750	Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
44		Demand	DEM-DA	$ 8,173	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 8,173
45		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
46		Total Meas. & Reg. Station - Gen. - DA		$ 8,173	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 8,173
47	8750	**Odorization**														
48		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
49		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
50		Commodity	COM	$ 273,994	$ 138,282	$ 67,771	$ 2,692	$ 11,264	$ —	$ —	$ 16,820	$ 18,775	$ 8,605	$ 3,733	$ 2,504	$ 3,548
51		Total Odorization		$ 273,994	$ 138,282	$ 67,771	$ 2,692	$ 11,264	$ —	$ —	$ 16,820	$ 18,775	$ 8,605	$ 3,733	$ 2,504	$ 3,548
52	8760	**Meas. & Reg. Stat. - Ind. - Allocated**														
53		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
54		Demand	NRDEM	$ 89,782	$ —	$ 49,841	$ 1,186	$ 12,918	$ —	$ —	$ 8,146	$ 6,497	$ 6,143	$ 891	$ 753	$ 3,407
55		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
56		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 89,782	$ —	$ 49,841	$ 1,186	$ 12,918	$ —	$ —	$ 8,146	$ 6,497	$ 6,143	$ 891	$ 753	$ 3,407
57	8760	**Meas. & Reg. Stat. - Ind. - DA**														
58		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
59		Demand	DEM-DA	$ 1,326	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 1,326
60		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
61		Total Meas. & Reg. Stat. - Ind. - DA		$ 1,326	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 1,326
62	8770	**Meas. & Reg. Stat.- City Gate**														

Allocated Cost of Service

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
63		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
64		Demand	DEM	$ 98,743	$ 65,818	$ 18,278	$ 435	$ 4,737	$ —	$ —	$ 2,987	$ 2,382	$ 2,253	$ 327	$ 276	$ 1,250
65		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
66		Total Meas. & Reg. Stat. - City Gate		$ 98,743	$ 65,818	$ 18,278	$ 435	$ 4,737	$ —	$ —	$ 2,987	$ 2,382	$ 2,253	$ 327	$ 276	$ 1,250
67	8780	**Meter & House Reg. Exp. - Alloc.**														
68		Customer	MTRGCUS-ALL	$ 15,692,849	$ 14,119,177	$ 1,280,279	$ 10,650	$ 179,396	$ 192	$ —	$ 55,415	$ 12,795	$ 33,209	$ 1,544	$ 192	$ —
69		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
70		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
71		Total Meter & House Reg. Exp. - Alloc.		$ 15,692,849	$ 14,119,177	$ 1,280,279	$ 10,650	$ 179,396	$ 192	$ —	$ 55,415	$ 12,795	$ 33,209	$ 1,544	$ 192	$ —
72	8780	**Meter & House Reg. Exp - Dir. Assn.**														
73		Customer	CUS-DA	$ 16,673	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 16,673
74		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
75		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
76		Total Meter & House Reg. Exp. - DA		$ 16,673	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 16,673
77	8780	**Odorization**														
78		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
79		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
80		Commodity	COM	$ 81	$ 41	$ 20	$ 1	$ 3	$ —	$ —	$ 5	$ 6	$ 3	$ 1	$ 1	$ 1
81		Total Odorization		$ 81	$ 41	$ 20	$ 1	$ 3	$ —	$ —	$ 5	$ 6	$ 3	$ 1	$ 1	$ 1
82	8790	**Customer Installation Expense**														
83		Customer	METCUS-ALL	$ 10,745	$ 9,768	$ 816	$ 6	$ 100	$ 0	$ —	$ 28	$ 7	$ 18	$ 1	$ 0	$ —
84		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
85		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
86		Total Customer Install. Expense		$ 10,745	$ 9,768	$ 816	$ 6	$ 100	$ 0	$ —	$ 28	$ 7	$ 18	$ 1	$ 0	$ —
87	8800	**Other Expenses**														
88		Customer	871-879CUS	$ 2,762,147	$ 2,535,922	$ 189,947	$ 1,241	$ 22,773	$ 21	$ —	$ 6,242	$ 1,425	$ 4,370	$ 170	$ 21	$ 16
89		Demand	DEM	$ 468,481	$ 312,270	$ 86,718	$ 2,063	$ 22,476	$ —	$ —	$ 14,174	$ 11,303	$ 10,687	$ 1,550	$ 1,310	$ 5,928
90		Commodity	COM	$ 57,705	$ 29,123	$ 14,273	$ 567	$ 2,372	$ —	$ —	$ 3,542	$ 3,954	$ 1,812	$ 786	$ 527	$ 747
91		Total Other Expenses		$ 3,288,333	$ 2,877,316	$ 290,938	$ 3,871	$ 47,622	$ 21	$ —	$ 23,958	$ 16,682	$ 16,870	$ 2,506	$ 1,858	$ 6,692
92	8800	**Odorization**														
93		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
94		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
95		Commodity	COM	$ 1,505	$ 760	$ 372	$ 15	$ 62	$ —	$ —	$ 92	$ 103	$ 47	$ 21	$ 14	$ 19
96		Total Odorization		$ 1,505	$ 760	$ 372	$ 15	$ 62	$ —	$ —	$ 92	$ 103	$ 47	$ 21	$ 14	$ 19
97	8810	**Rents**														
98		Customer	871-879CUS	$ 98,383	$ 90,325	$ 6,766	$ 44	$ 811	$ 1	$ —	$ 222	$ 51	$ 156	$ 6	$ 1	$ 1
99		Demand	DEM	$ 16,686	$ 11,123	$ 3,089	$ 73	$ 801	$ —	$ —	$ 505	$ 403	$ 381	$ 55	$ 47	$ 211
100		Commodity	COM	$ 2,055	$ 1,037	$ 508	$ 20	$ 84	$ —	$ —	$ 126	$ 141	$ 65	$ 28	$ 19	$ 27
101		Total Rents		$ 117,124	$ 102,485	$ 10,363	$ 138	$ 1,696	$ 1	$ —	$ 853	$ 594	$ 601	$ 89	$ 66	$ 238
102	8820	**Corporate & Div. Exp.**														
103		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
104		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
105		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
106		Total Corporate & Div. Exp.		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
107		**Total Distr. & Trans. Op. Expense**														
108		Customer		$ 33,173,437	$ 30,394,840	$ 2,276,648	$ 14,877	$ 272,949	$ 250	$ —	$ 74,810	$ 17,075	$ 52,378	$ 2,032	$ 254	$ 67,323
109		Demand		$ 14,750,728	$ 9,746,838	$ 2,756,562	$ 65,579	$ 714,465	$ —	$ —	$ 450,541	$ 359,306	$ 339,724	$ 49,280	$ 41,630	$ 226,802
110		Commodity		$ 925,262	$ 466,970	$ 228,858	$ 9,091	$ 38,039	$ —	$ —	$ 56,801	$ 63,401	$ 29,059	$ 12,607	$ 8,455	$ 11,981
111		Total Distr. & Trans. Operations Exp.		$ 48,849,427	$ 40,608,648	$ 5,262,068	$ 89,547	$ 1,025,454	$ 250	$ —	$ 582,152	$ 439,782	$ 421,161	$ 63,919	$ 50,339	$ 306,106
112		**Distribution Maintenance Expenses**														
113	8850	**Maintenance Supervision and Engineering**														
114		Customer	887-893CUS	$ 10,488	$ 9,882	$ 543	$ 2	$ 43	$ 0	$ —	$ 6	$ 1	$ 9	$ 0	$ 0	$ 0
115		Demand	887-893DEM	$ 8,504	$ 4,501	$ 2,222	$ 53	$ 576	$ —	$ —	$ 363	$ 290	$ 274	$ 40	$ 34	$ 152
116		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
117		Total Supervision and Engineering		$ 18,992	$ 14,383	$ 2,765	$ 54	$ 619	$ 0	$ —	$ 370	$ 291	$ 283	$ 40	$ 34	$ 152
118	8860	**Structures and Improvements**														
119		Customer	887-893CUS	$ 1,311,078	$ 1,235,401	$ 67,903	$ 200	$ 5,415	$ 2	$ —	$ 808	$ 169	$ 1,140	$ 18	$ 2	$ 21
120		Demand	887-893DEM	$ 1,063,129	$ 562,681	$ 277,818	$ 6,609	$ 72,007	$ —	$ —	$ 45,407	$ 36,212	$ 34,239	$ 4,967	$ 4,196	$ 18,993
121		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
122		Total Structures and Improvements		$ 2,374,207	$ 1,798,082	$ 345,721	$ 6,809	$ 77,421	$ 2	$ —	$ 46,215	$ 36,381	$ 35,379	$ 4,985	$ 4,198	$ 19,013
123	8870	**Maintenance of Mains-Allocated**														
124		Customer	CUS	$ 5,390,250	$ 5,098,272	$ 263,028	$ 700	$ 20,870	$ 8	$ —	$ 2,718	$ 564	$ 3,877	$ 61	$ 8	$ 145

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
125		Demand	DEM	$ 3,071,067	$ 2,047,051	$ 568,471	$ 13,524	$ 147,340	$ —	$ —	$ 92,913	$ 74,098	$ 70,059	$ 10,163	$ 8,585	$ 38,863
126		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
127		Total Mains - Allocated		$ 8,461,317	$ 7,145,323	$ 831,499	$ 14,224	$ 168,211	$ 8	$ —	$ 95,631	$ 74,662	$ 73,936	$ 10,224	$ 8,593	$ 39,008
128	8870	**Maintenance of Mains - Directly Assigned**														
129		Customer	CUS-DA	$ 32,752	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 32,752
130		Demand	DEM-DA	$ 25,788	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 25,788
131		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
132		Total Mains - Directly Assigned		$ 58,540	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 58,540
133	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**														
134		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
135		Demand	DEM	$ 2,784,748	$ 1,856,202	$ 515,472	$ 12,263	$ 133,604	$ —	$ —	$ 84,250	$ 67,189	$ 63,528	$ 9,215	$ 7,785	$ 35,240
136		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
137		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 2,784,748	$ 1,856,202	$ 515,472	$ 12,263	$ 133,604	$ —	$ —	$ 84,250	$ 67,189	$ 63,528	$ 9,215	$ 7,785	$ 35,240
138	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**														
139		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
140		Demand	DEM-DA	$ 18,902	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 18,902
141		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
142		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 18,902	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 18,902
143	8890	**Odorization**														
144		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
145		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
146		Commodity	COM	$ 343,209	$ 173,214	$ 84,891	$ 3,372	$ 14,110	$ —	$ —	$ 21,069	$ 23,518	$ 10,779	$ 4,676	$ 3,136	$ 4,444
147		Total Odorization		$ 343,209	$ 173,214	$ 84,891	$ 3,372	$ 14,110	$ —	$ —	$ 21,069	$ 23,518	$ 10,779	$ 4,676	$ 3,136	$ 4,444
148	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**														
149		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
150		Demand	NRDEM	$ 1,536,947	$ —	$ 853,219	$ 20,298	$ 221,143	$ —	$ —	$ 139,453	$ 111,213	$ 105,152	$ 15,253	$ 12,885	$ 58,329
151		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
152		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 1,536,947	$ —	$ 853,219	$ 20,298	$ 221,143	$ —	$ —	$ 139,453	$ 111,213	$ 105,152	$ 15,253	$ 12,885	$ 58,329
153	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**														
154		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
155		Demand	DEM-DA	$ 22,697	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 22,697
156		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
157		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ 22,697	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 22,697
158	8910	**Meas. & Reg. Sta. Eq.- City Gate**														
159		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
160		Demand	DEM	$ 69,264	$ 46,169	$ 12,821	$ 305	$ 3,323	$ —	$ —	$ 2,096	$ 1,671	$ 1,580	$ 229	$ 194	$ 877
161		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
162		Total Meas. & Reg. Sta. Eq.- City Gate		$ 69,264	$ 46,169	$ 12,821	$ 305	$ 3,323	$ —	$ —	$ 2,096	$ 1,671	$ 1,580	$ 229	$ 194	$ 877
163	8910	**Odorization**														
164		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
165		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
166		Commodity	COM	$ 100	$ 50	$ 25	$ 1	$ 4	$ —	$ —	$ 6	$ 7	$ 3	$ 1	$ 1	$ 1
167		**Total Odorization**		$ 100	$ 50	$ 25	$ 1	$ 4	$ —	$ —	$ 6	$ 7	$ 3	$ 1	$ 1	$ 1
168	8920	**Services - Allocated**														
169		Customer	SERCUS-ALL	$ 3,825,896	$ 3,587,095	$ 213,462	$ 691	$ 16,987	$ 6	$ —	$ 2,879	$ 605	$ 4,100	$ 63	$ 8	$ —
170		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
171		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
172		Total Services - Allocated		$ 3,825,896	$ 3,587,095	$ 213,462	$ 691	$ 16,987	$ 6	$ —	$ 2,879	$ 605	$ 4,100	$ 63	$ 8	$ —
173	8920	**Services - Directly Assigned**														
174		Customer	CUS-DA	$ 8,552	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 8,552
175		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
176		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
177		Total Services - Directly Assigned		$ 8,552	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 8,552
178	8930	**Meters & House Regulators - Alloc.**														
179		Customer	MTRGCUS-ALL	$ 27,992	$ 25,185	$ 2,284	$ 19	$ 320	$ 0	$ —	$ 99	$ 23	$ 59	$ 3	$ 0	$ —
180		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
181		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
182		Total Meters & House Regulators - Alloc.		$ 27,992	$ 25,185	$ 2,284	$ 19	$ 320	$ 0	$ —	$ 99	$ 23	$ 59	$ 3	$ 0	$ —
183	8930	**Meters & House Regulators - DA**														
184		Customer	CUS-DA	$ 30	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 30
185		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
186		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
187		Total Meters & House Regulators - DA		$ 30	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 30
188	8940	**Maintenance of Other Equipment**														
189		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
190		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
191		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
192		Total Maintenance of Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
193	8950	**Clearing - Meter Shop - Small Meters**														
194		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
195		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
196		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
197		Total Clearing-Meter-Shop-Small Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
198	8960	**Clearing - Meter Shop - Large Meters**														
199		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
200		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
201		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
202		Total Clearing-Meter Shop-Large Meters		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
203		**Total Distr. Maintenance Expense**														
204		Customer		$ 10,607,039	$ 9,955,835	$ 547,220	$ 1,611	$ 43,635	$ 16	$ —	$ 6,510	$ 1,363	$ 9,185	$ 145	$ 18	$ 41,500
205		Demand		$ 8,601,046	$ 4,516,604	$ 2,230,023	$ 53,052	$ 577,993	$ —	$ —	$ 364,482	$ 290,674	$ 274,832	$ 39,867	$ 33,678	$ 219,840
206		Commodity		$ 343,309	$ 173,264	$ 84,915	$ 3,373	$ 14,114	$ —	$ —	$ 21,075	$ 23,524	$ 10,782	$ 4,678	$ 3,137	$ 4,445
207		Total Distr. Maintenance Expense		$ 19,551,393	$ 14,645,704	$ 2,862,158	$ 58,036	$ 635,742	$ 16	$ —	$ 392,068	$ 315,561	$ 294,800	$ 44,690	$ 36,834	$ 265,785
208		**Total Oper. & Maint. Expense**														
209		Customer		$ 43,780,476	$ 40,350,676	$ 2,823,868	$ 16,488	$ 316,584	$ 266	$ —	$ 81,321	$ 18,438	$ 61,563	$ 2,177	$ 272	$ 108,822
210		Demand		$ 23,351,773	$ 14,263,442	$ 4,986,586	$ 118,631	$ 1,292,458	$ —	$ —	$ 815,024	$ 649,979	$ 614,556	$ 89,147	$ 75,308	$ 446,642
211		Commodity		$ 1,268,571	$ 640,234	$ 313,773	$ 12,464	$ 52,154	$ —	$ —	$ 77,876	$ 86,926	$ 39,842	$ 17,284	$ 11,592	$ 16,426
212		Total Operations & Maint. Expense		$ 68,400,820	$ 55,254,351	$ 8,124,227	$ 147,584	$ 1,661,196	$ 266	$ —	$ 974,220	$ 755,343	$ 715,961	$ 108,609	$ 87,173	$ 571,890
213		**Customer Accounts Expense**														
214	901	**Supervision**														
215		Customer	902-904CUS	$ 645	$ 610	$ 33	$ 0	$ 1	$ 0	$ —	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
216		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
217		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
218		Total Supervision		$ 645	$ 610	$ 33	$ 0	$ 1	$ 0	$ —	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
219	902	**Meter Reading Expense**														
220		Customer	METCUS-TOT	$ 1,423,705	$ 1,294,173	$ 108,140	$ 749	$ 13,292	$ 12	$ —	$ 3,734	$ 876	$ 2,440	$ 97	$ 12	$ 180
221		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
222		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
223		Total Meter Reading Expense		$ 1,423,705	$ 1,294,173	$ 108,140	$ 749	$ 13,292	$ 12	$ —	$ 3,734	$ 876	$ 2,440	$ 97	$ 12	$ 180
224	903	**Customer Accounting**														
225		Customer	903CUS	$ 11,808,882	$ 11,351,886	$ 432,914	$ 936	$ 17,647	$ 6	$ —	$ 1,985	$ 412	$ 2,939	$ 45	$ 6	$ 106
226		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
227		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
228		Total Customer Accounting		$ 11,808,882	$ 11,351,886	$ 432,914	$ 936	$ 17,647	$ 6	$ —	$ 1,985	$ 412	$ 2,939	$ 45	$ 6	$ 106
229	904	**Bad Debt Expense**														
230		Customer	904CUS	$ 3,374,231	$ 3,059,074	$ 306,239	$ 4,787	$ 1,752	$ —	$ —	$ 2,379	$ —	$ —	$ —	$ —	$ —
231		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
232		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
233		Total Bad Debt Expense		$ 3,374,231	$ 3,059,074	$ 306,239	$ 4,787	$ 1,752	$ —	$ —	$ 2,379	$ —	$ —	$ —	$ —	$ —
234	905	**Miscellaneous Customer Accounts**														
235		Customer	902-904CUS	$ 869,396	$ 822,191	$ 44,357	$ 339	$ 1,711	$ 1	$ —	$ 424	$ 67	$ 282	$ 7	$ 1	$ 15
236		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
237		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
238		Total Misc. Customer Accounts		$ 869,396	$ 822,191	$ 44,357	$ 339	$ 1,711	$ 1	$ —	$ 424	$ 67	$ 282	$ 7	$ 1	$ 15
239	907-910	**Customer Information Expense**														
240		Customer	CUS	$ 2,509,218	$ 2,373,299	$ 122,442	$ 326	$ 9,715	$ 4	$ —	$ 1,265	$ 263	$ 1,805	$ 28	$ 4	$ 67
241		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
242		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
243		Total Customer Information Expense		$ 2,509,218	$ 2,373,299	$ 122,442	$ 326	$ 9,715	$ 4	$ —	$ 1,265	$ 263	$ 1,805	$ 28	$ 4	$ 67
244		**Sales and Advertising Expense**														
245	911	**Supervision**														
246		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
247		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
248		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
249		Total Supervision Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
250	912	**Demonstrating and Selling**														
251		Customer	CUS	$ 1,630	$ 1,542	$ 80	$ 0	$ 6	$ 0	$ —	$ 1	$ 0	$ 1	$ 0	$ 0	$ 0
252		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
253		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
254		Total Demon. and Selling Expense		$ 1,630	$ 1,542	$ 80	$ 0	$ 6	$ 0	$ —	$ 1	$ 0	$ 1	$ 0	$ 0	$ 0
255	913	**Advertising**														
256		Customer	CUS	$ 191,835	$ 181,444	$ 9,361	$ 25	$ 743	$ 0	$ —	$ 97	$ 20	$ 138	$ 2	$ 0	$ 5
257		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
258		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
259		Total Advertising		$ 191,835	$ 181,444	$ 9,361	$ 25	$ 743	$ 0	$ —	$ 97	$ 20	$ 138	$ 2	$ 0	$ 5
260	914	**Employee Sales Referrals**														
261		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
262		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
263		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
264		Total Employee Sales Referrals		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
265	916	**Misc. Gas Sales Expense**														
266		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
267		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
268		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
269		Total Misc. Gas Sales Expense		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
270		**Administrative & General Exp.**														
271	920-940	**Administrative & General Expenses**														
272		Customer	OPEXPCUS	$ 65,695,784	$ 61,178,955	$ 3,818,816	$ 19,469	$ 354,689	$ 245	$ —	$ 80,107	$ 17,640	$ 70,303	$ 2,037	$ 255	$ 153,268
273		Demand	OPEXPDEM	$ 8,384,235	$ 5,177,014	$ 1,757,461	$ 41,810	$ 455,511	$ —	$ —	$ 287,245	$ 229,077	$ 216,593	$ 31,419	$ 26,541	$ 161,563
274		Commodity	COM	$ 455,468	$ 229,870	$ 112,657	$ 4,475	$ 18,725	$ —	$ —	$ 27,961	$ 31,210	$ 14,305	$ 6,206	$ 4,162	$ 5,898
275		Total Administrative & General Exp.		$ 74,535,487	$ 66,585,839	$ 5,688,934	$ 65,754	$ 828,925	$ 245	$ —	$ 395,312	$ 277,927	$ 301,201	$ 39,662	$ 30,958	$ 320,729
276		**Depreciation & Amortization Expense**														
277	301-303	**Intangible Plant - Allocated**														
278		Customer	CUS	$ 63,471	$ 60,032	$ 3,097	$ 8	$ 246	$ 0	$ —	$ 32	$ 7	$ 46	$ 1	$ 0	$ 2
279		Demand	DEM	$ 23,729	$ 15,817	$ 4,392	$ 104	$ 1,138	$ —	$ —	$ 718	$ 573	$ 541	$ 79	$ 66	$ 300
280		Commodity	COM	$ 130	$ 66	$ 32	$ 1	$ 5	$ —	$ —	$ 8	$ 9	$ 4	$ 2	$ 1	$ 2
281		Total Intangible Plant		$ 87,330	$ 75,915	$ 7,522	$ 114	$ 1,390	$ 0	$ —	$ 758	$ 588	$ 591	$ 81	$ 68	$ 304
282	301-303	**Intangible Plant - Directly Assigned**														
283		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
284		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
285		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
286		Total Intangible Plant		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
287	365	**Land and Land Rights**														
288		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
289		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
290		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
291		Total Land and Land Rights		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
292	366	**Meas. and Reg. Station Structures**														
293		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
294		Demand	DEM	$ 49,857	$ 33,232	$ 9,229	$ 220	$ 2,392	$ —	$ —	$ 1,508	$ 1,203	$ 1,137	$ 165	$ 139	$ 631
295		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
296		Total Measuring and Reg. Stat. Struct.		$ 49,857	$ 33,232	$ 9,229	$ 220	$ 2,392	$ —	$ —	$ 1,508	$ 1,203	$ 1,137	$ 165	$ 139	$ 631
297	367	**Transmission Mains**														
298		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
299		Demand	DEM	$ 3,282,834	$ 2,188,206	$ 607,670	$ 14,456	$ 157,500	$ —	$ —	$ 99,320	$ 79,207	$ 74,890	$ 10,864	$ 9,177	$ 41,543
300		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
301		Total Transmission Mains		$ 3,282,834	$ 2,188,206	$ 607,670	$ 14,456	$ 157,500	$ —	$ —	$ 99,320	$ 79,207	$ 74,890	$ 10,864	$ 9,177	$ 41,543
302	368	**Compression Station Equipment**														
303		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
304		Demand	DEM	$ 3,937	$ 2,624	$ 729	$ 17	$ 189	$ —	$ —	$ 119	$ 95	$ 90	$ 13	$ 11	$ 50
305		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
306		Total Compression Sta. Equipment		$ 3,937	$ 2,624	$ 729	$ 17	$ 189	$ —	$ —	$ 119	$ 95	$ 90	$ 13	$ 11	$ 50
307	369	**Meas. & Reg. Station Equipment**														
308		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
309		Demand	DEM	$ 890,894	$ 593,834	$ 164,909	$ 3,923	$ 42,742	$ —	$ —	$ 26,953	$ 21,495	$ 20,324	$ 2,948	$ 2,490	$ 11,274
310		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
311		Total Meas. & Reg. Stat. Equipment		$ 890,894	$ 593,834	$ 164,909	$ 3,923	$ 42,742	$ —	$ —	$ 26,953	$ 21,495	$ 20,324	$ 2,948	$ 2,490	$ 11,274
312	371	**Other Equipment**														
313		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
314		Demand	DEM	$ 2,818	$ 1,878	$ 522	$ 12	$ 135	$ —	$ —	$ 85	$ 68	$ 64	$ 9	$ 8	$ 36
315		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
316		Total Other Equipment		$ 2,818	$ 1,878	$ 522	$ 12	$ 135	$ —	$ —	$ 85	$ 68	$ 64	$ 9	$ 8	$ 36
317	375	**Structures and Improvements**														
318		Customer	376-379CUS	$ 11,442	$ 10,757	$ 555	$ 1	$ 44	$ 0	$ —	$ 6	$ 1	$ 8	$ 0	$ 0	$ 69
319		Demand	DEM	$ 7,784	$ 5,189	$ 1,441	$ 34	$ 373	$ —	$ —	$ 236	$ 188	$ 178	$ 26	$ 22	$ 99
320		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
321		Total Structures and Improvements		$ 19,226	$ 15,945	$ 1,996	$ 36	$ 417	$ 0	$ —	$ 241	$ 189	$ 186	$ 26	$ 22	$ 168
322	376	**Distribution Mains - Allocated**														
323		Customer	CUS	$ 18,434,684	$ 17,436,119	$ 899,556	$ 2,393	$ 71,376	$ 26	$ —	$ 9,296	$ 1,930	$ 13,258	$ 209	$ 26	$ 495
324		Demand	DEM	$ 10,503,067	$ 7,000,926	$ 1,944,174	$ 46,252	$ 503,905	$ —	$ —	$ 317,762	$ 253,415	$ 239,604	$ 34,757	$ 29,361	$ 132,911
325		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
326		Total Distribution Mains - Allocated		$ 28,937,751	$ 24,437,045	$ 2,843,730	$ 48,645	$ 575,281	$ 26	$ —	$ 327,059	$ 255,344	$ 252,861	$ 34,966	$ 29,387	$ 133,406
327	376	**Distribution Mains - Directly Assigned**														
328		Customer	CUS-DA	$ 103,492	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 103,492
329		Demand	DEM-DA	$ 81,487	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 81,487
330		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
331		Distribution Mains - Directly Assigned		$ 184,979	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 184,979
332	377	**Compressor Station Equipment**														
333		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
334		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
335		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
336		Total Compressor Station Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
337	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**														
338		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
339		Demand	DEM	$ 1,415,814	$ 943,725	$ 262,075	$ 6,235	$ 67,926	$ —	$ —	$ 42,834	$ 34,160	$ 32,299	$ 4,685	$ 3,958	$ 17,916
340		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
341		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 1,415,814	$ 943,725	$ 262,075	$ 6,235	$ 67,926	$ —	$ —	$ 42,834	$ 34,160	$ 32,299	$ 4,685	$ 3,958	$ 17,916
342	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**														
343		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
344		Demand	DEM-DA	$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7,213
345		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
346		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7,213
347	378	**Odorization**														
348		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
349		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
350		Commodity	COM	$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694	$ 318	$ 138	$ 93	$ 131
351		Total Odorization		$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694	$ 318	$ 138	$ 93	$ 131
352	379	**Meas.& Reg. Sta. Equip.- City Gate - Alloc.**														
353		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
354		Demand	DEM	$ 459,933	$ 306,573	$ 85,136	$ 2,025	$ 22,066	$ —	$ —	$ 13,915	$ 11,097	$ 10,492	$ 1,522	$ 1,286	$ 5,820
355		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
356		Total Meas. & Reg. Sta. Eq.- City Gate		$ 459,933	$ 306,573	$ 85,136	$ 2,025	$ 22,066	$ —	$ —	$ 13,915	$ 11,097	$ 10,492	$ 1,522	$ 1,286	$ 5,820
357	379	**Meas.& Reg. Sta. Equip.- City Gate - Dir. Assn.**														
358		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
359		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
360		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
361		Total Meas. & Reg. Sta. Eq.- City Gate		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
362	379	**Odorization**														
363		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
364		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
365		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
366		Total Odorization		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
367	380	**Services - Allocated**														
368		Customer	SERCUS-ALL	$ 25,906,053	$ 24,289,073	$ 1,445,400	$ 4,678	$ 115,021	$ 42	$ —	$ 19,495	$ 4,098	$ 27,765	$ 427	$ 55	$ —
369		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
370		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
371		Total Services - Allocated		$ 25,906,053	$ 24,289,073	$ 1,445,400	$ 4,678	$ 115,021	$ 42	$ —	$ 19,495	$ 4,098	$ 27,765	$ 427	$ 55	$ —
372	380	**Services - Directly Assigned**														

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
373		Customer	CUS-DA	$ 56,728	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 56,728
374		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
375		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
376		Total Services - Directly Assigned		$ 56,728	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 56,728
377	381	**Meters - Allocated**														
378		Customer	METCUS-ALL	$ 7,349,631	$ 6,681,789	$ 558,326	$ 3,865	$ 68,628	$ 62	$ —	$ 19,280	$ 4,522	$ 12,596	$ 499	$ 62	$ —
379		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
380		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
381		Total Meters - Allocated		$ 7,349,631	$ 6,681,789	$ 558,326	$ 3,865	$ 68,628	$ 62	$ —	$ 19,280	$ 4,522	$ 12,596	$ 499	$ 62	$ —
382	381	**Meters - Directly Assigned**														
383		Customer	CUS-DA	$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7,213
384		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
385		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
386		Total Meters - Directly Assigned		$ 7,213	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 7,213
387	382	**Meter Installations**														
388		Customer	METCUS-TOT	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
389		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
390		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
391		Total Meter Installations		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
392	383	**House Regulators - Allocated**														
393		Customer	REGCUS-ALL	$ 1,510,038	$ 1,296,188	$ 160,466	$ 2,054	$ 31,472	$ 42	$ —	$ 11,122	$ 2,546	$ 5,755	$ 350	$ 42	$ —
394		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
395		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
396		Total House Regulators - Allocated		$ 1,510,038	$ 1,296,188	$ 160,466	$ 2,054	$ 31,472	$ 42	$ —	$ 11,122	$ 2,546	$ 5,755	$ 350	$ 42	$ —
397	383	**House Regulators - Directly Assn.**														
398		Customer	CUS-DA	$ 3,363	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,363
399		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
400		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
401		House Regulators - Directly Assn.		$ 3,363	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 3,363
402	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**														
403		Customer	NRCUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
404		Demand	NRDEM	$ 940,499	$ —	$ 522,107	$ 12,421	$ 135,323	$ —	$ —	$ 85,335	$ 68,054	$ 64,346	$ 9,334	$ 7,885	$ 35,693
405		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
406		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 940,499	$ —	$ 522,107	$ 12,421	$ 135,323	$ —	$ —	$ 85,335	$ 68,054	$ 64,346	$ 9,334	$ 7,885	$ 35,693
407	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**														
408		Customer	CUS-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
409		Demand	DEM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
410		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
411		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
412	386	**Other Prop.- Customer Premises**														
413		Customer	CUS	$ 355,527	$ 336,268	$ 17,349	$ 46	$ 1,377	$ 1	$ —	$ 179	$ 37	$ 256	$ 4	$ 1	$ 10
414		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
415		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
416		Total Other Prop. - Customer Premises		$ 355,527	$ 336,268	$ 17,349	$ 46	$ 1,377	$ 1	$ —	$ 179	$ 37	$ 256	$ 4	$ 1	$ 10
417	387	**Other Equipment**														
418		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
419		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
420		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
421		Total Other Equipment		$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
422	389-98	**General Plant - Allocated**														
423		Customer	GENPTCUS	$ 15,397,496	$ 14,469,372	$ 802,883	$ 2,671	$ 68,426	$ 32	$ —	$ 11,338	$ 2,442	$ 13,444	$ 272	$ 34	$ 26,583
424		Demand	DISPLTDEM	$ 2,179,682	$ 1,327,267	$ 463,240	$ 11,021	$ 120,066	$ —	$ —	$ 75,713	$ 60,381	$ 57,091	$ 8,282	$ 6,996	$ 49,626
425		Commodity	COM	$ 21,678	$ 10,941	$ 5,362	$ 213	$ 891	$ —	$ —	$ 1,331	$ 1,485	$ 681	$ 295	$ 198	$ 281
426		Total General Plant - Allocated		$ 17,598,856	$ 15,807,579	$ 1,271,485	$ 13,904	$ 189,383	$ 32	$ —	$ 88,382	$ 64,309	$ 71,216	$ 8,849	$ 7,228	$ 76,489
427	389-98	**General Plant - Directly Assigned**														
428		Customer	CUS-DA	$ 2,171	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,171
429		Demand	DEM-DA	$ 307	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 307
430		Commodity	COM-DA	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 3
431		Total General Plant - Directly Assn.		$ 2,481	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,481
432	389-98	**General Plant - Odorization**														
433		Customer	CUS	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
434		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
435		Commodity	COM	$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694	$ 318	$ 138	$ 93	$ 131
436		Total General Plant - Odorization		$ 10,130	$ 5,113	$ 2,506	$ 100	$ 416	$ —	$ —	$ 622	$ 694	$ 318	$ 138	$ 93	$ 131
437	40730	**Pension & FAS 106 Amort. Expense**														
438		Customer	CUS	$ (582,896)	$ (551,322)	$ (28,444)	$ (76)	$ (2,257)	$ (1)	$ —	$ (294)	$ (61)	$ (419)	$ (7)	$ (1)	$ (16)
439		Demand	DEM	$ (142,676)	$ (95,102)	$ (26,410)	$ (628)	$ (6,845)	$ —	$ —	$ (4,317)	$ (3,442)	$ (3,255)	$ (472)	$ (399)	$ (1,805)
440		Commodity	COM	$ (7,751)	$ (3,912)	$ (1,917)	$ (76)	$ (319)	$ —	$ —	$ (476)	$ (531)	$ (243)	$ (106)	$ (71)	$ (100)
441		Total Pension & FAS 106 Amort. Exp.		$ (733,323)	$ (650,336)	$ (56,771)	$ (780)	$ (9,421)	$ (1)	$ —	$ (5,086)	$ (4,035)	$ (3,917)	$ (584)	$ (471)	$ (1,922)
442		**Total Depreciation & Amort. Exp.**														
443		Customer		$ 68,618,412	$ 64,028,276	$ 3,859,188	$ 15,640	$ 354,333	$ 205	$ —	$ 70,454	$ 15,522	$ 72,709	$ 1,755	$ 219	$ 200,110
444		Demand		$ 19,707,177	$ 12,324,170	$ 4,039,215	$ 96,093	$ 1,046,912	$ —	$ —	$ 660,182	$ 526,494	$ 497,801	$ 72,211	$ 61,001	$ 383,099
445		Commodity		$ 34,321	$ 17,320	$ 8,488	$ 337	$ 1,411	$ —	$ —	$ 2,107	$ 2,352	$ 1,078	$ 468	$ 314	$ 447
446		Total Depreciation & Amort. Expense		$ 88,359,910	$ 76,369,765	$ 7,906,891	$ 112,071	$ 1,402,656	$ 205	$ —	$ 732,743	$ 544,368	$ 571,587	$ 74,433	$ 61,534	$ 583,657
447		**Taxes Other Than Income**														
448	4081	**Payroll and Other Taxes**														
449		Customer	OPEXPCUS	$ 5,111,189	$ 4,759,775	$ 297,107	$ 1,515	$ 27,595	$ 19	$ —	$ 6,232	$ 1,372	$ 5,470	$ 159	$ 20	$ 11,924
450		Demand	OPEXPDEM	$ 1,251,072	$ 772,499	$ 262,243	$ 6,239	$ 67,970	$ —	$ —	$ 42,862	$ 34,182	$ 32,319	$ 4,688	$ 3,960	$ 24,108
451		Commodity	COM	$ 67,964	$ 34,301	$ 16,810	$ 668	$ 2,794	$ —	$ —	$ 4,172	$ 4,657	$ 2,135	$ 926	$ 621	$ 880
452		Total Payroll and Other Taxes		$ 6,430,224	$ 5,566,575	$ 576,161	$ 8,421	$ 98,359	$ 19	$ —	$ 53,266	$ 40,212	$ 39,924	$ 5,773	$ 4,601	$ 36,912
453	4081	**Ad Valorem Taxes - Allocated**														
454		Customer	CUS	$ 14,106,095	$ 13,342,000	$ 688,334	$ 1,831	$ 54,617	$ 20	$ —	$ 7,114	$ 1,477	$ 10,145	$ 160	$ 20	$ 379
455		Demand	DEM	$ 5,258,969	$ 3,505,419	$ 973,464	$ 23,159	$ 252,309	$ —	$ —	$ 159,106	$ 126,887	$ 119,972	$ 17,403	$ 14,701	$ 66,550
456		Commodity	COM	$ 28,961	$ 14,616	$ 7,163	$ 285	$ 1,191	$ —	$ —	$ 1,778	$ 1,984	$ 910	$ 395	$ 265	$ 375
457		Total Ad Valorem Taxes - Allocated		$ 19,394,025	$ 16,862,035	$ 1,668,961	$ 25,274	$ 308,117	$ 20	$ —	$ 167,997	$ 130,348	$ 131,026	$ 17,958	$ 14,986	$ 67,303
458	4081	**Ad Valorem Taxes - Directly Assn.**														
459		Customer	CUS-DA	$ 44,614	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 44,614
460		Demand	DEM-DA	$ 31,442	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 31,442
461		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
462		Total Ad Valorem Taxes - Directly Assn.		$ 76,057	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 76,057
463		**Revenue Related Taxes**														
464		Customer	TOTREVCUS	$ 329,692	$ 241,745	$ 64,767	$ 2,420	$ 10,213	$ 3	$ —	$ 2,691	$ 2,762	$ 1,669	$ 381	$ 114	$ 2,926
465		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
466		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
467		Total Revenue Related Taxes		$ 329,692	$ 241,745	$ 64,767	$ 2,420	$ 10,213	$ 3	$ —	$ 2,691	$ 2,762	$ 1,669	$ 381	$ 114	$ 2,926
468		**Total Taxes Other Than Income**														
469		Customer		$ 19,591,590	$ 18,343,520	$ 1,050,208	$ 5,765	$ 92,425	$ 42	$ —	$ 16,037	$ 5,611	$ 17,284	$ 699	$ 154	$ 59,844
470		Demand		$ 6,541,483	$ 4,277,918	$ 1,235,707	$ 29,398	$ 320,279	$ —	$ —	$ 201,968	$ 161,069	$ 152,291	$ 22,091	$ 18,662	$ 122,100
471		Commodity		$ 96,925	$ 48,917	$ 23,974	$ 952	$ 3,985	$ —	$ —	$ 5,950	$ 6,642	$ 3,044	$ 1,321	$ 886	$ 1,255
472		Total Taxes Other Than Income		$ 26,229,998	$ 22,670,356	$ 2,309,889	$ 36,115	$ 416,689	$ 42	$ —	$ 223,955	$ 173,322	$ 172,619	$ 24,111	$ 19,702	$ 183,199
473		**Excess Def. Income Tax Amort. - Directly Assn.**														
474		Customer	CUS-DA	$ (5,769)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (5,769)
475		Demand	DEM-DA	$ (4,148)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (4,148)
476		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
477		**Total Excess Def. Income Tax Amort. - DA**		$ (9,917)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ (9,917)
478		**Excess Def. Income Tax Amort. - Alloc.**														
479		Customer	CUS	$ (1,613,973)	$ (1,526,548)	$ (78,757)	$ (209)	$ (6,249)	$ (2)	$ —	$ (814)	$ (169)	$ (1,161)	$ (18)	$ (2)	$ (43)
480		Demand	DEM	$ (644,598)	$ (429,664)	$ (119,319)	$ (2,839)	$ (30,926)	$ —	$ —	$ (19,502)	$ (15,553)	$ (14,705)	$ (2,133)	$ (1,802)	$ (8,157)
481		Commodity	COM	$ (3,549)	$ (1,791)	$ (878)	$ (35)	$ (146)	$ —	$ —	$ (218)	$ (243)	$ (111)	$ (48)	$ (32)	$ (46)
482		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (2,262,121)	$ (1,958,003)	$ (198,954)	$ (3,083)	$ (37,321)	$ (2)	$ —	$ (20,534)	$ (15,965)	$ (15,977)	$ (2,200)	$ (1,837)	$ (8,246)
483		**Interest on Customer Deposits**														
484		Customer	DEPCUS	$ 824,647	$ 391,766	$ 414,090	$ 5,203	$ 4,257	$ —	$ —	$ 7,368	$ 1,963	$ —	$ —	$ —	$ —
485		Demand	DEM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
486		Commodity	COM	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
487		Total Interest on Cust. Deposits		$ 824,647	$ 391,766	$ 414,090	$ 5,203	$ 4,257	$ —	$ —	$ 7,368	$ 1,963	$ —	$ —	$ —	$ —
488		**Req. Return - Other Than Directly Assn.**														
489		Customer	CUS	$ 107,448,563	$ 101,628,316	$ 5,243,159	$ 13,946	$ 416,025	$ 153	$ —	$ 54,185	$ 11,247	$ 77,274	$ 1,220	$ 153	$ 2,885
490		Demand	DEM	$ 42,913,466	$ 28,604,407	$ 7,943,515	$ 188,976	$ 2,058,856	$ —	$ —	$ 1,298,314	$ 1,035,402	$ 978,974	$ 142,009	$ 119,964	$ 543,049
491		Commodity	COM	$ 236,298	$ 119,257	$ 58,447	$ 2,322	$ 9,715	$ —	$ —	$ 14,506	$ 16,192	$ 7,421	$ 3,220	$ 2,159	$ 3,060
492		Tot. Req. Return - Other Than Dir. Assn.		$ 150,598,327	$ 130,351,980	$ 13,245,120	$ 205,245	$ 2,484,596	$ 153	$ —	$ 1,367,005	$ 1,062,841	$ 1,063,669	$ 146,449	$ 122,276	$ 548,993
493		**Req. Return - Directly Assigned**														
494		Customer	CUS-DA	$ 384,051	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 384,051
495		Demand	DEM-DA	$ 276,140	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 276,140
496		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
497		Tot. Req. Return - Directly Assigned		$ 660,191	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 660,191
498		**Income Taxes - Other Than DA**														
499		Customer	CUS	$ 22,243,200	$ 21,038,336	$ 1,085,400	$ 2,887	$ 86,122	$ 32	$ —	$ 11,217	$ 2,328	$ 15,997	$ 253	$ 32	$ 597
500		Demand	DEM	$ 8,883,626	$ 5,921,471	$ 1,644,407	$ 39,121	$ 426,209	$ —	$ —	$ 268,767	$ 214,341	$ 202,660	$ 29,398	$ 24,834	$ 112,418
501		Commodity	COM	$ 48,917	$ 24,688	$ 12,099	$ 481	$ 2,011	$ —	$ —	$ 3,003	$ 3,352	$ 1,536	$ 666	$ 447	$ 633
502		Total Income Taxes - Other Than DA		$ 31,175,742	$ 26,984,495	$ 2,741,906	$ 42,488	$ 514,342	$ 32	$ —	$ 282,987	$ 220,021	$ 220,193	$ 30,317	$ 25,313	$ 113,648
503		**Income Taxes - Directly Assigned**														
504		Customer	CUS-DA	$ 79,503	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 79,503
505		Demand	DEM-DA	$ 57,164	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 57,164
506		Commodity	COM-DA	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
507		Total Income Taxes - Dir. Assigned		$ 136,668	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 136,668
508		**Total Cost of Service Before Revenue Credits**														
509		Customer		$ 347,226,026	$ 324,517,516	$ 19,239,537	$ 86,351	$ 1,663,055	$ 962	$ —	$ 329,760	$ 74,220	$ 321,574	$ 8,303	$ 1,105	$ 983,643
510		Demand		$ 109,466,318	$ 70,138,757	$ 21,487,572	$ 511,190	$ 5,569,300	$ —	$ —	$ 3,511,998	$ 2,800,810	$ 2,648,169	$ 384,142	$ 324,509	$ 2,089,871
511		Commodity		$ 2,136,950	$ 1,078,495	$ 528,560	$ 20,996	$ 87,854	$ —	$ —	$ 131,184	$ 146,429	$ 67,114	$ 29,116	$ 19,527	$ 27,673
512		**Total Cost of Service Before Revenue Credits**		$ 458,829,294	$ 395,734,768	$ 41,255,670	$ 618,538	$ 7,320,209	$ 962	$ —	$ 3,972,943	$ 3,021,458	$ 3,036,857	$ 421,561	$ 345,141	$ 3,101,187

Allocation Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUB. AUTH TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	Customer Cost Allocation Factors														
2															
3	Total Customers		704,554	666,390	34,380	91	2,728	1	0	355	74	507	8	1	19
4	Total Customers Factor (CUS)	CUS	1.00000	0.94583	0.04880	0.00013	0.00387	0.00000	0.00000	0.00050	0.00010	0.00072	0.00001	0.00000	0.00003
5															
6	Customers - Directly Assigned		19	0	0	0	0	0	0	0	0	0	0	0	19
7	**Customers - Directly Assigned Factor (CUS-DA)**	CUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
8															
9	Services - Allocated Weighting			1.00000	1.15345	1.40333	1.15681	1.15677	0.00000	1.50534	1.52440	1.50337	1.46577	1.50398	0.00000
10	Weighted Customers		710,753	666,390	39,656	128	3,156	1	0	535	112	762	12	2	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.93758	0.05579	0.00018	0.00444	0.00000	0.00000	0.00075	0.00016	0.00107	0.00002	0.00000	0.00000
12															
13	Meters - Allocated Weighting			1.00000	1.61963	4.21548	2.50902	6.20576	0.00000	5.41191	6.11572	2.47933	6.21545	6.20576	0.00000
14	Weighted Customers		732,995	666,390	55,683	385	6,844	6	0	1,923	451	1,256	50	6	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.90913	0.07597	0.00053	0.00934	0.00001	0.00000	0.00262	0.00062	0.00171	0.00007	0.00001	0.00000
16															
17	Meters - Total Weighting			1.00000	1.61963	4.21548	2.50902	6.20576	0.00000	5.41191	6.11572	2.47933	6.21545	6.20576	4.89953
18	Weighted Customers		733,088	666,390	55,683	385	6,844	6	0	1,923	451	1,256	50	6	93
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.90902	0.07596	0.00053	0.00934	0.00001	0.00000	0.00262	0.00062	0.00171	0.00007	0.00001	0.00013
20															
21	Regulators - Allocated Weighting			1.00000	2.39959	11.54692	5.93139	21.82621	0.00000	16.09336	17.75033	5.83955	22.49194	21.82621	0.00000
22	Weighted Customers		776,334	666,390	82,498	1,056	16,180	22	0	5,718	1,309	2,959	180	22	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.85838	0.10627	0.00136	0.02084	0.00003	0.00000	0.00737	0.00169	0.00381	0.00023	0.00003	0.00000
24															
25	Meters and Regulators - Allocated Weighting			1.00000	1.75759	5.49667	3.10384	9.08033	0.00000	7.36119	8.18848	3.09332	9.10767	9.08033	0.00000
26	Weighted Customers		740,663	666,390	60,426	503	8,467	9	0	2,615	604	1,567	73	9	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.89972	0.08158	0.00068	0.01143	0.00001	0.00000	0.00353	0.00082	0.00212	0.00010	0.00001	0.00000
28															
29	Non-Residential Customers		38,164	0	34,380	91	2,728	1	0	355	74	507	8	1	19
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.90085	0.00240	0.07148	0.00003	0.00000	0.00931	0.00193	0.01328	0.00021	0.00003	0.00050
31															
32	Customer Cost Allocation Factors														
33															
34	Distribution Plant Customer Costs		$ 1,572,088,582	$1,466,099,805	$ 88,124,439	$ 352,858	$ 8,037,523	$ 4,581	$ —	$ 1,583,972	$ 348,449	$ 1,655,640	$ 39,287	$ 4,915	$ 5,837,111
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.93258	0.05606	0.00022	0.00511	0.00000	0.00000	0.00101	0.00022	0.00105	0.00002	0.00000	0.00371
36															
37	Account 376-379 Customer Costs		$ 669,963,070	$ 629,845,609	$ 32,494,688	$ 86,433	$ 2,578,333	$ 945	$ —	$ 335,816	$ 69,706	$ 478,908	$ 7,561	$ 945	$ 4,064,125
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.94012	0.04850	0.00013	0.00385	0.00000	0.00000	0.00050	0.00010	0.00071	0.00001	0.00000	0.00607
39															
40	Total Revenue (inc. cost of gas)		$ 570,341,527	$ 418,199,958	$ 112,042,479	$ 4,185,762	$ 17,668,057	$ 4,533	$ —	$ 4,655,868	$ 4,778,368	$ 2,887,898	$ 658,287	$ 197,869	$ 5,062,449
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.73324	0.19645	0.00734	0.03098	0.00001	0.00000	0.00816	0.00838	0.00506	0.00115	0.00035	0.00888
42															
43	Mains - Allocated Customer Cost Factor		0.49397	0.46721	0.02410	0.00006	0.00191	0.00000	0.00000	0.00025	0.00005	0.00036	0.00001	0.00000	0.00001
44	Services - Allocated Customer Cost Factor		0.50603	0.47445	0.02823	0.00009	0.00225	0.00000	0.00000	0.00038	0.00008	0.00054	0.00001	0.00000	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.94166	0.05234	0.00016	0.00416	0.00000	0.00000	0.00063	0.00013	0.00090	0.00001	0.00000	0.00001
46															
47	Mains & Svcs. - Directly Assigned	MSCUS-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
48															
49	Total Plant Customer		$ 1,854,087,642	$1,731,078,328	$ 102,820,997	$ 401,683	$ 9,289,516	$ 5,175	$ —	$ 1,791,171	$ 393,073	$ 1,901,560	$ 44,250	$ 5,535	$ 6,356,354
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.93366	0.05546	0.00022	0.00501	0.00000	0.00000	0.00097	0.00021	0.00103	0.00002	0.00000	0.00343
51															
52	Non-Intangible Plant Customer														
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 1,854,087,642	$1,753,655,889	$ 90,473,762	$ 240,653	$ 7,178,756	$ 2,632	$ —	$ 935,000	$ 194,079	$ 1,333,407	$ 21,053	$ 2,632	$ 49,781
54		NONINCUS	1.00000	0.94583	0.04880	0.00013	0.00387	0.00000	0.00000	0.00050	0.00010	0.00072	0.00001	0.00000	0.00003
55															
56	Account 871-879 Customer Costs		$ 27,948,946	$ 25,659,877	$ 1,921,988	$ 12,560	$ 230,429	$ 211	$ —	$ 63,156	$ 14,415	$ 44,218	$ 1,715	$ 214	$ 162
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.91810	0.06877	0.00045	0.00824	0.00001	0.00000	0.00226	0.00052	0.00158	0.00006	0.00001	0.00001
58															
59	Account 887-893 Customer Costs		$ 9,244,138	$ 8,710,552	$ 478,773	$ 1,409	$ 38,177	$ 14	$ —	$ 5,696	$ 1,192	$ 8,036	$ 127	$ 16	$ 145
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.94228	0.05179	0.00015	0.00413	0.00000	0.00000	0.00062	0.00013	0.00087	0.00001	0.00000	0.00002
61															
62	Account 903 Customer		$ 11,808,882	$ 11,351,886	$ 432,914	$ 936	$ 17,647	$ 6	$ —	$ 1,985	$ 412	$ 2,939	$ 45	$ 6	$ 106
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.96130	0.03666	0.00008	0.00149	0.00000	0.00000	0.00017	0.00003	0.00025	0.00000	0.00000	0.00001

Allocation Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUB. AUTH TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
64															
65	Customer Cost Allocation Factors														
66															
67	Account 904 Customer		$ 3,374,231	$ 3,059,074	$ 306,239	$ 4,787	$ 1,752	$ —	$ —	$ 2,379	$ —	$ —	$ —	$ —	$ —
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.90660	0.09076	0.00142	0.00052	0.00000	0.00000	0.00071	0.00000	0.00000	0.00000	0.00000	0.00000
69															
70	Accounts 902-904 Customer		$ 16,606,818	$ 15,705,133	$ 847,293	$ 6,472	$ 32,691	$ 18	$ —	$ 8,099	$ 1,288	$ 5,379	$ 141	$ 18	$ 286
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.94570	0.05102	0.00039	0.00197	0.00000	0.00000	0.00049	0.00008	0.00032	0.00001	0.00000	0.00002
72															
73	Operating Expense Customer		$ 132,578,429	$ 123,463,171	$ 7,706,622	$ 39,290	$ 715,786	$ 494	$ —	$ 161,660	$ 35,598	$ 141,877	$ 4,112	$ 514	$ 309,306
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.93125	0.05813	0.00030	0.00540	0.00000	0.00000	0.00122	0.00027	0.00107	0.00003	0.00000	0.00233
75															
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 188,188,716	$ 175,501,204	$ 10,549,040	$ 42,239	$ 962,141	$ 548	$ —	$ 189,611	$ 41,712	$ 198,190	$ 4,703	$ 588	$ 698,738
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 219,962,293	$ 208,047,431	$ 10,733,482	$ 28,550	$ 851,662	$ 312	$ —	$ 110,925	$ 23,025	$ 158,191	$ 2,498	$ 312	$ 5,906
78	Total General Plant Customer Costs		$ 408,151,009	$ 383,548,635	$ 21,282,522	$ 70,790	$ 1,813,803	$ 861	$ —	$ 300,536	$ 64,736	$ 356,381	$ 7,201	$ 901	$ 704,644
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.93972	0.05214	0.00017	0.00444	0.00000	0.00000	0.00074	0.00016	0.00087	0.00002	0.00000	0.00173
80															
81	Customer Deposits		$ (16,329,640)	$ (7,757,745)	$ (8,199,802)	$ (103,027)	$ (84,295)	$ —	$ —	$ (145,892)	$ (38,879)	$ —	$ —	$ —	$ —
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.47507	0.50214	0.00631	0.00516	0.00000	0.00000	0.00893	0.00238	0.00000	0.00000	0.00000	0.00000
83															
84	Demand Cost Allocation Factors														
85															
86	System Demand														
87	**System Demand Factor (DEM)**	DEM	1.00000	0.66656	0.18511	0.00440	0.04798	0.00000	0.00000	0.03025	0.02413	0.02281	0.00331	0.00280	0.01265
88															
89	Non-Residential Demand														
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.55514	0.01321	0.14388	0.00000	0.00000	0.09073	0.07236	0.06842	0.00992	0.00838	0.03795
91															
92	Directly Assigned Demand														
93	**Dir. Assn. Demand Factor (DEM-DA)**	DEM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000
94															
95	Distribution Plant Demand		$ 497,032,940	$ 302,656,687	$ 105,632,702	$ 2,513,006	$ 27,378,625	$ —	$ —	$ 17,264,949	$ 13,768,756	$ 13,018,376	$ 1,888,438	$ 1,595,283	$ 11,316,116
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.60893	0.21253	0.00506	0.05508	0.00000	0.00000	0.03474	0.02770	0.02619	0.00380	0.00321	0.02277
97															
98	Demand Cost Allocation Factors														
99															
100	Non-Intangible Plant Demand		$ 692,494,004	$ 461,588,917	$ 128,184,387	$ 3,049,511	$ 33,223,729	$ —	$ —	$ 20,950,869	$ 16,708,268	$ 15,797,689	$ 2,291,604	$ 1,935,863	$ 8,763,167
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.66656	0.18511	0.00440	0.04798	0.00000	0.00000	0.03025	0.02413	0.02281	0.00331	0.00280	0.01265
102															
103	Total Plant Demand		$ 693,172,712	$ 430,164,848	$ 143,463,826	$ 3,413,009	$ 37,183,962	$ —	$ —	$ 23,448,190	$ 18,699,876	$ 17,680,756	$ 2,564,760	$ 2,166,616	$ 14,386,869
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.62057	0.20697	0.00492	0.05364	0.00000	0.00000	0.03383	0.02698	0.02551	0.00370	0.00313	0.02076
105															
106	Operating Expense Demand		$ 43,058,951	$ 26,587,611	$ 9,025,801	$ 214,724	$ 2,339,370	$ —	$ —	$ 1,475,206	$ 1,176,473	$ 1,112,357	$ 161,358	$ 136,309	$ 829,741
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.61747	0.20961	0.00499	0.05433	0.00000	0.00000	0.03426	0.02732	0.02583	0.00375	0.00317	0.01927
108															
109	Acct. 887-893 Demand		$ 7,462,026	$ 3,949,422	$ 1,949,983	$ 46,390	$ 505,410	$ —	$ —	$ 318,712	$ 254,172	$ 240,320	$ 34,861	$ 29,449	$ 133,308
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.52927	0.26132	0.00622	0.06773	0.00000	0.00000	0.04271	0.03406	0.03221	0.00467	0.00395	0.01786
111															
112	Rate Base Demand		$ 542,387,737	$ 337,400,422	$ 112,063,199	$ 2,665,987	$ 29,045,327	$ —	$ —	$ 18,315,970	$ 14,606,943	$ 13,810,883	$ 2,003,399	$ 1,692,398	$ 10,783,208
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.62206	0.20661	0.00492	0.05355	0.00000	0.00000	0.03377	0.02693	0.02546	0.00369	0.00312	0.01988
114															
115	Commodity Cost Allocation Factors														
116															
117	Annual Distribution Volumes (Ccf)		466,615,216	235,495,795	115,414,328	4,584,666	19,183,545	—	—	28,644,878	31,973,610	14,654,808	6,357,708	4,263,918	6,041,960
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.50469	0.24734	0.00983	0.04111	0.00000	0.00000	0.06139	0.06852	0.03141	0.01363	0.00914	0.01295
119															
120	Commodity - Direct Assignment		6,041,960	0	0	0	0	0	0	0	0	0	0	0	6,041,960
121	**Commodity - Direct Assignment - (COM-DA)**	COM-DA	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	1.00000

WKP Plant

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: PLANT WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Distribution Plant Reserve**					
2	374	Land & Land Rights - Allocated	$ (94,703)	DIS376-379-ALL	$ (56,360)	$ (38,343)	$ —
3	374	Land & Land Rights - Directly Assigned	$ (8,660)	DIS376-379-DA	$ (4,636)	$ (4,023)	$ —
4	375	Structures and Improvements	$ (335,608)	DIS376-379-ALL	$ (199,729)	$ (135,878)	$ —
5	376	Distribution Mains - Allocated	$ (172,170,008)	MAINS-ALLOC	$ (109,680,250)	$ (62,489,759)	$ —
6	376	Distribution Mains - Directly Assigned	$ (697,875)	MAINS-DA	$ (390,448)	$ (307,426)	$ —
7	377	Compressor Station Equipment	$ —	DEM	$ —	$ —	$ —
8	378	Meas. & Reg. Station Equip.- Gen. - Alloc.	$ (5,542,020)	DEM	$ —	$ (5,542,020)	$ —
9	378	Meas. & Reg. Station Equip.- Gen. - Dir. Assn.	$ (44,709)	DEM	$ —	$ (44,709)	$ —
10	378	Odorization	$ (186,592)	COM	$ —	$ —	$ (186,592)
11	379	Meas. & Reg. Station Equip.- City Gate	$ (2,085,232)	DEM	$ —	$ (2,085,232)	$ —
12	379	Odorization	$ (203,609)	COM	$ —	$ —	$ (203,609)
13	380	Services - Allocated	$ (112,646,444)	CUS	$ (112,646,444)	$ —	$ —
14	380	Services - Directly Assigned	$ (160,974)	CUS	$ (160,974)	$ —	$ —
15	381	Meters - Allocated	$ (47,294,132)	CUS	$ (47,294,132)	$ —	$ —
16	381	Meters - Directly Assigned	$ (39,495)	CUS	$ (39,495)	$ —	$ —
17	382	Meter Installations	$ (126,749)	CUS	$ (126,749)	$ —	$ —
18	383	House Regulators - Allocated	$ (11,583,951)	CUS	$ (11,583,951)	$ —	$ —
19	383	House Regulators - Directly Assigned	$ (15,367)	CUS	$ (15,367)	$ —	$ —
20	385	Meas. & Reg. Sta. Equip. -Ind. - Allocated	$ (7,758,786)	DEM	$ —	$ (7,758,786)	$ —
21	385	Meas. & Reg. Sta. Equip. -Ind. - Dir. Assn.	$ (39,779)	DEM	$ —	$ (39,779)	$ —
22	386	Other Property - Customer Premises	$ (1,137,465)	DIS376-379-ALL	$ (676,937)	$ (460,529)	$ —
23	387	Other Equipment	$ —	DIS376-379-ALL	$ —	$ —	$ —
24		Total Distribution Plant Reserve	$ (362,172,159)		$ (282,875,473)	$ (78,906,485)	$ (390,202)
25							
26		**General Plant - Service Area Direct**					
27	389	Land & Land Rights	$ 10,192,918	DISPLT	$ 7,734,577	$ 2,445,371	$ 12,969
28	390	Structures & Improvements	$ 48,657,313	DISPLT	$ 36,922,083	$ 11,673,319	$ 61,912
29	391	Office Furniture and Equip.	$ 7,520,528	DISPLT	$ 5,706,718	$ 1,804,241	$ 9,569
30	392	Transportation Equipment	$ 53,548,732	DISPLT	$ 40,633,783	$ 12,846,813	$ 68,135
31	393	Stores Equipment	$ 97,883	DISPLT	$ 74,276	$ 23,483	$ 125
32	394	Tools, Shop & Garage - Allocated	$ 33,122,980	DISPLT	$ 25,134,339	$ 7,946,495	$ 42,146
33	394	Tools, Shop & Garage - Directly Assigned	$ 11,690	DISPLT-DA	$ 6,857	$ 4,833	$ —
34	394	Odorization	$ 151,878	COM	$ —	$ —	$ 151,878
35	395	CNG Equipment	$ —	DISPLT	$ —	$ —	$ —
36	396	Major Work Equipment	$ 8,626,236	DISPLT	$ 6,545,750	$ 2,069,510	$ 10,976
37	397	Communication Equipment - Allocated	$ 70,682,576	DISPLT	$ 53,635,266	$ 16,957,374	$ 89,937
38	397	Communication Equipment - Dir. Assn.	$ 48,893	DISPLT-DA	$ 28,680	$ 20,212	$ —
39	398	Miscellaneous General Plant	$ 6,349	DISPLT	$ 4,818	$ 1,523	$ 8
40		**General Plant - Shared Svcs. & Distrigas**					
41	389	Land & Land Rights	$ 447,936	CUS	$ 447,936	$ —	$ —
42	390	Structures & Improvements	$ 8,596,335	CUS	$ 8,596,335	$ —	$ —
43	391	Office Furniture and Equipment	$ 93,229,996	CUS	$ 93,229,996	$ —	$ —
44	392	Transportation Equipment	$ 274,209	CUS	$ 274,209	$ —	$ —
45	393	Stores Equipment	$ —	CUS	$ —	$ —	$ —
46	394	Tools, Shop & Garage	$ 284,530	CUS	$ 284,530	$ —	$ —
47	395	CNG Equipment	$ —	CUS	$ —	$ —	$ —
48	396	Major Work Equipment	$ —	CUS	$ —	$ —	$ —
49	397	Communication Equipment	$ 923,511	CUS	$ 923,511	$ —	$ —
50	398	Miscellaneous General Plant	$ —	CUS	$ —	$ —	$ —
51		**Total General Plant**					
52	389	Land & Land Rights	$ 10,640,853	GENPLT	$ 8,182,513	$ 2,445,371	$ 12,969
53	390	Structures & Improvements	$ 57,253,648	GENPLT	$ 45,518,418	$ 11,673,319	$ 61,912
54	391	Office Furniture and Equip.	$ 100,750,525	GENPLT	$ 98,936,714	$ 1,804,241	$ 9,569
55	392	Transportation Equipment	$ 53,822,941	GENPLT	$ 40,907,992	$ 12,846,813	$ 68,135
56	393	Stores Equipment	$ 97,883	GENPLT	$ 74,276	$ 23,483	$ 125
57	394	Tools, Shop & Garage - Allocated	$ 33,407,511	GENPLT	$ 25,418,870	$ 7,946,495	$ 42,146
58	394	Tools, Shop & Garage - Dir. Assn.	$ 11,690	GENPLT	$ 6,857	$ 4,833	$ —
59	394	Odorization	$ 151,878	COM	$ —	$ —	$ 151,878
60	395	CNG Equipment	$ —	GENPLT	$ —	$ —	$ —
61	396	Major Work Equipment	$ 8,626,236	GENPLT	$ 6,545,750	$ 2,069,510	$ 10,976
62	397	Communication Equipment - Allocated	$ 71,606,087	GENPLT	$ 54,558,777	$ 16,957,374	$ 89,937
63	397	Communication Equipment - Dir. Assn.	$ 48,893	GENPLT	$ 28,680	$ 20,212	$ —

WKP Plant

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CLASS COST OF SERVICE STUDY: PLANT WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
64	398	Miscellaneous General Plant	$ 6,349	GENPLT	$ 4,818	$ 1,523	$ 8
65		Total General Plant	$ 336,424,493		$ 280,183,664	$ 55,793,175	$ 447,655

WKP Plant

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: PLANT WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
66		**General Plant Depreciation Expense**					
67	389	Land & Land Rights	$ —		$ —	$ —	$ —
68	390	Structures & Improvements	$ 1,707,444		$ 1,357,470	$ 348,127	$ 1,846
69	391	Office Furniture and Equip.	$ 8,833,349		$ 8,674,322	$ 158,188	$ 839
70	392	Transportation Equipment	$ 45,701		$ 34,735	$ 10,908	$ 58
71	393	Stores Equipment	$ 6,529		$ 4,954	$ 1,566	$ 8
72	394	Tools, Shop & Garage - Allocated	$ 2,229,831		$ 1,696,618	$ 530,400	$ 2,813
73	394	Tools, Shop & Garage - Dir. Assn.	$ (780)		$ (457)	$ (322)	$ —
74	394	Tools, Shop & Garage - Odorization	$ 10,130		$ —	$ —	$ 10,130
75	395	CNG Equipment	$ —		$ —	$ —	$ —
76	396	Major Work Equipment	$ —		$ —	$ —	$ —
77	397	Communication Equipment - Allocated	$ 4,775,578		$ 3,638,653	$ 1,130,927	$ 5,998
78	397	Communication Equipment - Dir. Assn.	$ 3,261		$ 1,913	$ 1,348	$ —
79	398	Miscellaneous General Plant	$ 423		$ 321	$ 102	$ 1
80		Total General Plant Depreciation Exp.	$ 17,611,467	GENDEP	$ 15,408,530	$ 2,181,244	$ 21,693
81		**General Plant**					
82		**Depreciation Reserve - Service Area Direct**					
83	389	Land & Land Rights	$ 4,733	DISPLT	$ 3,592	$ 1,136	$ 6
84	390	Structures & Improvements	$ (9,458,735)	DISPLT	$ (7,177,465)	$ (2,269,234)	$ (12,035)
85	391	Office Furniture and Equip.	$ (4,073,864)	DISPLT	$ (3,091,325)	$ (977,356)	$ (5,184)
86	392	Transportation Equipment	$ (14,492,058)	DISPLT	$ (10,996,846)	$ (3,476,773)	$ (18,440)
87	393	Stores Equipment	$ (20,882)	DISPLT	$ (15,845)	$ (5,010)	$ (27)
88	394	Tools, Shop & Garage - Allocated	$ (11,681,051)	DISPLT	$ (8,863,801)	$ (2,802,387)	$ (14,863)
89	394	Tools, Shop & Garage - Dir. Assn.	$ (3,498)	DISPLT-DA	$ (2,052)	$ (1,446)	$ —
90	394	Odorization	$ (28,806)	COM	$ —	$ —	$ (28,806)
91	395	CNG Equipment	$ 37,480	DISPLT	$ 28,440	$ 8,992	$ 48
92	396	Major Work Equipment	$ (2,344,303)	DISPLT	$ (1,778,901)	$ (562,419)	$ (2,983)
93	397	Communication Equipment - Allocated	$ (31,640,425)	DISPLT	$ (24,009,348)	$ (7,590,817)	$ (40,259)
94	397	Communication Equipment - Dir. Assn.	$ (28,294)	DISPLT-DA	$ (16,597)	$ (11,697)	$ —
95	398	Miscellaneous General Plant	$ (5,767)	DISPLT	$ (4,376)	$ (1,383)	$ (7)
96			$ (73,735,469)		$ (55,924,524)	$ (17,688,395)	$ (122,550)
97		**General Plant**					
98		**Depreciation Reserve - Shared Svcs. & Distrigas**					
99	389	Land & Land Rights	$ —	CUS	$ —	$ —	$ —
100	390	Structures & Improvements	$ (2,258,933)	CUS	$ (2,258,933)	$ —	$ —
101	391	Office Furniture and Equipment	$ (46,367,595)	CUS	$ (46,367,595)	$ —	$ —
102	392	Transportation Equipment	$ (31,096)	CUS	$ (31,096)	$ —	$ —
103	393	Stores Equipment	$ —	CUS	$ —	$ —	$ —
104	394	Tools, Shop & Garage	$ (47,320)	CUS	$ (47,320)	$ —	$ —
105	395	CNG Equipment	$ —	CUS	$ —	$ —	$ —
106	396	Major Work Equipment	$ —	CUS	$ —	$ —	$ —
107	397	Communication Equipment	$ (608,771)	CUS	$ (608,771)	$ —	$ —
108	398	Miscellaneous General Plant	$ —	CUS	$ —	$ —	$ —
109			$ (49,313,715)		$ (49,313,715)	$ —	$ —
110		**General Plant**					
111		**Total Depreciation Reserve**					
112	389	Land & Land Rights	$ 4,733		$ 3,592	$ 1,136	$ 6
113	390	Structures & Improvements	$ (11,717,667)		$ (9,436,398)	$ (2,269,234)	$ (12,035)
114	391	Office Furniture and Equip.	$ (50,441,459)		$ (49,458,920)	$ (977,356)	$ (5,184)
115	392	Transportation Equipment	$ (14,523,154)		$ (11,027,942)	$ (3,476,773)	$ (18,440)
116	393	Stores Equipment	$ (20,882)		$ (15,845)	$ (5,010)	$ (27)
117	394	Tools, Shop & Garage - Allocated	$ (11,728,371)		$ (8,911,121)	$ (2,802,387)	$ (14,863)
118	394	Tools, Shop & Garage - Dir. Assn.	$ (3,498)		$ (2,052)	$ (1,446)	$ —
119	394	Odorization	$ (28,806)		$ —	$ —	$ (28,806)
120	395	CNG Equipment	$ 37,480		$ 28,440	$ 8,992	$ 48
121	396	Major Work Equipment	$ (2,344,303)		$ (1,778,901)	$ (562,419)	$ (2,983)
122	397	Communication Equipment - Allocated	$ (32,249,195)		$ (24,618,119)	$ (7,590,817)	$ (40,259)
123	397	Communication Equipment - Dir. Assn.	$ (28,294)		$ (16,597)	$ (11,697)	$ —
124	398	Miscellaneous General Plant	$ (5,767)		$ (4,376)	$ (1,383)	$ (7)
125		Total General Plant Depr. Reserve	$ (123,049,183)	GENPLTRES	$ (105,238,239)	$ (17,688,395)	$ (122,550)

WKP Admin&Gen

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ADMINISTRATIVE AND GENERAL EXPENSE WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1	920	Salaries	$ 17,043,853	NONAGOPEXP	$ 12,306,623	$ 4,493,143	$ 244,087
2	921	Office Supplies & Expenses	$ 4,293,863	NONAGOPEXP	$ 3,100,411	$ 1,131,959	$ 61,493
3	922	Transferred Credit	$ (15,292,445)	NONAGOPEXP	$ (11,042,008)	$ (4,031,432)	$ (219,005)
4	923	Outside Services	$ 1,433,825	NONAGOPEXP	$ 1,035,302	$ 377,988	$ 20,534
5	924	Property Insurance	$ 831,344	NONAGOPEXP	$ 600,277	$ 219,161	$ 11,906
6	925	Injuries & Damages	$ 3,070,138	NONAGOPEXP	$ 2,216,813	$ 809,357	$ 43,968
7	926	Employee Pensions & Benefits	$ 13,083,657	NONAGOPEXP	$ 9,447,138	$ 3,449,146	$ 187,373
8	926	Distrigas	$ (11,907)	CUS	$ (11,907)	$ —	$ —
9	927	A&G Franchise Elections	$ —	NONAGOPEXP	$ —	$ —	$ —
10	928	Regulatory Commission Expenses	$ 681,119	NONAGOPEXP	$ 491,806	$ 179,558	$ 9,754
11	929	Duplicate Charges - Credit	$ —	NONAGOPEXP	$ —	$ —	$ —
12	930	Advertising	$ 57	NONAGOPEXP	$ 41	$ 15	$ 1
13	930	Other General	$ 4,402,415	NONAGOPEXP	$ 3,178,792	$ 1,160,576	$ 63,048
14	930	Distrigas	$ 42,743,447	CUS	$ 42,743,447	$ —	$ —
15	931	Rent	$ 1,648,068	NONAGOPEXP	$ 1,189,998	$ 434,468	$ 23,602
16	932	A&G Maintenance	$ 608,053	NONAGOPEXP	$ 439,049	$ 160,297	$ 8,708
17	940	Misc. General Expenses	$ —	NONAGOPEXP	$ —	$ —	$ —
18		Total Administrative & General Expense	$ 74,535,487	ADMINGEN	$ 65,695,784	$ 8,384,235	$ 455,468

WKP Selected Data

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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TWELVE MONTHS ENDED DECEMBER 31, 2024

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 Gas Sales Volumes	As Adjusted Gas Sales Volumes	Service Charges with Changes	Cost of Gas Revenue
Residential	7,996,677	235,495,795	$ 317,492,536	$ 100,707,422	$ 418,199,958	217,714,314	235,495,795	$ 4,552,248	
Commercial	412,561	115,414,328	$ 62,686,696	$ 49,355,783	$ 112,042,479	112,061,379	115,414,328	$ 213,363	
Industrial	1,097	4,584,666	$ 2,225,175	$ 1,960,587	$ 4,185,762	4,625,377	4,584,666	$ 411	
Public Authority	32,735	19,183,545	$ 9,464,406	$ 8,203,651	$ 17,668,057	18,171,587	19,183,545	$ 1,763	
Irrigation	1,650	4,555,267	$ 425,234	$ 1,948,014	$ 2,373,248	4,555,267	4,555,267	$ —	
CNG	12	0	$ 4,533	$ —	$ 4,533	0	0	$ —	
Electric Generation	0	0	$ —	$ —	$ —	0	0	$ —	
Commercial Transportation	4,264	28,644,878	$ 4,655,868	$ —	$ 4,655,868	0	0	$ 113	
Industrial Transportation	885	31,973,610	$ 4,778,368	$ —	$ 4,778,368	0	0	$ 113	
Public Authority Transportion	6,080	14,654,808	$ 2,887,898	$ —	$ 2,887,898	0	0	$ 73	
CNG Transportion	96	6,357,708	$ 658,287	$ —	$ 658,287	0	0	$ —	
Electric Generation Transportion	12	4,263,918	$ 197,869	$ —	$ 197,869	0	0	$ —	
Fort Bliss	227	6,041,960	$ 2,478,665	$ 2,583,784	$ 5,062,449	6,041,960	6,041,960	$ —	
Special Contract	255	102,203,694	$ 4,950,541	$ —	$ 4,950,541	0	0	$ —	
Irrigation Transportion	108	233,935	$ 83,246	$ —	$ 83,246	0	0	$ —	
Unmetered Gas Light	12	15,648	$ 1,980	$ —	$ 1,980	15,648	0	$ —	
Total	8,456,672	573,623,759	412,991,300	$ 164,759,241	$ 577,750,541	363,185,533	385,275,561	$ 4,768,085	$ 155,312,003
					$ 0.42764		365,619,594		
						at local pressure			
				COG Rate	$ 0.42764				
Customer Portion of Mains					$ 0.45063	at 14.65 psi			
TGS	63.70%								
Fort Bliss	55.95%								

Odorization Plant	Account	Original Cost	Reserve	Depr. Rate	Depr. Expense
	369	$ 707,150	$ (70,589)	3.47%	$ 24,538
	376	$ 144,153	$ (11,589)	2.47%	$ 3,561
	378	$ 1,103,014	$ (186,592)	2.59%	$ 28,568
	379	$ 1,337,096	$ (203,609)	2.18%	$ 29,149
	385	$ 51,841	$ (7,151)	2.38%	$ 1,234
	394	$ 151,878	$ (28,806)	6.67%	$ 10,130

Odorization Expense	Account	Total
	8650	$ 2,471
	8740	$ (45,825)
	8750	$ 273,994
	8780	$ 81
	8800	$ 1,505
	8890	$ 343,209
	8910	$ 100

WKP Selected Data

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER

Distrigas Accounts	Per Book Allocated to TGS	Net Adjustments (with O&M Factor Applied)	Adjusted Allocated to TGS	Adjusted Allocated to Direct
926	$ 193,920	$ (205,827)	$ (11,907)	$ (11,907)
930	$ 42,034,702	$ 708,745	$ 42,743,447	$ 42,743,447

100.00%

Factors	Residential	Commercial	Industrial	Public Authority	CNG	Electric Generation	Commercial Transport	Industrial Transport	Public Auth. Transport	CNG Transport	Electric Generation Transport	Fort Bliss
Meters	1.00000	1.61963	4.21548	2.50902	6.20576	0.00000	5.41191	6.11572	2.47933	6.21545	6.20576	4.89953
Regulators	1.00000	2.39959	11.54692	5.93139	21.82621	0.00000	16.09336	17.75033	5.83955	22.49194	21.82621	17.09007
Services	1.00000	1.15345	1.40333	1.15681	1.15677	0.00000	1.50534	1.52440	1.50337	1.46577	1.50398	0.00000
Meters & Regulators	1.00000	1.75759	5.49667	3.10384	9.08033	0.00000	7.36119	8.18848	3.09332	9.10767	9.08033	6.99447
PEAK DEMANDS:												
Total System	0.66656	0.18511	0.00440	0.04798	0.00000	0.00000	0.03025	0.02413	0.02281	0.00331	0.00280	0.01265
Account 385 Factor	0.00000	0.55514	0.01321	0.14388	0.00000	0.00000	0.09073	0.07236	0.06842	0.00992	0.00838	0.03795
OTHER ACCOUNTS:												
Account 903	0.96130	0.03666	0.00008	0.00149	0.00000	0.00000	0.00017	0.00003	0.00025	0.00000	0.00000	0.00001
Account 904	0.90660	0.09076	0.00142	0.00052	0.00000	0.00000	0.00071	0.00000	0.00000	0.00000	0.00000	0.00000
Customer Deposits	0.47507	0.50214	0.00631	0.00516	0.00000	0.00000	0.00893	0.00238	0.00000	0.00000	0.00000	0.00000

	Residential	Commercial	Industrial	Public Authority	CNG	Electric Generation	Commercial Transport	Industrial Transport	Public Auth. Transport	CNG Transport	Electric Generation Transport	Fort Bliss
Base Revenue	$ 317,492,536	$ 62,686,696	$ 2,225,175	$ 9,464,406	$ 4,533	$ —	$ 4,655,868	$ 4,778,368	$ 2,887,898	$ 658,287	$ 197,869	$ 2,478,665
COG Revenue	$ 100,707,422	$ 49,355,783	$ 4,185,762	$ 8,203,651	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 2,583,784

Fort Bliss Accounts	101	106	Total	Reserve	Net Plant	Depreciation Expense
301	$ —	$ —	$ —	$ —	$ —	$ —
302	$ —	$ —	$ —	$ —	$ —	$ —
374	$ 19,533	$ —	$ 19,533	$ (8,660)	$ 10,874	$ —
376	$ 6,542,576	$ 689,554	$ 7,232,130	$ (697,875)	$ 6,534,255	$ 184,979
378	$ 620,572	$ (295,036)	$ 325,537	$ (44,709)	$ 280,828	$ 8,789
379	$ —	$ —	$ —	$ —	$ —	$ —
380	$ 1,219,652	$ 305,303	$ 1,524,955	$ (160,974)	$ 1,363,980	$ 56,728
381	$ 108,468	$ 44,343	$ 152,811	$ (39,495)	$ 113,316	$ 7,213
383	$ 58,948	$ 16,622	$ 75,571	$ (15,367)	$ 60,204	$ 3,363
385	$ 306,223	$ 267,949	$ 574,172	$ (39,779)	$ 534,392	$ 13,034
391	$ —	$ —	$ —	$ 15,138	$ 15,138	$ —
390	$ —	$ —	$ —	$ —	$ —	$ —
394	$ 11,690	$ —	$ 11,690	$ (3,498)	$ 8,192	$ 780
397	$ 48,893	$ —	$ 48,893	$ (28,294)	$ 20,599	$ 3,261
	$ 8,936,556	$ 1,028,735	$ 9,965,290	$ (1,023,513)	$ 8,941,778	$ 278,147

903 Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: 903 FACTORS

	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	77,587	0.97961	138,949	0.95846	666,390	0.94583	0.96130
Commercial	1,599	0.02019	5,943	0.04099	34,380	0.04880	0.03666
Industrial	2	0.00003	12	0.00008	91	0.00013	0.00008
Public Authority	14	0.00018	63	0.00043	2,728	0.00387	0.00149
CNG	0	0.00000	0	0.00000	1	0.00000	0.00000
Commercial Transport	0	0.00000	0	0.00000	355	0.00050	0.00017
Industrial Transport	0	0.00000	0	0.00000	74	0.00010	0.00003
Public Authority Transport	0	0.00000	4	0.00003	507	0.00072	0.00025
CNG Transport	0	0.00000	0	0.00000	8	0.00001	0.00000
Electric Generation Transport	0	0.00000	0	0.00000	1	0.00000	0.00000
Fort Bliss	0	0.00000	0	0.00000	19	0.00003	0.00001

Source: Account 903.xlsx

904 Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: 904 FACTORS

	Total	Residential	Commercial	Industrial	Public Authority	CNG	Electric Generation	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Electric Generation Transport	Fort Bliss
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
3-yr. avg.	$ 2,457,760	$ 2,228,203	$ 223,062	$ 3,487	$ 1,276	$ —	$ —	$ 1,733	$ —	$ —	$ —	$ —	$ —
Factor	1.0000	0.90660	0.09076	0.00142	0.00052	0.00000	0.00000	0.00071	0.00000	0.00000	0.00000	0.00000	0.00000

Source: Account 904.xlsx

Billing Determinants Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

BILLING DETERMINANTS SUMMARY

Gas Sales	Test Year Bills	Test Year Volumes	As Adjusted Bills	As Adjusted Volumes	As Adjusted Volumes at Standard Pressure Base
Residential	3,507,070	83,581,960	0	0	0
Small Residential	2,666,997	55,259,738	5,218,692	108,043,015	102,550,422
Large Residential	1,785,628	78,872,617	2,777,985	127,452,779	120,032,299
Commercial	355,930	89,699,487	205,951	48,190,030	43,731,689
Small Commercial	39,539	4,458,333	151,908	15,930,643	15,973,978
Large Commercial	17,901	17,891,152	54,703	51,293,656	51,381,306
Church	189	12,408	0	0	0
Industrial	1,109	4,625,377	1,097	4,584,666	4,477,923
Public Authority	32,974	18,060,966	32,735	19,183,545	17,975,671
Public Schools Space Heat	77	110,621	0	0	0
Irrigation	1,650	4,555,267	1,650	4,555,267	4,098,251
CNG	12	0	12	0	0
Electric Generation	0	0	0	0	0
Unmetered Gas Light	12	15,648	12	15,648	15,968
Fort Bliss (City Gate Meters)	227	6,041,960	227	6,041,960	5,382,087
Gas Sales Total	8,409,315	363,185,533	8,444,972	385,291,209	365,619,594
Standard Transportation					
Commercial	4,264	28,644,878	4,264	28,644,878	27,961,376
Industrial	885	31,973,610	885	31,973,610	31,389,818
Public Authority	5,229	13,813,376	6,080	14,654,808	14,267,274
Public Schools Space Heat	851	841,431	0	0	0
CNG	96	6,357,708	96	6,357,708	5,773,325
Electric Generation	12	4,263,918	12	4,263,918	4,263,918
Irrigation	108	233,935	108	233,935	233,935
Standard Transportation Total	11,445	86,128,857	11,445	86,128,857	83,889,647
Transport - Special Contract	255	102,203,694	255	102,203,694	
Total	8,421,015	551,518,084	8,456,672	573,623,759	

Source: SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx, SCH G-2 and SCH G-3 Standard Pressure Base Adjustment.xlsx

Deposit Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: CUSTOMER DEPOSIT FACTORS

Total	Residential	Commercial	Industrial	Public Authority	CNG	Electric Generation	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Electric Generation Transport	Fort Bliss
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
$ 16,126,455	$ 7,661,218	$ 8,097,774	$ 101,745	$ 83,246	$ —	$ —	$ 144,077	$ 38,395	$ —	$ —	$ —	$ —
Factors	0.47507	0.50214	0.00631	0.00516	0.00000	0.00000	0.00893	0.00238	0.00000	0.00000	0.00000	0.00000

Source: Customer Deposits.xlsx

Mains Study Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

WNSA

Size	Footage	Composition	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	210,883	S	1	0	41.41	3.7235	9,239,781
2	6,424,630	S	2	0	43.37	3.7698	319,213,535
3	224,822	S	3	0	64.46	4.1661	12,667,364
4	2,474,076	S	4	0	58.93	4.0763	158,078,639
6	841,859	S	6	0	85.89	4.4530	69,171,392
8	97,273	S	8	0	121.75	4.8019	10,277,995
10	14,657	S	10	0	142.10	4.9565	1,991,565
12	9,921	S	12	0	210.66	5.3503	1,733,520
16	122,295	S	16	0	218.58	5.3872	35,337,191
1	98,572	P	1	1	27.85	3.3270	2,583,822
2	9,237,703	P	2	1	24.88	3.2141	274,590,237
3	174,140	P	3	1	36.92	3.6088	5,869,922
4	2,371,084	P	4	1	35.49	3.5693	90,634,818
6	876,079	P	6	1	48.84	3.8885	43,064,378
8	55,973	P	8	1	66.02	4.1900	3,538,203
10	6,695	P	10	1	86.59	4.4612	544,230
Total	23,240,664						1,038,536,592

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.982328961
R Square	0.964970187
Adjusted R Square	0.959580985
Standard Error	0.135385402
Observations	16

ANOVA

	df	SS	MS	F	Significance F
Regression	2	6.56391737	3.28195868	179.05622840	0.00000000
Residual	13	0.23827969	0.01832921		
Total	15	6.80219706			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.65422	0.07270	50.26405	0.00000	3.49716	3.81128
Size	0.12575	0.00827	15.19866	0.00000	0.10788	0.14363
Plastic	-0.51373	0.07027	-7.31105	0.00001	-0.66554	-0.36193

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Total Cost	Configured Cost	Customer Portion
Plastic	23.12	12,820,247	296,340,140		
Steel	38.64	10,420,418	402,616,273		
			698,956,413	1,038,536,592	67.30%

Minimum System Study:

	Two-Inch Cost/Ft	Two-Inch Total Cost	Configured Cost	Customer Portion
Plastic	24.88	318,989,556		
Steel	43.37	451,953,374		
		770,942,930	1,038,536,592	74.23 %
			w/Actual Cost	82.63 %

Mains Study
Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

FORT BLISS

Size	Footage	Composition	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	8,606	S	1	0	35.09	3.5580	324,468
2	86,222	S	2	0	40.87	3.7103	3,676,621
3	14,626	S	3	0	53.64	3.9822	705,377
4	73,181	S	4	0	53.08	3.9719	3,991,933
6	24,922	S	6	0	77.65	4.3523	1,739,079
8	26,453	S	8	0	102.14	4.6264	2,361,415
12	12,091	S	12	0	210.66	5.3503	1,766,383
16	10,866	S	16	0	218.58	5.3872	2,597,822
1	6,072	P	1	1	23.25	3.1464	142,883
2	143,458	P	2	1	23.85	3.1720	3,818,120
3	14,304	P	3	1	28.55	3.3517	430,574
4	227,784	P	4	1	32.45	3.4798	7,755,459
6	84,343	P	6	1	46.55	3.8405	3,673,570
8	1,352	P	8	1	65.11	4.1761	75,313
Total	734,279						33,059,017

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.989621460
R Square	0.979350635
Adjusted R Square	0.975596205
Standard Error	0.102755629
Observations	14

ANOVA

	df	SS	MS	F	Significance F
Regression	2	5.50852636	2.75426318	260.85201090	0.00000000
Residual	11	0.11614591	0.01055872		
Total	13	5.62467228			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.50654	0.05739	61.09884	0.00000	3.38022	3.63286
Size	0.12314	0.00684	18.01544	0.00000	0.10809	0.13818
Plastic	-0.47135	0.05807	-8.11745	0.00001	-0.59915	-0.34354

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Total Cost	Configured Cost	Customer Portion
Plastic	20.81	477,312	9,930,499		
Steel	33.33	256,967	8,565,424		
			18,495,923	33,059,017	55.95%

Minimum System Study:

	Two-Inch Cost/Ft	Two-Inch Total Cost	Configured Cost	Customer Portion
Plastic	23.85	11,385,910		
Steel	40.87	10,501,161		
		21,887,071	33,059,017	66.21 %
			w/Actual Cost	65.47 %

Mains Study
Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

CGSA

Size	Footage	Composition	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	259,195	S	1	0	37.70	3.6297	10,080,383
2	6,482,573	S	2	0	45.26	3.8123	282,916,654
3	129,144	S	3	0	51.36	3.9388	6,324,770
4	2,485,824	S	4	0	50.70	3.9260	136,616,618
6	1,955,765	S	6	0	63.58	4.1523	135,354,226
8	388,656	S	8	0	84.11	4.4321	33,872,096
10	149,989	S	10	0	125.81	4.8348	16,461,089
12	292,897	S	12	0	129.68	4.8650	40,479,663
14	21,637	S	14	0	207.74	5.3363	3,765,730
16	47,024	S	16	0	191.07	5.2527	10,305,807
20	21,426	S	20	0	300.86	5.7066	7,446,556
1	58	W	1	0	41.88	3.7347	2,259
2	3,448	W	2	0	49.68	3.9056	150,473
3	2,402	W	3	0	55.56	4.0174	117,657
4	88,202	W	4	0	51.56	3.9427	4,847,452
6	2,482	W	6	0	63.49	4.1509	171,746
1	204,341	P	1	1	22.48	3.1127	4,998,015
2	6,163,772	P	2	1	24.02	3.1789	169,179,979
3	191,310	P	3	1	30.14	3.4058	5,892,528
4	2,084,322	P	4	1	31.91	3.4631	72,042,592
6	1,266,107	P	6	1	43.46	3.7718	55,108,289
8	80,816	P	8	1	56.36	4.0318	4,429,597
12	2,138	P	12	1	116.49	4.7578	185,867
Total	22,323,528						1,000,750,046

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.986460035
R Square	0.973103401
Adjusted R Square	0.970413741
Standard Error	0.118541163
Observations	23

ANOVA

	df	SS	MS	F	Significance F
Regression	2.00000	10.16787	5.08393	361.79421	0.00000
Residual	20.00000	0.28104	0.01405		
Total	22.00000	10.448910080			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.54550	0.04508	78.65540	0.00000	3.45147	3.63952
Size	0.11527	0.00485	23.75644	0.00000	0.10515	0.12539
Plastic	-0.46376	0.05447	-8.51420	0.00000	-0.57738	-0.35014

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Total Cost	Configured Cost	Customer Portion
Plastic	21.80	9,992,807	217,805,009		
Steel/Wrought Iron	34.66	12,330,722	427,343,964		
			645,148,972	1,000,750,046	64.47%

Minimum System Study:

	Two-Inch Cost/Ft	Two-Inch Total Cost	Configured Cost	Customer Portion
Plastic	24.02	240,039,305		
Steel/Wrought Iron	45.26	558,057,655		
		798,096,960	1,000,750,046	79.75 %
			w/Actual Cost	83.19 %

Mains Study
Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

RGVSA

Size	Footage	Composition	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	137,037	P	1	1	15.48	2.7393	2,018,043
2	3,900,896	P	2	1	15.65	2.7506	67,441,301
3	280	P	3	1	21.24	3.0557	5,680
4	432,326	P	4	1	23.56	3.1596	10,301,777
6	83,794	P	6	1	33.37	3.5076	2,752,010
1	108,705	S	1	0	30.16	3.4064	3,406,232
2	4,532,241	S	2	0	38.33	3.6461	166,727,987
3	305,812	S	3	0	47.35	3.8576	13,207,477
4	1,929,476	S	4	0	48.47	3.8809	97,830,344
6	413,683	S	6	0	68.76	4.2306	28,909,489
8	197,229	S	8	0	94.83	4.5521	18,996,905
10	94,063	S	10	0	116.61	4.7588	12,487,351
12	286,187	S	12	0	204.63	5.3212	52,364,695
Total	12,421,728						476,449,291

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.996069842
R Square	0.992155129
Adjusted R Square	0.990586155
Standard Error	0.076331585
Observations	13

ANOVA

	df	SS	MS	F	Significance F
Regression	2.00000	7.36889	3.68445	632.35913	0.00000
Residual	10.00000	0.05827	0.00583		
Total	12.00000	7.427159674			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.28431	0.04773	68.81086	0.00000	3.17796	3.39066
Size	0.16042	0.00685	23.43090	0.00000	0.14516	0.17567
Plastic	-0.75510	0.04689	-16.10449	0.00000	-0.85957	-0.65062

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Total Cost	Configured Cost	Customer Portion
Plastic	12.54	4,554,333	57,127,811		
Steel	26.69	7,867,395	209,984,726		
			267,112,537	476,449,291	56.06%

Minimum System Study:

	Two-Inch Cost/Ft	Two-Inch Total Cost	Configured Cost	Customer Portion
Plastic	15.65	71,281,178		
Steel	38.33	301,521,405		
		372,802,583	476,449,291	78.25 %
			w/Actual Cost	78.02 %

	Zero-Inch Study Customer Portion	Footage
WNSA	67.30 %	23,240,664
Fort Bliss	55.95 %	734,279
CGSA	64.47 %	22,323,528
RGVSA	56.06 %	12,421,728
TGS (Weighted Average)	63.70 %	58,720,200

Source: Mains Study.xlsx

Meters & Regulator Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS COST OF SERVICE STUDY: METER AND REGULATOR FACTORS

	Residential	Commercial	Industrial	Public Authority	CNG	Electric Generation	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Electric Generation Transport	Fort Bliss
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Meters	1.0000	1.6196	4.2155	2.5090	6.2058	0.0000	5.4119	6.1157	2.4793	6.2155	6.2058	4.8995
Regulators	1.0000	2.3996	11.5469	5.9314	21.8262	0.0000	16.0934	17.7503	5.8395	22.4919	21.8262	17.0901
Meters & Regulators	1.0000	1.7576	5.4967	3.1038	9.0803	0.0000	7.3612	8.1885	3.0933	9.1077	9.0803	6.9945

Source: Meters and Regulators.xlsx

Odorization Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: ODORIZATION PLANT AND EXPENSE SUMMARY

Odorization Equipment (Plant in Service and CCNC)

Account	Book Cost	Allocated Reserve	Net Value
369	$ 707,150	$ 70,589	$ 636,560
376	$ 144,153	$ 11,589	$ 132,565
378	$ 1,103,014	$ 186,592	$ 916,422
379	$ 1,337,096	$ 203,609	$ 1,133,487
385	$ 51,841	$ 7,151	$ 44,690
394	$ 151,878	$ 28,806	$ 123,072
Total	$ 3,495,133	$ 508,336	$ 2,986,797

Source: Odorization Plant.xlsx

Odorization Expense

Account	Net Activity
8650	$ 2,471
8740	$ (45,825)
8750	$ 273,994
8780	$ 81
8800	$ 1,505
8890	$ 343,209
8910	$ 100
Total	$ 575,535

Source: Odorization Expense.xlsx

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: PEAK DEMAND SUMMARY

	Total	Residential	Commerical	Industrial	Public Authority	CNG	Electric Generation	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Electric Generation Transport	Fort Bliss
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Total Est. Peak Usage	5,435,641	3,623,182	1,006,167	23,937	260,785	0	0	164,451	131,149	124,002	17,988	15,195	68,785
Peak Usage	1.00000	0.66656	0.18511	0.00440	0.04798	0.00000	0.00000	0.03025	0.02413	0.02281	0.00331	0.00280	0.01265
Non-Residential Demand	1.00000	0.00000	0.55514	0.01321	0.14388	0.00000	0.00000	0.09073	0.07236	0.06842	0.00992	0.00838	0.03795

Source: Peak Demand.xlsx

Service Charges
Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: SERVICE CHARGES SUMMARY

	Service Charge Revenue	%	As Adj. Test Year
Residential	$ 4,030,187	95.47%	$ 4,552,248
Commercial	$ 188,894	4.47%	$ 213,363
Industrial	$ 364	0.01%	$ 411
Public Authority	$ 1,561	0.04%	$ 1,763
CNG	$ —	0.00%	$ —
Electric Generation	$ —	0.00%	$ —
Commercial Transport	$ 100	0.00%	$ 113
Industrial Transport	$ 100	0.00%	$ 113
Public Authority Transport	$ 65	0.00%	$ 73
CNG Transport	$ —	0.00%	$ —
Electric Generation Transport	$ —	0.00%	$ —
Fort Bliss	$ —	0.00%	$ —
	$ 4,221,271		$ 4,768,085

Source: Service Charges.xlsx

Service Line Factors

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CLASS COST OF SERVICE STUDY: SERVICE LINE FACTOR SUMMARY

	Factor
Residential	1.00000
Commercial	1.15345
Industrial	1.40333
Public Authority	1.15681
CNG	1.15677
Commercial Transport	1.50534
Industrial Transport	1.52440
Public Authority Transport	1.50337
CNG Transport	1.46577
Electric Generation Transport	1.50398

Source: Service Lines.xlsx

As Adj. Revenues
Summary

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

SUMMARY AS ADJUSTED REVENUES

Line No.	Revenue Class	Cost of Service	Remove the Cost of Gas	Reclass Annualization Adjustment	Remove Test Year Weather Normalization	Weather Normalization Adjustment	Customer Growth Annualization	Remove Test Year GRIP	2025 GRIP Annualization	Fort Bliss CRC Annualization	East Bliss Maintenance Agreement Annualization	Service Fee Annualization	Remove Interest on Storage	Remove Estimated Revenue	As Adjusted Test Year Revenues
	Gas Sales														
1	Residential	$ 83,966,476	$ 0	$ (83,966,476)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2	Small Residential	151,556,341	(41,799,471)	81,882,630	(7,643,318)	7,494,982	1,228,601	(26,272,416)	22,482,840	0	0	0	0	0	188,930,190
3	Large Residential	132,334,039	(54,529,305)	49,564,991	(965,661)	1,002,095	362,224	(12,029,397)	12,823,360	0	0	0	0	0	128,562,347
4	Commercial	54,546,119	(18,572,404)	(14,128,735)	(191,933)	182,114	(139,828)	(1,730,119)	3,672,388	0	0	0	0	0	23,637,602
5	Small Commercial	14,907,331	(4,741,152)	9,872,857	(353,210)	474,910	30,971	(4,353,865)	3,005,241	0	0	0	0	0	18,843,083
6	Large Commercial	32,198,779	(22,385,155)	10,523,240	(105,862)	119,087	88,307	(1,452,508)	1,220,122	0	0	0	0	0	20,206,011
7	Church	26,873	0	(26,873)	0	0	0	0	0	0	0	0	0	0	0
8	Industrial	3,610,089	(1,580,608)	0	0	0	(20,230)	(255,664)	471,588	0	0	0	0	0	2,225,175
9	Public Authority	16,920,462	(7,640,315)	27,240	(234,856)	172,076	(100,679)	(1,111,023)	1,431,501	0	0	0	0	0	9,464,406
10	Public Schools Space Heat	21,447	0	(21,447)	0	0	0	0	0	0	0	0	0	0	0
11	Irrigation	1,857,744	(1,432,510)	0	0	0	0	0	0	0	0	0	0	0	425,234
12	CNG	2,713	0	0	0	0	0	0	1,819	0	0	0	0	0	4,533
13	Electric Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Unmetered Gas Light	1,980	0	0	0	0	0	0	0	0	0	0	0	0	1,980
15	Fort Bliss (City Gate)	3,082,780	(2,631,083)	0	0	0	0	0	0	0	0	0	0	0	451,697
16	Total Gas Sales Revenue	$ 495,033,174	$ (155,312,003)	$ 53,727,427	$ (9,494,840)	$ 9,445,264	$ 1,449,367	$ (47,204,992)	$ 45,108,859	$ 0	$ 0	$ 0	$ 0	$ 0	$ 392,752,255
	Tranportation Revenue														
17	Commercial	$ 4,728,436	$ 0	$ 0	$ 0	$ 0	$ 0	$ (139,266)	$ 66,698	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,655,868
18	Industrial	4,670,475	0	0	0	0	0	(267,888)	375,782	0	0	0	0	0	4,778,368
19	Public Authority	2,870,582	0	268,152	0	0	0	(413,225)	162,389	0	0	0	0	0	2,887,898
20	Public Schools Space Heat	283,974	0	(283,974)	0	0	0	0	0	0	0	0	0	0	0
21	CNG	627,503	0	0	0	0	0	(63,165)	93,949	0	0	0	0	0	658,287
22	Electric Generation	198,316	0	0	0	0	0	(758)	312	0	0	0	0	0	197,869
23	Irrigation	83,246	0	0	0	0	0	0	0	0	0	0	0	0	83,246
24	Fort Bliss (Distribution System on Base)	1,655,235	0	0	0	0	0	0	0	71,733	300,000	0	0	0	2,026,968
25	Special Contract	4,950,541	0	0	0	0	0	0	0	0	0	0	0	0	4,950,541
26	Estimated Revenue	69,569	0	0	0	0	0	0	0	0	0	0	0	(69,569)	0
27	Total Tranportation Revenue	$ 20,137,876	$ 0	$ (15,822)	$ 0	$ 0	$ 0	$ (884,303)	$ 699,129		$	$ 0	$ 0	$ (69,569)	$ 20,239,045
28	Service Fee's (Acct 4880)	$ 4,221,356	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 546,729	$ 0	$ 0	$ 4,768,085
29	Other Revenue (Acct 4950300)	1,096,091	—	—	—	—	—	—	—	—	—	—	(1,096,091)	—	0.00
30	Total Revenue	$ 520,488,496	$ (155,312,003)	$ 53,711,605	$ (9,494,840)	$ 9,445,264	$ 1,449,367	$ (48,089,295)	$ 45,807,988	$ 0	$ 0	$ 546,729	$ (1,096,091)	$ (69,569)	$ 417,759,385

Source: SCH G-2 and G-3 Proof of Revenue.xlsx

Class Revenue Allocation

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	ELECTRIC GENERATION	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	ELECTRIC GENERATION TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Current Revenue-to-Cost Ratio (1)	0.9105	0.8257	1.5365	3.6100	1.3051	4.7222	0.0000	1.1838	1.5934	0.9629	1.5734	0.5852	0.8112
2														
3	Revenue Allocation One - Cost of Service Study Required Revenue Changes													
4	Revenue-to-Cost Ratio	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
5	Rate Design Revenue Increase	$ 41,069,909	$ 68,979,937	$ (22,135,415)	$ (1,614,410)	$ (2,233,085)	$ (3,582)	$ —	$ (730,324)	$ (1,792,984)	$ 112,741	$ (241,743)	$ 143,164	$ 585,611
6	% Increase - Non-Gas Revenue (2)	9.83%	21.11%	-34.92%	-72.30%	-23.38%	-78.82%	— %	-15.53%	-37.24%	3.86%	-36.45%	70.88%	23.28%
7	% Increase - Total Revenue (3)	7.07%	16.14%	-19.63%	-38.50%	-12.58%	-78.82%	— %	-15.53%	-37.24%	3.86%	-36.45%	70.88%	11.48%
8	% Total Revenue (for GRIP)	100.00 %	86.15 %	9.04 %	0.14 %	1.61 %	0.00 %	— %	0.88 %	0.67 %	0.67 %	0.09 %	0.08 %	0.68 %
9	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)													
10	Revenue-to-Cost Ratio	1.0000	0.9419	1.4292	3.0880	1.2440	3.9777	0.0000	1.1471	1.4747	1.0000	1.4588	1.0000	1.0000
11	Rate Design Revenue Increase	$ 41,069,909	$ 45,978,702	$ (4,427,083)	$ (322,882)	$ (446,617)	$ (716)	$ —	$ (146,065)	$ (358,597)	$ 112,741	$ (48,349)	$ 143,164	$ 585,611
12	% Increase - Non-Gas Revenue (2)	9.83%	14.07%	-6.98%	-14.46%	-4.68%	-15.76%	— %	-3.11%	-7.45%	3.86%	-7.29%	70.88%	23.28%
13	% Increase - Total Revenue (3)	7.07%	10.76%	-3.93%	-7.70%	-2.52%	-15.76%	— %	-3.11%	-7.45%	3.86%	-7.29%	70.88%	11.48%
14	% Total Revenue (for GRIP)	100.00 %	81.02 %	12.99 %	0.42 %	2.01 %	0.00 %	— %	1.01 %	0.99 %	0.67 %	0.14 %	0.08 %	0.68 %
15	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)													
16	Revenue-to-Cost Ratio	1.0000	0.9273	1.5365	3.6100	1.3051	4.7222	0.0000	1.1838	1.5934	1.0000	1.5734	1.0000	1.0000
17	Rate Design Revenue Increase	$ 41,069,909	$ 40,228,393	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ 112,741	$ —	$ 143,164	$ 585,611
18	% Increase - Non-Gas Revenue (2)	9.83%	12.31%	0.00%	0.00%	0.00%	0.00%	— %	— %	— %	3.86 %	— %	70.88 %	23.28%
19	% Increase - Total Revenue (3)	7.07%	9.41%	0.00%	0.00%	0.00%	0.00%	— %	— %	— %	3.86 %	— %	70.88 %	11.48%
20	% Total Revenue (for GRIP)	100.00 %	79.74 %	13.97 %	0.50 %	2.11 %	0.00 %	— %	1.04 %	1.07 %	0.67 %	0.15 %	0.08 %	0.68 %

(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 decreases 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 deceases is assigned to the residential class.

Proof of Revenue

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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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	4,773,445			$ 29.50		$ 140,816,628				
2			All Ccf	81,903,217		0.67553	$ 55,328,080				
3	Residential - Large	2,863,233			$ 39.50		$ 113,097,704				
4			All Ccf	130,659,132		0.31189	$ 40,751,277				
5	Residential Total							$ 349,993,688	$ 349,993,234	$ 454	78.56 %
6											
7	Customer Assistance Program	360,000			$ 22.13		$ 7,966,800				
8			All Ccf	10,020,372		0.55000	$ 5,511,204	$ 13,478,004	13,478,004	$ —	3.03 %
9											
10	Commercial - Small	304,010			$ 75.00		$ 22,800,750				
11			All Ccf	13,603,609		0.43589	$ 5,929,677				
12	Commercial - Large	108,551			$ 150.00		$ 16,282,650				
13			All Ccf	97,483,364		0.13589	$ 13,247,014				
14	Commercial Total							$ 58,260,091	$ 58,259,612	$ 479	13.08 %
15											
16	Electric Generation (Gas Sales)	0			$ —		$ —				
17			Oct.-Apr								
18			First 5000	0		—	$ —				
19			Next 95000	0		—	$ —				
20			Next 300000	0		—	$ —				
21			Over 400000	0		—	$ —				
22			May-Sep								
23			First 5000	0		—	$ —				
24			Next 95000	0		—	$ —				
25			Next 300000	0		—	$ —				
26			Over 400000	0		—	$ —	$ —			
27	Electric Generation (Gas Sales)								$ —	$ —	— %
28											
29	Industrial	1,097			$ 1,250.00		$ 1,371,725				
30			All Ccf	4,477,923		0.11849	$ 530,589	$ 1,902,314	$ 1,902,293	$ 22	0.43 %
31											
32	Public Authority	32,735			$ 200.00		$ 6,547,031				
33			All Ccf	17,975,671	$	0.13745	$ 2,470,756	$ 9,017,787	$ 9,017,789	$ (2)	2.02 %
34											
35	CNG (Compressed Natural Gas)	12			$ 320.00		$ 3,840				
36			All Ccf	0	$	—	$ —	$ 3,840	$ 3,816	$ 24	0.00 %
37											
38	General Transportation	11,325			$ 500.00		$ 5,662,471				
39			All Ccf	79,391,794	$	0.08831	$ 7,011,089	$ 12,673,560	$ 12,673,274	$ 286	2.84 %
40											
41	Electric Generation Transportation	12			$ 1,000.00		$ 12,000				
42			MDQ	12,709		0.72542	$ 110,632				
43			All Ccf	4,263,918		0.02000	$ 85,278				
44	Electric GenerationTransportation							$ 207,911	$ 207,911	$ —	0.05 %
45											
46	Total Revenue - All Classes										
47											
48	Recommended Rate Revenue							$ 445,537,196	$ 445,535,933		
49	Current Rate Revenue							$ 405,051,635	$ 405,051,635		
50	Revenue Change							$ 40,485,561	$ 40,484,298		
51											
52	Fort Bliss Assigned Rev. Change. (1)								$ 585,611		
53	Total Change - All Classes								$ 41,069,909		
54											
55	Schedule A - Revenue Deficiency								$ 41,069,909		

(1) The amount reflects the revenue change assigned to Fort Bliss shown on the Class Revenue Allocation tab within the model.

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

CURRENT AND RECOMMENDED RATES

Description		CGSA Incorporated and Environs Rates		WNSA Incorporated and Environs Rates		RGVSA Incorporated and Environs Rates		All TGS Customers Incorporated and Environs Rates	
		Current		Current		Current		Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Residential		Small	Large	Small	Large	Small	Large	Small	Large
Customer Charge		$21.36	$33.36	$21.85	$38.35	$23.64	$38.64	$29.50	$39.50
Usage Rates	All Ccf	$0.87646	$0.46737	$0.46668	$0.01668	$2.02007	$0.63545	$0.67553	$0.31189
Customer Assistance Program									
Customer Charge		N/A	N/A	N/A	N/A	N/A	N/A	$22.13	$22.13
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	N/A	N/A	$0.55000	$0.55000
Commercial									
Customer Charge - Sales		$72.88	$87.88	$92.73	$92.73	$120.32	$275.32	$75.00	$150.00
Usage Rates	All Ccf	$0.27930	$0.22985	$0.09394	$0.09394	$0.63855	$0.26655	$0.43589	$0.13589
Industrial									
Customer Charge - Sales		$1,033.21		$1,295.93		$1,234.53		$1,250.00	
Usage Rates	All Ccf	$0.14569		$0.11486		$0.28220		$0.11849	
Public Authority									
Customer Charge - Sales		$181.93		$253.05		$243.91		$200.00	
Usage Rates	All Ccf	$0.13768		$0.13511		$0.16208		$0.13745	
CNG									
Customer Charge - Sales		$746.15		$1,955.67		N/A		$320.00	
Usage Rates	All Ccf	$0.07817		$0.08643		N/A		$0.08831	
Transportation									
Customer Charge		N/A	N/A	N/A	N/A	N/A	N/A	$500.00	
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	N/A	N/A	$0.08831	
Commercial Customer Charge		$320.96		$517.73		$545.32		N/A	
Usage Rates	All Ccf	$0.12679		$0.09394		$0.10770		N/A	
Industrial Customer Charge		$1,233.21		$1,495.93		$1,384.53		N/A	
Usage Rates	All Ccf	$0.14569		$0.11486		$0.08722		N/A	
Public Authority Customer Charge		$204.93		$553.05		$2,543.91		N/A	
Usage Rates	All Ccf	$0.13768		$0.13511		$0.00840		N/A	
Compressed Natural Gas Customer Charge		$771.15		$2,255.67		N/A		N/A	
Usage Rates	All Ccf	$0.07817		$0.08643		N/A		N/A	
Electric Generation Transportation									
Customer Charge		$201.64		$717.73		$545.32		$1,000.00	
Demand Charges	MDQ/month	N/A		N/A		N/A		$0.72542	
Usage Rates	All Ccf	N/A		N/A		N/A		$0.02000	
Usage Rates (Year-Round)	All Ccf					$0.10770			
	First 5,000	$0.07724		N/A		N/A			
	Next 35,000	$0.06853		N/A		N/A			
	Next 60,000	$0.05527		N/A		N/A			
	100,000	$0.04018		N/A		N/A			
Usage Rates - (October - April)	All Ccf								
	First 5,000	N/A		$0.05260		N/A			
	Next 95,000	N/A		$0.04260		N/A			
	Next 300,000	N/A		$0.03260		N/A			
	400,000	N/A		$0.02260		N/A			
Usage Rates - (May - September)	All Ccf								
	First 5,000	N/A		$0.04259		N/A			
	Next 95,000	N/A		$0.03258		N/A			
	Next 300,000	N/A		$0.02259		N/A			

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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CURRENT AND RECOMMENDED RATES

Description		CGSA Incorporated and Environs Rates		WNSA Incorporated and Environs Rates		RGVSA Incorporated and Environs Rates		All TGS Customers Incorporated and Environs Rates	
		Current		Current		Current		Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	400,000	N/A		$0.01258		N/A			
Unmetered Gas Light									
	Residential All	$0.87646		$0.46668		$2.02007		$0.67553	
	Commercial All	$0.27930		$0.09394		$0.63855		$0.43589	
	Industrial All	$0.14569		$0.11486		$0.28220		$0.11849	
	Public	$0.13768		$0.13511		$0.16208		$0.13745	

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	0.94898	1.00262	0.90021	1.00000	to convert from local pressure to 14.65 psi
	1.05376	0.99739	1.11085	1.00000	to convert from 14.65 psi to local pressure

	TGS	CGSA	WNSA	RGVSA
Gas Costs at local pressure	$0.42764	$0.49791	$0.40379	$0.24658
Gas Costs at 14.65 psi	$0.45063	$0.49661	$0.44855	$0.24658
Transportation Gas Cost Savings Assumed	5 %			

Description		Current CGSA Incorporated and Envrions Rates		Current WNSA Incorporated and Envrions Rates		Current RGVSA Incorporated and Envrions Rates		Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Residential		Small	Large	Small	Large	Small	Large	Small	Large
Customer Charge		$21.36	$33.36	$21.85	$38.35	$23.64	$38.64	$29.50	$39.50
Usage Rates	All Ccf	$0.87646	$0.46737	$0.46668	$0.01668	$2.02007	$0.63545	$0.67553	$0.31189
Customer Assistance Program									
Customer Charge		N/A	N/A	N/A	N/A	N/A	N/A	$22.13	$22.13
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	N/A	N/A	$0.55000	$0.55000
Commercial									
Customer Charge - Sales		$72.88	$87.88	$92.73	$92.73	$120.32	$275.32	$75.00	$150.00
Usage Rates	All Ccf	$0.27930	$0.22985	$0.09394	$0.09394	$0.63855	$0.26655	$0.43589	$0.13589
Industrial									
Customer Charge - Sales		$1,033.21		$1,295.93		$1,234.53		$1,250.00	
Usage Rates	All Ccf	$0.14569		$0.11486		$0.28220		$0.11849	
Public Authority									
Customer Charge - Sales		181.93		253.05		$243.91		$200.00	
Usage Rates	All Ccf	$0.13768		$0.13511		$0.16208		$0.13745	
Compressed Natural Gas (CNG)									
Customer Charge - Sales		$746.15		$1,955.67		N/A		$320.00	
Usage Rates	All Ccf	$0.07817		$0.08643		N/A		$0.08831	
Transportation									
General Transportation Customer Charge		N/A		N/A		N/A		$500.00	
Usage Rates	All Ccf	N/A		N/A		N/A		$0.08831	
Commercial Customer Charge		$320.96		$517.73		$545.32		N/A	
Usage Rates	All Ccf	$0.12679		$0.09394		$0.10770		N/A	
Industrial Customer Charge		$1,233.21		$1,495.93		$1,384.53		N/A	
Usage Rates	All Ccf	$0.14569		$0.11486		$0.08722		N/A	
Public Authority Customer Charge		$204.93		$553.05		$2,543.91		N/A	
Usage Rates	All Ccf	0.13768		$0.13511		$0.00840		N/A	
Compressed Natural Gas Customer Charge		$771.15		$2,255.67		N/A		N/A	
Usage Rates	All Ccf	0.07817		$0.08643		N/A		N/A	

						Average Monthly Bills
Residential	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Sm - Cons. Av. Monthly Usage	17					$ 48.82
Sm - CGSA Av. Monthly Usage	17	17	$ 44.88			$ 48.82
Sm - WNSA Av. Monthly Usage	17	19		$ 38.44		$ 48.82
Sm - RGV. Av. Monthly Usage	17	17			$ 62.53	$ 48.82
Lg - Cons. Av. Monthly Usage	46					$ 74.30
Lg - CGSA Av. Monthly Usage	46	46	$ 77.29			$ 74.30
Lg - WNSA Av. Monthly Usage	46	51		$ 59.66		$ 74.30
Lg - RGV. Av. Monthly Usage	46	46			$ 78.89	$ 74.30
Customer Assistance	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Sm - Cons. Av. Monthly Usage	17					$ 39.30
Sm - CGSA Av. Monthly Usage	17	17	$ 44.88			$ 39.30
Sm - WNSA Av. Monthly Usage	17	19		$ 38.44		$ 39.30
Sm - RGV. Av. Monthly Usage	17	17			$ 62.53	$ 39.30
Lg - Cons. Av. Monthly Usage	46					$ 67.79
Lg - CGSA Av. Monthly Usage	46	46	$ 77.29			$ 67.79
Lg - WNSA Av. Monthly Usage	46	51		$ 59.66		$ 67.79
Lg - RGV. Av. Monthly Usage	46	46			$ 78.89	$ 67.79
Commercial Sales	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Sm - Cons. Av. Monthly Usage	45					$ 114.67
Sm - CGSA Av. Monthly Usage	45	45	$ 107.56			$ 114.67
Sm - WNSA Av. Monthly Usage	45	50		$ 117.47		$ 114.67
Sm - RGV. Av. Monthly Usage	45	45			$ 159.93	$ 114.67
Lg - Cons. Av. Monthly Usage	898					$ 676.72
Lg - CGSA Av. Monthly Usage	898	896	$ 739.73			$ 676.72
Lg - WNSA Av. Monthly Usage	898	998		$ 589.26		$ 676.72
Lg - RGV. Av. Monthly Usage	898	898			$ 736.13	$ 676.72
Industrial Sales	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Cons. Av. Monthly Usage	4,081					$ 3,572.33
CGSA Av. Monthly Usage	4,081	4,070	$ 3,652.60			$ 3,572.33
WNSA Av. Monthly Usage	4,081	4,533		$ 3,646.91		$ 3,572.33
RGV. Av. Monthly Usage	4,081	4,081			$ 3,392.24	$ 3,572.33
Pub. Auth. Sales	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Cons. Av. Monthly Usage	549					$ 522.93
CGSA Av. Monthly Usage	549	548	$ 530.03			$ 522.93
WNSA Av. Monthly Usage	549	610		$ 581.78		$ 522.93
RGV. Av. Monthly Usage	549	549			$ 468.32	$ 522.93
CNG Sales	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Cons. Av. Monthly Usage	—					$ 320.00
CGSA Av. Monthly Usage	—	—	$ 746.15			$ 320.00
WNSA Av. Monthly Usage	N/A	N/A		N/A		N/A
RGV. Av. Monthly Usage	N/A	N/A			N/A	N/A
Transportation	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Cons. Av. Monthly Usage						
CGSA Av. Monthly Usage						
WNSA Av. Monthly Usage						
RGV. Av. Monthly Usage						
Cons. Av. Monthly Usage	6,558					$ 3,886.69
CGSA Av. Monthly Usage	6,558	6,541	$ 3,807.64			$ 3,886.69
WNSA Av. Monthly Usage	6,558	7,285		$ 4,161.74		$ 3,886.69
RGV. Av. Monthly Usage	6,558	6,558			$ 3,915.94	$ 3,886.69
Cons. Av. Monthly Usage	35,469					$ 18,816.36
CGSA Av. Monthly Usage	35,469	35,376	$ 20,758.98			$ 18,816.36
WNSA Av. Monthly Usage	35,469	39,400		$ 22,028.20		$ 18,816.36
RGV. Av. Monthly Usage	35,469	35,469			$ 18,887.56	$ 18,816.36
Cons. Av. Monthly Usage	2,346					$ 1,711.73
CGSA Av. Monthly Usage	2,346	2,340	$ 1,477.92			$ 1,711.73
WNSA Av. Monthly Usage	2,346	2,607		$ 1,964.16		$ 1,711.73
RGV. Av. Monthly Usage	2,346	2,346			$ 3,516.89	$ 1,711.73
Cons. Av. Monthly Usage	60,139					$ 31,556.20
CGSA Av. Monthly Usage	60,139	59,982	$ 29,828.01			$ 31,556.20
WNSA Av. Monthly Usage	60,139	66,805		$ 35,169.78		$ 31,556.20
RGV. Av. Monthly Usage	N/A	N/A			N/A	N/A

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
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					to convert from local pressure to 14.65 psi
0.94898	1.00262	0.90021	1.00000		
1.05376	0.99739	1.11085	1.00000		to convert from 14.65 psi to local pressure

	TGS	CGSA	WNSA	RGVSA
Gas Costs at local pressure	$0.42764	$0.49791	$0.40379	$0.24658
Gas Costs at 14.65 psi	$0.45063	$0.49661	$0.44855	$0.24658
Transportation Gas Cost Savings Assumed	5 %			

Description		Current CGSA Incorporated and Envrions Rates		Current WNSA Incorporated and Envrions Rates		Current RGVSA Incorporated and Envrions Rates		Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Electric Generation Transportation									
Transportation Customer Charge		$201.64		$717.73		$545.32		$1,000.00	
Electric Generation Demand Charge	MDQ/month							$0.72542	
All Ccf								$0.02000	
Usage Rates (CGSA Year-Round)	All Ccf					$0.10770			
	First 5,000	$0.07724		N/A		N/A			
	Next 35,000	$0.06853		N/A		N/A			
	Next 60,000	$0.05527		N/A		N/A			
	All Over 100,000	$0.04018		N/A		N/A			
Usage Rates - (WNSA October - April)	All Ccf								
	First 5,000	N/A		$0.05260		N/A			
	Next 95,000	N/A		$0.04260		N/A			
	Next 300,000	N/A		$0.03260		N/A			
	All Over 400,000	N/A		$0.02260		N/A			
Usage Rates - (WNSA May - September)	All Ccf								
	First 5,000	N/A		$0.04259		N/A			
	Next 95,000	N/A		$0.03258		N/A			
	Next 300,000	N/A		$0.02259		N/A			
	All Over 400,000	N/A		$0.01258		N/A			
Unmetered Gas Light									
	Residential All Ccf	$0.87646		$0.46668		$2.02007		$0.67553	
	Commercial All Ccf	$0.27930		$0.09394		$0.63855		$0.43589	
	Industrial All Ccf	$0.14569		$0.11486		$0.28220		$0.11849	
	Public Authority All Ccf	$0.13768		$0.13511		$0.16208		$0.13745	

Average Monthly Bills

Electrical Generation Transportation	Volume At 14.65 psi	Volume At Local-Pressure	CGSA	WNSA	RGVSA	Recommended
Cons. Av. Monthly Usage	355,327					$ 185,400.48
CGSA MDQ	12,709					
CGSA Av. Monthly Usage	355,327	355,327	$ 184,636.19			$ 185,400.48
WNSA Av. Monthly Usage	N/A	N/A		N/A		N/A
RGV. Av. Monthly Usage	N/A	N/A			N/A	N/A

Customer Bill Impacts

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

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CUSTOMER BILL IMPACTS

	Average Monthly Bill		Change	
Description	Current Service Area	Recommended TGS All Customers	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
CGSA Incorporated and Environs	$ 44.88	$ 48.82	$ 3.94	8.8%
WNSA Incorporated and Environs	$ 38.44	$ 48.82	$ 10.38	27.0%
RGVSA Incorporated and Environs	$ 62.53	$ 48.82	$ (13.71)	-21.9%
Residential - Large				
CGSA Incorporated and Environs	$ 77.29	$ 74.30	$ (2.99)	-3.9%
WNSA Incorporated and Environs	$ 59.66	$ 74.30	$ 14.64	24.5%
RGVSA Incorporated and Environs	$ 78.89	$ 74.30	$ (4.59)	-5.8%
Customer Assistance				
CGSA Incorporated and Environs	$ 44.88	$ 39.30	$ (5.58)	-12.4%
WNSA Incorporated and Environs	$ 38.44	$ 39.30	$ 0.86	2.2%
RGVSA Incorporated and Environs	$ 62.53	$ 39.30	$ (23.23)	-37.2%
Commercial - Small				
CGSA Incorporated and Environs	$ 107.56	$ 114.67	$ 7.11	6.6%
WNSA Incorporated and Environs	$ 117.47	$ 114.67	$ (2.80)	-2.4%
RGVSA Incorporated and Environs	$ 159.93	$ 114.67	$ (45.26)	-28.3%
Commercial - Large				
CGSA Incorporated and Environs	$ 739.73	$ 676.72	$ (63.01)	-8.5%
WNSA Incorporated and Environs	$ 589.26	$ 676.72	$ 87.46	14.8%
RGVSA Incorporated and Environs	$ 736.13	$ 676.72	$ (59.41)	-8.1%
Industrial				
CGSA Incorporated and Environs	$ 3,652.60	$ 3,572.33	$ (80.27)	-2.2%
WNSA Incorporated and Environs	$ 3,646.91	$ 3,572.33	$ (74.58)	-2.0%
RGVSA Incorporated and Environs	$ 3,392.24	$ 3,572.33	$ 180.09	5.3%
Public Authority				
CGSA Incorporated and Environs	$ 530.03	$ 522.93	$ (7.10)	-1.3%
WNSA Incorporated and Environs	$ 581.78	$ 522.93	$ (58.85)	-10.1%
RGVSA Incorporated and Environs	$ 468.32	$ 522.93	$ 54.61	11.7%
Compressed Natural Gas				
CGSA Incorporated and Environs	$ 746.15	$ 320.00	$ (426.15)	-57.1%
WNSA Incorporated and Environs	N/A	N/A	N/A	N/A
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A
Transportation Service: (3)				
Commercial Transportation				
CGSA Incorporated and Environs	$ 3,807.64	$ 3,886.69	$ 79.05	2.1%
WNSA Incorporated and Environs	$ 4,161.74	$ 3,886.69	$ (275.05)	-6.6%
RGVSA Incorporated and Environs	$ 3,915.94	$ 3,886.69	$ (29.25)	-0.7%
Industrial Transportation				
CGSA Incorporated and Environs	$ 20,758.98	$ 18,816.36	$ (1,942.62)	-9.4%
WNSA Incorporated and Environs	$ 22,028.20	$ 18,816.36	$ (3,211.84)	-14.6%
RGVSA Incorporated and Environs	$ 18,887.56	$ 18,816.36	$ (71.20)	-0.4%
Public Authority Transportation				
CGSA Incorporated and Environs	$ 1,477.92	$ 1,711.73	$ 233.81	15.8%
WNSA Incorporated and Environs	$ 1,964.16	$ 1,711.73	$ (252.43)	-12.9%
RGVSA Incorporated and Environs	$ 3,516.89	$ 1,711.73	$ (1,805.16)	-51.3%
Compressed Natural Gas Transportation				
CGSA Incorporated and Environs	$ 29,828.01	$ 31,556.20	$ 1,728.19	5.8%
WNSA Incorporated and Environs	$ 35,169.78	$ 31,556.20	$ (3,613.58)	-10.3%
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A
Electric Generation Transportation				
CGSA Incorporated and Environs	$ 184,636.19	$ 185,400.48	$ 764.29	0.4%
WNSA Incorporated and Environs	N/A	N/A	N/A	N/A
RGVSA Incorporated and Environs	N/A	N/A	N/A	N/A

(1) Bill impacts are shown for those schedules with customers during the test year. The test year cost of gas in each area 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) Current and recommended bills are based on the following average monthly usage levels at local pressure and at 14.65 psi, respectively.

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

CUSTOMER BILL IMPACTS

	CGSA	WNSA	RGVSA	CGSA	WNSA	RGVSA
	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure
Residential - Small	17	17	17	17	19	17
Residential - Large	46	46	46	46	51	46
Commercial - Small	45	45	45	45	50	45
Commercial - Large	898	898	898	896	998	898
Industrial	4,081	4,081	4,081	4,070	4,533	4,081
Public Authority	549	549	549	548	610	549
Compressed Natural Gas	0	N/A	N/A	—	N/A	N/A

(3) 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. Current and recommended bills are based on the following usage levels at local pressure and at 14.65 psi, respectively.

	CGSA	WNSA	RGVSA	CGSA	WNSA	RGVSA
	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At 14.65 psi	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure	Average Monthly Volume At Local Pressure
Commercial Transportation	6,558	6,558	6,558	6,541	7,285	6,558
Industrial Transportation	35,469	35,469	35,469	35,376	39,400	35,469
Public Authority Transportation	2,346	2,346	2,346	2,340	2,607	2,346
Compressed Natural Gas Transportation	60,139	60,139	N/A	59,982	66,805	N/A
Electric Generation Transportation	355,327	355,327	N/A	355,327	N/A	N/A

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Small Rates

$ 21.36	$ 1.32709	$ 1.32709	Small	$ 29.50	$ 1.12616	$ 1.12616	Small
$ 33.36	$ 0.91800	$ 0.91800	Large	$ 39.50	$ 0.76252	$ 0.76252	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	20	55,404	$ 256.29	$ —	$ 26.54	$ 256.29	$ 282.83	$ 354.00	$ —	$ 22.52	$ 354.00	$ 376.52	$ 8.14	$ 7.81	38%	33%
21	40	46,592	$ 256.29	$ 27.87	$ 53.08	$ 284.16	$ 309.38	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ 7.79	$ 7.47	33%	29%
41	60	61,047	$ 256.29	$ 54.41	$ 79.63	$ 310.70	$ 335.92	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ 7.46	$ 7.14	29%	25%
61	80	74,953	$ 256.29	$ 80.95	$ 106.17	$ 337.24	$ 362.46	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ 7.12	$ 6.80	25%	23%
81	100	95,123	$ 256.29	$ 107.49	$ 132.71	$ 363.79	$ 389.00	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ 6.79	$ 6.47	22%	20%
101	120	117,870	$ 256.29	$ 134.04	$ 159.25	$ 390.33	$ 415.54	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ 6.45	$ 6.13	20%	18%
121	140	138,214	$ 256.29	$ 160.58	$ 185.79	$ 416.87	$ 442.08	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ 6.12	$ 5.80	18%	16%
141	160	159,441	$ 256.29	$ 187.12	$ 212.33	$ 443.41	$ 468.63	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ 5.78	$ 5.46	16%	14%
161	180	180,046	$ 256.29	$ 213.66	$ 238.88	$ 469.95	$ 495.17	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ 5.45	$ 5.13	14%	12%
181	200	198,335	$ 256.29	$ 240.20	$ 265.42	$ 496.50	$ 521.71	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ 5.11	$ 4.79	12%	11%
201	220	209,086	$ 256.29	$ 266.75	$ 291.96	$ 523.04	$ 548.25	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ 4.78	$ 4.46	11%	10%
221	240	209,535	$ 256.29	$ 293.29	$ 318.50	$ 549.58	$ 574.79	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ 4.44	$ 4.12	10%	9%
241	260	205,802	$ 256.29	$ 319.83	$ 345.04	$ 576.12	$ 601.34	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ 4.11	$ 3.79	9%	8%
261	280	200,434	$ 256.29	$ 346.37	$ 371.59	$ 602.66	$ 627.88	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ 3.77	$ 3.45	8%	7%
281	300	187,483	$ 256.29	$ 372.91	$ 398.13	$ 629.20	$ 654.42	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ 3.44	$ 3.12	7%	6%
301	330	246,664	$ 256.29	$ 399.45	$ 437.94	$ 655.75	$ 694.23	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ 3.10	$ 2.62	6%	5%
331	530	208,783	$ 256.29	$ 439.27	$ 703.36	$ 695.56	$ 959.65	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ 2.57	$ (6.79)	4%	-8%
531	730	9,029	$ 256.29	$ 704.68	$ 968.78	$ 960.98	$ 1,225.07	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ (6.84)	$ (16.20)	-9%	-16%
731	930	2,662	$ 256.29	$ 970.10	$ 1,234.19	$ 1,226.39	$ 1,490.49	$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14	$ (16.25)	$ (25.61)	-16%	-21%
931	1,130	1,013	$ 256.29	$ 1,235.52	$ 1,499.61	$ 1,491.81	$ 1,755.90	$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65	$ (25.66)	$ (35.02)	-21%	-24%
1,131	1,330	767	$ 256.29	$ 1,500.94	$ 1,765.03	$ 1,757.23	$ 2,021.32	$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15	$ (35.07)	$ (44.43)	-24%	-26%
1,331	1,530	347	$ 256.29	$ 1,766.36	$ 2,030.45	$ 2,022.65	$ 2,286.74	$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66	$ (44.48)	$ (53.84)	-26%	-28%
1,531	1,730	304	$ 256.29	$ 2,031.78	$ 2,295.87	$ 2,288.07	$ 2,552.16	$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16	$ (53.89)	$ (63.25)	-28%	-30%
1,731	1,930	217	$ 256.29	$ 2,297.19	$ 2,561.28	$ 2,553.48	$ 2,817.58	$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66	$ (63.30)	$ (72.66)	-30%	-31%
1,931	2,130	116	$ 256.29	$ 2,562.61	$ 2,826.70	$ 2,818.90	$ 3,082.99	$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17	$ (72.71)	$ (82.07)	-31%	-32%
2,131	2,330	72	$ 256.29	$ 2,828.03	$ 3,092.12	$ 3,084.32	$ 3,348.41	$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67	$ (82.12)	$ (91.48)	-32%	-33%
2,331	2,530	72	$ 256.29	$ 3,093.45	$ 3,357.54	$ 3,349.74	$ 3,613.83	$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18	$ (91.53)	$ (100.89)	-33%	-34%
2,531	2,730	72	$ 256.29	$ 3,358.87	$ 3,622.96	$ 3,615.16	$ 3,879.25	$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68	$ (100.93)	$ (110.30)	-34%	-34%
2,731	2,930	29	$ 256.29	$ 3,624.28	$ 3,888.37	$ 3,880.58	$ 4,144.67	$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18	$ (110.34)	$ (119.71)	-34%	-35%
2,931	3,130	58	$ 256.29	$ 3,889.70	$ 4,153.79	$ 4,145.99	$ 4,410.08	$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69	$ (119.75)	$ (129.12)	-35%	-35%
3,131	55,767	289	$ 256.29	$ 4,155.12	$ 74,007.84	$ 4,411.41	$ 74,264.13	$ 474.00	$ 2,387.45	$ 42,523.47	$ 2,861.45	$ 42,997.47	$ (129.16)	$ (2,605.56)	-35%	-42%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Large Rates

			$ 21.36	$ 1.32709	$ 1.32709	Small			$ 29.50	$ 1.12616	$ 1.12616	Small								
			$ 33.36	$ 0.91800	$ 0.91800	Large			$ 39.50	$ 0.76252	$ 0.76252	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	20	29	$ 400.29	$ —	$ 18.36	$ 400.29	$ 418.65		$ 354.00	$ —	$ 22.52	$ 354.00	$ 376.52		$ (3.86)	$ (3.51)		-12%	-10%
21	40	0	$ 400.29	$ 19.28	$ 36.72	$ 419.57	$ 437.01		$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05		$ (3.49)	$ (3.16)		-10%	-9%
41	60	0	$ 400.29	$ 37.64	$ 55.08	$ 437.93	$ 455.37		$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57		$ (3.15)	$ (2.82)		-9%	-7%
61	80	0	$ 400.29	$ 56.00	$ 73.44	$ 456.29	$ 473.73		$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09		$ (2.80)	$ (2.47)		-7%	-6%
81	100	0	$ 400.29	$ 74.36	$ 91.80	$ 474.65	$ 492.09		$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62		$ (2.45)	$ (2.12)		-6%	-5%
101	120	0	$ 400.29	$ 92.72	$ 110.16	$ 493.01	$ 510.45		$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14		$ (2.11)	$ (1.78)		-5%	-4%
121	140	0	$ 400.29	$ 111.08	$ 128.52	$ 511.37	$ 528.81		$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66		$ (1.76)	$ (1.43)		-4%	-3%
141	160	14	$ 400.29	$ 129.44	$ 146.88	$ 529.73	$ 547.17		$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19		$ (1.41)	$ (1.08)		-3%	-2%
161	180	188	$ 400.29	$ 147.80	$ 165.24	$ 548.09	$ 565.53		$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71		$ (1.06)	$ (0.74)		-2%	-2%
181	200	449	$ 400.29	$ 166.16	$ 183.60	$ 566.45	$ 583.89		$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23		$ (0.72)	$ (0.39)		-2%	-1%
201	220	781	$ 400.29	$ 184.52	$ 201.96	$ 584.81	$ 602.25		$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76		$ (0.37)	$ (0.04)		-1%	-0%
221	240	492	$ 400.29	$ 202.88	$ 220.32	$ 603.17	$ 620.61		$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28		$ (0.02)	$ 0.31		-0%	1%
241	260	362	$ 400.29	$ 221.24	$ 238.68	$ 621.53	$ 638.97		$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80		$ 0.32	$ 0.65		1%	1%
261	280	752	$ 400.29	$ 239.60	$ 257.04	$ 639.89	$ 657.33		$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32		$ 0.67	$ 1.00		1%	2%
281	300	1,375	$ 400.29	$ 257.96	$ 275.40	$ 658.25	$ 675.69		$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85		$ 1.02	$ 1.35		2%	2%
301	330	9,839	$ 400.29	$ 276.32	$ 302.94	$ 676.61	$ 703.23		$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63		$ 1.36	$ 1.87		2%	3%
331	530	719,749	$ 400.29	$ 303.86	$ 486.54	$ 704.15	$ 886.83		$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14		$ 1.85	$ (0.72)		3%	-1%
531	730	259,933	$ 400.29	$ 487.46	$ 670.14	$ 887.75	$ 1,070.43		$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64		$ (0.74)	$ (3.32)		-1%	-4%
731	930	84,083	$ 400.29	$ 671.06	$ 853.74	$ 1,071.35	$ 1,254.03		$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14		$ (3.33)	$ (5.91)		-4%	-6%
931	1,130	34,221	$ 400.29	$ 854.66	$ 1,037.34	$ 1,254.95	$ 1,437.63		$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65		$ (5.92)	$ (8.50)		-6%	-7%
1,131	1,330	17,798	$ 400.29	$ 1,038.26	$ 1,220.94	$ 1,438.55	$ 1,621.23		$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15		$ (8.51)	$ (11.09)		-7%	-8%
1,331	1,530	9,912	$ 400.29	$ 1,221.86	$ 1,404.54	$ 1,622.15	$ 1,804.83		$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66		$ (11.10)	$ (13.68)		-8%	-9%
1,531	1,730	6,396	$ 400.29	$ 1,405.46	$ 1,588.14	$ 1,805.75	$ 1,988.43		$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16		$ (13.69)	$ (16.27)		-9%	-10%
1,731	1,930	4,196	$ 400.29	$ 1,589.06	$ 1,771.74	$ 1,989.35	$ 2,172.03		$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66		$ (16.29)	$ (18.86)		-10%	-10%
1,931	2,130	3,169	$ 400.29	$ 1,772.66	$ 1,955.34	$ 2,172.95	$ 2,355.63		$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17		$ (18.88)	$ (21.46)		-10%	-11%
2,131	2,330	2,359	$ 400.29	$ 1,956.26	$ 2,138.94	$ 2,356.55	$ 2,539.23		$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67		$ (21.47)	$ (24.05)		-11%	-11%
2,331	2,530	1,982	$ 400.29	$ 2,139.86	$ 2,322.54	$ 2,540.15	$ 2,722.83		$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18		$ (24.06)	$ (26.64)		-11%	-12%
2,531	2,730	1,534	$ 400.29	$ 2,323.46	$ 2,506.14	$ 2,723.75	$ 2,906.43		$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68		$ (26.65)	$ (29.23)		-12%	-12%
2,731	2,930	1,042	$ 400.29	$ 2,507.06	$ 2,689.74	$ 2,907.35	$ 3,090.03		$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18		$ (29.24)	$ (31.82)		-12%	-12%
2,931	3,130	1,056	$ 400.29	$ 2,690.66	$ 2,873.34	$ 3,090.95	$ 3,273.63		$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69		$ (31.83)	$ (34.41)		-12%	-13%
3,131	55,767	8,928	$ 400.29	$ 2,874.26	$ 51,194.12	$ 3,274.55	$ 51,594.41		$ 474.00	$ 2,387.45	$ 42,523.47	$ 2,861.45	$ 42,997.47		$ (34.42)	$ (716.41)		-13%	-17%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing West-North Small Service Area Rates

$ 21.85	$ 0.91731	$ 0.91731	Small	$ 29.50	$ 1.12616	$ 1.12616	Small
$ 38.35	$ 0.46731	$ 0.46731	Large	$ 39.50	$ 0.76252	$ 0.76252	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	20	23,540	$ 262.20	$ —	$ 18.35	$ 262.20	$ 280.55	$ 354.00	$ —	$ 22.52	$ 354.00	$ 376.52	$ 7.65	$ 8.00	35%	34%
21	40	13,525	$ 262.20	$ 19.26	$ 36.69	$ 281.46	$ 298.89	$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05	$ 8.02	$ 8.35	34%	34%
41	60	19,339	$ 262.20	$ 37.61	$ 55.04	$ 299.81	$ 317.24	$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57	$ 8.36	$ 8.69	33%	33%
61	80	24,218	$ 262.20	$ 55.96	$ 73.38	$ 318.16	$ 335.58	$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09	$ 8.71	$ 9.04	33%	32%
81	100	29,896	$ 262.20	$ 74.30	$ 91.73	$ 336.50	$ 353.93	$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62	$ 9.06	$ 9.39	32%	32%
101	120	35,399	$ 262.20	$ 92.65	$ 110.08	$ 354.85	$ 372.28	$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14	$ 9.41	$ 9.74	32%	31%
121	140	44,099	$ 262.20	$ 110.99	$ 128.42	$ 373.19	$ 390.62	$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66	$ 9.76	$ 10.09	31%	31%
141	160	51,919	$ 262.20	$ 129.34	$ 146.77	$ 391.54	$ 408.97	$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19	$ 10.10	$ 10.43	31%	31%
161	180	60,443	$ 262.20	$ 147.69	$ 165.12	$ 409.89	$ 427.32	$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71	$ 10.45	$ 10.78	31%	30%
181	200	71,299	$ 262.20	$ 166.03	$ 183.46	$ 428.23	$ 445.66	$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23	$ 10.80	$ 11.13	30%	30%
201	220	81,761	$ 262.20	$ 184.38	$ 201.81	$ 446.58	$ 464.01	$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76	$ 11.15	$ 11.48	30%	30%
221	240	94,893	$ 262.20	$ 202.73	$ 220.15	$ 464.93	$ 482.35	$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28	$ 11.50	$ 11.83	30%	29%
241	260	104,421	$ 262.20	$ 221.07	$ 238.50	$ 483.27	$ 500.70	$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80	$ 11.84	$ 12.18	29%	29%
261	280	114,856	$ 262.20	$ 239.42	$ 256.85	$ 501.62	$ 519.05	$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32	$ 12.19	$ 12.52	29%	29%
281	300	124,193	$ 262.20	$ 257.76	$ 275.19	$ 519.96	$ 537.39	$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85	$ 12.54	$ 12.87	29%	29%
301	330	196,075	$ 262.20	$ 276.11	$ 302.71	$ 538.31	$ 564.91	$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63	$ 12.89	$ 13.39	29%	28%
331	530	822,314	$ 262.20	$ 303.63	$ 486.17	$ 565.83	$ 748.37	$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14	$ 13.38	$ 10.81	28%	17%
531	730	73,223	$ 262.20	$ 487.09	$ 669.64	$ 749.29	$ 931.84	$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64	$ 10.80	$ 8.23	17%	11%
731	930	12,129	$ 262.20	$ 670.55	$ 853.10	$ 932.75	$ 1,115.30	$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14	$ 8.22	$ 5.65	11%	6%
931	1130	3,117	$ 262.20	$ 854.02	$ 1,036.56	$ 1,116.22	$ 1,298.76	$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65	$ 5.64	$ 3.07	6%	3%
1,131	1330	1,409	$ 262.20	$ 1,037.48	$ 1,220.02	$ 1,299.68	$ 1,482.22	$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15	$ 3.06	$ 0.49	3%	0%
1,331	1530	583	$ 262.20	$ 1,220.94	$ 1,403.48	$ 1,483.14	$ 1,665.68	$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66	$ 0.48	$ (2.09)	0%	-2%
1,531	1730	271	$ 262.20	$ 1,404.40	$ 1,586.95	$ 1,666.60	$ 1,849.15	$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16	$ (2.10)	$ (4.67)	-2%	-3%
1,731	1930	244	$ 262.20	$ 1,587.86	$ 1,770.41	$ 1,850.06	$ 2,032.61	$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66	$ (4.68)	$ (7.25)	-3%	-4%
1,931	2130	203	$ 262.20	$ 1,771.33	$ 1,953.87	$ 2,033.53	$ 2,216.07	$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17	$ (7.26)	$ (9.83)	-4%	-5%
2,131	2330	108	$ 262.20	$ 1,954.79	$ 2,137.33	$ 2,216.99	$ 2,399.53	$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67	$ (9.84)	$ (12.41)	-5%	-6%
2,331	2530	68	$ 262.20	$ 2,138.25	$ 2,320.79	$ 2,400.45	$ 2,582.99	$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18	$ (12.42)	$ (14.98)	-6%	-7%
2,531	2730	54	$ 262.20	$ 2,321.71	$ 2,504.26	$ 2,583.91	$ 2,766.46	$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68	$ (15.00)	$ (17.56)	-7%	-8%
2,731	2930	41	$ 262.20	$ 2,505.17	$ 2,687.72	$ 2,767.37	$ 2,949.92	$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18	$ (17.58)	$ (20.14)	-8%	-8%
2,931	3130	27	$ 262.20	$ 2,688.64	$ 2,871.18	$ 2,950.84	$ 3,133.38	$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69	$ (20.16)	$ (22.72)	-8%	-9%
3,131	88392	176	$ 262.20	$ 2,872.10	$ 81,082.89	$ 3,134.30	$ 81,345.09	$ 474.00	$ 2,387.45	$ 67,400.69	$ 2,861.45	$ 67,874.69	$ (22.74)	$ (1,122.53)	-9%	-17%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing West-North Large Service Area Rates

			$ 21.85	$ 0.91731	$ 0.91731	Small			$ 29.50	$ 1.12616	$ 1.12616	Small								
			$ 38.35	$ 0.46731	$ 0.46731	Large			$ 39.50	$ 0.76252	$ 0.76252	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	20	1,450	$ 460.20	$ —	$ 9.35	$ 460.20	$ 469.55		$ 354.00	$ —	$ 22.52	$ 354.00	$ 376.52		$ (8.85)	$ (7.75)		-23%	-20%	
21	40	745	$ 460.20	$ 9.81	$ 18.69	$ 470.01	$ 478.89		$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05		$ (7.70)	$ (6.65)		-20%	-17%	
41	60	1,328	$ 460.20	$ 19.16	$ 28.04	$ 479.36	$ 488.24		$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57		$ (6.60)	$ (5.56)		-17%	-14%	
61	80	1,355	$ 460.20	$ 28.51	$ 37.38	$ 488.71	$ 497.58		$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09		$ (5.50)	$ (4.46)		-14%	-11%	
81	100	1,721	$ 460.20	$ 37.85	$ 46.73	$ 498.05	$ 506.93		$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62		$ (4.40)	$ (3.36)		-11%	-8%	
101	120	2,236	$ 460.20	$ 47.20	$ 56.08	$ 507.40	$ 516.28		$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14		$ (3.30)	$ (2.26)		-8%	-5%	
121	140	2,046	$ 460.20	$ 56.54	$ 65.42	$ 516.74	$ 525.62		$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66		$ (2.21)	$ (1.16)		-5%	-3%	
141	160	2,819	$ 460.20	$ 65.89	$ 74.77	$ 526.09	$ 534.97		$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19		$ (1.11)	$ (0.07)		-3%	-0%	
161	180	3,063	$ 460.20	$ 75.24	$ 84.12	$ 535.44	$ 544.32		$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71		$ (0.01)	$ 1.03		-0%	2%	
181	200	3,429	$ 460.20	$ 84.58	$ 93.46	$ 544.78	$ 553.66		$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23		$ 1.09	$ 2.13		2%	5%	
201	220	4,391	$ 460.20	$ 93.93	$ 102.81	$ 554.13	$ 563.01		$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76		$ 2.19	$ 3.23		5%	7%	
221	240	5,448	$ 460.20	$ 103.28	$ 112.15	$ 563.48	$ 572.35		$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28		$ 3.28	$ 4.33		7%	9%	
241	260	6,586	$ 460.20	$ 112.62	$ 121.50	$ 572.82	$ 581.70		$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80		$ 4.38	$ 5.43		9%	11%	
261	280	7,101	$ 460.20	$ 121.97	$ 130.85	$ 582.17	$ 591.05		$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32		$ 5.48	$ 6.52		11%	13%	
281	300	9,053	$ 460.20	$ 131.31	$ 140.19	$ 591.51	$ 600.39		$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85		$ 6.58	$ 7.62		13%	15%	
301	330	17,550	$ 460.20	$ 140.66	$ 154.21	$ 600.86	$ 614.41		$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63		$ 7.68	$ 9.27		15%	18%	
331	530	521,710	$ 460.20	$ 154.68	$ 247.67	$ 614.88	$ 707.87		$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14		$ 9.29	$ 14.19		18%	24%	
531	730	557,759	$ 460.20	$ 248.14	$ 341.14	$ 708.34	$ 801.34		$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64		$ 14.21	$ 19.11		24%	29%	
731	930	203,515	$ 460.20	$ 341.60	$ 434.60	$ 801.80	$ 894.80		$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14		$ 19.13	$ 24.03		29%	32%	
931	1130	74,307	$ 460.20	$ 435.07	$ 528.06	$ 895.27	$ 988.26		$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65		$ 24.05	$ 28.95		32%	35%	
1,131	1330	31,875	$ 460.20	$ 528.53	$ 621.52	$ 988.73	$ 1,081.72		$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15		$ 28.97	$ 33.87		35%	38%	
1,331	1530	15,233	$ 460.20	$ 621.99	$ 714.98	$ 1,082.19	$ 1,175.18		$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66		$ 33.89	$ 38.79		38%	40%	
1,531	1730	8,524	$ 460.20	$ 715.45	$ 808.45	$ 1,175.65	$ 1,268.65		$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16		$ 38.81	$ 43.71		40%	41%	
1,731	1930	5,611	$ 460.20	$ 808.91	$ 901.91	$ 1,269.11	$ 1,362.11		$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66		$ 43.73	$ 48.63		41%	43%	
1,931	2130	3,225	$ 460.20	$ 902.38	$ 995.37	$ 1,362.58	$ 1,455.57		$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17		$ 48.65	$ 53.55		43%	44%	
2,131	2330	2,006	$ 460.20	$ 995.84	$ 1,088.83	$ 1,456.04	$ 1,549.03		$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67		$ 53.57	$ 58.47		44%	45%	
2,331	2530	1,586	$ 460.20	$ 1,089.30	$ 1,182.29	$ 1,549.50	$ 1,642.49		$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18		$ 58.49	$ 63.39		45%	46%	
2,531	2730	1,084	$ 460.20	$ 1,182.76	$ 1,275.76	$ 1,642.96	$ 1,735.96		$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68		$ 63.41	$ 68.31		46%	47%	
2,731	2930	772	$ 460.20	$ 1,276.22	$ 1,369.22	$ 1,736.42	$ 1,829.42		$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18		$ 68.33	$ 73.23		47%	48%	
2,931	3130	854	$ 460.20	$ 1,369.69	$ 1,462.68	$ 1,829.89	$ 1,922.88		$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69		$ 73.26	$ 78.15		48%	49%	
3,131	88392	3,768	$ 460.20	$ 1,463.15	$ 41,306.49	$ 1,923.35	$ 41,766.69		$ 474.00	$ 2,387.45	$ 67,400.69	$ 2,861.45	$ 67,874.69		$ 78.18	$ 2,175.67		49%	63%	

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Small Rates

			$ 23.64	$ 2.47070	$ 2.47070	Small			$ 29.50	$ 1.12616	$ 1.12616	Small						
			$ 38.64	$ 1.08608	$ 1.08608	Large			$ 39.50	$ 0.76252	$ 0.76252	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	20	6,098	$ 283.71	$ —	$ 49.41	$ 283.71	$ 333.12		$ 354.00	$ —	$ 22.52	$ 354.00	$ 376.52		$ 5.86	$ 3.62	25%	13%
21	40	5,097	$ 283.71	$ 51.88	$ 98.83	$ 335.59	$ 382.54		$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05		$ 3.50	$ 1.38	13%	4%
41	60	4,941	$ 283.71	$ 101.30	$ 148.24	$ 385.01	$ 431.95		$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57		$ 1.26	$ (0.87)	4%	-2%
61	80	5,623	$ 283.71	$ 150.71	$ 197.66	$ 434.42	$ 481.36		$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09		$ (0.98)	$ (3.11)	-3%	-8%
81	100	5,654	$ 283.71	$ 200.13	$ 247.07	$ 483.83	$ 530.78		$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62		$ (3.22)	$ (5.35)	-8%	-12%
101	120	4,143	$ 283.71	$ 249.54	$ 296.48	$ 533.25	$ 580.19		$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14		$ (5.46)	$ (7.59)	-12%	-16%
121	140	1,841	$ 283.71	$ 298.95	$ 345.90	$ 582.66	$ 629.61		$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66		$ (7.70)	$ (9.83)	-16%	-19%
141	160	756	$ 283.71	$ 348.37	$ 395.31	$ 632.08	$ 679.02		$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19		$ (9.94)	$ (12.07)	-19%	-21%
161	180	348	$ 283.71	$ 397.78	$ 444.73	$ 681.49	$ 728.43		$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71		$ (12.18)	$ (14.31)	-21%	-24%
181	200	169	$ 283.71	$ 447.20	$ 494.14	$ 730.90	$ 777.85		$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23		$ (14.42)	$ (16.55)	-24%	-26%
201	220	107	$ 283.71	$ 496.61	$ 543.55	$ 780.32	$ 827.26		$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76		$ (16.66)	$ (18.79)	-26%	-27%
221	240	62	$ 283.71	$ 546.02	$ 592.97	$ 829.73	$ 876.68		$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28		$ (18.90)	$ (21.03)	-27%	-29%
241	260	40	$ 283.71	$ 595.44	$ 642.38	$ 879.15	$ 926.09		$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80		$ (21.15)	$ (23.27)	-29%	-30%
261	280	32	$ 283.71	$ 644.85	$ 691.80	$ 928.56	$ 975.50		$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32		$ (23.39)	$ (25.51)	-30%	-31%
281	300	12	$ 283.71	$ 694.27	$ 741.21	$ 977.97	$ 1,024.92		$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85		$ (25.63)	$ (27.76)	-31%	-32%
301	330	18	$ 283.71	$ 743.68	$ 815.33	$ 1,027.39	$ 1,099.04		$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63		$ (27.87)	$ (31.12)	-33%	-34%
331	530	33	$ 283.71	$ 817.80	$ 1,309.47	$ 1,101.51	$ 1,593.18		$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14		$ (31.26)	$ (59.59)	-34%	-45%
531	730	13	$ 283.71	$ 1,311.94	$ 1,803.61	$ 1,595.65	$ 2,087.32		$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64		$ (59.73)	$ (88.06)	-45%	-51%
731	930	2	$ 283.71	$ 1,806.08	$ 2,297.75	$ 2,089.79	$ 2,581.46		$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14		$ (88.20)	$ (116.53)	-51%	-54%
931	1130	4	$ 283.71	$ 2,300.22	$ 2,791.89	$ 2,583.93	$ 3,075.60		$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65		$ (116.67)	$ (145.00)	-54%	-57%
1,131	1330	3	$ 283.71	$ 2,794.36	$ 3,286.03	$ 3,078.07	$ 3,569.74		$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15		$ (145.14)	$ (173.47)	-57%	-58%
1,331	1530	0	$ 283.71	$ 3,288.50	$ 3,780.17	$ 3,572.21	$ 4,063.88		$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66		$ (173.61)	$ (201.94)	-58%	-60%
1,531	1730	0	$ 283.71	$ 3,782.64	$ 4,274.31	$ 4,066.35	$ 4,558.02		$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16		$ (202.08)	$ (230.40)	-60%	-61%
1,731	1930	0	$ 283.71	$ 4,276.78	$ 4,768.45	$ 4,560.49	$ 5,052.16		$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66		$ (230.55)	$ (258.87)	-61%	-61%
1,931	2130	0	$ 283.71	$ 4,770.92	$ 5,262.59	$ 5,054.63	$ 5,546.30		$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17		$ (259.02)	$ (287.34)	-61%	-62%
2,131	2330	1	$ 283.71	$ 5,265.06	$ 5,756.73	$ 5,548.77	$ 6,040.44		$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67		$ (287.49)	$ (315.81)	-62%	-63%
2,331	2530	0	$ 283.71	$ 5,759.20	$ 6,250.87	$ 6,042.91	$ 6,534.58		$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18		$ (315.96)	$ (344.28)	-63%	-63%
2,531	2730	0	$ 283.71	$ 6,253.34	$ 6,745.01	$ 6,537.05	$ 7,028.72		$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68		$ (344.43)	$ (372.75)	-63%	-64%
2,731	2930	0	$ 283.71	$ 6,747.48	$ 7,239.15	$ 7,031.19	$ 7,522.86		$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18		$ (372.90)	$ (401.22)	-64%	-64%
2,931	3130	0	$ 283.71	$ 7,241.62	$ 7,733.29	$ 7,525.33	$ 8,017.00		$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69		$ (401.37)	$ (429.69)	-64%	-64%
3,131	30012	2	$ 283.71	$ 7,735.76	$ 74,150.66	$ 8,019.47	$ 74,434.36		$ 474.00	$ 2,387.45	$ 22,884.76	$ 2,861.45	$ 23,358.76		$ (429.83)	$ (4,256.30)	-64%	-69%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Large Rates

			Current Charges						Proposed Charges						Absolute Change		Percentage Change	
			$ 23.64	$ 2.47070	$ 2.47070	Small			$ 29.50	$ 1.12616	$ 1.12616	Small						
			$ 38.64	$ 1.08608	$ 1.08608	Large			$ 39.50	$ 0.76252	$ 0.76252	Large						
Consumption																		
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	20	73	$ 463.71	$ —	$ 21.72	$ 463.71	$ 485.43		$ 354.00	$ —	$ 22.52	$ 354.00	$ 376.52		$ (9.14)	$ (9.08)	-24%	-22%
21	40	74	$ 463.71	$ 22.81	$ 43.44	$ 486.52	$ 507.15		$ 354.00	$ 23.65	$ 45.05	$ 377.65	$ 399.05		$ (9.07)	$ (9.01)	-22%	-21%
41	60	184	$ 463.71	$ 44.53	$ 65.16	$ 508.24	$ 528.87		$ 354.00	$ 46.17	$ 67.57	$ 400.17	$ 421.57		$ (9.01)	$ (8.94)	-21%	-20%
61	80	390	$ 463.71	$ 66.25	$ 86.89	$ 529.96	$ 550.59		$ 354.00	$ 68.70	$ 90.09	$ 422.70	$ 444.09		$ (8.94)	$ (8.88)	-20%	-19%
81	100	843	$ 463.71	$ 87.97	$ 108.61	$ 551.68	$ 572.32		$ 354.00	$ 91.22	$ 112.62	$ 445.22	$ 466.62		$ (8.87)	$ (8.81)	-19%	-18%
101	120	2,155	$ 463.71	$ 109.69	$ 130.33	$ 573.40	$ 594.04		$ 354.00	$ 113.74	$ 135.14	$ 467.74	$ 489.14		$ (8.80)	$ (8.74)	-18%	-18%
121	140	3,529	$ 463.71	$ 131.42	$ 152.05	$ 595.12	$ 615.76		$ 354.00	$ 136.27	$ 157.66	$ 490.27	$ 511.66		$ (8.74)	$ (8.67)	-18%	-17%
141	160	3,726	$ 463.71	$ 153.14	$ 173.77	$ 616.85	$ 637.48		$ 354.00	$ 158.79	$ 180.19	$ 512.79	$ 534.19		$ (8.67)	$ (8.61)	-17%	-16%
161	180	3,182	$ 463.71	$ 174.86	$ 195.49	$ 638.57	$ 659.20		$ 354.00	$ 181.31	$ 202.71	$ 535.31	$ 556.71		$ (8.60)	$ (8.54)	-16%	-16%
181	200	2,425	$ 463.71	$ 196.58	$ 217.22	$ 660.29	$ 680.92		$ 354.00	$ 203.84	$ 225.23	$ 557.84	$ 579.23		$ (8.54)	$ (8.47)	-16%	-15%
201	220	1,850	$ 463.71	$ 218.30	$ 238.94	$ 682.01	$ 702.65		$ 354.00	$ 226.36	$ 247.76	$ 580.36	$ 601.76		$ (8.47)	$ (8.41)	-15%	-14%
221	240	1,361	$ 463.71	$ 240.02	$ 260.66	$ 703.73	$ 724.37		$ 354.00	$ 248.88	$ 270.28	$ 602.88	$ 624.28		$ (8.40)	$ (8.34)	-14%	-14%
241	260	1,010	$ 463.71	$ 261.75	$ 282.38	$ 725.45	$ 746.09		$ 354.00	$ 271.40	$ 292.80	$ 625.40	$ 646.80		$ (8.34)	$ (8.27)	-14%	-13%
261	280	712	$ 463.71	$ 283.47	$ 304.10	$ 747.17	$ 767.81		$ 354.00	$ 293.93	$ 315.32	$ 647.93	$ 669.32		$ (8.27)	$ (8.21)	-13%	-13%
281	300	541	$ 463.71	$ 305.19	$ 325.82	$ 768.90	$ 789.53		$ 354.00	$ 316.45	$ 337.85	$ 670.45	$ 691.85		$ (8.20)	$ (8.14)	-13%	-12%
301	330	554	$ 463.71	$ 326.91	$ 358.41	$ 790.62	$ 822.11		$ 354.00	$ 338.97	$ 371.63	$ 692.97	$ 725.63		$ (8.14)	$ (8.04)	-12%	-12%
331	530	1,127	$ 463.71	$ 359.49	$ 575.62	$ 823.20	$ 1,039.33		$ 474.00	$ 252.39	$ 404.14	$ 726.39	$ 878.14		$ (8.07)	$ (13.43)	-12%	-16%
531	730	183	$ 463.71	$ 576.71	$ 792.84	$ 1,040.42	$ 1,256.55		$ 474.00	$ 404.90	$ 556.64	$ 878.90	$ 1,030.64		$ (13.46)	$ (18.83)	-16%	-18%
731	930	94	$ 463.71	$ 793.92	$ 1,010.05	$ 1,257.63	$ 1,473.76		$ 474.00	$ 557.40	$ 709.14	$ 1,031.40	$ 1,183.14		$ (18.85)	$ (24.22)	-18%	-20%
931	1130	51	$ 463.71	$ 1,011.14	$ 1,227.27	$ 1,474.85	$ 1,690.98		$ 474.00	$ 709.91	$ 861.65	$ 1,183.91	$ 1,335.65		$ (24.25)	$ (29.61)	-20%	-21%
1,131	1330	29	$ 463.71	$ 1,228.36	$ 1,444.49	$ 1,692.06	$ 1,908.19		$ 474.00	$ 862.41	$ 1,014.15	$ 1,336.41	$ 1,488.15		$ (29.64)	$ (35.00)	-21%	-22%
1,331	1530	15	$ 463.71	$ 1,445.57	$ 1,661.70	$ 1,909.28	$ 2,125.41		$ 474.00	$ 1,014.91	$ 1,166.66	$ 1,488.91	$ 1,640.66		$ (35.03)	$ (40.40)	-22%	-23%
1,531	1730	9	$ 463.71	$ 1,662.79	$ 1,878.92	$ 2,126.50	$ 2,342.63		$ 474.00	$ 1,167.42	$ 1,319.16	$ 1,641.42	$ 1,793.16		$ (40.42)	$ (45.79)	-23%	-23%
1,731	1930	9	$ 463.71	$ 1,880.00	$ 2,096.13	$ 2,343.71	$ 2,559.84		$ 474.00	$ 1,319.92	$ 1,471.66	$ 1,793.92	$ 1,945.66		$ (45.82)	$ (51.18)	-23%	-24%
1,931	2130	8	$ 463.71	$ 2,097.22	$ 2,313.35	$ 2,560.93	$ 2,777.06		$ 474.00	$ 1,472.43	$ 1,624.17	$ 1,946.43	$ 2,098.17		$ (51.21)	$ (56.57)	-24%	-24%
2,131	2330	7	$ 463.71	$ 2,314.44	$ 2,530.57	$ 2,778.14	$ 2,994.27		$ 474.00	$ 1,624.93	$ 1,776.67	$ 2,098.93	$ 2,250.67		$ (56.60)	$ (61.97)	-24%	-25%
2,331	2530	11	$ 463.71	$ 2,531.65	$ 2,747.78	$ 2,995.36	$ 3,211.49		$ 474.00	$ 1,777.43	$ 1,929.18	$ 2,251.43	$ 2,403.18		$ (61.99)	$ (67.36)	-25%	-25%
2,531	2730	6	$ 463.71	$ 2,748.87	$ 2,965.00	$ 3,212.58	$ 3,428.71		$ 474.00	$ 1,929.94	$ 2,081.68	$ 2,403.94	$ 2,555.68		$ (67.39)	$ (72.75)	-25%	-25%
2,731	2930	2	$ 463.71	$ 2,966.09	$ 3,182.22	$ 3,429.79	$ 3,645.92		$ 474.00	$ 2,082.44	$ 2,234.18	$ 2,556.44	$ 2,708.18		$ (72.78)	$ (78.14)	-25%	-26%
2,931	3130	3	$ 463.71	$ 3,183.30	$ 3,399.43	$ 3,647.01	$ 3,863.14		$ 474.00	$ 2,234.95	$ 2,386.69	$ 2,708.95	$ 2,860.69		$ (78.17)	$ (83.54)	-26%	-26%
3,131	30012	23	$ 463.71	$ 3,400.52	$ 32,595.44	$ 3,864.23	$ 33,059.15		$ 474.00	$ 2,387.45	$ 22,884.76	$ 2,861.45	$ 23,358.76		$ (83.56)	$ (808.37)	-26%	-29%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Small Rates

			$ 72.88	$ 0.72993	$ 0.72993	Small			$ 75.00	$ 0.88652	$ 0.88652	Small								
			$ 87.88	$ 0.68048	$ 0.68048	Large			$ 150.00	$ 0.58652	$ 0.58652	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	188	3,136	$ 874.51	$ —	$ 137.23	$ 874.51	$ 1,011.74		$ 900.00	$ —	$ 166.67	$ 900.00	$ 1,066.67		$ 2.12	$	4.58		3%	5%
189	375	1,753	$ 874.51	$ 137.96	$ 273.72	$ 1,012.47	$ 1,148.23		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ 4.59	$	7.02		5%	7%
376	563	1,017	$ 874.51	$ 274.45	$ 410.95	$ 1,148.96	$ 1,285.46		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ 7.03	$	9.47		7%	9%
564	750	668	$ 874.51	$ 411.68	$ 547.45	$ 1,286.19	$ 1,421.96		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ 9.48	$	11.91		9%	10%
751	938	492	$ 874.51	$ 548.18	$ 684.67	$ 1,422.69	$ 1,559.18		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ 11.92	$	14.36		10%	11%
939	1125	385	$ 874.51	$ 685.40	$ 821.17	$ 1,559.91	$ 1,695.68		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ 14.38	$	16.80		11%	12%
1,126	1313	333	$ 874.51	$ 821.90	$ 958.40	$ 1,696.41	$ 1,832.91		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ 16.82	$	19.26		12%	13%
1,314	1500	233	$ 874.51	$ 959.13	$ 1,094.90	$ 1,833.64	$ 1,969.40		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ 19.27	$	21.70		13%	13%
1,501	1688	229	$ 874.51	$ 1,095.63	$ 1,232.12	$ 1,970.13	$ 2,106.63		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ 21.71	$	24.15		13%	14%
1,689	1875	193	$ 874.51	$ 1,232.85	$ 1,368.62	$ 2,107.36	$ 2,243.13		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ 24.16	$	26.59		14%	14%
1,876	2063	150	$ 874.51	$ 1,369.35	$ 1,505.85	$ 2,243.86	$ 2,380.36		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ 26.60	$	29.04		14%	15%
2,064	2250	158	$ 874.51	$ 1,506.58	$ 1,642.34	$ 2,381.09	$ 2,516.85		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ 29.06	$	31.48		15%	15%
2,251	2438	145	$ 874.51	$ 1,643.07	$ 1,779.57	$ 2,517.58	$ 2,654.08		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ 31.50	$	33.94		15%	15%
2,439	2625	105	$ 874.51	$ 1,780.30	$ 1,916.07	$ 2,654.81	$ 2,790.58		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ 33.95	$	36.38		15%	16%
2,626	2813	119	$ 874.51	$ 1,916.80	$ 2,053.29	$ 2,791.31	$ 2,927.80		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ 36.39	$	38.83		16%	16%
2,814	3000	112	$ 874.51	$ 2,054.02	$ 2,189.79	$ 2,928.53	$ 3,064.30		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ 38.84	$	41.27		16%	16%
3,001	5000	336	$ 874.51	$ 2,190.52	$ 3,649.65	$ 3,065.03	$ 4,524.16		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ 41.26	$	17.37		16%	5%
5,001	7000	5	$ 874.51	$ 3,650.38	$ 5,109.51	$ 4,524.89	$ 5,984.02		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ 17.36	$	(6.53)		5%	-1%
7,001	9000	9	$ 874.51	$ 5,110.24	$ 6,569.37	$ 5,984.75	$ 7,443.88		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ (6.54)	$	(30.43)		-1%	-5%
9,001	11000	6	$ 874.51	$ 6,570.10	$ 8,029.23	$ 7,444.61	$ 8,903.74		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (30.45)	$	(54.33)		-5%	-7%
11,001	13000	1	$ 874.51	$ 8,029.96	$ 9,489.09	$ 8,904.47	$ 10,363.60		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (54.35)	$	(78.24)		-7%	-9%
13,001	15000	0	$ 874.51	$ 9,489.82	$ 10,948.95	$ 10,364.33	$ 11,823.46		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (78.25)	$	(102.14)		-9%	-10%
15,001	17000	0	$ 874.51	$ 10,949.68	$ 12,408.81	$ 11,824.19	$ 13,283.32		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (102.15)	$	(126.04)		-10%	-11%
17,001	19000	0	$ 874.51	$ 12,409.54	$ 13,868.67	$ 13,284.05	$ 14,743.18		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (126.05)	$	(149.94)		-11%	-12%
19,001	21000	0	$ 874.51	$ 13,869.40	$ 15,328.53	$ 14,743.91	$ 16,203.04		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (149.95)	$	(173.84)		-12%	-13%
21,001	23000	1	$ 874.51	$ 15,329.26	$ 16,788.40	$ 16,203.77	$ 17,662.90		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (173.86)	$	(197.74)		-13%	-13%
23,001	25000	0	$ 874.51	$ 16,789.13	$ 18,248.26	$ 17,663.63	$ 19,122.77		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (197.76)	$	(221.65)		-13%	-14%
25,001	27000	0	$ 874.51	$ 18,248.99	$ 19,708.12	$ 19,123.49	$ 20,582.63		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (221.66)	$	(245.55)		-14%	-14%
27,001	29000	0	$ 874.51	$ 19,708.85	$ 21,167.98	$ 20,583.36	$ 22,042.49		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (245.56)	$	(269.45)		-14%	-15%
29,001	31000	0	$ 874.51	$ 21,168.71	$ 22,627.84	$ 22,043.22	$ 23,502.35		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (269.46)	$	(293.35)		-15%	-15%
31,001	1305510	1	$ 874.51	$ 22,628.57	$ 952,931.21	$ 23,503.08	$ 953,805.72		$ 1,800.00	$ 18,182.71	$ 765,708.02	$ 19,982.71	$ 767,508.02		$ (293.36)	$	(15,524.81)		-15%	-20%

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing Central Gulf Service Area Large Rates

			$ 72.88	$ 0.72993	$ 0.72993	Small			$ 75.00	$ 0.88652	$ 0.88652	Small										
			$ 87.88	$ 0.68048	$ 0.68048	Large			$ 150.00	$ 0.58652	$ 0.58652	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	188	0	$ 1,054.51	$ —	$ 127.93	$ 1,054.51	$ 1,182.44		$ 900.00	$ —	$ 166.67	$ 900.00	$ 1,066.67		$ (12.88)	$	(9.65)		-15%		-10%	
189	375	0	$ 1,054.51	$ 128.61	$ 255.18	$ 1,183.12	$ 1,309.69		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (9.63)	$	(6.44)		-10%		-6%	
376	563	0	$ 1,054.51	$ 255.86	$ 383.11	$ 1,310.37	$ 1,437.62		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (6.42)	$	(3.21)		-6%		-3%	
564	750	0	$ 1,054.51	$ 383.79	$ 510.36	$ 1,438.30	$ 1,564.87		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (3.19)	$	0.00		-3%		0%	
751	938	0	$ 1,054.51	$ 511.04	$ 638.29	$ 1,565.55	$ 1,692.80		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ 0.02	$	3.23		0%		2%	
939	1125	0	$ 1,054.51	$ 638.97	$ 765.54	$ 1,693.48	$ 1,820.05		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ 3.25	$	6.44		2%		4%	
1,126	1313	0	$ 1,054.51	$ 766.22	$ 893.47	$ 1,820.73	$ 1,947.98		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ 6.46	$	9.67		4%		6%	
1,314	1500	0	$ 1,054.51	$ 894.15	$ 1,020.72	$ 1,948.66	$ 2,075.23		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ 9.69	$	12.88		6%		7%	
1,501	1688	0	$ 1,054.51	$ 1,021.40	$ 1,148.65	$ 2,075.91	$ 2,203.16		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ 12.90	$	16.11		7%		9%	
1,689	1875	0	$ 1,054.51	$ 1,149.33	$ 1,275.90	$ 2,203.84	$ 2,330.41		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ 16.12	$	19.32		9%		10%	
1,876	2063	0	$ 1,054.51	$ 1,276.58	$ 1,403.83	$ 2,331.09	$ 2,458.34		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ 19.34	$	22.55		10%		11%	
2,064	2250	0	$ 1,054.51	$ 1,404.51	$ 1,531.08	$ 2,459.02	$ 2,585.59		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ 22.56	$	25.76		11%		12%	
2,251	2438	3	$ 1,054.51	$ 1,531.76	$ 1,659.01	$ 2,586.27	$ 2,713.52		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ 25.77	$	28.98		12%		13%	
2,439	2625	1	$ 1,054.51	$ 1,659.69	$ 1,786.26	$ 2,714.20	$ 2,840.77		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ 29.00	$	32.20		13%		14%	
2,626	2813	1	$ 1,054.51	$ 1,786.94	$ 1,914.19	$ 2,841.45	$ 2,968.70		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ 32.21	$	35.42		14%		14%	
2,814	3000	1	$ 1,054.51	$ 1,914.87	$ 2,041.44	$ 2,969.38	$ 3,095.95		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ 35.44	$	38.63		14%		15%	
3,001	5000	660	$ 1,054.51	$ 2,042.12	$ 3,402.40	$ 3,096.63	$ 4,456.91		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ 38.63	$	22.97		15%		6%	
5,001	7000	684	$ 1,054.51	$ 3,403.08	$ 4,763.36	$ 4,457.59	$ 5,817.87		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ 22.97	$	7.31		6%		2%	
7,001	9000	490	$ 1,054.51	$ 4,764.04	$ 6,124.32	$ 5,818.55	$ 7,178.83		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ 7.31	$	(8.35)		2%		-1%	
9,001	11000	316	$ 1,054.51	$ 6,125.00	$ 7,485.28	$ 7,179.51	$ 8,539.79		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (8.35)	$	(24.01)		-1%		-3%	
11,001	13000	240	$ 1,054.51	$ 7,485.96	$ 8,846.24	$ 8,540.47	$ 9,900.75		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (24.01)	$	(39.67)		-3%		-5%	
13,001	15000	168	$ 1,054.51	$ 8,846.92	$ 10,207.20	$ 9,901.43	$ 11,261.71		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (39.67)	$	(55.33)		-5%		-6%	
15,001	17000	145	$ 1,054.51	$ 10,207.88	$ 11,568.16	$ 11,262.39	$ 12,622.67		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (55.33)	$	(70.99)		-6%		-7%	
17,001	19000	102	$ 1,054.51	$ 11,568.84	$ 12,929.12	$ 12,623.35	$ 13,983.63		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (70.99)	$	(86.65)		-7%		-7%	
19,001	21000	61	$ 1,054.51	$ 12,929.80	$ 14,290.08	$ 13,984.31	$ 15,344.59		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (86.65)	$	(102.31)		-7%		-8%	
21,001	23000	68	$ 1,054.51	$ 14,290.77	$ 15,651.05	$ 15,345.27	$ 16,705.55		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (102.31)	$	(117.97)		-8%		-8%	
23,001	25000	60	$ 1,054.51	$ 15,651.73	$ 17,012.01	$ 16,706.24	$ 18,066.52		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (117.97)	$	(133.63)		-8%		-9%	
25,001	27000	33	$ 1,054.51	$ 17,012.69	$ 18,372.97	$ 18,067.20	$ 19,427.48		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (133.63)	$	(149.29)		-9%		-9%	
27,001	29000	31	$ 1,054.51	$ 18,373.65	$ 19,733.93	$ 19,428.16	$ 20,788.44		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (149.29)	$	(164.95)		-9%		-10%	
29,001	31000	37	$ 1,054.51	$ 19,734.61	$ 21,094.89	$ 20,789.12	$ 22,149.40		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (164.95)	$	(180.61)		-10%		-10%	
31,001	1305510	145	$ 1,054.51	$ 21,095.57	$ 888,373.74	$ 22,150.08	$ 889,428.25		$ 1,800.00	$ 18,182.71	$ 765,708.02	$ 19,982.71	$ 767,508.02		$ (180.61)	$	(10,160.02)		-10%		-14%	

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing West-North Service Area Rates

			$ 92.73	$ 0.54457	$ 0.54457	Small			$ 75.00	$ 0.88652	$ 0.88652	Small										
			$ 92.73	$ 0.54457	$ 0.54457	Large			$ 150.00	$ 0.58652	$ 0.58652	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	188	2,992	$ 1,112.76	$ —	$ 102.38	$ 1,112.76	$ 1,215.14		$ 900.00	$ —	$ 166.67	$ 900.00	$ 1,066.67		$ (17.73)	$	(12.37)		-19%		-12%	
189	375	2,786	$ 1,112.76	$ 102.92	$ 204.21	$ 1,215.68	$ 1,316.97		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (12.34)	$	(7.04)		-12%		-6%	
376	563	2,012	$ 1,112.76	$ 204.76	$ 306.59	$ 1,317.52	$ 1,419.35		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (7.02)	$	(1.69)		-6%		-1%	
564	750	1,183	$ 1,112.76	$ 307.14	$ 408.43	$ 1,419.90	$ 1,521.19		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (1.66)	$	3.64		-1%		3%	
751	938	924	$ 1,112.76	$ 408.97	$ 510.81	$ 1,521.73	$ 1,623.57		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ 3.67	$	9.00		3%		7%	
939	1125	658	$ 1,112.76	$ 511.35	$ 612.64	$ 1,624.11	$ 1,725.40		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ 9.03	$	14.33		7%		10%	
1,126	1313	515	$ 1,112.76	$ 613.19	$ 715.02	$ 1,725.95	$ 1,827.78		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ 14.36	$	19.69		10%		13%	
1,314	1500	461	$ 1,112.76	$ 715.57	$ 816.86	$ 1,828.33	$ 1,929.62		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ 19.71	$	25.01		13%		16%	
1,501	1688	336	$ 1,112.76	$ 817.40	$ 919.23	$ 1,930.16	$ 2,031.99		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ 25.04	$	30.37		16%		18%	
1,689	1875	313	$ 1,112.76	$ 919.78	$ 1,021.07	$ 2,032.54	$ 2,133.83		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ 30.40	$	35.70		18%		20%	
1,876	2063	243	$ 1,112.76	$ 1,021.61	$ 1,123.45	$ 2,134.37	$ 2,236.21		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ 35.73	$	41.06		20%		22%	
2,064	2250	247	$ 1,112.76	$ 1,123.99	$ 1,225.28	$ 2,236.75	$ 2,338.04		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ 41.09	$	46.39		22%		24%	
2,251	2438	217	$ 1,112.76	$ 1,225.83	$ 1,327.66	$ 2,338.59	$ 2,440.42		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ 46.41	$	51.74		24%		25%	
2,439	2625	171	$ 1,112.76	$ 1,328.21	$ 1,429.50	$ 2,440.97	$ 2,542.26		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ 51.77	$	57.07		25%		27%	
2,626	2813	169	$ 1,112.76	$ 1,430.04	$ 1,531.88	$ 2,542.80	$ 2,644.64		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ 57.10	$	62.43		27%		28%	
2,814	3000	153	$ 1,112.76	$ 1,532.42	$ 1,633.71	$ 2,645.18	$ 2,746.47		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ 62.46	$	67.76		28%		30%	
3,001	5000	1,072	$ 1,112.76	$ 1,634.26	$ 2,722.85	$ 2,747.02	$ 3,835.61		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ 67.76	$	74.75		30%		23%	
5,001	7000	691	$ 1,112.76	$ 2,723.40	$ 3,811.99	$ 3,836.16	$ 4,924.75		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ 74.75	$	81.74		23%		20%	
7,001	9000	491	$ 1,112.76	$ 3,812.54	$ 4,901.13	$ 4,925.30	$ 6,013.89		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ 81.74	$	88.73		20%		18%	
9,001	11000	294	$ 1,112.76	$ 4,901.68	$ 5,990.27	$ 6,014.44	$ 7,103.03		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ 88.74	$	95.72		18%		16%	
11,001	13000	227	$ 1,112.76	$ 5,990.82	$ 7,079.41	$ 7,103.58	$ 8,192.17		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ 95.73	$	102.72		16%		15%	
13,001	15000	187	$ 1,112.76	$ 7,079.96	$ 8,168.55	$ 8,192.72	$ 9,281.31		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ 102.72	$	109.71		15%		14%	
15,001	17000	141	$ 1,112.76	$ 8,169.10	$ 9,257.69	$ 9,281.86	$ 10,370.45		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ 109.71	$	116.70		14%		14%	
17,001	19000	117	$ 1,112.76	$ 9,258.24	$ 10,346.83	$ 10,371.00	$ 11,459.59		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ 116.70	$	123.69		14%		13%	
19,001	21000	88	$ 1,112.76	$ 10,347.38	$ 11,435.97	$ 11,460.14	$ 12,548.73		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ 123.69	$	130.68		13%		12%	
21,001	23000	81	$ 1,112.76	$ 11,436.52	$ 12,525.12	$ 12,549.28	$ 13,637.88		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ 130.69	$	137.67		12%		12%	
23,001	25000	62	$ 1,112.76	$ 12,525.66	$ 13,614.26	$ 13,638.42	$ 14,727.02		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ 137.68	$	144.67		12%		12%	
25,001	27000	43	$ 1,112.76	$ 13,614.80	$ 14,703.40	$ 14,727.56	$ 15,816.16		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ 144.67	$	151.66		12%		12%	
27,001	29000	28	$ 1,112.76	$ 14,703.94	$ 15,792.54	$ 15,816.70	$ 16,905.30		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ 151.66	$	158.65		12%		11%	
29,001	31000	23	$ 1,112.76	$ 15,793.08	$ 16,881.68	$ 16,905.84	$ 17,994.44		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ 158.65	$	165.64		11%		11%	
31,001	1520781	239	$ 1,112.76	$ 16,882.22	$ 828,172.06	$ 17,994.98	$ 829,284.82		$ 1,800.00	$ 18,182.71	$ 891,968.82	$ 19,982.71	$ 893,768.82		$ 165.64	$	5,373.67		11%		8%	

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Small Rates

			$ 120.32	$ 1.08918	$ 1.08918	Small			$ 75.00	$ 0.88652	$ 0.88652	Small									
			$ 275.32	$ 0.71718	$ 0.71718	Large			$ 150.00	$ 0.58652	$ 0.58652	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	188	622	$ 1,443.83	$ —	$ 204.77	$ 1,443.83	$ 1,648.60		$ 900.00	$ —	$ 166.67	$ 900.00	$ 1,066.67		$ (45.32)	$	(48.49)		-38%		-35%
189	375	213	$ 1,443.83	$ 205.86	$ 408.44	$ 1,649.69	$ 1,852.27		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (48.51)	$	(51.65)		-35%		-33%
376	563	150	$ 1,443.83	$ 409.53	$ 613.21	$ 1,853.36	$ 2,057.04		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (51.67)	$	(54.83)		-33%		-32%
564	750	121	$ 1,443.83	$ 614.30	$ 816.89	$ 2,058.13	$ 2,260.72		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (54.84)	$	(57.99)		-32%		-31%
751	938	103	$ 1,443.83	$ 817.97	$ 1,021.65	$ 2,261.81	$ 2,465.48		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ (58.00)	$	(61.16)		-31%		-30%
939	1125	103	$ 1,443.83	$ 1,022.74	$ 1,225.33	$ 2,466.57	$ 2,669.16		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ (61.18)	$	(64.32)		-30%		-29%
1,126	1313	92	$ 1,443.83	$ 1,226.42	$ 1,430.09	$ 2,670.25	$ 2,873.93		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ (64.34)	$	(67.49)		-29%		-28%
1,314	1500	81	$ 1,443.83	$ 1,431.18	$ 1,633.77	$ 2,875.02	$ 3,077.60		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ (67.51)	$	(70.65)		-28%		-28%
1,501	1688	74	$ 1,443.83	$ 1,634.86	$ 1,838.54	$ 3,078.69	$ 3,282.37		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ (70.67)	$	(73.83)		-28%		-27%
1,689	1875	83	$ 1,443.83	$ 1,839.63	$ 2,042.21	$ 3,283.46	$ 3,486.05		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ (73.84)	$	(76.98)		-27%		-27%
1,876	2063	63	$ 1,443.83	$ 2,043.30	$ 2,246.98	$ 3,487.13	$ 3,690.81		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ (77.00)	$	(80.16)		-26%		-26%
2,064	2250	52	$ 1,443.83	$ 2,248.07	$ 2,450.66	$ 3,691.90	$ 3,894.49		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ (80.18)	$	(83.32)		-26%		-26%
2,251	2438	55	$ 1,443.83	$ 2,451.74	$ 2,655.42	$ 3,895.58	$ 4,099.25		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ (83.33)	$	(86.49)		-26%		-25%
2,439	2625	53	$ 1,443.83	$ 2,656.51	$ 2,859.10	$ 4,100.34	$ 4,302.93		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ (86.51)	$	(89.65)		-25%		-25%
2,626	2813	55	$ 1,443.83	$ 2,860.19	$ 3,063.86	$ 4,304.02	$ 4,507.70		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ (89.67)	$	(92.83)		-25%		-25%
2,814	3000	68	$ 1,443.83	$ 3,064.95	$ 3,267.54	$ 4,508.79	$ 4,711.37		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ (92.84)	$	(95.98)		-25%		-24%
3,001	5000	510	$ 1,443.83	$ 3,268.63	$ 5,445.90	$ 4,712.46	$ 6,889.73		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ (96.03)	$	(179.76)		-24%		-31%
5,001	7000	70	$ 1,443.83	$ 5,446.99	$ 7,624.26	$ 6,890.82	$ 9,068.09		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ (179.80)	$	(263.54)		-31%		-35%
7,001	9000	22	$ 1,443.83	$ 7,625.35	$ 9,802.62	$ 9,069.18	$ 11,246.45		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ (263.58)	$	(347.31)		-35%		-37%
9,001	11000	9	$ 1,443.83	$ 9,803.71	$ 11,980.98	$ 11,247.54	$ 13,424.81		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (347.36)	$	(431.09)		-37%		-39%
11,001	13000	4	$ 1,443.83	$ 11,982.07	$ 14,159.34	$ 13,425.90	$ 15,603.18		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (431.13)	$	(514.87)		-39%		-40%
13,001	15000	4	$ 1,443.83	$ 14,160.43	$ 16,337.70	$ 15,604.26	$ 17,781.54		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (514.91)	$	(598.64)		-40%		-40%
15,001	17000	1	$ 1,443.83	$ 16,338.79	$ 18,516.06	$ 17,782.62	$ 19,959.90		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (598.69)	$	(682.42)		-40%		-41%
17,001	19000	0	$ 1,443.83	$ 18,517.15	$ 20,694.42	$ 19,960.99	$ 22,138.26		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (682.46)	$	(766.20)		-41%		-42%
19,001	21000	1	$ 1,443.83	$ 20,695.51	$ 22,872.78	$ 22,139.35	$ 24,316.62		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (766.24)	$	(849.97)		-42%		-42%
21,001	23000	0	$ 1,443.83	$ 22,873.87	$ 25,051.15	$ 24,317.71	$ 26,494.98		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (850.02)	$	(933.75)		-42%		-42%
23,001	25000	2	$ 1,443.83	$ 25,052.23	$ 27,229.51	$ 26,496.07	$ 28,673.34		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (933.79)	$	(1,017.53)		-42%		-43%
25,001	27000	0	$ 1,443.83	$ 27,230.59	$ 29,407.87	$ 28,674.43	$ 30,851.70		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (1,017.57)	$	(1,101.30)		-43%		-43%
27,001	29000	0	$ 1,443.83	$ 29,408.96	$ 31,586.23	$ 30,852.79	$ 33,030.06		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (1,101.35)	$	(1,185.08)		-43%		-43%
29,001	31000	0	$ 1,443.83	$ 31,587.32	$ 33,764.59	$ 33,031.15	$ 35,208.42		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (1,185.12)	$	(1,268.86)		-43%		-43%
31,001	1440450	3	$ 1,443.83	$ 33,765.68	$ 1,568,909.66	$ 35,209.51	$ 1,570,353.49		$ 1,800.00	$ 18,182.71	$ 844,853.06	$ 19,982.71	$ 846,653.06		$ (1,268.90)	$	(60,308.37)		-43%		-46%

Commercial Bill Impacts Existing Rates
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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

PROPOSED COMMERCIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Commercial Bill Impacts of Proposed Rates Relative to Existing RGV Service Area Large Rates

			$ 120.32	$ 1.08918	$ 1.08918	Small			$ 75.00	$ 0.88652	$ 0.88652	Small						
			$ 275.32	$ 0.71718	$ 0.71718	Large			$ 150.00	$ 0.58652	$ 0.58652	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	188	0	$ 3,303.83	$ —	$ 134.83	$ 3,303.83	$ 3,438.66		$ 900.00	$ —	$ 166.67	$ 900.00	$ 1,066.67		$ (200.32)	$ (197.67)	-73%	-69%
189	375	0	$ 3,303.83	$ 135.55	$ 268.94	$ 3,439.38	$ 3,572.77		$ 900.00	$ 167.55	$ 332.45	$ 1,067.55	$ 1,232.45		$ (197.65)	$ (195.03)	-69%	-66%
376	563	1	$ 3,303.83	$ 269.66	$ 403.77	$ 3,573.49	$ 3,707.60		$ 900.00	$ 333.33	$ 499.11	$ 1,233.33	$ 1,399.11		$ (195.01)	$ (192.37)	-65%	-62%
564	750	1	$ 3,303.83	$ 404.49	$ 537.89	$ 3,708.32	$ 3,841.72		$ 900.00	$ 500.00	$ 664.89	$ 1,400.00	$ 1,564.89		$ (192.36)	$ (189.74)	-62%	-59%
751	938	0	$ 3,303.83	$ 538.60	$ 672.72	$ 3,842.43	$ 3,976.55		$ 900.00	$ 665.78	$ 831.56	$ 1,565.78	$ 1,731.56		$ (189.72)	$ (187.08)	-59%	-56%
939	1125	0	$ 3,303.83	$ 673.43	$ 806.83	$ 3,977.26	$ 4,110.66		$ 900.00	$ 832.44	$ 997.34	$ 1,732.44	$ 1,897.34		$ (187.07)	$ (184.44)	-56%	-54%
1,126	1313	0	$ 3,303.83	$ 807.54	$ 941.66	$ 4,111.38	$ 4,245.49		$ 900.00	$ 998.22	$ 1,164.00	$ 1,898.22	$ 2,064.00		$ (184.43)	$ (181.79)	-54%	-51%
1,314	1500	1	$ 3,303.83	$ 942.37	$ 1,075.77	$ 4,246.21	$ 4,379.60		$ 900.00	$ 1,164.89	$ 1,329.78	$ 2,064.89	$ 2,229.78		$ (181.78)	$ (179.15)	-51%	-49%
1,501	1688	1	$ 3,303.83	$ 1,076.49	$ 1,210.60	$ 4,380.32	$ 4,514.43		$ 900.00	$ 1,330.67	$ 1,496.45	$ 2,230.67	$ 2,396.45		$ (179.14)	$ (176.50)	-49%	-47%
1,689	1875	0	$ 3,303.83	$ 1,211.32	$ 1,344.71	$ 4,515.15	$ 4,648.55		$ 900.00	$ 1,497.33	$ 1,662.23	$ 2,397.33	$ 2,562.23		$ (176.48)	$ (173.86)	-47%	-45%
1,876	2063	1	$ 3,303.83	$ 1,345.43	$ 1,479.54	$ 4,649.26	$ 4,783.38		$ 900.00	$ 1,663.11	$ 1,828.89	$ 2,563.11	$ 2,728.89		$ (173.85)	$ (171.21)	-45%	-43%
2,064	2250	0	$ 3,303.83	$ 1,480.26	$ 1,613.66	$ 4,784.09	$ 4,917.49		$ 900.00	$ 1,829.78	$ 1,994.67	$ 2,729.78	$ 2,894.67		$ (171.19)	$ (168.57)	-43%	-41%
2,251	2438	0	$ 3,303.83	$ 1,614.37	$ 1,748.49	$ 4,918.20	$ 5,052.32		$ 900.00	$ 1,995.56	$ 2,161.34	$ 2,895.56	$ 3,061.34		$ (168.55)	$ (165.92)	-41%	-39%
2,439	2625	0	$ 3,303.83	$ 1,749.20	$ 1,882.60	$ 5,053.03	$ 5,186.43		$ 900.00	$ 2,162.22	$ 2,327.12	$ 3,062.22	$ 3,227.12		$ (165.90)	$ (163.28)	-39%	-38%
2,626	2813	1	$ 3,303.83	$ 1,883.32	$ 2,017.43	$ 5,187.15	$ 5,321.26		$ 900.00	$ 2,328.00	$ 2,493.78	$ 3,228.00	$ 3,393.78		$ (163.26)	$ (160.62)	-38%	-36%
2,814	3000	0	$ 3,303.83	$ 2,018.15	$ 2,151.54	$ 5,321.98	$ 5,455.37		$ 900.00	$ 2,494.67	$ 2,659.56	$ 3,394.67	$ 3,559.56		$ (160.61)	$ (157.98)	-36%	-35%
3,001	5000	70	$ 3,303.83	$ 2,152.26	$ 3,585.90	$ 5,456.09	$ 6,889.73		$ 1,800.00	$ 1,760.15	$ 2,932.60	$ 3,560.15	$ 4,732.60		$ (158.00)	$ (179.76)	-35%	-31%
5,001	7000	296	$ 3,303.83	$ 3,586.62	$ 5,020.26	$ 6,890.45	$ 8,324.09		$ 1,800.00	$ 2,933.19	$ 4,105.64	$ 4,733.19	$ 5,905.64		$ (179.77)	$ (201.54)	-31%	-29%
7,001	9000	297	$ 3,303.83	$ 5,020.98	$ 6,454.62	$ 8,324.81	$ 9,758.45		$ 1,800.00	$ 4,106.23	$ 5,278.68	$ 5,906.23	$ 7,078.68		$ (201.55)	$ (223.31)	-29%	-27%
9,001	11000	168	$ 3,303.83	$ 6,455.34	$ 7,888.98	$ 9,759.17	$ 11,192.81		$ 1,800.00	$ 5,279.27	$ 6,451.72	$ 7,079.27	$ 8,251.72		$ (223.33)	$ (245.09)	-27%	-26%
11,001	13000	125	$ 3,303.83	$ 7,889.70	$ 9,323.34	$ 11,193.53	$ 12,627.18		$ 1,800.00	$ 6,452.31	$ 7,624.76	$ 8,252.31	$ 9,424.76		$ (245.10)	$ (266.87)	-26%	-25%
13,001	15000	115	$ 3,303.83	$ 9,324.06	$ 10,757.70	$ 12,627.89	$ 14,061.54		$ 1,800.00	$ 7,625.35	$ 8,797.80	$ 9,425.35	$ 10,597.80		$ (266.88)	$ (288.64)	-25%	-25%
15,001	17000	63	$ 3,303.83	$ 10,758.42	$ 12,192.06	$ 14,062.25	$ 15,495.90		$ 1,800.00	$ 8,798.39	$ 9,970.84	$ 10,598.39	$ 11,770.84		$ (288.66)	$ (310.42)	-25%	-24%
17,001	19000	61	$ 3,303.83	$ 12,192.78	$ 13,626.42	$ 15,496.61	$ 16,930.26		$ 1,800.00	$ 9,971.43	$ 11,143.88	$ 11,771.43	$ 12,943.88		$ (310.43)	$ (332.20)	-24%	-24%
19,001	21000	41	$ 3,303.83	$ 13,627.14	$ 15,060.78	$ 16,930.97	$ 18,364.62		$ 1,800.00	$ 11,144.47	$ 12,316.92	$ 12,944.47	$ 14,116.92		$ (332.21)	$ (353.97)	-24%	-23%
21,001	23000	43	$ 3,303.83	$ 15,061.50	$ 16,495.15	$ 18,365.33	$ 19,798.98		$ 1,800.00	$ 12,317.51	$ 13,489.97	$ 14,117.51	$ 15,289.97		$ (353.99)	$ (375.75)	-23%	-23%
23,001	25000	21	$ 3,303.83	$ 16,495.86	$ 17,929.51	$ 19,799.69	$ 21,233.34		$ 1,800.00	$ 13,490.55	$ 14,663.01	$ 15,290.55	$ 16,463.01		$ (375.76)	$ (397.53)	-23%	-22%
25,001	27000	11	$ 3,303.83	$ 17,930.22	$ 19,363.87	$ 21,234.06	$ 22,667.70		$ 1,800.00	$ 14,663.59	$ 15,836.05	$ 16,463.59	$ 17,636.05		$ (397.54)	$ (419.30)	-22%	-22%
27,001	29000	17	$ 3,303.83	$ 19,364.58	$ 20,798.23	$ 22,668.42	$ 24,102.06		$ 1,800.00	$ 15,836.63	$ 17,009.09	$ 17,636.63	$ 18,809.09		$ (419.32)	$ (441.08)	-22%	-22%
29,001	31000	14	$ 3,303.83	$ 20,798.94	$ 22,232.59	$ 24,102.78	$ 25,536.42		$ 1,800.00	$ 17,009.67	$ 18,182.13	$ 18,809.67	$ 19,982.13		$ (441.09)	$ (462.86)	-22%	-22%
31,001	1440450	68	$ 3,303.83	$ 22,233.30	$ 1,033,062.26	$ 25,537.14	$ 1,036,366.09		$ 1,800.00	$ 18,182.71	$ 844,853.06	$ 19,982.71	$ 846,653.06		$ (462.87)	$ (15,809.42)	-22%	-18%

Residential

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2024

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.
	$ 363,471,238	2

| | | Total Determinants | | Adjusted Determinants | | Recommended | | |

Commercial

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

COMMERCIAL CLASS RATE DESIGN

Select class revenue allocation (1, 2, or 3) and recommended customer charge.

Proposed Revenue	Class Revenue Alloc.
$ 58,259,612	2

Small/Large Rates:						To Implement Small/Large Rates:		
Small	*	304,010	Customer Charge	$	75.00	1. Input Small Customer Charge:	$ 75.00	$ 22,800,750
	*	13,603,609	Usage Rate	$	0.43589	2. Input Large Customer Charge:	$ 150.00	$ 16,282,650
		44.75				3. Input Initial Large Usage Charge:	$ 0.00500	$ 487,417
						Internally Calculated:		
						4. Calculate Small Usage Charge:	$ 0.30500	$ 4,149,101
Large	*	108,551	Customer Charge	$	150.00	5. Revenue Requirement Adjustment:	$ 0.13089	$ 14,539,695
	*	97,483,364	Usage Rate	$	0.13589			
		898.04						
			Calculated Revenue	$	58,260,091			
			Rounding	$	479			

*Source: billing determinants_com.xlsx

Industrial

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

INDUSTRIAL CLASS RATE DESIGN

	Proposed Revenue	Class Revenue Alloc.
	$ 1,902,293	2
	Industrial	
Determinants:		
Bills	1,097	
Volumes	4,477,923	
Recommended		
Customer Charge	$ 1,250.00	
Volumes	$ 0.11849	
Calculated Revenue	$ 1,902,314	
Rounding	22	

Public Authority

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

PUBLIC AUTHORITY CLASS RATE DESIGN

	Proposed Revenue	Class Revenue Alloc.
	$ 9,017,789	2
	Public Authority	
Determinants:		
Bills	32,735	
Volumes	17,975,671	
Recommended		
Customer Charge	$200.00	
Volumes	$ 0.13745	
Calculated Revenue	$ 9,017,787	
Rounding	-2	

Compressed Nat. Gas

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

COMPRESSED NATURAL GAS CLASS RATE DESIGN

	Proposed Revenue	Class Revenue Alloc.
	$ 3,816	2
	CNG	
Determinants:		
Bills	12	
Volumes	0	
Recommended		
Customer Charge	$320.00	
Volumes	$ 0.08831	
Calculated Revenue	$ 3,840	
Rounding	24	

General Transportation

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

TWELVE MONTHS ENDED DECEMBER 31, 2024

GENERAL TRANSPORTATION

	Proposed Revenue	Class Revenue Alloc.	
	$ 12,881,185		2

	General Transportation	Electric Generation Transportation	
Determinants:			
Bills	11,325	12	$ 12.00
MDQ	0	12,709	$ 12,709.00
Volumes	79,391,794	4,263,918	$ 355,326.50
Recommended			
Customer Charge	$500.00	$1,000.00	1,000
Demand Charge	$ —	$ 0.72542	$ 0.73
Volumes	$ 0.08831	$ 0.02000	$ 0.02
Calculated Revenue	$ 12,673,560	$ 207,911	$ 17,326
Rounding		$ 286	

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 or Protective Order issued in this proceeding.

TESTIMONY WORKPAPERS

Testimony Workpapers are being provided in electronic format.