Coffin | Renner

June 30, 2022

To the Honorable Mayors and Council Members:

Attached is a copy of the Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS" or the "Company"), to change gas utility rates within the incorporated areas of the West Texas Service Area ("WTSA") and the Borger Skellytown Service Area ("BSSA"). In addition to the rate and tariff changes contained in the Statement of Intent, TGS is also requesting consolidation of the WTSA, BSSA and North Texas Service Area ("NTSA") into a single West North Service Area ("WNSA"). The filing includes schedules for the proposed WNSA as well as schedules that reflect stand-alone rate calculations for the WNSA, BSSA and NTSA. The combined WNSA data provides the basis for the Company's requested rates. The Company is also providing a version of the WNSA cost of service schedules that is fully integrated and linked to all supporting workpapers. The Company requests that the proposed rates and tariffs contained in the Statement of Intent become effective on August 30, 2022, which is 61 days from the date of this filing. No action on the part of the WTSA Cities or BSSA Cities is required to permit the Company's proposed rates to take effect.

Simultaneous with this city-level filing, the Company is also making a Statement of Intent filing with the Railroad Commission of Texas for the unincorporated areas of the WTSA, BSSA and NTSA in which it is requesting the same rates that are contained in the attached city-level filing. TGS will file a Statement of Intent with the cities in the North Texas Service Area after new rates are approved in this Statement of Intent filing. Although there is no requirement that the Company file testimony with a city-level Statement of Intent filing, the Company is providing the cities with a copy of the testimony that is being filed with the Commission.

If you have any questions, please do not hesitate to contact me.

Best regards,

Kate Norman

Kate Norman
Attorney for Texas Gas Service Company

KWN:ssm
Attachment

cc: Stephanie Houle
Stacey McTaggart

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., STATEMENT OF INTENT TO CHANGE GAS UTILITY RATES WITHIN THE INCORPORATED AREAS OF THE BORGER SKELLYTOWN SERVICE AREA AND WEST TEXAS SERVICE AREA

To All Cities Within Texas Gas Service Company's Borger Skellytown and West Texas 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, 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 incorporated areas of the Borger Skellytown Service Area ("BSSA"), which includes Borger and Skellytown, Texas and the West Texas Service Area ("WTSA"), which includes Andrews, Anthony, Barstow, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas. As part of this Statement of Intent, the Company proposes to consolidate the BSSA, the WTSA, and its North Texas Service Area ("NTSA") into a new service area called the West North Service Area ("WNSA"). Consistent with its request to consolidate service areas, the Company's proposed rates were developed based on the cost of providing service to the entire proposed WNSA. Contemporaneously with this filing, TGS is also filing a Statement of Intent to Change Rates for the unincorporated areas of the WTSA, NTSA and BSSA with the Commission.[1]

The Company requests that the proposed rate schedules and tariffs for the proposed new WNSA, attached to this Statement of Intent as **Exhibit A** and incorporated herein by reference,

[1] With regard to the cities within the NTSA, the Company's consolidation request will result in an overall rate reduction. To facilitate uniform rate implementation within the NTSA and other service areas affected by the consolidation request, the Company will file with the NTSA Cities a request to implement the resulting rate reduction upon receiving approval of the requested consolidation and resulting WNSA rates.

become effective on August 30, 2022, which is 61 days from the date of this filing. No action on the part of the cities is required to permit these proposed rates to take effect. In support of its request, the Company respectfully shows as follows:

I. INTRODUCTION AND SUMMARY OF THE RATE REQUEST

TGS calculated the revenue requirement for this filing using the system-wide cost of providing service to all customers within the incorporated and unincorporated areas of the proposed WNSA.[2] The new rates will affect all customers in the proposed WNSA. Current rate schedules include residential, commercial, commercial transportation, commercial air conditioning, industrial, industrial transportation, public authority, public authority transportation, public authority air conditioning, school and municipal, school and municipal transportation, municipal water pumping, compressed natural gas, compressed natural gas transportation, electrical cogeneration, electrical cogeneration transportation, and standby service.

For the 12-month period ended December 31, 2021, the Company's overall, combined revenue requirement for the proposed WNSA on a system-wide basis totaled approximately $140.5 million, as adjusted. The total revenue TGS received during the test year from customers within the proposed WNSA was approximately $127.5 million, leaving a revenue deficiency on a combined basis of approximately $13.0 million.

If approved, the requested rates will increase TGS's revenues in the proposed WNSA by $13.0 million, which is an increase of 6.27% including gas costs, or 10.19% excluding gas costs. Because the proposed changes will increase TGS's total aggregate revenues within the proposed WNSA 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

[2] The Company's cost to serve Fort Bliss was included in the calculation of the Company's WNSA revenue requirement, however, those costs are fully allocated to Fort Bliss and recovered under the Company's existing contracts with Fort. Bliss. The proposed WNSA rates, therefore, do not include any costs incurred to serve Fort Bliss.

115% of the average of all rates for similar services of all municipalities served by the Company within the same county.

As part of this Statement of Intent, the Company is requesting: (1) Commission approval of new depreciation rates for Direct and Division distribution and general plant within the proposed WNSA; (2) a finding from the Commission that the approvals of the administrative orders by the Gas Services Department of the Commission based on the Accounting Order in Gas Utilities Docket ("GUD") No. 10695 are reasonable and accurate; (3) a finding from the Commission that expenses for Winter Storm Uri and COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (4) a prudence determination for capital investment made in the proposed WNSA through December 31, 2021, including capital investment in the Company's Interim Rate Adjustment ("IRA") filings made since the last rate cases in the WTSA, NTSA and BSSA pursuant to Texas Utilities Code § 104.301;[3] (5) approval of the form of notice pursuant to the proposed Rate Schedule PIT; (6) approval to include Excess Deferred Income Taxes ("EDIT") in base rates, with discontinuance of the EDIT Rider, to return EDIT to customers; and (7) approval to recover the reasonable rate case expenses associated with this filing through a surcharge on rates, as provided by law. The exact amount 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 WNSA rate schedules and tariffs would be applicable to the entire WNSA if consolidation is approved, with minor exceptions for rate schedules or tariffs that apply to a subset of the proposed WNSA.[4] If

[3] The Company is not requesting a prudence determination regarding capital investment within the NTSA Cities because that determination has already been made for investment prior to the 2021 test year and will be addressed in a separate Statement of Intent filing with the NTSA Cities for 2021.

[4] The following rate schedules or tariffs do not or would not apply to the entire WNSA: Rate Schedule URI-Rider, Rate Schedule EDR, Tapping Fees, Rate Schedule E5, and Rate Schedule UGC.

new WNSA tariffs are approved, TGS will need to withdraw the existing WTSA, NTSA, and BSSA tariffs to reflect the new WNSA rates and/or related changes necessary to reflect consolidation. The Company is proposing: (1) a new Small and Large Residential rate design and related rate schedules based on customer usage patterns; (2) new Rate Schedules 70 and 7Z for unmetered gas street lights; (3) new Rate Schedules CNG-1 and CNG-1-ENV for compressed natural gas service; and (4) revisions to the Rules of Service for consistency with Commission rules and other Company service areas. Additional proposed revisions to the Company's rate schedules and tariffs are detailed in Section E of this Statement of Intent.

II. JURISDICTION

TGS is a gas utility as that term is defined in § 101.003(7) of the Texas Utilities Code. Pursuant to Texas Utilities Code § 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 incorporated areas of the proposed WNSA.

III. CONSOLIDATION OF SERVICE AREAS

The Company is proposing to consolidate the WTSA, NTSA and BSSA into a new, combined service area known as the WNSA. The WTSA includes the incorporated 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 their associated environs, including the environs of Fabens and Canutillo, Texas. The NTSA includes the incorporated areas of Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Mineral Wells, Jacksboro, Millsap, Weatherford and Willow Park, Texas and their associated environs as well as Possum Kingdom. The BSSA includes the incorporated and unincorporated areas of Borger and Skellytown, Texas. While the Company's past practice has been to develop separate rates based on the individual costs of service of the BSSA, NTSA and WTSA, the Company seeks in this Statement of Intent, consistent with several prior Commission decisions for TGS, to consolidate these three service areas and use a system-wide cost of service for the entire proposed WNSA. The Company's proposed rates for customers in the WTSA, NTSA, and BSSA are based on the system-wide cost of providing service to the proposed WNSA.

If the Company's consolidation request is not approved, the Company requests approval of new base rates for the WTSA, NTSA, and BSSA based on the separate cost of service schedules for each service area that are included with the Statement of Intent filing.

IV. DETAILS OF PROPOSED CHANGES

A. Rate Filing Package

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

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

B. Test Year

The Company's proposed cost of service for the proposed WNSA as set forth in this Statement of Intent and Rate Filing Package is based on the 12-month period ended December 31, 2021, updated for known changes and conditions that are measurable with reasonable accuracy.

C. Effective Date

The Company requests that the proposed rates be effective for meters read on and after August 30, 2022.

D. Class and Number of Customers Affected

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

Customer Class	BSSA Customers		NTSA Customers		WTSA Customers	
	Incorporated	Environs	Incorporated	Environs	Incorporated	Environs
Residential	4,606	421	12,631	1,448	239,815	24,737
Commercial	447	36	1,793	161	13,870	897
Industrial			8	—	29	3
Public Authority	9	2	180	31	952	112
School and Municipal	41	1	—	—	—	—
Industrial Transportation	—	—	—	—	11	4
Cogeneration Transportation	—	—	—	—	2	—
Commercial Transportation	—	—	—	—	20	—
Public Authority Transportation	—	—	—	—	7	—
Compressed Natural Gas Transport	—	—	—	—	4	—
Custom Transportation	—	—	2	—	6	—
Public Authority AC	—	—	—	—	5	—
Commercial AC	—	—	—	—	128	14
Irrigation	—	—	—	—	8	131
Municipal Water Pumping	—	—	—	—	18	2

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

E. Proposed Rate Schedules and Tariffs

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

1. All proposed WNSA tariffs include a revision to reflect application to the WNSA.

2. All proposed Rate Schedules for General Sales and Transportation Customers include a revision to the "Other Adjustments" section to remove references to Rate Schedule EDIT-Rider, add references to Rate Schedules URI-Rider, UGC, RCE, RCE-Env, and PSF, and remove references to standby charges under "Conditions."

3. Residential Rate Schedules 10, 15, 1Y and 1Z: Add residential builders to the "Applicability" sections, designate Rate Schedules 10 and 1Z as Small Residential and add new 15 and 1Y Large Residential rate schedules.

4. Commercial Rate Schedules: Withdraw Commercial Air Conditioning Rate Schedules 21 and 2A, Commercial Air Conditioning, and serve these customers under Rate Schedules 20 and 2Z.

5. Industrial Rate Schedules 30 and 3Z: Revisions to the "Applicability" section to revise the description of industrial customers.

6. Public Authority Rate Schedules: Withdraw Public Authority Air Conditioning Rate Schedules 41 and 4A, and Municipal Water Pumping Rate Schedules 42 and 4B, and School and Municipal Rate Schedules 48 and 4H, and serve these customers under Rate Schedules 40 and 4Z.

7. Unmetered Gas Light Rate Schedules 70 and 7Z: New rate schedules that provide a mechanism to provide unmetered gas service to customers for gas lighting only.

8. Rate Schedules CNG-1 and CNG-1-ENV: New rate schedules for compressed natural gas service to be used as motor fuel for non-residential customers.

9. Transportation Rate Schedules T-1, T-1-ENV and T-TERMS: Add rates for Compressed Natural Gas and Electrical Cogeneration service; include definitions

for commercial, electrical cogeneration, and industrial service under "Definitions"; add Section 1.3 to clarify Customer and Company rights and responsibilities; make an administrative correction in section 1.5(d); add clarifying language to section 1.6(d) to address upstream pipeline costs that may be incurred by the Company; and add Section 1.8 regarding Liability Limitations.

10. Cost of Gas Clauses 1-INC and 1-ENV: Add clarifying language to section B.3 to include other renewable sources of natural gas; add section B.5 for a Customer Rate Relief charge applicable to certain WNSA customers, authorized by the Commission's Financing Order in Case No. OS-21-00007061; add clarifying language to sections B, D, E, F and I to make consistent with approved Cost of Gas clauses in GUD Nos. 10656, 10739, 10766, and 10928; include language for the use of financial instruments in sections B.3, B.6, B.8, H, and I.5 in the incorporated tariff to make consistent with the recently approved cost of gas clause in GUD No. 10928.

11. Rate Schedule WNA: Updated weather factors for each class consistent with weather normalization calculation in this case.

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

13. Rate Schedule UGC-Rider: Provides a new tariff to recover uncollected Gas Reliability Infrastructure Program (GRIP) charges from certain WNSA customers.

14. Rules of Service: Revisions for consistency with the Commission's Quality of Service Rules. In addition, the Company proposes:

    a. Updating § 1.3, Definitions, so all definitions are consistent with definitions in this approved Rules of Service from GUD Nos. 10739, 10766, and 10928 as well as add a definition for "electrical cogeneration service," while removing definition for "power generation service" to establish consistency with terminology used across all proposed WNSA tariffs;
    b. Revisions to § 3 to include language for the availability of rate schedules on the Company's website;
    c. Revisions to § 4.4 to remove a reference to the Company's curtailment plans and § 4.4(iv) to include curtailment language consistent with the new Commission Rule § 7.455;

d. Revisions to § 4.9 to add language regarding force majeure situations to the limitation of liability provision;
e. Revision to § 4.6, § 7.4, § 7.7, § 9.1 and § 9.6 to provide for electronic billing and notice;
f. Revisions to § 9.9 (previously § 20.1) to update the language to reflect the current plan description for Average Payment Plan;
g. Revisions to the table in § 13.1 (previously § 11.1) to include all WNSA atmospheric and standard serving pressures;
h. Revisions to § 15 (previously § 21), Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas; and
i. Withdraw the rules of service addenda WTSA-Env 7-45; WTSA-Env 7-46; WTSA-EFV; NTSA-Env 7-46 and BSSA-Env 7-46, as these provisions have been included within the proposed WNSA Rules of Service in Sections 7.5, 7.7 and 8.3(f).

15. Withdraw Standby Service Rate Schedule SS, Dell City Cost of Gas Clauses 1-INC-DC and 1-ENV-DC, and Rate Schedule EDIT-Rider.

F. Effect of Proposed Rate Changes

The specific proposed changes to the Company's rates are shown in the following table of existing and proposed rates for customers in the proposed WNSA:

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Residential							
Customers Affected	4,606	421	12,631	1,448	239,815	24,737	
Customer Charge	$16.48	$16.48	$15.44	$24.50	$23.53	$23.53	$20.00 (Small) $35.00 (Large)
Ccf	$0.21548	$0.21548	$0.67101	$0.59366	$0.09317	$0.09317	$0.41173 (Small) $0.00264 (Large)

<table>
<tr><td></td><td colspan="6">Incorporated (“Inc”) and Unincorporated/Environs (“Env”)
Current Rates</td><td></td></tr>
<tr><td>Customer Class</td><td>BSSA Inc</td><td>BSSA Env</td><td>NTSA Inc</td><td>NTSA Env</td><td>WTSA Inc</td><td>WTSA Env</td><td>Proposed WNSA</td></tr>
<tr><td colspan="8">Commercial</td></tr>
<tr><td>Customers Affected</td><td>447</td><td>36</td><td>1,793</td><td>161</td><td>13,870</td><td>897</td><td></td></tr>
<tr><td>Customer Charge</td><td>$39.11</td><td>$39.11</td><td>$47.80</td><td>$76.33</td><td>$63.58</td><td>$63.58</td><td>$75.00</td></tr>
<tr><td>Ccf</td><td>$0.29344</td><td>$0.29344</td><td>$0.68165</td><td>$0.60165</td><td>$0.08223
(First 500 Ccf)
$0.06223
(All Over 500 Ccf)</td><td>$0.08223
(First 500 Ccf)
$0.06223
(All Over 500 Ccf)</td><td>$0.06808</td></tr>
<tr><td colspan="8">Commercial Transportation</td></tr>
<tr><td>Customers Affected</td><td></td><td></td><td></td><td></td><td>20</td><td></td><td></td></tr>
<tr><td>Customer Charge</td><td>$254.11</td><td>$254.11</td><td>$250.00</td><td>$286.33</td><td>$424.58</td><td>$424.58</td><td>$500.00</td></tr>
<tr><td>Ccf</td><td>$0.29344</td><td>$0.29344</td><td>$0.57978</td><td>$0.57978</td><td>$0.08223
(First 500 Ccf)
$0.06223
(All Over 500 Ccf)</td><td>$0.08223
(First 500 Ccf)
$0.06223
(All Over 500 Ccf)</td><td>$0.06808</td></tr>
<tr><td colspan="8">Commercial Air Conditioning (Withdrawing)</td></tr>
<tr><td>Customers Affected</td><td></td><td></td><td></td><td></td><td>128</td><td>14</td><td></td></tr>
<tr><td>Customer Charge</td><td></td><td></td><td></td><td></td><td>$63.58</td><td>$63.58</td><td rowspan="2">Reclass to Commercial</td></tr>
<tr><td>Ccf</td><td></td><td></td><td></td><td></td><td>October - April
$0.08223
(First 500 Ccf)
$0.06223
(All Over 500 Ccf)

May – September
$0.06223
(First 500 Ccf)
$0.04223
(All Over 500 Ccf)</td><td>October - April
$0.08223
(First 500 Ccf)
$0.06223
(All Over 500 Ccf)

May – September
$0.06223
(First 500 Ccf)
$0.04223
(All Over 500 Ccf)</td></tr>
</table>

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Industrial							
Customers Affected			8		29	3	
Customer Charge			$308.59	$509.26	$857.20	$857.20	$850.00
Ccf			$0.62874	$0.55395	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.08875
Industrial Transportation							
Customers Affected					11	4	
Customer Charge			$250.00	$509.26	$424.58	$424.58	$1,050.00
Ccf			$0.55395	$0.55395	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.08875
Public Authority							
Customers Affected	9	2	180	31	952	112	
Customer Charge	$49.07	$49.07	$101.32	$160.93	$195.79	$195.79	$200.00
Ccf	$0.23148	$0.23148	$0.61329	$0.54101	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11113
Public Authority Transportation							
Customers Affected					7		
Customer Charge	$254.07	$254.07	$250.00	$325.93	$495.79	$495.79	$500.00
All Ccf	$0.23148	$0.23148	$0.54101	$0.54101	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11113

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Public Authority Air Conditioning (Withdrawing)							
Customers Affected					5		
Customer Charge					$195.79	$195.79	Reclass to Public Authority
Ccf					*October – April* $0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf) *May – September* $0.08461 (First 500 Ccf) $0.06461 (All Over 500 Ccf)	*October – April* $0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf) *May – September* $0.08461 (First 500 Ccf) $0.06461 (All Over 500 Ccf)	
Electrical Cogeneration							
Customers Affected							
Customer Charge					$424.58	$424.58	$700.00
Ccf					*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05260 (First 5,000 Ccf) $0.04260 (Next 95,000 Ccf) $0.03260 (Next 300,000 Ccf) $0.02260 (All Over 400,000 Ccf) *May – September* $0.04259 (First 5,000 Ccf) $0.03258 (Next 95,000 Ccf) $0.02259 (Next 300,000 Ccf) $0.01258 (All Over 400,000 Ccf)

	Incorporated (“Inc”) and Unincorporated/Environs (“Env”) Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Electrical Cogeneration Transportation							
Customers Affected					2		
Customer Charge					$424.58	$424.58	$700.00
Ccf					*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05260 (First 5,000 Ccf) $0.04260 (Next 95,000 Ccf) $0.03260 (Next 300,000 Ccf) $0.02260 (All Over 400,000 Ccf) *May – September* $0.04259 (First 5,000 Ccf) $0.03258 (Next 95,000 Ccf) $0.02259 (Next 300,000 Ccf) $0.01258 (All Over 400,000 Ccf)
School and Municipal (Withdrawing)							
Customers Affected	41	1					
Customer Charge	$56.80	$56.80					Reclass to Public Authority
Ccf	$0.37651	$0.37651					
School and Municipal Transportation (Withdrawing)							
Customers Affected							
Customer Charge	$261.80	$261.80					Reclass to Public Authority Transportation
Ccf	$0.37651	$0.37651					

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Municipal Water Pumping (Withdrawing)							
Customers Affected					18	2	
Customer Charge					$768.75	$768.75	Reclass to Public Authority
Ccf					$0.06111 (First 5,000 Ccf) $0.05111 (All Over 5,000 Ccf)		
Compressed Natural Gas (Proposed)							
Customers Affected							
Customer Charge							$150.00
Ccf							$0.07652
Compressed Natural Gas Transportation (Reclassed from Commercial)							
Customers Affected					1		Reclassed from Commercial
Customer Charge					$424.58	$424.58	$450.00
Ccf					$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.07652

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Compressed Natural Gas Transportation (Reclassed from Public Authority)							
Customers Affected					3		Reclassed from Public Authority
Customer Charge					$495.79	$495.79	$450.00
Ccf					$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.07652

Exhibit C shows the average bill impact by customer class.

G. Witness Testimony

Although not required, the Company is including as **Exhibit D** to the Statement of Intent direct testimony supporting the Company's requested revenue requirement. The attached testimony includes the following witnesses:

- *Shantel Norman* is Vice-President of Operations for TGS. Ms. Norman provides an overview of operations within the proposed WNSA; introduces the TGS witnesses filing testimony in support of the SOI; supports the proposed consolidation to create the WNSA; addresses TGS's efforts during COVID-19 and Winter Storm Uri; addresses the reasonableness and necessity of capital investment and Operations and Maintenance (O&M) expenses; addresses ONE Gas' response to Winter Storm Uri and COVID-19; and addresses the Company's Pipeline Integrity Testing Program.

- *Stacey L. McTaggart* is the Rates and Regulatory Director for TGS. Ms. McTaggart provides an overview of the cost of service and overall revenue requirement calculation and supports TGS's Direct rate case and Direct expense adjustments; addresses the Company's request to consolidate its existing WTSA, NTSA, and BSSA into a new consolidated service area, the WNSA; describes the Company's compliance with certain regulatory and statutory requirements, including affiliate cost recovery issues related to Utility Insurance Company ("UIC"); addresses the Company's proposed EDIT adjustment to return EDIT to customers, the treatment of cloud-based computing costs, TGS's recovery of costs associated with COVID-19 and Winter Storm URI, the Company's recovery of pipeline integrity testing costs, and the Company's recovery of rate case expenses; and describes the proposed WNSA rate schedules and tariffs as well as rate schedules and tariffs currently in effect for the WTSA, NTSA, and BSSA.

- *Stacey R. Borgstadt* is Director Rates and Regulatory Analysis for ONE Gas and supports certain TGS Division and Corporate capital investment that is included in the WNSA revenue requirement as well as Corporate depreciation and amortization expense and the cost allocation methodology used to determine TGS's share of allocated costs and certain Corporate expense adjustments, and explains Direct, TGS Division and Corporate expense adjustments related to payroll and incentive compensation.

- *Jeff D. Branz* is the Director of Compensation and Benefits for ONE Gas. Mr. Branz addresses the reasonableness of ONE Gas' compensation philosophy and structure, as well as related costs for base pay, incentive plans and benefits.

- *Mark W. Smith* is a Vice-President and the Treasurer for ONE Gas. Mr. Smith supports the recovery of a return on the Company's prepaid pension asset and describes ONE Gas' captive insurance company, UIC, and interest rate and equity return issues.

- *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.

- *Jeffrey J. Husen* is a Vice-President and the Chief Accounting Officer and Controller for ONE Gas. Mr. Husen describes the calculation of the Company's EDIT.

- *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.

- *Ronald E. White* is an engineer and President of Foster Associates Consultants, LLC. Dr. White sponsors a study of the depreciation rates for TGS plant located in the proposed WNSA and for common facilities shared among all TGS service areas, including Corporate assets.

- *Bruce H. Fairchild* is a financial accountant and former professor and regulator. Dr. Fairchild is a principal with Financial Concepts and Applications, Inc. Dr. Fairchild supports TGS's requested return on equity, cost of debt, capital structure, and overall return on invested capital.

- *Teresa Serna* is a Rates Specialist for TGS. Ms. Serna supports TGS's revenue adjustments, and describes the class cost of service study and supports TGS's proposed class revenue allocation.

- *Paul H. Raab* is an independent economic consultant, and describes and supports TGS's proposed rate design.

V. RATE CASE EXPENSES

Pursuant to Texas Utilities Code § 104.051, 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

The Company will promptly undertake to notify the public of the proposed change in its gas rates consistent with the requirements of Texas Utilities Code § 104.103. The public notice that TGS will provide regarding the requested change in rates for the proposed WNSA is attached as **Exhibit E** to the Statement of Intent. The Company will submit proof of notice promptly upon completion thereof along with a copy of the notice.

VII. COMPANY REPRESENTATIVES FOR NOTIFICATION

TGS's authorized representatives are:

Stephanie G. Houle
Stacey L. McTaggart
Stacey R. Borgstadt
Texas Gas Service Company
Barton Skyway IV
1301 S. Mopac, Suite 400
Austin, Texas 78746
512-370-8354
512-370-8440 (fax)
Stephanie.Houle@onegas.com
Stacey.Borgstadt@onegas.com
Stacey.McTaggart@onegas.com

and

Kate Norman
C. Glenn Adkins
Coffin Renner LLP
1011 W. 31st Street
Austin, Texas 78705
512-879-0900
512-879-0912 (fax)
kate.norman@crtxlaw.com
glenn.adkins@crtxlaw.com

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

VIII. PROTECTIVE AGREEMENT

The Company's Rate Filing Package includes certain confidential materials. In addition, the scope of discovery in this case may require the production of additional confidential material. Accordingly, TGS attaches as **Exhibit F** to this Statement of Intent a Protective Agreement to be used in this case. TGS will provide confidential material upon execution of Exhibit A attached to the Protective Agreement.

IX. CONCLUSION

TGS requests that: (1) rates are approved for the proposed WNSA consistent with those proposed herein, to become effective for meters read on and after August 30, 2022; (2) consolidation of the existing WTSA, NTSA, and BSSA is approved to create the WNSA; (3) the Commission approve new depreciation rates for Direct and Division distribution and general plant; (4) the Commission find the approvals of the administrative orders by the Gas Services Department of the Commission based on the Accounting Order in GUD No. 10695 are reasonable and accurate; (5) the Commission find that expenses for Winter Storm Uri and COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (6) capital investment made in the proposed WNSA through December 31, 2021, including capital investment in the Company's IRA filings made since the last rate cases in the WTSA, NTSA and BSSA pursuant to Texas Utilities Code § 104.301, is deemed prudent; (7) form of notice for the proposed Rate Schedule PIT be approved; (8) including EDIT in base rates, with discontinuance of the EDIT Rider, to return EDIT to customers be approved; (9) all reasonable rate case expenses incurred in connection with this Statement of Intent filing are authorized for recovery by the Company; and (10) for such further relief to which the Company may be entitled.

Respectfully submitted,

By: Kate Norman

Stephanie G. Houle
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glenn.adkins@crtxlaw.com

ATTORNEYS FOR TEXAS GAS SERVICE COMPANY

SMALL RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a small residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential consumer 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 West-North Service Area, which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$20.00 plus
All Ccf per monthly billing period @	$0.41173 per Ccf

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

Annual Normalized Volume Less than 420 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 420 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 provisions of the Cost of Gas Clause, Rate Schedule 1-INC.

Supersedes Rate Schedule Dated	Meters Read On and After
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

SMALL RESIDENTIAL SERVICE RATE (Continued)

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

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

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

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

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

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
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

LARGE RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a large residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential consumer 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 West-North Service Area, which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$35.00 plus
All Ccf per monthly billing period @	$0.00264 per Ccf

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

Annual Normalized Volume Less than 420 Ccf	Small Residential, Rate Schedule 10
Annual Normalized Volume 420 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 provisions of the Cost of Gas Clause, Rate Schedule 1-INC.

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, if applicable.

Initial Rate Schedule	Meters Read On and After
	TBD

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

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

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

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

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to commercial consumers and to consumers not otherwise specifically provided for under any other rate schedule.

TERRITORY

The incorporated areas of the West-North Service Area, which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$75.00 plus
All Ccf per monthly billing period @	$0.06808 per Ccf

OTHER ADJUSTMENTS

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

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

COMMERCIAL SERVICE RATE (Continued)

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

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

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

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
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

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 West-North Service Area, which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$850.00 plus
All Ccf per monthly billing period @	$0.08875 per Ccf

OTHER ADJUSTMENTS

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

INDUSTRIAL SERVICE RATE (Continued)

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

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

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
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

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 West-North Service Area, which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$200.00 plus
All Ccf per monthly billing period @	$0.11113 per Ccf

OTHER ADJUSTMENTS

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

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, 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.

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

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated
January 27, 2022 (Borger/Skellytown Service Area)
November 28, 2018 (North Texas Service Area)
June 28, 2021 (All West Texas cities except El Paso)
August 3, 2021 (City of El Paso)

Meters Read On and After
TBD

PUBLIC AUTHORITY SERVICE RATE (Continued)

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

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

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

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.
West-North Service Area **RATE SCHEDULE 70**

UNMETERED GAS LIGHT SERVICE RATE

APPLICABILITY

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

TERRITORY

The incorporated areas of the West-North Service Area which includes 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.

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	$0.41173 per Ccf
Commercial	$0.06808 per Ccf
Industrial	$0.08875 per Ccf
Public Authority	$0.11113 per Ccf

OTHER ADJUSTMENTS

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

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

CONDITIONS

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

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

Initial Rate Schedule

Meters Read On and After
TBD

ELECTRICAL COGENERATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any customer who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc. to use natural gas for the purpose of cogeneration. Cogeneration is defined as the use of thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.

TERRITORY

This rate shall be available in the incorporated areas of the West-North Service Area which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A Customer Charge of $700.00 plus

		Oct. - April Winter	May - Sept. Summer
The First	5,000 Ccf	$0.05260 per Ccf	$0.04259 per Ccf
The Next	95,000 Ccf	$0.04260 per Ccf	$0.03258 per Ccf
The Next	300,000 Ccf	$0.03260 per Ccf	$0.02259 per Ccf
All Over	400,000 Ccf	$0.02260 per Ccf	$0.01258 per Ccf

OTHER ADJUSTMENTS

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

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, 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.

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

Supersedes Rate Schedule Dated
June 28, 2021 (All West Texas cities except El Paso)
August 3, 2021 (City of El Paso)

Meters Read On and After
TBD

ELECTRICAL COGENERATION SERVICE RATE (Continued)

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

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

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

3. To qualify for the summer discounts, the customers' peak summer months load must be at least 75 percent of the customers' peak winter months load. Failure to meet this requirement will result in an adjustment to the customers' October bill equal to the difference between the winter and summer rates times that year's total May through September consumption by that customer.

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

COMPRESSED NATURAL GAS SERVICE RATE

APPLICABILITY

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

TERRITORY

The incorporated areas of the West-North Service Area, which includes 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.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$150.00 plus
All Ccf per monthly billing period @	$0.07652 per Ccf

OTHER ADJUSTMENTS

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

Economic Development Rider: The billing shall reflect adjustments in accordance with provisions of the Economic Development Rider, Rate Schedule EDR, 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.

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

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

Uncollected GRIP Charges Surcharge: The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, Rate Schedule UGC-Rider, if applicable.

Initial Rate Schedule	Meters Read On and After TBD

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

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

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

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

5. Compressor station subject to inspection by Company engineers.

SMALL RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a small residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential consumer 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 West-North Service Area, which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	\$20.00 plus
All Ccf per monthly billing period @	\$0.41173 per Ccf

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

Annual Normalized Volume Less than 420 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 420 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 provisions of the Cost of Gas Clause, Rate Schedule 1-ENV.

Supersedes Rate Schedule Dated
January 11, 2022 (Billing Implementation January 27, 2022 - Borger/Skellytown Service Area)
October 12, 2021 (Billing Implementation October 27, 2021 - North Texas Service Area, Rate Schedule 1A)
June 28, 2021 (West Texas Service Area)

Meters Read On and After
TBD

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

Taxes: Plus applicable taxes and fees related to above.

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

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

LARGE RESIDENTIAL SERVICE RATE

APPLICABILITY

Applicable to a large residential customer or builder in a single dwelling, or in a dwelling unit of a multiple dwelling or residential apartment, for domestic purposes. A residential consumer 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 West-North Service Area, which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$35.00 plus
All Ccf per monthly billing period @	$0.00264 per Ccf

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

Annual Normalized Volume Less than 420 Ccf	Small Residential, Rate Schedule 1Z
Annual Normalized Volume 420 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 provisions of the Cost of Gas Clause, Rate Schedule 1-ENV.

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

Initial Rate Schedule	Meters Read On and After
	TBD

LARGE RESIDENTIAL SERVICE RATE (Continued)

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

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

Taxes: Plus applicable taxes and fees related to above.

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

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

COMMERCIAL SERVICE RATE

APPLICABILITY

Applicable to commercial consumers and to consumers not otherwise specifically provided for under any other rate schedule.

TERRITORY

Environs of the West-North Service Area, which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$75.00 plus
All Ccf per monthly billing period @	$0.06808 per Ccf

OTHER ADJUSTMENTS

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

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

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

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

Taxes: Plus applicable taxes and fees related to above.

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 11, 2022 (Billing Implementation January 27, 2022 - Borger/Skellytown Service Area) October 12, 2021 (Billing Implementation October 27, 2021 - North Texas Service Area, Rate Schedule 2A) June 28, 2021 (West Texas Service Area)	TBD

COMMERCIAL SERVICE RATE (Continued)

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

INDUSTRIAL SERVICE RATE

APPLICABILITY

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

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

TERRITORY

Environs of the West-North Service Area, which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	\$850.00 plus
All Ccf per monthly billing period @	\$0.08875 per Ccf

OTHER ADJUSTMENTS

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

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

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

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

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated	Meters Read On and After
January 11, 2022 (Billing Implementation January 27, 2022 - Borger/Skellytown Service Area) October 12, 2021 (Billing Implementation October 27, 2021 - North Texas Service Area, Rate Schedule 3A) June 28, 2021 (West Texas Service Area)	TBD

INDUSTRIAL SERVICE RATE (Continued)

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

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 West-North Service Area which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$200.00 plus
All Ccf per monthly billing period @	$0.11113 per Ccf

OTHER ADJUSTMENTS

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

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

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

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

Taxes: Plus applicable taxes and fees related to above.

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 11, 2022 (Billing Implementation January 27, 2022 - Borger/Skellytown Service Area) October 12, 2021 (Billing Implementation October 27, 2021 - North Texas Service Area, Rate Schedule 4A) June 28, 2021 (West Texas Service Area)	TBD

PUBLIC AUTHORITY SERVICE RATE (Continued)

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

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.
West-North Service Area **RATE SCHEDULE 7Z**

UNMETERED GAS LIGHT SERVICE RATE

APPLICABILITY

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

TERRITORY

Environs of the West-North Service Area which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

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

Residential	$0.41173 per Ccf
Commercial	$0.06808 per Ccf
Industrial	$0.08875 per Ccf
Public Authority	$0.11113 per Ccf

OTHER ADJUSTMENTS

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

Taxes: Plus applicable taxes and fees related to above.

CONDITIONS

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

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

Initial Rate Schedule	Meters Read On and After
	TBD

ELECTRICAL COGENERATION SERVICE RATE

APPLICABILITY

Service under this rate schedule is available to any customer who enters into a contract with Texas Gas Service Company, a Division of ONE Gas, Inc. to use natural gas for the purpose of cogeneration. Cogeneration is defined as the use of thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.

TERRITORY

This rate shall be available in the unincorporated areas of the West-North Service Area which includes Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A Customer Charge of $700.00 plus

		Oct. - April Winter	May - Sept. Summer
The First	5,000 Ccf	$0.05260 per Ccf	$0.04259 per Ccf
The Next	95,000 Ccf	$0.04260 per Ccf	$0.03258 per Ccf
The Next	300,000 Ccf	$0.03260 per Ccf	$0.02259 per Ccf
All Over	400,000 Ccf	$0.02260 per Ccf	$0.01258 per Ccf

OTHER ADJUSTMENTS

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

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

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

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

Taxes: Plus applicable taxes and fees related to above.

Supersedes Rate Schedule Dated
June 28, 2021 (West Texas Service Area)

Meters Read On and After
TBD

ELECTRICAL COGENERATION SERVICE RATE (Continued)

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

CONDITIONS

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

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

3. To qualify for the summer discounts, the customers' peak summer months load must be at least 75 percent of the customers' peak winter months load. Failure to meet this requirement will result in an adjustment to the customers' October bill equal to the difference between the winter and summer rates times that year's total May through September consumption by that customer.

4. 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-ENV**
West-North 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 West-North Service Area, which includes the unincorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

COST OF SERVICE RATE

During each monthly billing period:

A customer charge per meter per month of	$150.00 plus
All Ccf per monthly billing period @	$0.07652 per Ccf

OTHER ADJUSTMENTS

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

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

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

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

Taxes: Plus applicable taxes and fees related to above.

Winter Storm Uri Surcharge Rider: The billing shall reflect adjustments in accordance with provisions of the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, if applicable.

Initial Rate Schedule

Meters Read On and After
TBD

COMPRESSED NATURAL GAS SERVICE RATE
(Continued)

CONDITIONS

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

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

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

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

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

COST OF GAS CLAUSE

A. APPLICABILITY

This Cost of Gas Clause shall apply to all gas sales service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") in all incorporated areas of its West-North Service Area including 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.

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, if applicable, the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, and the revenue associated fees (including franchise fees) and taxes. The Cost of Gas will also include the FERC Intervention Costs.

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

3. Cost of Purchased Gas – The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average prudently incurred 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). Renewable Natural Gas 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. The Cost of Purchased Gas may also include the cost of carbon "Environmental Attributes" purchased and retired in association with the purchase of Renewable Natural Gas. Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of Renewable Natural Gas, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions. The Cost of Purchased Gas shall also 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 the Company shall not be allowed to charge fees for transactions related to natural gas financial instruments utilized for purposes in this Cost of Gas Clause and hence cannot realize a profit in this regard.

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, if applicable, which is a non-bypassable charge as defined in Tex. Util. Code § 104.362(7).

5. Reconciliation Component – The amount to be returned to or recovered from sales customers each month from December through August 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 August to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total prudently incurred amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its sales customers during the period, including prudently incurred gains or losses on the use of natural gas financial instruments; (b) the revenues received from operation of the provisions of this Cost of Gas Clause reduced by the amount of revenue associated fees (including franchise fees) and taxes paid by the Company on those revenues; (c) the total amount of surcharges or refunds made to sales customers during the period and any other revenues or credits received by the Company as a result of relevant gas purchases or operation of this Cost of Gas Clause; (d) the total amount accrued for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; (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.

7. Purchase/Sales Ratio – A ratio determined by dividing the total sales 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 14.73 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 prudently incurred 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 prudently incurred gains or losses on the use of natural gas financial instruments; (b) the revenues produced by the operation of this Cost of Gas Clause reduced by the amount of fees (including franchise fees) and taxes; (c) refunds, payments, or charges provided for herein or as approved by the regulatory authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s); (e) 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, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

COST OF GAS CLAUSE (Continued)

9. FERC Intervention Costs – Costs prudently incurred from outside vendors and attorneys for the purpose of protecting the interest of sales customers in the West-North Service Area 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 prudently incurred internal travel expenses related to this purpose.

10. 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.

11. Applicable in the incorporated area of Weatherford, Texas, only. The "revenue associated fees" referenced in Section B.1 of the Cost of Gas Clause 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.

C. COST OF GAS

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

D. DETERMINATION AND APPLICATION OF THE RECONCILIATION COMPONENT

If the Reconciliation Audit reflects either an over recovery or under recovery of revenues, such amount, plus or minus the amount of interest calculated pursuant to Section E below, if any, shall be divided by the sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the December billing cycle through the August 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 December billing cycle and continuing through the next August 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, including any cost of gas inventory in storage and margins on non-utility transactions as described in paragraph "G" below, within the period of audit. The Company shall debit or credit to the Reconciliation Account for each month of the reconciliation period:

COST OF GAS CLAUSE (Continued)

(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 suppliers 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 divided between the Company and ratepayers with the Company retaining 33 1/3% of aggregate annual Net Margins generated from such activities and 66 2/3% shall be credited to sales customers in the month during which the transaction closes. 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 within the West-North Service Area: off-system sales of natural gas, releases of transportation or storage capacity, financial arbitrage of storage inventories, trading of natural gas inventories, and use of financial instruments pertaining to purchase, storage, and/or transportation of natural gas, so long as such instruments are not intended to hedge the cost of system supplies. “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 allocated to ratepayers shall be credited to the ratepayers once per year through an adjustment of the Reconciliation Account as determined in the Annual Reconciliation filing. The Company shall be fully responsible for any aggregate annual net losses incurred from such activities and no such losses shall be paid by the ratepayers. This provision does not permit the Company to include in the calculation of gas cost storage, or gas stored except as prudently and necessarily needed to serve sales customers in this service area.

COST OF GAS CLAUSE (Continued)

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, if applicable; (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.

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 by month for the 12 months ending August 31.

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 West-North Service Area sales customers.

5. A description of the hedging activities conducted each month during the 12 months ending August 31, 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 within the service area, including monthly imbalances incurred, the monthly balances 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.

COST OF GAS CLAUSE (Continued)

This report shall be filed concurrently with the Cost of Gas Statement for December. The Company shall provide complete detail within 20 days of request by a representative of the City of El Paso, other municipality or Regulatory Authority. 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.

J. SUPPORTING MATERIAL ACCOMPANYING ANNUAL RECONCILIATION REPORT

For the City of El Paso, the Company shall file supporting materials with its Annual Reconciliation Report to demonstrate that gas costs were acquired during ordinary and atypical periods at the lowest prudently incurred price and necessary to provide reliable service to retail customers.

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 West-North Service Area including Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas.

B. DEFINITIONS

1. Cost of Gas – The rate per billing unit or the total calculation under this clause, consisting of the Commodity Cost, the Customer Rate Relief Component, if applicable, the Reconciliation Component, any surcharges or refunds, Uncollectible Cost of Gas, and the revenue associated fees and taxes. The Cost of Gas will also include the FERC Intervention Costs.

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

3. Cost of Purchased Gas – The estimated cost for gas purchased by the Company from its suppliers or the estimated weighted average prudently incurred 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). Renewable Natural Gas 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. The Cost of Purchased Gas may also include the cost of carbon "Environmental Attributes" purchased and retired in association with the purchase of Renewable Natural Gas. Environmental Attributes means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the production and delivery of Renewable Natural Gas, including but not limited to: (1) any avoided emissions of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4) and other greenhouse gases; (3) displacement or avoidance of any amount of conventional gas or fossil energy generation resources; and (4) the reporting rights to these avoided emissions. 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 may 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, if applicable, which is a non-bypassable charge as defined in Tex. Util. Code § 104.362(7).

5. Reconciliation Component – The amount to be returned to or recovered from sales customers each month from December through August 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 August to determine the amount of over or under collection occurring during such 12-month period. The audit shall determine: (a) the total prudently incurred amount paid for gas purchased by the Company (per Section B(3) above) to provide service to its sales customers during the period, including prudently incurred gains or losses on the approved use of natural gas financial instruments; (b) the revenues received from operation of the provisions of this Cost of Gas Clause reduced by the amount of revenue associated fees and taxes paid by the Company on those revenues; (c) the total amount of surcharges or refunds made to sales customers during the period and any other revenues or credits received by the Company as a result of relevant gas purchases or operation of this Cost of Gas Clause; (d) the total amount accrued for imbalances under the transportation rate schedule(s) net of fees and applicable taxes; (e) the total amount of Uncollectible Cost of Gas during the period; (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.

7. Purchase/Sales Ratio – A ratio determined by dividing the total sales 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 14.73 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 prudently incurred 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 prudently incurred gains or losses on the use of approved natural gas financial instruments; (b) the revenues produced by the operation of this Cost of Gas Clause reduced by the amount of fees and taxes; (c) refunds, payments, or charges provided for herein or as approved by the regulatory authority; (d) amounts accrued pursuant to the treatment of imbalances under any transportation rate schedule(s); (e) 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, for lost and unaccounted for gas during the period in excess of 5 percent of purchases.

COST OF GAS CLAUSE (Continued)

9. FERC Intervention Costs – Costs prudently incurred from outside vendors and attorneys for the purpose of protecting the interest of sales customers in the West-North Service Area 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 prudently incurred internal travel expenses related to this purpose.

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

C. COST OF GAS

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

D. DETERMINATION AND APPLICATION OF THE RECONCILIATION COMPONENT

If the Reconciliation Audit reflects either an over recovery or under recovery of revenues, such amount, plus or minus the amount of interest calculated pursuant to Section E below, if any, shall be divided by the sales volumes, adjusted for the effects of weather, growth, and conservation for the period beginning with the December billing cycle through the August 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 December billing cycle and continuing through the next August 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, including any cost of gas inventory in storage and margins on non-utility transactions as described in paragraph "G" below, 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.

COST OF GAS CLAUSE (Continued)

F. SURCHARGE OR REFUND PROCEDURES

In the event that the rates and charges of the Company's suppliers 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 divided between the Company and ratepayers with the Company retaining 33 1/3% of aggregate annual Net Margins generated from such activities and 66 2/3% shall be credited to sales customers in the month during which the transaction closes. 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 within the West-North Service Area: off-system sales of natural gas, releases of transportation or storage capacity, financial arbitrage of storage inventories, trading of natural gas inventories, and use of financial instruments pertaining to purchase, storage, and/or transportation of natural gas, so long as such instruments are not intended to hedge the cost of system supplies. “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 allocated to ratepayers shall be credited to the ratepayers once per year through an adjustment of the Reconciliation Account as determined in the Annual Reconciliation filing. The Company shall be fully responsible for any aggregate annual net losses incurred from such activities and no such losses shall be paid by the ratepayers. This provision does not permit the Company to include in the calculation of gas cost storage, or gas stored except as prudently and necessarily needed to serve sales customers in this service area.

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, if applicable; (e) the Reconciliation Component; (f) the revenue associated fees and taxes to be applied to revenues generated by the Cost of Gas; (g) the Cost of Gas calculation, including gains and losses from approved hedging activities for the month; and (h) the beginning and ending date of the billing period. The statement shall include all data necessary for the Regulatory Authority to review and verify the calculations of the Cost of Gas.

COST OF GAS CLAUSE (Continued)

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 by month for the 12 months ending August 31.

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 West-North Service Area sales customers.

5. A description of the hedging activities conducted each month during the 12 months ending August 31, 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 within the service area, including monthly imbalances incurred, the monthly balances 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.

This report shall be filed concurrently with the Cost of Gas Statement for December. 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.

TRANSPORTATION SERVICE RATE

APPLICABILITY

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

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

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's West-North Service Area distribution system which includes the incorporated areas 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. Such service shall be provided at any point on the Company's System where adequate capacity and gas supply exists, or where such capacity and gas supply can be provided in accordance with the applicable rules and regulations and at a reasonable cost as determined by the Company in its sole opinion.

COST OF SERVICE RATE

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

Commercial	$500.00 per month
Industrial	$1,050.00 per month
Public Authority	$500.00 per month
Compressed Natural Gas	$450.00 per month
Electrical Cogeneration	$700.00 per month

TRANSPORTATION SERVICE RATE (Continued)

Plus – All Ccf per monthly billing period listed by customer class as follows:

Commercial	$0.06808 per Ccf
Industrial	$0.08875 per Ccf
Public Authority	$0.11113 per Ccf
Compressed Natural Gas	$0.07652 per Ccf

Electrical Cogeneration	Oct. – Apr. (Winter)	
	First 5,000 Ccf @	$0.05260 per Ccf
	Next 95,000 Ccf @	$0.04260 per Ccf
	Next 300,000 Ccf @	$0.03260 per Ccf
	All Over 400,000 Ccf @	$0.02260 per Ccf
	May – Sept. (Summer)	
	First 5,000 Ccf @	$0.04259 per Ccf
	Next 95,000 Ccf @	$0.03258 per Ccf
	Next 300,000 Ccf @	$0.02259 per Ccf
	All Over 400,000 Ccf @	$0.01258 per Ccf

ADDITIONAL CHARGES

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

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

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

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

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 27, 2022 (Borger/Skellytown Service Area)	TBD
November 28, 2018 (North Texas Service Area)	
June 28, 2021 (All West Texas cities except El Paso)	
August 3, 2021 (City of El Paso)	

TRANSPORTATION SERVICE RATE (Continued)

7. The billing shall reflect adjustments in accordance with provisions of the Uncollected GRIP Charges Surcharge, if applicable.

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

4. The Agreement shall be interpreted under Texas law.

TRANSPORTATION SERVICE RATE

APPLICABILITY

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

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

AVAILABILITY

Natural gas service under this rate schedule is available to any individually metered, non-residential customer for the transportation of customer owned natural gas through the Company's unincorporated areas of the West-North Service Area distribution system which includes the environs of Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas. Such service shall be provided at any point on the Company's System where adequate capacity and gas supply exists, or where such capacity and gas supply can be provided in accordance with the applicable rules and regulations and at a reasonable cost as determined by the Company in its sole opinion.

COST OF SERVICE RATE

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

Commercial	$500.00 per month
Industrial	$1,050.00 per month
Public Authority	$500.00 per month
Compressed Natural Gas	$450.00 per month
Electrical Cogeneration	$700.00 per month

Supersedes Rate Schedule Dated
January 11, 2022 (Billing Implementation January 27, 2022 - Borger/Skellytown Service Area)
October 12, 2021 (Billing Implementation October 27, 2021 - North Texas Service Area)
June 28, 2021 (West Texas Service Area)

Meters Read On and After
TBD

TRANSPORTATION SERVICE RATE (Continued)

Plus – All Ccf per monthly billing period listed by customer class as follows:

Commercial	$0.06808 per Ccf
Industrial	$0.08875 per Ccf
Public Authority	$0.11113 per Ccf
Compressed Natural Gas	$0.07652 per Ccf

Electrical Cogeneration	Oct. – Apr. (Winter)	
	First 5,000 Ccf @	$0.05260 per Ccf
	Next 95,000 Ccf @	$0.04260 per Ccf
	Next 300,000 Ccf @	$0.03260per Ccf
	All Over 400,000 Ccf @	$0.02260per Ccf
	May – Sept. (Summer)	
	First 5,000 Ccf @	$0.04259 per Ccf
	Next 95,000 Ccf @	$0.03258 per Ccf
	Next 300,000 Ccf @	$0.02259 per Ccf
	All Over 400,000 Ccf @	$0.01258 per Ccf

ADDITIONAL CHARGES

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

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

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

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

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

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

Supersedes Rate Schedule Dated	Meters Read On and After
January 11, 2022 (Billing Implementation January 27, 2022 - Borger/Skellytown Service Area) October 12, 2021 (Billing Implementation October 27, 2021 - North Texas Service Area) June 28, 2021 (West Texas Service Area)	TBD

TRANSPORTATION SERVICE RATE (Continued)

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

4. The Agreement shall be interpreted under Texas law.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE

1.1 REQUIREMENTS FOR TRANSPORTATION SERVICE

Nothing shall be deemed to supersede the respective rights and obligations of Texas Gas Service Company, a Division of ONE Gas, Inc. ("Company") and Customer as provided by Texas statutes, rules, and/or regulations. The Company reserves the right to seek modification or termination of transportation service or any of the tariffs to which it applies and the unilateral right to seek regulatory approval to make any changes to, or to supersede, the rates, charges and terms of transportation service. This rate schedule shall apply to customers who have elected Transportation Service through the Company's West-North distribution system which includes the incorporated and unincorporated areas 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 the unincorporated areas of Canutillo, Fabens, Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas.

1.2 DEFINITIONS

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

Adder:	Shall mean the Company's incremental cost to purchase natural gas.
Aggregation Areas:	Shall mean aggregation pools established by the Company within geographic, operational, administrative, and/or other appropriate parameters, for the purposes of nominating and imbalances.
Agreement:	Shall mean any 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.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Btu:	Shall mean British thermal unit(s) and shall be computed on a temperature base of 60° Fahrenheit and at the standard pressure base of the applicable service area and on a gross-real-dry basis and shall not be corrected for real water vapor as obtained by means commonly acceptable to the industry, and "MMBtu" shall mean 1,000,000 Btu.
Commercial Service:	Service to Consumers engaged primarily in the sale or furnishing of goods and services and any usage not otherwise provided for.
Commission or The Commission:	The Railroad Commission of Texas.
Company:	Texas Gas Service Company, a Division of ONE Gas, Inc.
Consumption Period:	Shall mean a volumetric billing period.
Cumulative Tolerance Limit:	Shall mean the percent of aggregate historical annual deliveries of a Qualified Supplier's Aggregation Area pool of customers for the most recent year ended on June 30. The Company, at its sole discretion, may make adjustments to the Cumulative Tolerance Limit.
Customer:	Any person or organization now being billed for gas service whether used by him or her, or by others.
Day or Gas Day:	Shall mean the 24-hour period commencing at 9:00 a.m. (Central Standard Time) on one calendar day and ending at 9:00 a.m. (Central Standard Time) the following calendar day.
Dekatherm (Dth):	Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.

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

Electrical Cogeneration Service:	Service to Consumers who use natural gas for the purpose of generating electricity. This service uses thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.
Electronic Flow Measurement (EFM):	A device that remotely reads a gas meter.
Gas or Natural Gas:	Shall mean the effluent vapor stream in its natural, gaseous state, including gas-well gas, casing head gas, residue gas resulting from processing both casing head gas and gas-well gas, and all other hydrocarbon and non-hydrocarbon components thereof.
Industrial Service:	Service to Consumers engaged primarily in a process which changes raw or unfinished materials into another form of product. This classification shall embrace all Consumers included in Division A (except Major Groups 01 and 02) and Division D of the Standard Industrial Classification Manual.
Mcf:	Shall mean 1,000 cubic feet of Gas.
Month:	Shall mean the period beginning at 9:00 a.m. Central Standard Time on the first Day of each calendar month and ending at 9:00 a.m. Central Standard Time on the first Day of the next succeeding calendar month.
Monthly Tolerance Limit:	Shall mean 5% of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
Payment in Kind (PIK):	Shall mean a reimbursement for lost and unaccounted for gas.
PDA:	Shall mean a predetermined allocation method.

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

Pipeline System:	Shall mean the current existing utility distribution facilities of Company located in the State of Texas.
Point of Delivery:	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.
Point of Receipt:	Shall mean the point or points where Company shall receive Gas into the Pipeline System from Customer.
Point Operator:	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.
Qualified Supplier:	Shall mean an approved supplier of natural gas for transportation to customers through the Company's pipeline system.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the West-North Service Area, or the Railroad Commission of Texas, as applicable.
Service Area:	The area receiving gas utility service provided by the Company under the terms of this Tariff.
Tariff:	Shall mean every rate schedule, or provision thereof, and all terms, conditions, rules and regulations for furnishing gas service filed with the regulatory authorities or agencies having jurisdiction over Company or the services provided hereunder.
Transportation Form:	Shall mean the Company approved selection of transportation service document.
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.

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

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

1.3 RESTRICTIONS AND RESERVATIONS

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

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

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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

d) Company presently is transporting Gas to third parties on the Pipeline System and shall have the right in the future to transport additional Gas for such purposes and to transport Gas to additional third parties as it may desire, and Company shall have the right to make additional connections to the Pipeline System as may be required to serve presently existing and new customers, all of which is subject to the provisions of the Agreement. Company's transportation of 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 mutually agreed upon Point of Receipt, less Payment in Kind (PIK).

1.5 CUSTOMER'S RESPONSIBILITY

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

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

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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

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

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

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

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

g) In the event Customer's source of gas supply is terminated by Customer's Qualified Supplier due to non-payment or other reasons, or if customer is otherwise unable to continue as a transportation customer, Customer may, upon the first of the month after 30 calendar days advance 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 mutually agreed upon Points of Receipt and shall act as the Customer's agent with respect to nominations, operational notices and resolution of imbalances.

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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

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

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

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.

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

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

1.8 <u>LACK OF LIABILITY</u>

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. 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

GENERAL TERMS AND CONDITIONS
FOR TRANSPORTATION SERVICE
(Continued)

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.

e) If a portion of the Pipeline System required to make the transportation service available is partially damaged by fire or other casualty, the damage may be repaired by Company, at its option and in its sole discretion, as speedily as practicable, due allowance being made for 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 damage is so extensive as to render the Pipeline System wholly unusable, in Company's sole opinion, the payments, if any, shall cease until such time as the Pipeline System is again useable. In case the damage shall, in Company's sole opinion, amount substantially to a destruction of the portion of the Pipeline System available for the transportation of Gas and Company shall elect not to repair the damage, then the Agreement shall terminate at the time of such damage, and Company shall not be liable to Customer for any liability, damage, or claim which arises out of any failure to make repairs.

WEATHER NORMALIZATION ADJUSTMENT CLAUSE

APPLICABILITY

The Weather Normalization Adjustment Clause (WNA) shall apply to the following general service rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") in the incorporated and unincorporated areas served in the West-North Service Area including 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 the unincorporated areas including Canutillo, Fabens, Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas: Rate Schedules 10, 1Z, 15, 1Y, 20, 2Z, 40, and 4Z. The WNA shall be effective during the September through May billing cycles.

PURPOSE

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

WNA MECHANISM

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

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

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.

CB = Number of customers billed for the billing period.

WEATHER NORMALIZATION ADJUSTMENT CLAUSE
(Continued)

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

Borger and Skellytown:
Residential 0.13147; Commercial 0.53991; Public Authority 1.54062
Weather Station: Rick Husband Amarillo International Airport (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 0.14782; Commercial 0.42139; Public Authority 1.89205
Weather Station: Abilene Regional Airport (KABI)

Anthony, Canutillo, Clint, El Paso, Fabens, Horizon City, San Elizario, Socorro, and Vinton:
Residential 0.13977; Commercial 0.44079; Public Authority 2.76130
Weather Station: El Paso International Airport (KELP)

Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett, and Wink:
Residential 0.12336; Commercial 0.30250; Public Authority 1.57811
Weather Station: Midland International Air and Space Port (KMAF)

Dell City:
Residential 0.13977; Commercial 0.44079; Public Authority 2.76130
Weather Station: El Paso International Airport (KELP)

CV = Current Volumes for the billing period.

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.

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. ("TGS" or 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 TGS employees. These legally mandated operating and maintenance expenses shall be recovered through a separate monthly volumetric charge (the Pipeline Integrity Testing or "PIT" Surcharge) that shall be shown as a separate line item on the customer's monthly bill and calculated for each customer class as described below. Capital expenditures associated with the Pipeline Integrity Program shall continue to be recovered through base rates and any interim rate adjustments implemented pursuant to Section 104.301 of the Gas Utility Regulatory Act.

APPLICABILITY

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

TERRITORY

This Rider shall apply to the following gas sales and standard transportation rate schedules of the Company's West-North Service Area ("WNSA") within the incorporated and unincorporated areas 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 in the environs areas of Canutillo, Fabens, Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas: 10, 15, 20, 30, 40, 60, C-1, CNG-1, E5, 1Z, 1Y, 2Z, 3Z, 4Z, 6Z, C-1-ENV, CNG-1-ENV, T-1, and T-1-ENV.

QUALIFYING EXPENSES

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

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

and any other operating and maintenance expenses reasonably necessary to safely and effectively perform required safety testing of the Company's pipelines in the WNSA. Neither capital expenditures by the Company, nor the labor cost of TGS 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 WNSA. 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.

PIPELINE INTEGRITY TESTING (PIT) RIDER
(Continued)

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.

ANNUAL REPORT & APPLICABLE PSCC

On or before February 21st after each calendar year, the Company shall file a report with the Commission and the WNSA Cities showing all Pipeline Integrity Safety Testing expenses incurred during the previous calendar year and verifying the prior year's collections and any underrecoveries or overrecoveries accruing to date under this Rider. The report shall separately identify and list such expenses by account number and project number. Prior to the effective date of this Rider and on or before February 21st of each succeeding year while this Rider is in effect, the Company shall also file an Addendum to this Rider with the Commission and the WNSA Cities (a) identifying the PIT Surcharges that will be applied during the ensuing 12-month recovery period from April 1st through March 31st, and (b) providing the underlying data and calculations on which each PIT Surcharge for that period is based.

NOTICE TO AFFECTED CUSTOMERS

In addition to the annual report and Addendum to this Rider required above, the Company shall provide, on or before March 31st after each calendar year, written notice to each affected customer of (a) the PIT Surcharge that will be applied during the ensuing 12-month period from April 1st through March 31st, 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 WNSA Cities certifying that notice has been provided to customers in this manner. The notice shall be presumed to be complete three calendar days after the date the separate mailing or billing statement is deposited in a postage-paid, properly addressed wrapper in a post office or official depository under care of the United States Postal Service. The initial notice shall be filed with, reviewed, and approved by the regulatory authority, and each subsequent notice shall follow the same format as that of the approved initial notice.

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 West-North Service Area ("WNSA") within the incorporated and unincorporated areas 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 in the environs areas of Canutillo, Fabens, Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas: 10, 15, 20, 30, 40, 60, C-1, CNG-1, 1Z, 1Y, 2Z, 3Z, 4Z, 6Z, C-1-ENV, CNG-1-ENV, T-1, and T-1-ENV.

B. PIT RATE

$0.00075 per Ccf

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

C. OTHER ADJUSTMENTS

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

D. CONDITIONS

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

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

RATE CASE EXPENSE SURCHARGE

A. APPLICABILITY

The Rate Case Expense Surcharge (RCE) rate as set forth in Section (B) below is pursuant to City Ordinance. This rate shall apply to the following rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. in the incorporated areas of the West-North Service Area which includes 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: 10, 15, 20, 30, 40, 60, C-1, CNG-1, E5, and T-1.

B. RCE RATE

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

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

C. OTHER ADJUSTMENTS

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

D. CONDITIONS

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

RATE CASE EXPENSE SURCHARGE

A. APPLICABILITY

The Rate Case Expense Surcharge (RCE) rate as set forth in Section (B) below is pursuant to Gas Utilities Case No. XXXXX: Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. to Increase Gas Utility Rates Within the Unincorporated Areas of the West-North Service Area, Final Order Finding of Fact No. XX-XX. This rate shall apply to the following rate schedules of Texas Gas Service Company, a Division of ONE Gas, Inc. in the unincorporated areas of the West-North Service Area which includes Aledo, Andrews, Anthony, Barstow, Borger, Breckenridge, Bryson, Canutillo, Clint, Crane, Dell City, El Paso, Fabens, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, Jermyn, McCamey, Millsap, Mineral Wells, Monahans, Palo Pinto, Pecos, Perrin, Possum Kingdom, Punkin Center, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Whitt, Wickett, Willow Park and Wink, Texas: 1Z, 1Y, 2Z, 3Z, 4Z, 6Z, C-1-ENV, CNG-1-ENV and T-1-ENV.

B. RCE RATE

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

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

C. OTHER ADJUSTMENTS

Taxes: Plus applicable taxes and fees related to above.

D. CONDITIONS

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

RATE CASE EXPENSE SURCHARGE (Continued)

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 Docket No. 10766 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

Texas Gas Service Company, a Division of ONE Gas, Inc.
West-North Service Area (Select City) **RATE SCHEDULE UGC-Rider**

UNCOLLECTED GRIP CHARGES SURCHARGE

A. APPLICABILITY

The Uncollected GRIP Charges Surcharge (UGC) rate as set forth in Section (B) below is implemented pursuant to the final order in Case No. _____, City Ordinances, other regulatory approval or by operation of law. The UGC Surcharge provides a mechanism for the recovery of GRIP charges that Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") was unable to implement for incorporated El Paso customers from June 28, 2021 to August 2, 2021. This occurred because the City of El Paso approved a motion denying the Company's 2021 Gas Reliability Infrastructure Program filing, which was implemented on June 28, 2021 in all incorporated and environs areas of the West Texas Service Area except incorporated El Paso. Due to the City of El Paso's denial, the Company was unable to implement the charge in the incorporated areas of El Paso until August 3, 2021, which is the date the Railroad Commission of Texas approved the El Paso GRIP charges through the exercise of its appellate jurisdiction. This rate shall apply to the following rate schedules of the Company in the incorporated areas of El Paso, Texas: 10, 15, 20, 30, 40, 60, C-1, CNG-1, E5, and T-1.

B. UGC RATE

Flat rate per bill during each billing period:

Residential	$2.23 per bill
Commercial	7.45 per bill
Industrial	238.74 per bill
Public Authority	27.54 per bill
Municipal Water Pumping	124.18 per bill

This rate will be in effect for monthly billing period only. The UGC Surcharge will be a separate line item on the bill.

C. OTHER ADJUSTMENTS

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

D. CONDITIONS

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

Initial Rate Schedule

Meters Read On and After
TBD

RULES OF SERVICE

WEST-NORTH SERVICE AREA

Effective for Meters Read On and After TBD

Communications Regarding this Tariff Should Be Addressed To:
Lorraine Scott
401 N. Harvey
Oklahoma City, OK 73102
customerrelations@onegas.com
(405) 551-6633

Supersedes and Replaces "Incorporated and Unincorporated West Texas Service Area" (Incorporated and Unincorporated areas of Anthony, Clint, Dell City, El Paso, Fabens, Horizon City, San Elizario, Socorro, Vinton and the Unincorporated areas of Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett, and Wink, Texas) dated October 5, 2016; "Incorporated West Texas Service Area" (Incorporated areas of Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett and Wink, Texas) dated December 1, 2016; "Unincorporated Areas of Canutillo, Texas" dated June 26, 2018; "Incorporated and Unincorporated North Texas Service Area" (Incorporated and Unincorporated areas of Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Jermyn, Millsap, Mineral Wells, Palo Pinto, Perrin, Possum Kingdom, Punkin Center, Weatherford, Whitt, and Willow Park, Texas) dated November 28, 2018; "Incorporated Borger/Skellytown Service Area" (Incorporated areas of Borger and Skellytown, Texas) dated December 31, 2018; "Unincorporated Borger/Skellytown Service Area" (Unincorporated areas of Borger and Skellytown, Texas) dated February 28, 2019

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SECTION 1 — GENERAL STATEMENT AND DEFINITIONS

1.1 TARIFF APPLICABILITY

Texas Gas Service Company, a Division of ONE Gas, Inc. (the "Company") operates as a gas utility under Texas Utilities Code § 101.003(7) within the State of Texas. This Tariff applies to all incorporated areas, unincorporated areas and census designated places in the Company's West-North Service Area, which includes the Cities and environs 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, and the environs of Canutillo, Fabens, Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas.

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

1.2 RATE SCHEDULES

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

1.3 DEFINITIONS

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

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

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

Dekatherm (Dth):	Shall mean 1,000,000 Btu's (1 MMBtu). This unit will be on a dry basis.
Domestic Service:	Service to any Consumer which consists of gas service used directly for heating, air conditioning, cooking, water heating and similar purposes whether in a single or multiple dwelling unit.
Electrical Cogeneration Service:	Service to Consumers who use natural gas for the purpose of generating electricity. This service uses thermal energy to produce electricity with recapture of by-product heat in the form of steam, exhaust heat, etc. for industrial process use, space heating, food processing or other purposes.
Electronic Document:	Any document sent electronically via email or the internet.
Electronic Flow Measurement (EFM):	An electronic means of obtaining readings on a gas meter.
Electronic Fund Transfer (EFT):	The process to convert a paper check or electronic bill payment request to an electronic transfer. Paper checks received by Company or their agents are destroyed.
Electronic Radio Transponder (ERT):	A device that assists with remotely reading a gas meter.
Excess Flow Valve (EFV):	A safety device installed on a natural gas service line. The EFV is designed to automatically shut off the flow of natural gas in the service line and mitigate the impact of a significant break, puncture or severance in the line. EFVs are not designed to shut off the flow of gas in the line breaks at the connection of a gas appliance in a residence or in the customer's piping system (interior or exterior) on the customer's side of the gas meter.
Expedited Service:	Customer request for same day service or service during non-business hours for connection or reconnection of gas service.
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.
<u>Irrigation or Irrigation Pumping Service:</u>	(SIC Division A - Major Group 01) who use gas for operating engine-driven pumping equipment.
<u>Master Meter:</u>	A single large volume gas measurement device by which gas is metered and sold to a single purchaser who distributes the gas to one or more additional persons downstream from that meter. Master meter operators shall comply with the minimum safety standards in 49 CFR Part 192.
<u>Mcf:</u>	Shall mean one thousand (1,000) cubic feet of Gas.
<u>Month:</u>	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.
<u>Monthly Tolerance Limit:</u>	Shall mean five percent (5%) of the aggregate deliveries for a Qualified Suppliers Aggregation Area pool of customers for such month.
<u>Optional Rate Schedule:</u>	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.
<u>Overtime Rate:</u>	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.
<u>Payment in Kind (PIK):</u>	Shall mean a reimbursement for lost and unaccounted for gas.
<u>PDA:</u>	Shall mean a predetermined allocation method.
<u>Pipeline System:</u>	Shall mean the current existing utility distribution facilities of the Company located in the State of Texas.
<u>Point of Delivery:</u>	Shall mean the point or points where gas is delivered from the Pipeline System to Customer.
<u>Point of Receipt:</u>	Shall mean the point or points where the Company shall receive Gas into the Pipeline System from Customer.
<u>Point Operator:</u>	Shall mean the person or entity that controls the Point of Receipt or Point of Delivery.

Qualified Supplier:	Shall mean an approved supplier of natural gas for transportation to customers through the Company's pipeline system.
Regulatory Authority:	The City Council or equivalent municipal governing body of each respective city in the West-North Service Area, or the Railroad Commission of Texas, as applicable.
Service Area:	The area receiving gas utility service provided by the Company under the terms of this Tariff.
Special Rate Schedule:	A rate schedule designed for a specific Customer.
System:	Any group of interconnected pipelines and appurtenances owned or operated by the Company and independent from any other such group of facilities.
Tariff:	Shall mean every rate schedule, or provision thereof, and all terms, conditions, rules and regulations for furnishing gas service filed with the regulatory authorities or agencies having jurisdiction over the Company or the services provided hereunder.
Temporary Service:	Any service which will not be utilized continuously at the same location for a period of two or more years.
Transportation Form:	Shall mean the Company approved selection of transportation service document.
Transportation Rate Schedule:	A rate schedule designed for service to any Customer for the transportation of Customer-owned natural gas through the Company's distribution system.
Transportation Service:	The transportation by the Company of natural gas owned by someone other than the Company through the Company's distribution system.
Week:	Shall mean a period of seven (7) consecutive Days beginning at 9:00 a.m. Central Standard Time on each Monday and ending at the same time on the next succeeding Monday.
Year:	Shall mean a period of three hundred sixty-five (365) consecutive Days, or three hundred sixty-six (366) consecutive Days when such period includes a February 29.

SECTION 2. [Reserved for future rules]

SECTION 3: RATES AND UTILITY CHARGES

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

SECTION 4 – CONDITIONS OF SERVICE

4.1 PROVISION OF SERVICE

The Company will provide gas service to any person or organization located within the West-North 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.

4.2 FEES AND CHARGES

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

4.3 RESALE OF GAS

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

4.4 CONTINUITY OF SERVICE

a) Service interruptions

i) The Company shall make all reasonable efforts to prevent interruptions of service. When interruptions occur, the Company shall reestablish 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 gas 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.

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

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

4.5 AVAILABILITY OF TARIFFS

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

4.6 CUSTOMER INFORMATION

The Company shall:

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

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

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

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

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

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

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

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

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

iii) the time allowed to pay outstanding bills;

iv) grounds for termination of service;

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

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

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

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

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

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

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

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

4.7 CUSTOMER COMPLAINTS

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

4.8 COMPANY RESPONSE

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

4.9 LIMITATION OF LIABILITY

THE CUSTOMER ASSUMES ALL RESPONSIBILITY FOR ALL FACILITIES AND THEIR INSTALLATION, MAINTENANCE, OPERATION, FUNCTIONALITY, TESTING AND CONDITION THEREOF ON THE CUSTOMER'S SIDE OF THE POINT OF DELIVERY OF

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

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

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

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

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 satisfactory to the Company, provides clear access to Company's facilities, and enables the Company to provide service to Customer's property or the premises of the Consumer.

SECTION 5 — INITIATION OF SERVICE

5.1 REGULAR SERVICE

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

5.2 RESPONSE TO REQUEST FOR SERVICE

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

5.3 SPECIAL CONTRACTS

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

5.4 TEMPORARY SERVICE

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

5.5 FEES AND CHARGES

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

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

SECTION 6 —REFUSAL OF SERVICE

6.1 COMPLIANCE BY APPLICANT

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

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

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

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

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

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

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

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

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

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

6.2 APPLICANT'S RECOURSE

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

6.3 INSUFFICIENT GROUNDS FOR REFUSAL TO SERVE

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

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

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

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

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

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

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

SECTION 7 – DISCONTINUANCE OF SERVICE

7.1 CUSTOMER REQUESTED DISCONTINUANCE

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

7.2 DUE DATE OF BILL

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

7.3 DELINQUENT ACCOUNT

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

7.4 REASONS FOR DISCONNECTION

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

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

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

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

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

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

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

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

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

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

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

7.5 DISCONNECTION NOT ALLOWED

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

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

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

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

d) failure to pay for merchandise or charges for nonutility service by the Company.

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

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

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

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

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

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

7.6 TIME OF DISCONNECTIONS

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

7.7 SUSPENSION OF DISCONNECTIONS DURING EXTREME WEATHER EMERGENCY

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

a) A delinquent residential customer during an extreme weather emergency. An extreme weather emergency means a day when the previous day's highest temperature did not exceed 32 degrees Fahrenheit and the temperature is predicted to remain at or below that level for the next 24 hours according to the nearest National Weather Station for the county where the customer takes service.

b) A delinquent residential customer for a billing period in which the Company receives a written pledge, letter of intent, purchase order, or other written notification from an energy assistance provider that it is forwarding sufficient payment to continue service.

c) A delinquent residential customer on a weekend day, unless personnel or agents of the Company are available for the purpose of receiving payment or making connections and reconnecting service.

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

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

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

b) The Company shall provide a copy of Railroad Commission of Texas Rule 7.460, Suspension of

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

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

7.8 RECONNECTION OF SERVICE

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

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

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

7.9 RIGHT OF ENTRY TO DISCONNECT SERVICE

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

7.10 ABANDONMENT OF SERVICE

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

SECTION 8 – SECURITY DEPOSITS

8.1 ESTABLISHMENT OF CREDIT FOR RESIDENTIAL APPLICANT

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

8.2 DEPOSIT REQUIRED

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

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

8.3 RESIDENTIAL DEPOSIT NOT REQUIRED

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

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

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

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

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

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

8.4 OTHER EXEMPTIONS FROM DEPOSIT

The Company may not require a deposit if:

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

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

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

8.5 REESTABLISHMENT 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 reestablish credit as provided in Section 8.6.

8.6 AMOUNT OF DEPOSIT

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

8.7 INTEREST ON DEPOSITS

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

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

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

8.8 RECORDS OF DEPOSITS

a) The Company shall keep records to show:

i) the name and address of each depositor;

ii) the amount and date of the deposit; and

iii) each transaction concerning the deposit.

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

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

8.9 REFUND OF DEPOSITS

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

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

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

8.10 ACCEPTABLE FORMS OF DEPOSIT

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

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

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

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

8.11 DEPOSITS FOR TEMPORARY OR SEASONAL SERVICE

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

8.12 SALE OR TRANSFER OF COMPANY

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

8.13 COMPLAINT

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

8.14 FRANCHISE AGREEMENTS

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

SECTION 9 – BILLING AND PAYMENT OF BILLS

9.1 RENDERING OF BILLS

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

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

9.2 REQUIRED BILL INFORMATION

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

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

b) the number and kind of units billed;

c) the applicable rate schedule title or code;

d) the total base bill;

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

f) a distinct marking to identify an estimated bill.

9.3 ESTIMATED BILLS

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

9.4 DISPUTED BILLS

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

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

9.5 PAYMENT RE-PROCESSING FEE

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

9.6 ELECTRONIC BILLING STATEMENTS

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

9.7 PAYMENT OPTIONS

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

9.8 DEFERRED PAYMENT PLANS

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

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

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

i) size of delinquent account;

ii) Customer's ability to pay;

iii) Customer's payment history;

iv) time that the debt has been outstanding;

v) reasons why debt has been outstanding; and

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

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

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

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

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

9.9 AVERAGE PAYMENT PLAN

Any residential Customer or non-residential Customer with annual usage less than 500 Ccf may elect to participate in the Company's Average Payment Plan (also known as the Average Bill Calculation Plan) ("APP Plan"). The terms, conditions, and other information regarding the Average Payment Plan are set forth on the Company's website at www.texasgasservice.com, which is incorporated herein by reference.

SECTION 10 – FACILITIES AND EQUIPMENT

10.1 STANDARDS OF CONSTRUCTION

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

10.2 COMPANY OWNED FACILITIES

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

10.3 CUSTOMER OWNED FACILITIES

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

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

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

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

10.4 LEAKS

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

10.5 MATERIALS OR EQUIPMENT FURNISHED BY THE COMPANY

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

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

10.6 MATERIALS OR EQUIPMENT FURNISHED BY THE APPLICANT

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

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

10.7 RELOCATION OF COMPANY FACILITIES

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

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

10.8 REPLACEMENT OF CUSTOMER-OWNED PIPING

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

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

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

SECTION 11 – EXTENSION OF FACILITIES

11.1 LINE EXTENSION AND CONSTRUCTION CHARGES

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

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

11.2 DESIGN AND COST OF FACILITIES

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

11.3 ALLOWANCE FOR NEW BUSINESS

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

11.4 ADVANCES

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

11.5 CONSTRUCTION OF FACILITIES

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

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

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

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

SECTION 12 – METERS

12.1 METER REQUIREMENTS

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

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

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

12.2 METER READING

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

a) That Customer's use of gas during the same period(s) in previous years;
b) That Customer's normal use of gas during preceding months; or
c) The use of a similar Customer for the period missed.

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

12.3 METER LOCATION

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

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

12.4 METER RECORDS

The Company must keep the following records:

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

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

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

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

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

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

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

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

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

i) the last six months; or

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

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

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

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

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

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

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

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

12.13 MULTIPLE METERS

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

12.14 INDIVIDUALLY METERED SYSTEMS

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

12.15 MASTER METERS

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

SECTION 13 – GAS MEASUREMENT

13.1 PRESSURE

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

Cities and their Environs	Atmospheric Pressure PSIA	Standard Serving Pressure PSIA
Aledo	14.40	14.65
Andrews	13.10	13.35
Anthony	12.80	13.05
Barstow	13.50	13.75
Borger	13.10	13.35
Breckenridge	14.40	14.90
Bryson	14.40	14.65
Clint	12.80	13.05
Crane	13.50	13.75
Dell City	12.80	13.05
El Paso	12.80	13.05
Graford	14.40	14.65
Graham	14.40	14.90
Horizon City	12.80	13.05
Hudson Oaks	14.40	14.65
Jacksboro	14.40	14.65
McCamey	13.50	13.75
Millsap	14.40	14.65
Mineral Wells	14.40	14.65
Monahans	13.50	13.75
Pecos	13.50	13.75
Pyote	13.50	13.75
San Elizario	12.80	13.05
Skellytown	13.02	13.27
Socorro	12.80	13.05
Thorntonville	13.50	13.75
Vinton	12.80	13.05
Weatherford	14.40	14.65
Wickett	13.50	13.75
Willow Park	14.40	14.65
Wink	13.50	13.75

Environs Only	Atmospheric Pressure PSIA	Standard Serving Pressure PSIA
Canutillo	12.80	13.05
Fabens	12.80	13.05
Jermyn	14.40	14.65
Palo Pinto	14.40	14.65
Perrin	14.40	14.65
Possum Kingdom	14.40	14.65

Punkin Center	14.40	14.65
Whitt	14.40	14.65

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

13.2 UNIT OF MEASUREMENT

The standard unit of measurement shall be one hundred cubic feet (Ccf). A cubic foot shall be defined as the amount of gas which occupies a volume of one cubic foot at the standard serving pressure and at a temperature of 60 degrees Fahrenheit. Whenever the Company delivers gas at any pressure other than the standard serving pressure, volumes shall be corrected to the standard serving pressure in the manner provided in this Tariff, provided however, that such correction may be made to any other standard provided in the rate schedules or special agreement under which the Customer is served. The Company may, at its sole option, waive the correction of measurement for temperature deviation.

13.3 BILLING UNIT

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

13.4 PRESSURE CORRECTION - STANDARD METERING

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

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

b) The Company may use factor billing whenever the volumes to be delivered are too small to justify special metering. The factor shall be determined by dividing the actual serving pressure by the standard serving pressure, both expressed in absolute units based on the standard atmospheric pressure in the area as specified in Paragraph 11.1 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 ("supercompressability") may be made whenever the volumes delivered justify the cost of making such corrections.

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

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

13.6 METERING - SPECIAL ORIFICE

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

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

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

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

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

13.7 BTU MEASUREMENT

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

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

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

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

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

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

13.8 CUSTOMER-INSTALLED AND OPERATED METERS

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

SECTION 14 – QUALITY OF GAS

14.1 HEATING VALUE

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

14.2 CHARACTER OF GAS

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

14.3 ODORIZATION

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

SECTION 15 – SERVICE FEES AND DEPOSIT AMOUNTS

15.1 ADJUSTMENTS TO FEES AND CHARGES

All fees and charges shall be adjusted by taxes and fees (including franchise fees) where applicable. In the incorporated areas of Aledo, Andrews, Anthony, Barstow, Borger, Bryson, Clint, Crane, Dell City, El Paso, Graford, Graham, Horizon City, Hudson Oaks, Jacksboro, McCamey, Millsap, Mineral Wells, Monahans, Pecos, Pyote, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Willow Park and Wink only, all fees and charges (excluding advances, contributions in aid of construction and deposits) shall be adjusted by the amount which represents the actual gross receipts, occupation, revenue taxes and franchise fees paid by Texas Gas Service Company, a Division of ONE Gas, Inc.

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 housepiping 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. 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.	$35.00
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.	$15.00
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	$15.00
		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.	$65.00
d)	Services from Others	Whenever service is furnished from the facilities of others and the Company must pay any special fees to the supplying Company, the Applicant may be requested to reimburse the Company for such charge.	Actual cost plus 20% for handling
e)	Customer Requested Meter Test	Positive Displacement Up to 1500 cubic feet per hour Over 1500 cubic feet per hour Orifice Meters All sizes	 $150.00 $200.00 $200.00
f)	Payment Re-processing Fee		$25.00
g)	Collection Fee	A Collection Fee shall be charged to any Customer whose failure to respond to a termination notice necessitates the dispatch of a Company representative to attempt collection of payment from Customer.	$15.00
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	$35.00 $48.00 $65.00
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.	$18.00

j)	Meter Exchange Fee - Customer Request	A fee will be charged for customer requested meter exchanges when a meter is working properly or done for the Customers convenience.	$150.00
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).	$150.00
l)	Unauthorized Consumption Fee	Charges for the replacement of an illegally broken meter seal or locking device to the Customer who could be reasonably expected to benefit from gas service received through said meter.	$30.00 plus expenses
m)	No Access Fee	A fee charged to a Customer who schedules an appointment but fails to appear.	$15.00
n)	Meter Removal Fee		$25.00
o)	Account Research Fee	A fee will be charged for Customer account information requiring research of accounting/billing information.	$20.00/hour
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)	Advances Deposit	Estimated expenditure to serve the premises of new business beyond the existing distribution facilities of the Company.	Actual cost
b)	Residential Customer Deposit		Minimum $75.00
c)	Non-Residential Deposit		Minimum $250.00

SECTION 16 – TAPPING FEES

16.1 TAPPING FEE

The Company may, at its option, extend lines to serve a group of new Customers in the incorporated or unincorporated areas of El Paso County 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 (50) percent 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 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 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.

PIPELINE SAFETY AND REGULATORY PROGRAM FEES

TEXAS ADMINISTRATIVE CODE

TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 8	PIPELINE SAFETY REGULATIONS
SUBCHAPTER C	REQUIREMENTS FOR GAS PIPELINES ONLY
Rule §8.201	**Pipeline Safety and Regulatory Program Fees**

(a) Application of fees. Pursuant to Texas Utilities Code, §121.211, the Commission establishes a pipeline safety and regulatory program fee, to be assessed annually against operators of natural gas distribution pipelines and pipeline facilities and natural gas master metered pipelines and pipeline facilities subject to the Commission's jurisdiction under Texas Utilities Code, Title 3. The total amount of revenue estimated to be collected under this section does not exceed the amount the Commission estimates to be necessary to recover the costs of administering the pipeline safety and regulatory programs under Texas Utilities Code, Title 3, excluding costs that are fully funded by federal sources for any fiscal year.

(b) Natural gas distribution systems. The Commission hereby assesses each operator of a natural gas distribution system an annual pipeline safety and regulatory program fee of $1.00 for each service (service line) in service at the end of each calendar year as reported by each system operator on the U.S. Department of Transportation (DOT) Gas Distribution Annual Report, Form PHMSA F7100.1-1 due on March 15 of each year.

(1) Each operator of a natural gas distribution system shall calculate the annual pipeline safety and regulatory program total to be paid to the Commission by multiplying the $1.00 fee by the number of services listed in Part B, Section 3, of Form PHMSA F7100.1-1, due on March 15 of each year.

(2) Each operator of a natural gas distribution system shall remit to the Commission on March 15 of each year the amount calculated under paragraph (1) of this subsection.

(3) Each operator of a natural gas distribution system shall recover, by a surcharge to its existing rates, the amount the operator paid to the Commission under paragraph (1) of this subsection. The surcharge:

(A) shall be a flat rate, one-time surcharge;

(B) shall not be billed before the operator remits the pipeline safety and regulatory program fee to the Commission;

(C) shall be applied in the billing cycle or cycles immediately following the date on which the operator paid the Commission;

**PIPELINE SAFETY AND REGULATORY PROGRAM FEES
(Continued)**

(D) shall not exceed $1.00 per service or service line ***(For the calendar year 2021 annual pipeline safety and regulatory program fee, billed effective with meters read on and after March 28, 2022, Texas Gas Service Company, a Division of ONE Gas, Inc. will bill all customers a one-time customer charge per bill of $1.00, based on $1.00 per service line)***; and

(E) shall not be billed to a state agency, as that term is defined in Texas Utilities Code, §101.003.

(4) No later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers, each operator of a natural gas distribution system shall file with the Commission's Oversight and Safety Division a report showing:

(A) the pipeline safety and regulatory program fee amount paid to the Commission;

(B) the unit rate and total amount of the surcharge billed to each customer;

(C) the date or dates on which the surcharge was billed to customers; and

(D) the total amount collected from customers from the surcharge.

(5) Each operator of a natural gas distribution system that is a utility subject to the jurisdiction of the Commission pursuant to Texas Utilities Code, Chapters 101 - 105, shall file a generally applicable tariff for its surcharge in conformance with the requirements of §7.315 of this title (relating to Filing of Tariffs).

(6) Amounts recovered from customers under this subsection by an investor-owned natural gas distribution system or a cooperatively owned natural gas distribution system shall not be included in the revenue or gross receipts of the system for the purpose of calculating municipal franchise fees or any tax imposed under Subchapter B, Chapter 182, Tax Code, or under Chapter 122, nor shall such amounts be subject to a sales and use tax imposed by Chapter 151, Tax Code, or Subtitle C, Title 3, Tax Code.

(c) Natural gas master meter systems. The Commission hereby assesses each natural gas master meter system an annual pipeline safety and regulatory program fee of $100 per master meter system.

(1) Each operator of a natural gas master meter system shall remit to the Commission the annual pipeline safety and regulatory program fee of $100 per master meter system no later than June 30 of each year.

(2) The Commission shall send an invoice to each affected natural gas master meter system operator no later than April 30 of each year as a courtesy reminder. The failure of a natural gas master meter system operator to receive an invoice shall not exempt the natural gas master meter system operator from its obligation to remit to the Commission the annual pipeline safety and regulatory program fee on June 30 each year.

PIPELINE SAFETY AND REGULATORY PROGRAM FEES
(Continued)

(3) Each operator of a natural gas master meter system shall recover as a surcharge to its existing rates the amounts paid to the Commission under paragraph (1) of this subsection.

(4) No later than 90 days after the last billing cycle in which the pipeline safety and regulatory program fee surcharge is billed to customers, each natural gas master meter system operator shall file with the Oversight and Safety Division a report showing:

(A) the pipeline safety and regulatory program fee amount paid to the Commission;

(B) the unit rate and total amount of the surcharge billed to each customer;

(C) the date or dates on which the surcharge was billed to customers; and

(D) the total amount collected from customers from the surcharge.

(d) Late payment penalty. If the operator of a natural gas distribution system or a natural gas master meter system does not remit payment of the annual pipeline safety and regulatory program fee to the Commission within 30 days of the due date, the Commission shall assess a late payment penalty of 10 percent of the total assessment due under subsection (b) or (c) of this section, as applicable, and shall notify the operator of the total amount due to the Commission.

Source Note: The provisions of this §8.201 adopted to be effective September 8, 2003, 28 TexReg 7682; amended to be effective November 24, 2004, 29 TexReg 10733; amended to be effective May 15, 2005, 30 TexReg 2849; amended to be effective December 19, 2005, 30 TexReg 8428; amended to be effective April 18, 2007, 32 TexReg 2136; amended to be effective November 12, 2007, 32 TexReg 8121; amended to be effective September 21, 2009, 34 TexReg 6446; amended to be effective August 30, 2010, 35 TexReg 7743; amended to be effective November 14, 2011, 36 TexReg 7663; amended to be effective November 11, 2013, 38 TexReg 7947;amended to be effective January 6, 2020, 45 TexReg 121

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, 20, 30, 40, C-1, CNG-1, and T-1.

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. 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 @ $ 0.002 per Ccf

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, 20, 30, 40, C-1, CNG-1, and T-1.

WINTER STORM URI SURCHARGE

A. PURPOSE

The purpose of the Winter Storm Uri Surcharge is to authorize Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS" or the "Company") to recover the reasonable, necessary and prudent extraordinary costs incurred by the Company for its West-North Service Area applicable to the incorporated and unincorporated areas shown in Section B below as a result of Winter Storm Uri. The rate schedule is authorized by the Railroad Commission of Texas's ("Commission") (1) Regulatory Asset Determination Order in OS-21-00007061, (2) original jurisdiction to prescribe the manner and form of the books, records, and accounts for gas utilities under Texas Utilities Code § 102.101(a), (b) and (d), (3) Regulatory Asset Notice issued on February 13, 2021, and (4) Notice to Gas Utilities issued on June 17, 2021. The Commission authorizes and directs the Company to assess the Winter Storm Uri Surcharge rate as set forth in Section (C) below.

B. APPLICABILITY

This rate shall apply to the following rate schedules of the Company within only the following incorporated and unincorporated areas of its West-North Service Area: 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: 10, 15, 20, 30, 40, 60, E5, C-1, 1Z, 1Y, 2Z, 3Z, 4Z, 6Z and C-1-ENV.

C. SURCHARGE RATE

All Ccf during each billing period: $0.11800 per Ccf

This rate will be in effect until all approved and expended Winter Storm Uri costs, up to $59,663,320 ("Regulatory Asset Amount") plus carrying cost, are recovered under the applicable rate schedules. Any excess recovery of the Regulatory Asset Amount shall be calculated and refunded to customers through a final true-up under this rate schedule.

D. OTHER ADJUSTMENTS

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

E. CONDITIONS

1. Subject to all applicable laws and orders, and the Company's rules and regulations on file with the regulatory authority.
2. Carrying cost shall be applied beginning January 1, 2022 at the pre-tax weighted average cost of capital approved in the last West Texas Service Area rate case, GUD No. 10506.

WINTER STORM URI SURCHARGE (Continued)

3. Uncollectible amounts, actually written off, associated with this surcharge shall be added back to the balance to be recovered via this surcharge.
4. Any amounts that were included in the Regulatory Asset Amount that are refunded to the Company subsequent to the Regulatory Determination Order shall be subtracted from the balance and shall not be recovered via this surcharge.
5. City of El Paso's actual legal and consulting expenses in an amount not to exceed $132,560 will be reimbursed by the Company and recovered via this surcharge in addition to the Regulatory Asset Amount in subsection C.
6. By January 31, 2022, TGS will provide to Commission Staff and the City of El Paso confirmation of actual legal and consulting costs expended to confirm the balance to be recovered as stated in (C).

F. <u>WINTER STORM URI SURCHARGE RECOVERY COMPLIANCE REPORT</u>

TGS shall file a reconciliation report annually on or before December 31st, commencing in 2022 and ceasing after a reconciliation report is filed at the end of the month following the month in which the Regulatory Asset Amount is fully recovered via the final reconciliation true-up (if applicable). TGS shall file the report with the Commission, addressed to the Director of the Oversight and Safety Division and referencing OS-21-00007061, Winter Storm Uri Surcharge Recovery Report. The report shall include:

- The volumes used by month by customer class during the applicable period,
- The amount of surcharge recovered, by month
- The outstanding balance, by month
- The carry cost accrued, by month
- The associated uncollectibles, by month
- Any credits for amounts the Company received that would offset the Regulatory Asset Amount

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

TGS shall also provide a copy of annual reconciliation report to the City of El Paso.

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.

TAPPING FEE RATE – AGUA DULCE COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Agua Dulce Colonia.

B. TERRITORY

Agua Dulce Colonia in the environs of El Paso, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 8.82.

TAPPING FEE RATE – BURBRIDGE ACRES COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Burbridge Acres Colonia.

B. TERRITORY

Burbridge Acres Colonia in the environs of El Paso, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 7.22.

TAPPING FEE RATE – BURBRIDGE ACRES COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Burbridge Acres Colonia.

B. TERRITORY

Burbridge Acres Colonia in the City of Clint, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 7.22.

TAPPING FEE RATE – COTTON VALLEY ESTATES COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Cotton Valley Estates Colonia.

B. TERRITORY

Cotton Valley Estates Colonia in the City of Socorro, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 8.41.

TAPPING FEE RATE – HACIENDAS DEL VALLE COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Haciendas Del Valle Colonia.

B. TERRITORY

Haciendas Del Valle Colonia in the City of Socorro, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 3.63.

Texas Gas Service Company, a Division of ONE Gas, Inc.
West-North Service Area **RATE SCHEDULE TF – JONES**

TAPPING FEE RATE – JONES SUBDIVISION

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Jones Subdivision.

B. TERRITORY

Jones Subdivision in the City of Socorro, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 7.82.

TAPPING FEE RATE – PANORAMA VILLAGE COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Panorama Village Colonia.

B. TERRITORY

Panorama Village Colonia in the environs of El Paso, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 4.85.

Texas Gas Service Company, a Division of ONE Gas, Inc.
West-North Service Area **RATE SCHEDULE TF – POOLE**

TAPPING FEE RATE – POOLE SUBDIVISION

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Poole Subdivision.

B. TERRITORY

Poole Subdivision in the City of Socorro, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 6.29.

Texas Gas Service Company, a Division of ONE Gas, Inc.
West-North Service Area **RATE SCHEDULE TF – WESTWAY**

TAPPING FEE RATE – WESTWAY COLONIA

A. APPLICABILITY

The Tapping Fee rate, as set forth in Section (C) below and pursuant to the Quality of Service Rules, Section 16 Tapping Fees, shall apply to all existing and subsequent customers in the Westway Colonia.

B. TERRITORY

The Westway Colonia in the environs of the El Paso, TX.

C. CURRENT RATE

During each monthly billing period:

A tapping fee charge per meter per month of $ 26.33.

Line No. (a)	Description (b)	Bills (c)	Units (d)	Volumes (e)	Recommended Rates: Customer Charge (f)	Recommended Rates: Usage Charges (g)	Recommended Revenue (h)	Assigned Revenue (i)	Rounding Diff. (j)	Test Year As Adjusted Revenue (k)	Revenue Change (l)
1	Residential - Small										
2	Incorporated	1,846,009		44,310,526	$20.00	$0.411730	$55,164,149	$55,164,059	$90	$47,607,824	$7,556,235
3	Environs	191,072		4,792,129			5,794,508	5,794,498	9	5,000,782	793,716
4		2,037,081		49,102,655			$60,958,656	$60,958,557	$99	$52,608,606	$8,349,951
5											
6	Residential - Large										
7	Incorporated	1,238,617		68,243,579	$35.00	$0.002640	$43,531,765	$43,531,695	$71	$37,568,832	$5,962,863
8	Environs	128,204		7,380,459			4,506,617	4,506,610	7	3,889,306	617,304
9		1,366,821		75,624,039			$48,038,382	$48,038,304	$78	$41,458,137	$6,580,167
10											
11	Total Residential										
12	Incorporated	3,084,626		112,554,105			$98,695,914	$98,695,754	$160	76,038,394	$22,657,360
13	Environs	319,276		12,172,589			$10,301,125	$10,301,108	$17	18,028,349	(7,727,242)
14	**Total Residential**	**3,403,902**		**124,726,694**			**$108,997,039**	**$108,996,862**	**$177**	**$94,066,743.20**	**$14,930,119**
15	Commercial										
16	Incorporated	194,859		44,622,559	$ 75.00	0.06808	$17,652,304	$17,652,266	$38	$19,024,936	$(1,372,670)
17	Environs	13,296		2,133,359			1,142,432	1,142,430	2	1,207,585	(65,155)
18							$18,794,736	$18,794,696	$41	$20,232,521	$(1,437,826)
19											
20	Commercial Transportation										
21	Incorporated	240		6,717,889	$ 500.00	0.06808	$577,354	$577,353	$1	522,204	$55,148
22	Environs	0		0			0	0	0	-	0
23							$577,354	$577,353	$1	$522,204	$55,148
24	Electrical Cogeneration Transportation										
25		24	Oct.-		$ 700.00		$16,800	$16,800		$73,037	$(56,237)
26			First	35,010		0.05260	1,842	1,842	0		1,842
27			Next	665,000		0.04260	28,329	28,329	0		28,329
28			Next	240,050		0.03260	7,826	7,826	0		7,826
29			Over	0		0.02260	0	0	0		0
30			May-								
31			First	25,000		0.04259	1,065	1,065	0		1,065
32			Next	475,000		0.03258	15,476	15,475	0		15,475
33			Next	75,420		0.02259	1,704	1,704	0		1,704
34			Over	0		0.01258	0	0	0		0
35							$73,040	$73,040	$0	$73,037	$3
36	Total Commercial										
37	Incorporated	195,123		51,375,457			$18,302,698	$18,302,658	$40	$19,620,177	$(1,317,519)
38	Environs	13,296		2,133,359			1,142,432	1,142,430	2	1,207,585	(65,155)
39	**Total Commercial**	**208,419**		**53,508,817**			**$19,445,130**	**$19,445,088**	**$42**	**$20,827,762.73**	**$(1,382,674)**
29	Industrial										
30	Incorporated	446		1,237,272	$ 850.00	0.08875	$488,816	$488,826	-$9	$585,246	$(96,420)
31	Environs	41		132,820			46,729	46,730	(1)	49,335	$(2,605)
32							$535,546	$535,556	-$10	$634,581	$(99,026)
33											
34	Industrial Transportation										
35	Incorporated	132		4,808,649	$ 1,050.00	0.08875	$565,368	$565,378	-$11	644,872	$(79,494)
36	Environs	48		1,752,409			205,926	205,930	(4)	234,480	$(28,549)
37							$771,294	$771,308	-$15	$879,352	$(108,043)
38	Total Industrial										
39	Incorporated	578		6,045,921			$1,054,184	$1,054,204	-$20	$1,230,118	$(175,914)
40	Environs	89		1,885,229			252,656	252,660	(5)	283,815	(31,155)
41	**Total Industrial**	**667**		**7,931,149**			**$1,306,840**	**$1,306,864**	**-$25**	**$1,513,933.20**	**$(207,069)**
42	Public Authority										
43	Incorporated	14,464		10,724,243	$ 200.00	$ 0.11113	$4,084,630	$4,084,619	$11	$4,398,320	$(313,701)
44	Environs	1,773		1,382,369			508,207	508,205	1	572,930	(64,724)
45							$4,592,837	$4,592,824	$13	$4,971,249	$(378,425)
46											
47	Public Authority Transportation										
48	Incorporated	84		2,192,902	$ 500.00	$ 0.11113	$285,697	$285,696	$1	$250,253	$35,443
49	Environs	0		0			-	-	-	-	-
50							$285,697	$285,696	$1	$250,253	$35,443
51											
76	Total Public Authority										
77	Incorporated	14,548		12,917,145			$4,370,328	$4,370,315	$12	$4,648,573	$(278,257)
78	Environs	1,773		1,382,369			508,207	508,205	1	572,930	(64,724)
79	**Total Public Authority**	**16,321**		**14,299,514**			**$4,878,534**	**$4,878,521**	**$14**	**$5,221,502**	**$(342,982)**

Line No. (a)	Description (b)	Bills (c)	Units (d)	Volumes (e)	Recommended Rates: Customer Charge (f)	Recommended Rates: Usage Charges (g)	Recommended Revenue (h)	Assigned Revenue (i)	Rounding Diff. (j)	Test Year As Adjusted Revenue (k)	Revenue Change (l)
80	Compressed Nat. Gas										
81	Incorporated	0		0			$0	$0	$0	$0	$0
82	Environs	0		0			-	-	-	-	-
83							$0	$0	$0	$0	$0
84											
85	Compressed Nat. Gas Transportation				$ 450.00	$ 0.07652					
86	Incorporated	48		5,160,298			$416,466	$416,451	$15	$467,600	$(51,149)
87	Environs	0		0			-	-	-	-	-
88							$416,466	$416,451	$15	$467,600	$(51,149)
89											
90	Total Compressed Nat. Gas										
91	Incorporated	48		10,320,596			$416,466	$416,451	$15	$467,600	$(51,149)
92	Environs	0		0			-	-	-	-	-
93	**Total Compressed Nat. Gas**	**48**		**10,320,596**			**$416,466**	**$416,451**	**$15**	**$467,600**	**$(51,149)**
94	Fort Bliss[1]									$2,299,383	$48,883

Line No.	Description	Recommended Revenue	Assigned Revenue	Rounding Diff.	Test Year As Adjusted Revenue	Revenue Change	Service Charges and Other Revenue	Cost of Gas	% Change (Non Gas Revenue)	% Change (Total Revenue
94	Proposed WNSA Revenue									
95	Incorporated	$122,839,590	$122,839,382	$208	$104,304,244	$20,883,404	$2,511,426	71,555,950	19.55 %	11.71 %
96	Environs	12,204,419	12,204,403	$16	20,092,680	(7,888,276)	557,425	8,201,735	(38.20)%	(27.34)%
97	**Total Revenue**	$135,044,009	$135,043,785	$223	$124,396,924	$12,995,128	$3,068,851	$79,757,685	10.19 %	6.27 %
99	Rounding Difference					$(0.95)				
100	Revenue Increase					$12,995,127				

101 [1] The amount reflects the revenue change assigned to Fort Bliss in the class revenue allocation

Company's overall combined revenue requirement for the proposed WNSA:		$138,112,860	
The total revenue received during the test year		$127,465,775	
revenue deficiency on a combined basis	127,465,775	$12,995,128	
Rounding Difference		$0.95	
rates will increase TGS's revenues in the proposed WNSA by		$13.0	Million
which is an increase of including the cost of gas		6.27 %	
which is an increase of excluding the cost of gas		10.19 %	

Exhibit C

Average Bill Impact By Class
(Including Cost of Gas)

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
Sales Service: (1) (2)				
Residential - Small (3)				
WTSA Incorporated and Environs	$35.50	$39.89	$4.39	12.4%
NTSA Incorporated	$44.59	$39.89	$(4.70)	-10.5%
NTSA Environs	$51.78	$39.89	$(11.89)	-23.0%
BSSA Incorporated and Environs	$31.21	$39.89	$8.68	27.8%
Residential - Large (3)				
WTSA Incorporated and Environs	$51.01	$58.02	$7.01	13.7%
NTSA Incorporated	$82.35	$58.02	$(24.33)	-29.5%
NTSA Environs	$87.13	$58.02	$(29.11)	-33.4%
BSSA Incorporated and Environs	$50.91	$58.02	$7.11	14.0%
Commercial				
WTSA Incorporated and Environs	$172.93	$183.39	$10.46	6.0%
NTSA Incorporated	$322.38	$183.39	$(138.99)	-43.1%
NTSA Environs	$332.91	$183.39	$(149.52)	-44.9%
BSSA Incorporated and Environs	$196.65	$183.39	$(13.26)	-6.7%
Commercial Air Conditioning (4)				
WTSA Incorporated and Environs (Withdrawing) (Proposed reclass to Commercial)	$215.66	$227.89	$12.23	5.7%
Industrial				
WTSA Incorporated and Environs	$2,275.65	$2,262.91	$(12.74)	-0.6%
NTSA Incorporated	$3,591.72	$2,262.91	$(1,328.81)	-37.0%
NTSA Environs	$3,581.98	$2,262.91	$(1,319.07)	-36.8%
Public Authority				
WTSA Incorporated and Environs	$535.41	$547.09	$11.68	2.2%
NTSA Incorporated	$863.21	$547.09	$(316.12)	-36.6%
NTSA Environs	$875.00	$547.09	$(327.91)	-37.5%
BSSA Incorporated and Environs	$475.13	$547.09	$71.96	15.1%
Public Authority Air Conditioning (4)				
WTSA Incorporated and Environs (Withdrawing) (Proposed reclass to Public Authority)	$1,206.33	$1,258.63	$52.30	4.3%
Municipal Water Pumping				
WTSA Incorporated and Environs (Withdrawing) (Proposed reclass to Public Authority)	$1,073.85	$544.44	$(529.41)	-49.3%
School and Municipal				
BSSA Incorporated and Environs (Withdrawing) (Proposed reclass to Public Authority)	$4,956.43	$3,449.25	$(1,507.18)	-30.4%
Transportation Service: (5)				
Commercial Transportation				
WTSA Incorporated and Environs	$12,908.33	$13,400.49	$492.16	3.8%
Industrial Transportation				
WTSA Incorporated and Environs	$18,221.64	$18,602.53	$380.89	2.1%
Public Authority Transportation				
WTSA Incorporated and Environs	$30,689.79	$32,320.44	$1,630.65	5.3%
CNG Transportation				
WTSA Incorporated and Environs (Reclassed from Commercial)	$50,941.58	$53,641.47	$2,699.89	5.3%
WTSA Incorporated and Environs (Reclassed from Public Authority)	$151,885.50	$149,076.28	$(2,809.22)	-1.8%
Cogeneration Transportation (4)				
WTSA Incorporated and Environs	$39,065.97	$39,899.16	$833.19	2.1%

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

	WNSA	
	Year-Round	
Residential - Small	24	
Residential - Large	55	
Commercial	225	
Industrial	2,813	
Public Authority	662	
Municipal Water Pumping	657	
School and Municipal	6,194	
	August	January
Commercial AC	$259.27	359.08
Public Authority AC	$151.33	3,351.29

(3) Calculations for current Residential rates are based on the current rates for the WTSA, NTSA and BSSA for usage at the Small and Large Residential amounts shown in Note 2 (24 Ccf for Small and 55 Ccf for Large).

(4) Year-round average bill is approximated based on the average August bill assumed to occur in each of the 5 summer months and the average January bill assumed to occur in each of the 7 winter months.

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

	WNSA	
	Year-Round	
Commercial Transportation	27,991	
Industrial Transportation	36,450	
Public Authority Transportation	63,145	
CNG Transportation	113,338	
	August	January
Cogeneration Transportation	106,900	79,655

CASE NO. 00009896

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	§ § § § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

SHANTEL NORMAN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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DIRECT TESTIMONY OF SHANTEL NORMAN

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Shantel Norman. 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"), which is 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 Natural Gas Engineering from Texas A&M-Kingsville. I am a Registered Mechanical Engineer in the State of Texas (P.E. #84755). I began my employment with Southern Union Gas in July 1995 and served in roles of increasing responsibility in Engineering where my responsibilities focused on issues including pipeline integrity, operator qualifications, state and federal inspection audits, maintenance of operation standards, capital and O&M budgets, and system replacement. From May 2006 to October 2008, I worked as a Gas Engineering Manager for CPS Energy and led the Codes & Standards, Customer Engineering and System Reliability sections. In November 2008, I returned to TGS (formerly Southern Union Gas) and worked as a Process Improvement and Quality Assurance Manager, where I led the process improvement efforts by developing and managing projects to increase efficiency, improve customer satisfaction, reduce costs and achieve best practices. I was Director of Gas Supply from July 2010 to July 2017 and led the gas supply functions to ensure accurate gas usage forecasting, available supplies of natural gas and transportation capacity. I next served as Director of Field Compliance, with responsibilities for overseeing line location, leak survey, pressure control and measurement and cathodic protection, from July 2017 to February 2018. I began serving in my current position as Vice President of Operations in March 2018.

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") Nos. 10739, 10766, 10928, and Case No. OS-21-00007061.

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 the West Texas Service Area ("WTSA"), North Texas Service Area ("NTSA") and Borger Skellytown Service Area ("BSSA"), which are the subject of this rate case. In addition, my testimony supports:

- the reasonableness and necessity of the Company's requested O&M expenses;
- a determination that the capital investment (Direct, TGS Division and Corporate) that has been made through December 31, 2021 is used and useful and was prudently incurred; and
- the Company's request to consolidate the WTSA, NTSA and BSSA into a new, combined regulatory service area that will be known as the West North Service Area ("WNSA") if consolidation is approved.

In addressing these issues, I also explain how the costs TGS incurs are necessary for maintaining a safe and reliable natural gas distribution system and how TGS's operations and costs have been affected by the COVID-19 pandemic, Winter Storm Uri, a tight labor market, and economic conditions.

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

A. In addition to my testimony, the Company's witnesses and the subjects addressed in the testimony are identified below. Please also note that Exhibit SN-1 is a copy of the Table of Contents Summary to the WNSA Cost of Service schedules, which lists all the schedules and workpapers in this filing, along with the sponsor(s).

Witness	Title	Testimony Subjects
Shantel Norman	Vice-President of Operations for TGS	Provides an overview of operations within the proposed WNSA; supports the proposed consolidation to create the WNSA; addresses TGS's efforts during COVID-19 and Winter Storm Uri; addresses the reasonableness and necessity of capital investment and O&M expenses; and addresses the Company's Pipeline Integrity Testing Program.
Stacey L. McTaggart	Rates and Regulatory Director 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 proposed consolidation of the existing WTSA, NTSA, and BSSA into the new WNSA; the Company's compliance with certain regulatory and statutory requirements; affiliate cost recovery issues related to Utility Insurance Company ("UIC"); the Company's proposed Excess Accumulated Deferred Income Tax ("EDIT") adjustment to return excess deferred income taxes to customers; the treatment of cloud-based computing costs; TGS's recovery of costs associated with COVID-19 and Winter Storm Uri; the Company's recovery of pipeline integrity testing costs; and the Company's recovery of rate case expenses. Describes the proposed WNSA rate schedules and tariffs as well as rate schedules and tariffs currently in effect for the WTSA, NTSA, and BSSA.

Stacey R. Borgstadt	Director of Rates and Regulatory Analysis for ONE Gas	Supports the cost allocation methodology used to determine TGS's share of allocated costs and certain Corporate expense adjustments. Supports certain TGS Division and Corporate capital investment that is included in the proposed WNSA revenue requirement as well as Corporate depreciation and amortization expense. Explains Direct, TGS Division and Corporate expense adjustments related to payroll and incentive compensation.
Jeff D. Branz	Director of Compensation and Benefits for ONE Gas	Addresses the reasonableness of ONE Gas' compensation philosophy and structure and related costs of base pay, incentive plans and benefits.
Mark W. Smith	Vice-President and Treasurer for ONE Gas	Supports the recovery of a return on TGS's portion of the prepaid pension asset. Describes ONE Gas' captive insurance company, UIC, and interest rate and equity return issues.
Jeffrey J. Husen	Vice President, Chief Accounting Officer and Controller for ONE Gas	Addresses the calculation and treatment of 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 calculations.
Ronald E. White	Engineer and President of Foster Associates Consultants, LLC	Sponsors a study of the depreciation rates for TGS plant located in the proposed WNSA and for common facilities shared among all TGS service areas, including Corporate assets.
Bruce H. Fairchild	Principal with Financial Concepts and Applications, Inc.	Supports TGS's requested return on equity, cost of debt, capital structure, and overall return on invested capital.
Teresa Serna	Rate Specialist for TGS	Supports TGS's revenue adjustments. Describes the class cost of service study and supports TGS's proposed class revenue allocation.

Paul H. Raab	Economic Consultant	Describes and supports TGS's proposed rate design, including "large" and "small" residential rate options.

II. OVERVIEW OF TEXAS GAS SERVICE COMPANY

Q. PLEASE DESCRIBE TGS'S OPERATIONS IN TEXAS, INCLUDING THE PROPOSED WNSA.

A. TGS provides safe, clean and reliable natural gas service to approximately 689,000 customers in 100 communities within five regulatory service areas in Texas. A map of the areas TGS currently serves is attached to my testimony as Exhibit SN-2. TGS and its predecessor utilities have served these areas for approximately 90 years. Operational decisions for TGS are made at the statewide level in coordination with management decision-making based in Tulsa, Oklahoma.

TGS provides natural gas distribution service to approximately 330,000 customers in the proposed WNSA[1] and operates approximately 4,300 miles of distribution mains and approximately 2,200 miles of service lines. These system assets combined represent more than $589 million in net investment. As of the end of 2021, the Company directly employed approximately 460 TGS Division and Direct WTSA, NTSA, and BSSA personnel with a combined annual payroll of over $33 million. The Company remitted approximately $6 million in annual property taxes to local taxing authorities in the WTSA, NTSA, and BSSA.

[1] The proposed WNSA would include the cities of Aledo, Andrews, Anthony, Barstow, Breckenridge, Borger, Bryson, Clint, Crane, Dell City, El Paso, Horizon City, Graford, Graham, Hudson Oaks, Jacksboro, McCamey, Mineral Wells, Monahans, Milsap, Pecos, Possum Kingdom, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Weatherford, Wickett, Willow Park, and Wink, Texas and surrounding environs areas.

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

A. TGS is one of three divisions operated by ONE Gas. ONE Gas operates as an independent natural gas distribution company focusing on delivering natural gas safely and reliably to customers through its three divisions in Oklahoma, Kansas and Texas. ONE Gas has 3,650 employees, 1,128 of which are in Texas. As a 100% regulated company, focused solely on distribution operations, all costs ONE Gas incurs support its natural gas distribution business.

Q. PLEASE EXPLAIN HOW THE TGS SYSTEM IS MANAGED.

A. The centralized approach to decision-making and management of TGS's gas service means that the employees within the regulatory service area boundaries do not represent the full scope of the activities, personnel and workload associated with its actual operations in the existing WTSA, NTSA, or BSSA. Instead, the centralized approach means that the regulatory service areas are actually operated on a statewide basis.

This functional operating approach has been utilized since 2013 and allows ONE Gas to operate the local distribution companies ("LDCs") in each state as one company, rather than three separate companies. Many activities that affect the Company's operations are centralized at the corporate level in Tulsa, the TGS Division level statewide, and within specific regions of Texas. Because ONE Gas' leadership and workforce are responsible for a specific function, the construction and operation of LDC systems, ONE Gas can better align common processes across the enterprise, regardless of the state where that function is completed. 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.

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. DESCRIBE ONE GAS' FOCUS ON SAFETY.

A. ONE Gas continually seeks to improve processes for risk assessment and risk mitigation as part of its integrity management programs, as well as its procedures for ensuring full compliance with all laws and regulations. ONE Gas measures: (1) preventable vehicle incident rate (PVIR); (2) total recordable incident rate (TRIR); (3) days away, restricted and transferred (DART); and (4) emergency response time (ERT). Exhibit SN-3 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 SN-3 confirms that ONE Gas has improved significantly from being in the 4th quartile in 2009 to the 1st quartile in recent years. TGS has also implemented more stringent standards for leak classification and repairs. ONE Gas regularly reviews its leak classification and repair standards for enhancements to its procedures. The more stringent standards are appropriate for management of the system, and the resulting leak repair or system maintenance is a reasonable and necessary expense.

Q. IS TGS REQUIRED TO COMPLY WITH STATE AND FEDERAL REGULATORY REQUIREMENTS?

A. Yes. The Company is subject to many rules and regulations on both the federal and state levels that are focused on ensuring the safety and reliability of TGS's infrastructure throughout the state and safe operation of its equipment. Examples include integrity testing, leak surveys and replacing facilities that present risks to TGS's system, which I will describe in more detail below. TGS must employ qualified personnel or hire contractors and incur costs that are necessary to meet its regulatory compliance obligations. Those costs include both O&M expenses and capital investment, which are costs TGS proposes to recover through base rates or specific riders as part of this rate case.

III. OPERATION AND MAINTENANCE EXPENSES

Q. PLEASE DESCRIBE THE O&M EXPENSES TGS INCURS.

A. TGS's O&M expenses are the result of normal operating, maintenance and administrative activities. In TGS's case, the primary drivers of O&M expenses are those 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 employees in the field are performing 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 Human Resources that are necessary to operate the natural gas distribution system.

Q. WHAT IS THE AMOUNT OF O&M EXPENSE REQUESTED IN THIS FILING?

A. TGS is requesting recovery of approximately $51 million of O&M expense that occurred during the test year. Approximately $24 million of O&M expense is directly incurred within the proposed WNSA. Ms. Borgstadt sponsors the TGS Division and ONE Gas Corporate allocated costs in the amount of $27 million.

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.[2] Specifically, the Company must establish a risk-based approach to pipeline maintenance and safety. Commission Rule § 8.209 requires the Company to develop and implement a risk-based program for the removal or replacement of distribution facilities, including steel service lines. TGS's distribution integrity management program and its risk-based program use scheduled replacements to manage identified risks associated with the integrity of distribution facilities and comply with the requirements mentioned above.

[2] *See generally* 49 C.F.R. § 192.1001-.10015 (2020) (distribution integrity management standards).

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 three years for non-business district polyethylene ("PE") systems or segments within a system; (3) every two 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 pipeline integrity testing 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.[3] Once the risk assessment and testing schedule has been established statewide, TGS coordinates and schedules testing in an efficient and cost-effective manner. Ms. McTaggart

[3] 16 Tex. Admin. Code §§ 8.101, 8.209 and 49 C.F.R. §§ 192.937 and 192.1001.

explains why it is appropriate to use a Pipeline Integrity Testing rider to recover these reasonable and necessary O&M costs that TGS must incur to comply with applicable regulations. (There can also be capital costs associated with testing, which is recovered in the Company's next Gas Reliability Infrastructure Program ("GRIP") filing or Cost of Service Adjustment ("COSA") 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 LEVEL OF O&M EXPENSE REQUESTED FOR RECOVERY IN THIS RATE CASE REASONABLE AND NECESSARY?

A. Yes, it is. The level of O&M expense requested is reasonable and necessary because it reflects costs TGS incurs to continue the safe and reliable operation of the system and to provide effective and efficient customer service. The test year O&M costs in this rate case are the annual amount of costs TGS incurs for its employees, as well as TGS Division and Corporate employees, to perform the day-to-day functions necessary to operate the TGS system. Together, the reasonable and necessary costs TGS incurs for personnel and the activities they perform are integral to the provision of safe and reliable service to customers.

IV. CAPITAL INVESTMENT

Q. WHAT IS CAPITAL INVESTMENT?

A. Capital investment is funds TGS spends to acquire or install equipment or facilities that are expected to be used and useful to provide service and will 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 maintain and expand the utility system in order to provide safe and reliable service to customers.

Q. WHAT DRIVES 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 El Paso, a distribution mainline extension was completed to improve a low-pressure point, the Bauman District Regulator Station was also installed to boost the distribution system, and the Westway City Gates were replaced to add capacity.
- In Borger, TGS replaced thousands of feet of bare or coated steel mains and services with PE pipe because it was vintage piping needing replacement. As part of this work, TGS also tested and reconnected facilities.
- In North Texas, TGS installed new PE main and associated services, which allowed for the retirement of bare steel vintage pipe.
- In North Texas, TGS completed the replacement of cast iron pipe from 2018-2020. As part of this replacement, TGS installed thousands of feet of PE main and 42 service lines that allowed for retirement of thousands of feet of cast iron main in Northwest Mineral Wells.

Q. WHAT CAPITAL INVESTMENT IS THE COMPANY SEEKING RECOVERY OF IN THIS RATE CASE?

A. TGS requests recovery of the reasonable and necessary capital investment made in the proposed WNSA since the last rate cases in the WTSA, NTSA, and BSSA in the amount of approximately $303 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, 2021.[4] As addressed by Ms. McTaggart and Ms. Borgstadt, the Company has proposed adjustments to capital investment to remove costs for activities such as miscoded investment, costs for meals greater than $25 per person, exclusive of taxes and tip amount, and hotel stays greater than $175 per night, exclusive of taxes.

Q. PLEASE EXPLAIN THE COMPANY'S CAPITAL INVESTMENT PLANNING PROCESS TO ENSURE CAPITAL INVESTMENT IS REASONABLE, NECESSARY AND PRUDENT.

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.

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[4] Capital investment in the incorporated areas of the NTSA for the period of January 1, 2018 through December 31, 2020 is also included, which the Company recovered through the Company's annual COSA filings with the NTSA cities.

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 projects throughout the Company that maximize risk reduction under given financial, resource and regulatory constraints. For each proposed project, engineering alternatives are evaluated, the preferred course of action is selected, and average cost metrics are applied to develop and assign a cost estimate to each project. General plant expenditures are reviewed to identify and prioritize investment projects needed to maintain working equipment and structures, ensure safety, enhance efficiencies, and meet regulatory requirements. Once a project has been approved, the Company's capital budgeting process includes additional cost controls to ensure that construction projects remain within funded limits. Before the work on a capital project begins, and before payments are made, required managerial approvals are obtained. TGS senior management also meets on a regular basis to review capital spending levels and make adjustments as appropriate.

Q. CAN ALL CAPITAL INVESTMENT BE PLANNED IN ADVANCE?

A. No. Based on experience, some investment needs will arise during the year that are not specifically known in advance. For example, leaks can occur on the system at any time of year, and the Company must revise budgeted amounts and allocate capital accordingly. Likewise, state, county, and municipal officials submit relocation requests throughout the year. For example, a government agency may postpone or delay a project until later in the year if funds are not available for the project earlier in the year. The projected level of capital expenditures for these items is developed based on experience and by working with the appropriate planning departments. Growth project budgets are based on known projects and experience. TGS's investments in General Plant, like all other capital investments, are identified through Company work processes and are subject to capital funding evaluation.

Q. DO ANY ADDITIONAL FACTORS AFFECT CAPITAL INVESTMENTS?

A. Yes. Pipeline safety and system integrity requirements imposed by the federal government through statutes and regulations require significant capital investment and lead to increased operating costs. To satisfy these requirements, first and foremost, the Company invests capital to maintain and improve the safety, reliability and efficiencies of operating the system and serving customers. Aging asset replacement is also part of the Company's on-going capital investment. The Company has also implemented new technology to reduce risk, increase operational capabilities and efficiencies and improve customer service.

Q. WHAT AMOUNT OF INVESTMENT HAS BEEN MADE SINCE THE LAST RATE CASES?

A. Since the last rate cases, the Company has, on a combined basis, increased its net plant in the proposed WNSA by approximately $61 million per year, on average, or 14% per year, which totals approximately $303 million as shown on Exhibit SN-7. This investment is related to capital investment TGS has incurred to provide safe and reliable service by replacing aging infrastructure, responding to relocation requests, complying with regulatory requirements and accommodating growth. This amount shows that TGS continues to make necessary investment on an ongoing basis, year over year.

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 and interim rate adjustment filings, also known as GRIP filings. Texas Utilities Code § 104.301 establishes the state's Gas Reliability Infrastructure Program and is commonly referred to as the "GRIP statute." The purpose of the statute is to encourage the timely investment in needed system improvements and to reduce the frequency of traditional rate cases by providing a streamlined process for utilities to recover the costs of those investments on an interim basis between rate cases. Capital investment in a GRIP filing is not subject to a prudence review during the GRIP process. Instead, the prudence review, which involves a determination that capital investment is just and reasonable, occurs in the next general rate case for that service area.

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

A. Yes. The Company has made annual GRIP filings in the WTSA, unincorporated areas of the NTSA and the BSSA since the last rate cases in each service area. TGS has included GRIP investment since January 1, 2016 for the WTSA and since January 1, 2018 for the BSSA and unincorporated areas of the NTSA.

Q. IN ADDITION TO THIS TESTIMONY, WHAT SUPPORT ARE YOU PROVIDING FOR THE COMPANY'S CAPITAL INVESTMENT AMOUNTS?

A. In Exhibits SN-4 through SN-6, I am providing capital investments reports, including Corporate and TGS Division investment, for the test year and as provided in TGS's GRIP filings since the last base rate case in the BSSA, WTSA and unincorporated NTSA.

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.[5]

[5] TGS does not need a prudence determination for capital investment in the incorporated areas of the NTSA for the period of January 1, 2018 through December 31, 2020 because the cities within the NTSA already made the necessary prudence determination in the Company's annual COSA filings.

Q. IS THE CAPITAL INVESTMENT INCLUDED IN THE COMPANY'S RATE CASE REASONABLE AND NECESSARY?

A. Yes. Each capital investment expenditure or project must be approved through a thorough decision-making process. Each investment included in this rate case was prudent, reasonable in amount, and necessary for TGS to maintain a safe and reliable system and to provide an appropriate level and quality of gas utility service to customers. This is also true for TGS Division and Corporate capital investment amounts that are allocated to the proposed WNSA and contribute to the Company's ability to provide service in the proposed WNSA. These capital costs are necessary for the Company's operations and are reasonable and prudent.

V. <u>ISSUES THAT AFFECT TGS OPERATIONS</u>

Q. ARE THERE ANY RECENT ISSUES THAT HAVE AFFECTED THE COMPANY'S OPERATIONS AND ITS SYSTEM?

A. Yes. The Company provided safe and reliable natural gas throughout 2020 and 2021 under unprecedented conditions, including COVID-19, Winter Storm Uri, changing economic factors, and a competitive labor market. Specifically, on March 13, 2020, the Governor of Texas declared a State of Disaster in all Texas counties related to COVID-19, which affected TGS's operations in 2020, 2021 and continues to do so. Likewise, a national emergency was declared on March 13, 2020, due to COVID-19 on a federal level.[6] In addition, on February 12, 2021, the Governor of Texas declared a State of Disaster in Texas for all Texas counties in

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[6] Continued in effect beyond March 1, 2022 on February 18, 2022 (Coronavirus Disease 2019 (COVID-19) Pandemic; Continuation of National Emergency (Notice of February 18, 2022), 87 Fed. Reg. 10,289 (Feb. 23, 2022).

response to the unprecedented winter weather event known as Winter Storm Uri. Similarly, on February 14, 2021, a major disaster declaration was issued on a federal level due to Winter Storm Uri.[7] These major events, in addition to economic and labor market issues, affected the Company's operations and required TGS to incur costs that are included in this rate case.

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

A. TGS incurred COVID-19 costs as a result of the implementation of protocols to ensure that employees, whose work was essential to provide and maintain service, could safely continue their day-to-day tasks in the midst of the pandemic. The protocols included infection prevention measures and modifications across operating areas to reduce employee risk of exposure to COVID-19. These measures aligned with the guidance provided by the Centers for Disease Control and Prevention ("CDC"). More specifically, the COVID-19 related costs in this filing include:

- Increased cleaning and disinfecting services on high-contact touchpoints across all facilities to ensure employees and customers were as safe as possible. The cleaning and disinfecting services included cleaning and disinfecting elevators and elevator buttons, spray down of offices, desks, chairs, equipment, tools, and any other items employees touched or used.
- Air purifying systems were installed in each HVAC unit in all populated facilities to maintain air quality and remove bacteria. Additionally, all air filters have been updated and upgraded where applicable and were changed monthly in all facilities where personnel work instead of quarterly which was the practice prior to COVID-19.

[7] President Joseph R. Biden, Jr. Approves Texas Emergency Declaration | The White House (Feb. 14, 2021).

- Disinfecting or cleaning supplies and hand sanitizer were provided to all operational employees.
- Tyvek suits, similar to hazmat suits, were provided to essential workers in the field to be used when entering customers' homes when someone in the customer household tested positive for COVID-19.
- Water and ice were purchased because employees could not utilize the water cooler or ice machine due to social distancing and avoiding touching objects. In fact, the ice machines were turned off.
- Safe work supplies were available at every facility entrance and throughout seating areas including masks, gloves, hand sanitizer and spray disinfectant.

Q. PLEASE EXPLAIN HOW COVID-19 AFFECTED OPERATIONS AND THE MEASURES TGS TOOK TO CONTINUE TO PROVIDE SERVICE TO CUSTOMERS.

A. TGS Operations were significantly affected by COVID-19. More specifically, TGS implemented a safety plan regarding the manner in which its essential employees operate when interacting with each other and customers. In that regard, TGS implemented a Field Operation Activities Per COVID-19 Response Level chart (provided as Exhibit SN-8) that details which field operational activities can be performed depending on the current COVID-19 environment. TGS implemented these new protocols to better protect its employees and the communities it serves. COVID-19 also caused contract labor shortages, delayed delivery times, lower quantities of necessary materials and supplies, and fleet vehicle shortages.

Further, the Company required all employees who were able to work from home to do so in accordance with state and local orders issued in mid-March 2020. TGS also formed an internal COVID-19 task force to address safety measures required for continued operations. The added safety measures include a significant increase in personal protective equipment, which ranges from masks and gloves to sanitizing spray, and additional cleaning of facilities and vehicles where necessary. TGS has closely followed the guidelines recommended by the CDC and Occupational Safety and Health Administration.

Q. WHAT COSTS DID THE COMPANY INCUR RELATED TO WINTER STORM URI THAT ARE INCLUDED IN THIS RATE CASE?

A. The costs included in the Winter Storm Uri regulatory asset include costs for direct service area overtime labor and contractor labor, supplies and expenses, meals and travel, stores issuances and stores overhead, as well as a portion of short-term incentive compensation and amounts for employee recognition awards for extraordinary performance during the winter storm.

Q. PLEASE BRIEFLY EXPLAIN HOW THE COMPANY RESPONDED TO WINTER STORM URI AND THE ACTIONS TGS TOOK TO MAINTAIN SERVICE.

A. In the midst of unprecedented weather conditions, TGS's priority was maintaining service to human needs customers. To do so, employees across ONE Gas and TGS worked tirelessly and collaborated on a daily (and sometimes hourly) basis including ONE Gas management, Operations, Engineering, Gas Supply, Communications, Rates and Legal. During the storm, TGS maintained service to 99.9% of its residential customers throughout the state.

At the local levels, field technicians were deployed to locations throughout Texas to physically monitor critical equipment and address system constraints identified by Engineering. In El Paso, for example, service technicians were placed on site in East El Paso to monitor pressures and to be ready to bypass the system if necessary. Construction and maintenance crews were also on site in East El Paso in the event a section of the pipeline needed to be isolated.

Another example of the efforts taken by TGS to ensure reliable service to its customers occurred in El Paso when an upstream gas supplier experienced a supply shortage during Winter Storm Uri. TGS quickly addressed the issue by constructing an above-ground bypass of over 1,000 feet to maintain gas service to that portion of the city. While the costs for the bypass facility are not included in the regulatory asset, some costs related to the employee work to construct this facility are included in the regulatory asset, which is discussed in more detail by Ms. McTaggart. These efforts required employees to endure difficult weather conditions and be positioned at critical locations for multiple days to ensure regulator stations operated properly and did not freeze.

In North Texas, TGS immediately sent a team to the area to monitor the local system to ensure it continued to operate. Additional foreman and construction and maintenance crews were sent to Aledo to monitor gauges and the school systems, and Pressure and Measurement personnel monitored the equipment throughout the entire winter storm. Further, TGS had to re-route gas due to a rupture on a pipeline from which it takes service. Expenses for the employees needed to monitor the situation and remedy issues as they arose are included in the regulatory asset as discussed by Ms. McTaggart.

Q. PLEASE DESCRIBE THE LABOR MARKET CONDITIONS THAT HAVE AFFECTED TGS OPERATIONS.

A. TGS employs qualified, experienced, and skilled operations employees to ensure that it provides safe and reliable service. As Mr. Branz testifies, due to recent market conditions, a tight labor force, and rising labor costs, TGS faces competition for employees from other industries. TGS pays a reasonable salary but cannot always compete with the salaries being offered by other employers. TGS must also invest in necessary training for new employees. For example, it can take six months to train a field technician before they are qualified to actually perform work on the system. There have been instances when TGS loses that newly trained employee to a better job opportunity, and TGS must start the hiring and training process over again. TGS also utilizes contract labor. In recent years, contractor costs have increased as the demand for contract labor has risen. Nevertheless, TGS must continue to directly employ qualified personnel or hire qualified contractors to perform work required to operate and maintain the system in a safe and reliable manner.

VI. CONSOLIDATION TO CREATE THE WNSA

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

A. TGS proposes to consolidate the WTSA, NTSA, and the BSSA to form a new, combined service area called the West North Service Area.

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 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 service areas have been the result of historical factors, particularly prior to the three consolidations in 2016.[8] 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 to identify geographic boundaries around the gas distribution systems TGS operated. 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 WTSA, NTSA, BSSA already share personnel for certain services and rely on centralized management of certain functions and operations. Many of the

[8] With Commission approval in 2016, TGS consolidated two service areas to create the then-existing Gulf Coast Service Area, three service areas to create the West Texas Service Area, and two service areas to create the Central Texas Service Area.

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 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 centralized Customer Information Center located in El Paso means that customers within the proposed WNSA receive uniform responses to similar inquiries concerning payment activity, establishing or changing service, and service or payment disputes. Similarly, a centralized dispatch center ensures that field operation employees in the proposed WNSA are efficiently deployed 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 within the WNSA.

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

A. Yes. Between 2016 and 2020, the Commission approved consolidation of service areas in four TGS rate cases. As a result, the number of service areas has gone down from ten to five 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 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 WTSA, NTSA and BSSA 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 in the WNSA 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.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
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1	SCHEDULE A	Summary of Revenue Requirement	McTaggart
2	WKP A.a	Proof of Revenue Requirement	McTaggart
3	WKP A.b	Customer Allocation Factors	McTaggart
4	SCHEDULE B	Rate Base	McTaggart
5	WKP B.a	Summary of Plant Adjustments	McTaggart
6	SCHEDULE B-1	Materials and Supplies	McTaggart
7	SCHEDULE B-2	Prepayments	McTaggart
8	WKP B-2.a.1	Prepayments - TGS Division	Borgstadt
9	WKP B-2.b.1	Prepayments - Corporate Allocated through Distrigas	Borgstadt
10	SCHEDULE B-3	Rule 8.209 Regulatory Asset	McTaggart
11	WKP B-3.a	Rule 8.209 Regulatory Asset	McTaggart
12	SCHEDULE B-4	Pension and OPEB Regulatory Asset	McTaggart
13	WKP B-4.a	Pension and OPEB Regulatory Asset	McTaggart
14	SCHEDULE B-5	Prepaid Pension Asset	McTaggart/Smith
15	SCHEDULE B-6	Cash Working Capital	Lyons
16	SCHEDULE B-7	Customer Deposits	McTaggart
17	SCHEDULE B-8	Customer Advances	McTaggart
18	SCHEDULE B-9	Accumulated Deferred Income Taxes	Simpson
19	SCHEDULE B-10	Unamortized Excess Accumulated Deferred Income Taxes	McTaggart/Husen
20	SCHEDULE B-11	Regulatory Assets	McTaggart
21	SCHEDULE C	Total Plant in Service - Direct and Allocated	McTaggart/Borgstadt
22	WKP C.a	Plant in Service - Service Area Direct	McTaggart
23	WKP Ca.1	Fort Bliss	McTaggart
24	WKP C.b	Plant in Service - TGS Division	Borgstadt
25	WKP C.c	Plant in Service - Corporate	Bortstadt
26	SCHEDULE C-1	Total Completed Construction Not Classified (CCNC) - Direct and Allocated	McTaggart/Borgstadt
27	WKP C-1.a	CCNC - Service Area Direct	McTaggart
28	WKP C-1.a.1	Fort Bliss	McTaggart
29	WKP C-1.b	CCNC - TGS Division	Borgstadt
30	WKP C-1.c	CCNC - Corporate	Borgstadt
31	SCHEDULE D	Total Accumulated Reserves for Depreciation and Amortization - Direct and Allocated	McTaggart/Borgstadt
32	WKP D.a	Total Accumulated Reserves for Depreciation and Amortization - Direct	McTaggart
33	WKP D.a.1	Fort Bliss	McTaggart
34	WKP D.b	Total Accumulated Reserves for Depreciation and Amortization - TGS Division	McTaggart/Borgstadt
35	WKP D.c	Total Accumulated Reserves for Depreciation and Amortization - Corporate	McTaggart/Borgstadt
36	SCHEDULE E	Cost of Capital	Fairchild
37	SCHEDULE F	Federal Income Tax	McTaggart
38	SCHEDULE G	Summary of Operating Revenue and Expense Adjustments	McTaggart/Serna/Borgstadt
39	SCHEDULE G	Summary of Operating Revenue and Expenses	McTaggart/Serna/Borgstadt

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41	WKP G.a.2	Operating Revenue and Expense Per Book	McTaggart/Serna/Borgstadt
42	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	Borgstadt
43	SCHEDULE G-1	Remove Gas Revenue, Cost of Gas and Related Taxes	Serna
44	SCHEDULE G-2	Normalize Gas Sales Revenue	Serna
45	SCHEDULE G-3	Normalize Other Utility Revenue	Serna
46	SCHEDULE G-4	Base Payroll Adjustment	Borgstadt
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48	WKP G-4.b	Test Year Payroll	Borgstadt
49	WKP G-4.c	December Base Payroll	Borgstadt
50	SCHEDULE G-5	Overtime Payroll Adjustment	Borgstadt
51	WKP G-5.a	Overtime Payroll Expense	Borgstadt
52	SCHEDULE G-6	Benefits and Payroll Tax Adjustment	Borgstadt
53	WKP G-6.a	Benefits and Payroll Tax Expense	Borgstadt
54	WKP G-6.b	Benefits and Taxes	Borgstadt
55	SCHEDULE G-7	Pension and OPEB	McTaggart
56	SCHEDULE G-8	Incentive Compensation	Borgstadt
57	SCHEDULE G-9	Miscellaneous Adjustments	McTaggart/Borgstadt
58	WKP G-9.a	Miscellaneous Adjustments - Direct Service Area	McTaggart
59	WKP G-9.b	Miscellaneous Adjustments - Shared Services	Borgstadt
60	WKP G-9.c	Miscellaneous Adjustments Meals and Hotels - Shared Services	Borgstadt
61	SCHEDULE G-10	Rents and Leases	McTaggart/Borgstadt
62	WKP G-10.a	Rents and Leases - Direct Service Area	McTaggart
63	WKP G-10.b	Rents and Leases - Shared Services	Borgstadt
64	SCHEDULE G-11	Interest on Customer Deposits	McTaggart
65	SCHEDULE G-12	Uncollectible Expense	McTaggart
66	SCHEDULE G-13	Injuries and Damages	Borgstadt
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68	SCHEDULE G-14	Advertising Expense	McTaggart/Borgstadt
69	SCHEDULE G-15	Depreciation and Amortization Expense	McTaggart/Borgstadt
70	WKP G-15.a.1	Depreciation and Amortization Expense - Direct Service Area	McTaggart
71	WKP G-15.a.2	Fully Depreciated Plant - Direct Service Area	McTaggart
72	WKP G-15.b.1	Depreciation and Amortization Expense - TGS Division	Borgstadt
73	WKP G-15.b.2	Fully Depreciated Plant - TGS Division	Borgstadt
74	WKP G-15.c.1	Depreciation and Amortization Expense - Corporate	Borgstadt
75	WKP G-15.c.2	Fully Depreciated Plant - Corporate	Borgstadt
76	SCHEDULE G-16	Ad Valorem Tax Expense	McTaggart
77	WKP G-16.a	Plant in Service - Direct, Ad Valorem Tax Workpaper	McTaggart

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79	WKP G-16.c	Accumulated Reserves for Depreciation and Amortization - Direct, Ad Valorem Tax Workpaper	McTaggart
80	SCHEDULE G-17	Franchise ("Gross Margin") Tax Expense	McTaggart
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82	SCHEDULE G-19	Transportation and Work Equipment Clearing	McTaggart
83	SCHEDULE G-20	Regulatory Expense Amortization	McTaggart
84	SCHEDULE G-21	Distrigas Allocation Percentage	Borgstadt
85	WKP G-21.a	Distrigas Allocation Percentage Workpaper	Borgstadt
86	SCHEDULE G-22	Causal Allocation Percentage	Borgstadt
87	WKP G-22.a	Causal Allocation Factor	Borgstadt
88	SCHEDULE G-23	Pipeline Integrity Testing Expense	McTaggart
89	SCHEDULE G-24	Excess Deferred Income Tax Amortization	McTaggart/Husen
89	Study Summary	Class Cost of Service Study Summary	Serna
90	Study Summary for Rate Design	Class Cost of Service Study Summary for Revenue Allocations	Serna
91	Classified Rate Base	Classified Rate Base	Serna
92	Classified Cost of Service	Classified Cost of Service	Serna
93	Classification Factors	Classification Factors	Serna
94	Allocated Rate Base	Allocated Rate Base	Serna
95	Allocated Cost of Service	Allocated Cost of Service	Serna
96	Allocation Factors	Allocation Factors	Serna
97	WKP Plant	Plant and Depreciation Workpaper	Serna
98	WKP Admin&Gen	Administrative & General Workpaper	Serna
99	WKP Selected Data	Selected Data Workpaper - Volumes, Bills, Margin, Odorization, Distrigas, Allocation Factors, Mains (Customer) Percentage	Serna
100	903 Factors	Account 903 Factors Summary for CCOSS	Serna
101	904 Factors	Account 904 Factors Summary for CCOSS	Serna
102	Billing Determinants Summary	Billing Determinants Summary for CCOSS	Serna
103	Customer Deposit Factors	Customer Deposit Factors Summary for CCOSS	Serna
104	Mains Study Summary	Mains Study Summary for CCOSS	Serna
105	Meters & Regulator Factors	Meter & Regulator Factors Summar for COSS	Serna
106	Odorization Summary	Odorization Summary for COSS	Serna
107	Peak Demand	Peak Demand Summary for COSS	Serna
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112	Proof of Revenue	Proof of Revenue	Raab
113	Current & Rec Rates	Current and Recommended Rates	Raab
114	WKP Current & Rec Rates	Current and Recommended Rates Workpaper	Raab
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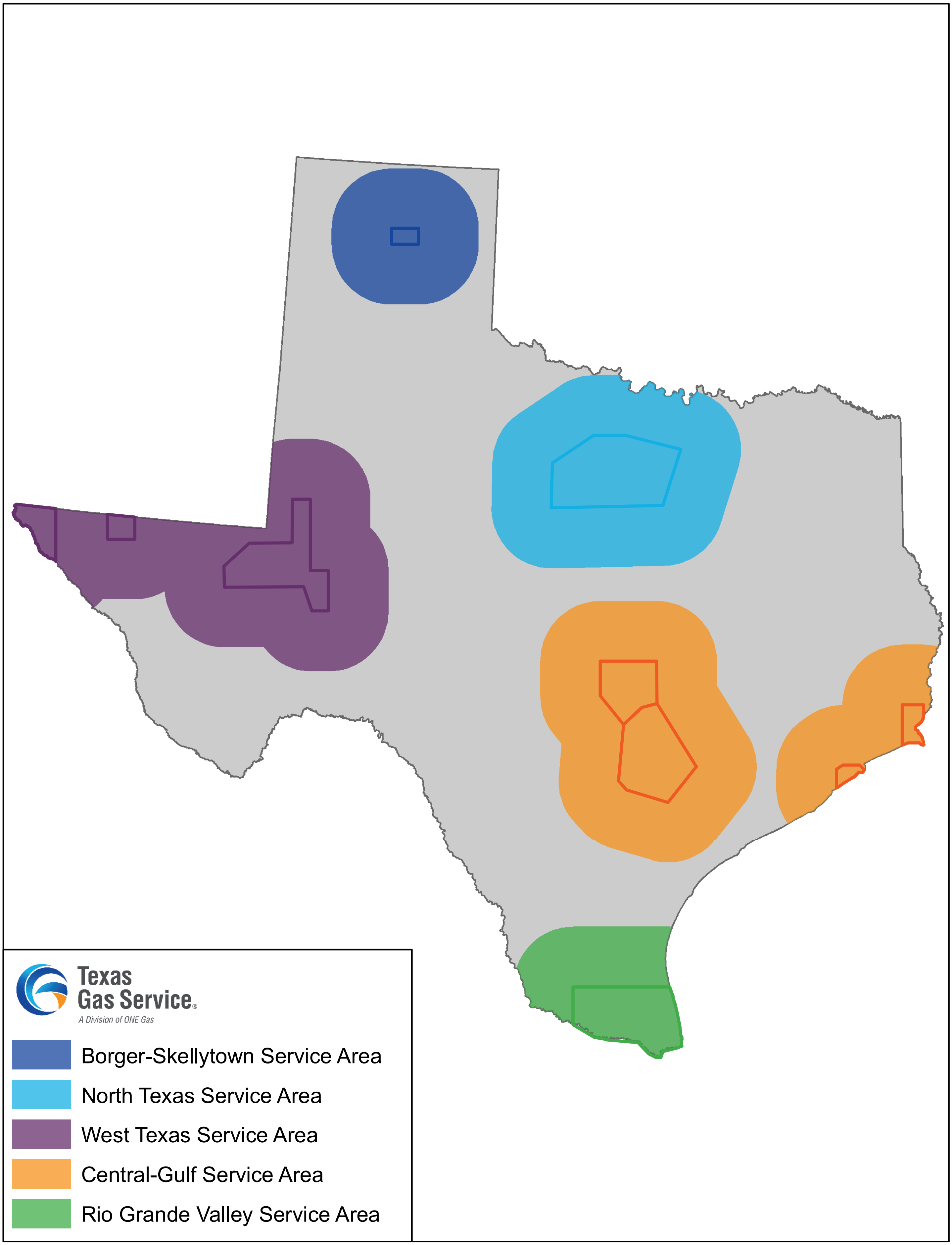
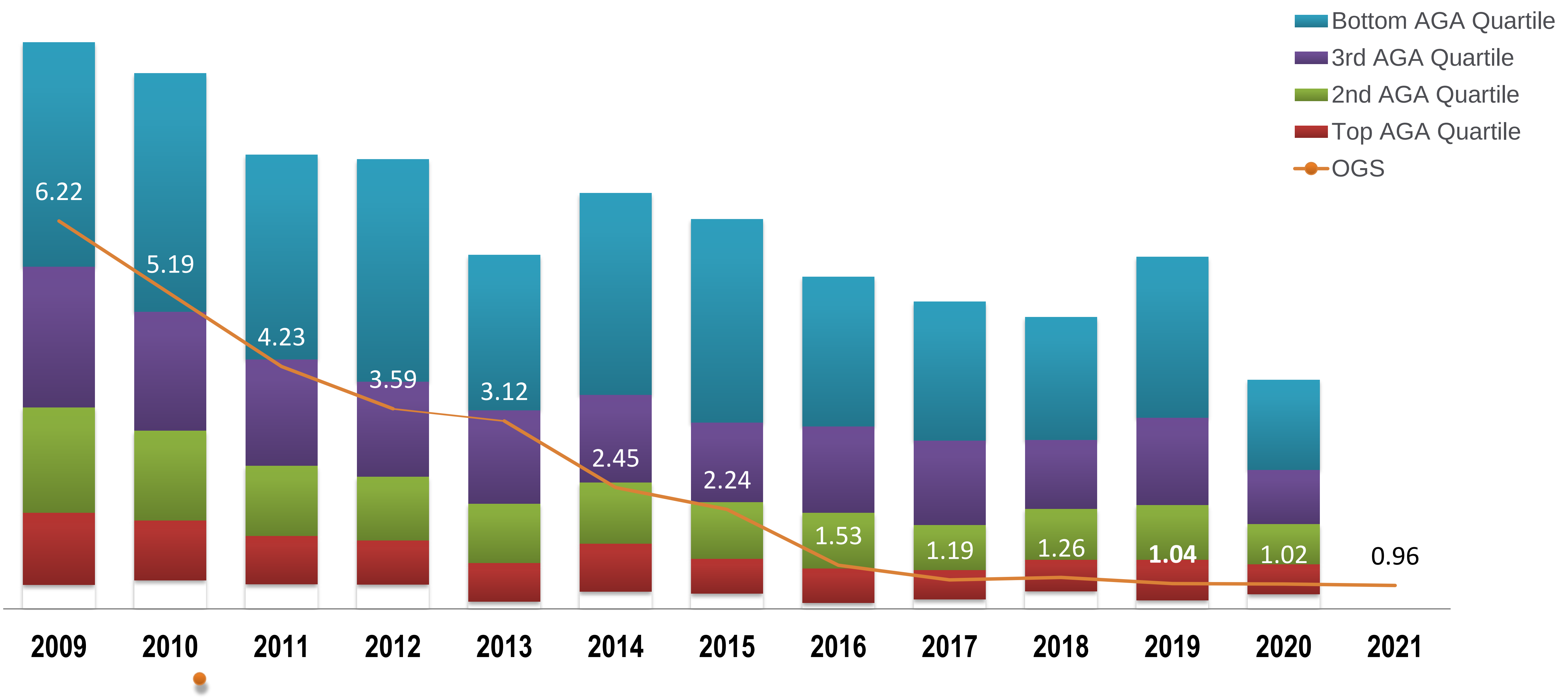
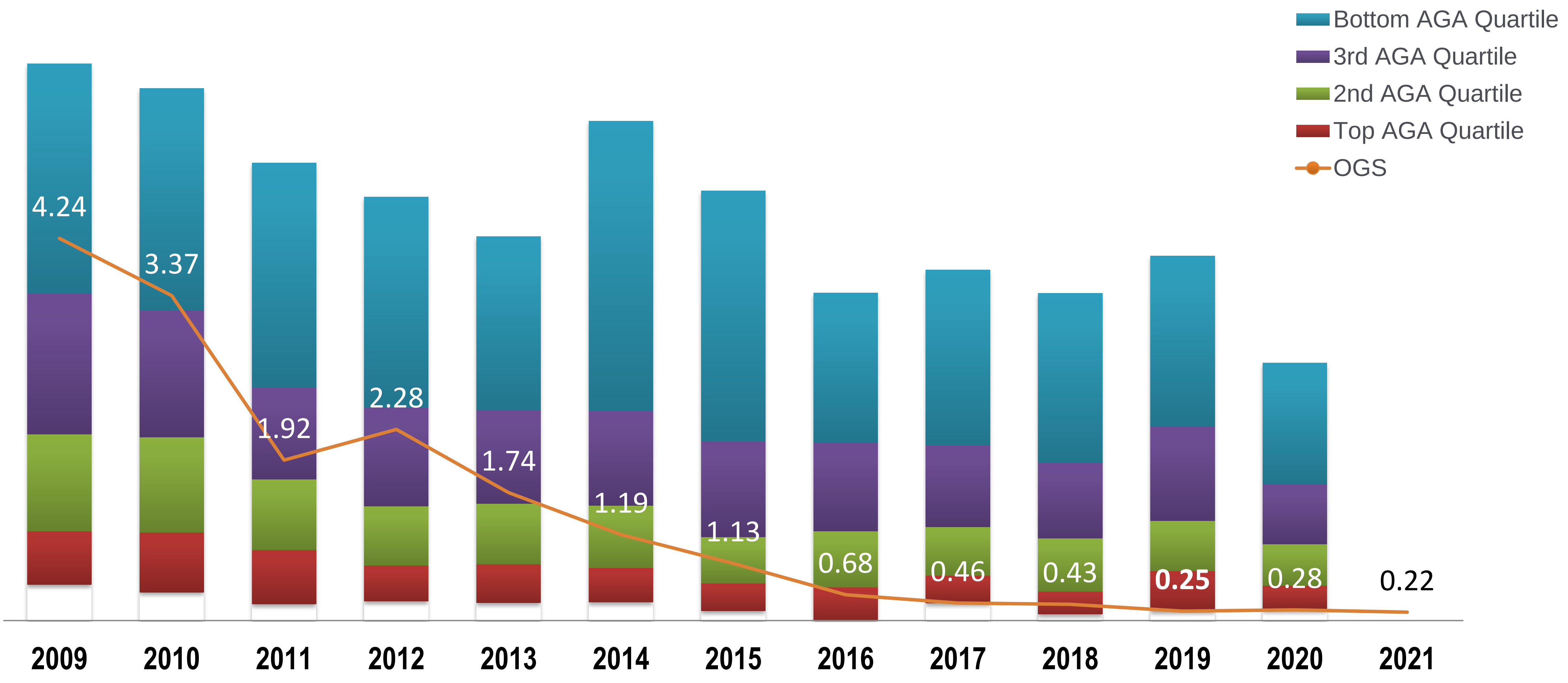
117	A_B Bill Impacts Existing Rates	Annual Residential Bill Impacts - Proposed A/B Rate Structure compared to Existing Rate Structure	Raab
118	Residential	Residential Rate Design	Raab
119	Commercial	Commercial Rate Design	Raab
120	Public Authority	Public Authority Rate Design	Raab
121	Industrial	Industrial Rate Design	Raab


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

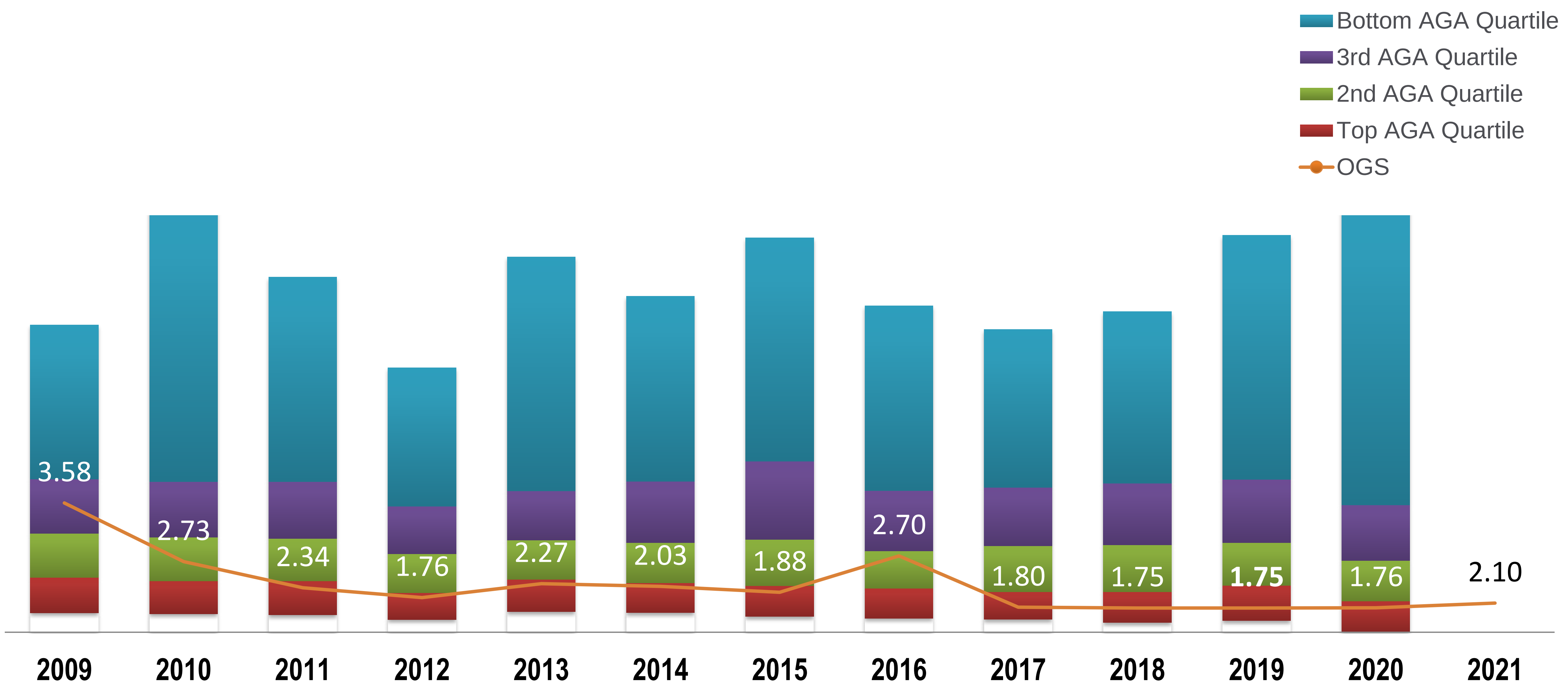
AGA Total Recordable Incident Rate (TRIR) Quartile Compared to OGS TRIR



AGA Days Away, Restricted and Transferred (DART) Quartile Compared to OGS DART



AGA Preventable Vehicle Incident Rate (PVIR) Quartile Compared to OGS PVIR



Emergency Response Time: Percent of Onsite Times in Less than 30 Minutes

Exhibits SN-4 through SN-6 are Voluminous
and will be provided electronically.

Year	Total WNSA Net Adjusted Plant (Note 1)	Dollar Increase in Net Plant	Percentage Increase in Net Plant
2016	$335,537,501		
2017	$367,564,840	$32,027,339	9.55%
2018	$472,205,500	$104,640,660	28.47%
2019	$510,899,953	$38,694,453	8.19%
2020	$595,799,200	$84,899,247	16.62%
2021	$638,311,773	$42,512,573	7.14%
Total Increase from 2016 to 2021		$302,774,273	90.24%
Average Increase in Net Plant between 2016 to 2021		$60,554,855	13.99%

Note 1: Plant balances include Rule 8.209 regulatory assets through December 2021.

Field Operation Activities Per COVID-19 Response Level

Activities with an X will continue. Items with an X and * are subject to resource constraints.

In Levels 2 and 3, activities without an X **can be done still if**:

- They don't conflict with a higher level (e.g., you can do Rebuilds in Level 3, but we specifically state to do Rebuilds only without service disruption in Level 2).
- The work does not create a discretionary service disruption (service tie-overs from existing main).
- We have adequate resources (e.g., if we have personnel still available, we keep working our government relocation projects, but will stop if we need to dedicate those people to higher priority work).

In Level 1, items without an X cannot be done without VPO approval.

Field Operations Activities	**Level 5 (lowest)**	**Level 4**	**Level 3**	**Level 2**	**Level 1 (highest)**
Gas Control	X	X	X	X	X
Gas Supply	X	X	X	X	X
Dispatch	X	X	X	X	X
Emergencies	X	X	X	X	X
Leak Repair (Grade I)	X	X	X	X	X
Compliance	X	X	X	X	X*
Turn-ons /New Sets /Reconnects of critical facilities/outages)	X	X	X	X	X**
Turn-ons	X	X	X	X*	
Reconnects	X	X	X	X*	
New Sets (Builder only non-contact)	X	X	X	X*	
Integrity Management	X	X	X	X*	
Leak Repair (Grade II & III)	X	X	X	X	
Line Extensions	X	X	X	X	
New Services	X	X	X	X	
Reinforcements (w/o service disruption)	X	X	X	X	
Rebuilds (w/o service disruption)	X	X	X	X	
Collections	X	X	X		
Completion of Projects	X	X	X		
Reinforcement Projects	X	X	X		
Rebuilds	X	X	X		
Relocation Projects	X	X	X		
New sets	X	X	X		
Service Kills	X	X*			
Abandonments	X	X*			

X indicates work to be completed at the level.

* As resources allow

** Requires VPO or designee approval

Updated Aug. 11, 2021

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF SHANTEL NORMAN

BEFORE ME, the undersigned authority, on this day personally appeared Shantel Norman who having been placed under oath by me did depose as follows:

1. "My name is Shantel Norman. 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, 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.

DocuSigned by:
Shantel Norman
B4C321B1159645B...
Shantel Norman

SUBSCRIBED AND SWORN TO BEFORE ME by the said Shantel Norman on this 20th day of June 2022.

DocuSigned by:
Christine Marie Bell
1C45AAFD08DC44A...
Notary Public in and for the State of Texas

NOTARY PUBLIC
STATE OF TEXAS
CHRISTINE MARIE BELL
Notary ID
130547096
My Commission Expires
2/19/2024

CASE NO. 00009896

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	§ § § § § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

DIRECT TESTIMONY

OF

STACEY L. MCTAGGART

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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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"), which is a Division of ONE Gas, Inc. ("ONE Gas"). I am responsible for managing the regulatory matters for TGS.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Business Administration degree in finance and accounting from St. Edward's University in August 1988. From 1983 to 1990, I worked for NCNB Texas, now Bank of America. In April 1990, I joined Southern Union Company as a Rate Analyst. In that capacity, I was responsible for the preparation of rate schedules and testimony in connection with rate requests in the various regulatory jurisdictions in which Southern Union Company operated. From April 1993 to January 1997, I served as a Utility Specialist at the Railroad Commission of Texas ("Commission"). At the Commission, I participated in numerous cases as either a Staff witness or a technical examiner. In January 1997, I returned to Southern Union Company as Manager of Pricing and Economic Analysis, managing rate cases primarily for the Company's Southern Union Gas ("SUG") division. In September 2001, I became SUG's Director of Financial and Regulatory Analysis. Upon the sale of Southern Union's Texas assets to ONEOK, Inc.

("ONEOK") in January 2003, I joined ONEOK's TGS division and maintained my position. Upon the separation of ONE Gas from ONEOK in January 2014, I continued as Rates and Regulatory Director.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I have prepared and sponsor the exhibits listed in the table of contents.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, they were.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the following issues in this rate case:

1. Introduction of TGS's Statement of Intent ("SOI") filing;
2. The Company's request to consolidate its existing West Texas Service Area ("WTSA"), North Texas Service Area ("NTSA"), and Borger Skellytown Service Area ("BSSA") into a new West North Service Area ("WNSA");
3. Compliance with certain regulatory and statutory requirements, including affiliate cost recovery issues related to Utility Insurance Company ("UIC");
4. Summary of the Direct costs attributed to the proposed WNSA in the Company's cost of service calculation that demonstrate the Company's need for a rate change in the proposed WNSA. I also describe the portion of the Company's requested rate base amounts related to proposed WNSA Direct costs. Company witness Stacey R. Borgstadt supports TGS Division and Corporate rate base and expense adjustments in her direct testimony;
5. Treatment of cloud-based computing costs;

6. The Company's request for regulatory asset treatment of deferred costs related to prior regulatory proceedings, COVID-19, and Winter Storm Uri;

7. Adjustment to include Excess Deferred Income Taxes ("EDIT") in base rates, with discontinuance of the EDIT Rider, to return EDIT to customers;

8. Support the Company's recovery of pipeline integrity testing costs;

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

10. Describe the rate schedules and tariffs currently in effect for the WTSA, NTSA, and BSSA and describe the rate schedules and tariffs that would be applicable for the proposed WNSA should consolidation as proposed by the Company be approved.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring or co-sponsoring the following schedules:

RATE BASE:	
Schedule A (Revenue Requirement)	Sponsoring
Schedule B (Rate Base)	Co-Sponsor with Stacey R. Borgstadt
Schedule B-1 M&S	Sponsoring
Schedule B-2 Prepayments	Sponsoring
Schedule B-3 8.209 Reg Asset	Sponsoring
Schedule B-4 Pens-OPEB Reg Asset	Sponsoring
Schedule B-5 Prepaid Pension Asset	Co-Sponsor with Mark W. Smith
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 Jeffrey J. Husen
Schedule C (Plant)	Co-Sponsor with Stacey R. Borgstadt
Schedule C-1 (CCNC)	Co-Sponsor with Stacey R. Borgstadt
Schedule D (Reserves)	Co-Sponsor with Stacey R. Borgstadt
Schedule F (Federal Income Tax)	Sponsoring

OPERATING INCOME:	
Schedule G (Summary of Operating Revenue & Expense Adj)	Co-Sponsor with Teresa Serna and Stacey R. Borgstadt
Schedule G-7 (Pension OPEB)	Sponsoring

Schedule G-9 (Miscellaneous Adjustments)	Co-Sponsor with Stacey R. Borgstadt
Schedule G-10 (Rents)	Co-Sponsor with Stacey R. Borgstadt
Schedule G-11 (Interest on Customer Deposits)	Sponsoring
Schedule G-12 (Uncollectible Expense)	Sponsoring
Schedule G-14 (Advertising Expense)	Co-Sponsor with Stacey R. Borgstadt
Schedule G-15 (Depreciation & Amortization)	Co-Sponsor with Stacey R. Borgstadt
Schedule G-16 (Ad Valorem Tax Expense)	Sponsoring
Schedule G-17 (Texas Franchise Tax Expense)	Sponsoring
Schedule G-18 (Stores Load)	Sponsoring
Schedule G-19 (TWE Load)	Sponsoring
Schedule G-20 (Regulatory Asset Amortization)	Sponsoring
Schedule G-23 (PIT)	Sponsoring
Schedule G-24 (EDIT)	Co-Sponsor with Jeffrey J. Husen

The schedules that I address in my testimony are for the Company's proposed WNSA. In addition to schedules that reflect the Company's requested consolidation for the WNSA, TGS is also providing stand-alone cost of service schedules for the WTSA, NTSA and BSSA.

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 in Gas Utilities Docket ("GUD") Nos. 9770, 9790, 9839, 9988, 10094, 10453, 10488, 10506, 10526, 10656, 10739, 10766, and 10928 and Case No. OS-21-00007061.

III. OVERVIEW OF TGS'S STATEMENT OF INTENT FILING

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

A. First, TGS is required to file a SOI for the WTSA by December 3, 2022 because TGS has filed the maximum number of Interim Rate Adjustment filings ("IRA" or Gas Reliability Infrastructure Program "GRIP" filings) permitted by Gas Utility Regulatory Act ("GURA") § 104.301 before a rate case must be filed. In addition to that requirement, this rate case gives TGS the opportunity to continue its efforts to achieve regulatory and administrative efficiencies through consolidation and to request rates that more accurately reflect the current and expected costs of providing service in the proposed WNSA at the time new rates will go into effect. For context, following ONE Gas' separation from ONEOK in January 2014, TGS filed a rate case in each of its service areas, including four rate cases in which separate services areas were consolidated. Those Statements of Intent, filed between 2015 and 2019, established rates that more accurately reflected the cost of providing service to customers, allowed TGS to obtain approval of consistent tariffs and rate schedules for its various service areas and approved consolidation of several TGS service areas.

Q. WHAT TEST YEAR WAS UTILIZED IN THIS SOI?

A. The Company's SOI filing is based on the financial results for the test year ended December 31, 2021.

Q. WHY IS TGS REQUESTING A RATE INCREASE IN THIS SOI?

A. In terms of revenue requirement, the Company's cost of service calculations show that TGS is experiencing a revenue deficiency primarily driven by plant investment and related depreciation and ad valorem tax expense, payroll-related expenses, and regulatory and safety requirements. TGS has continued to invest in system safety and reliability, resulting in an increase of over $302.8 million in net plant since base rate cases were last filed in the WTSA, NTSA and BSSA. In addition, TGS must 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. Regulatory and safety requirements to document, test, survey, repair, plan and replace system assets also continue to increase. The costs associated with these requirements include operating expenses for activities such as leak repair, leak survey, and distribution integrity management. TGS also made additional capital investments in its natural gas distribution system for technology that enhances the Company's ability to provide safe and reliable service. 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 and efficiencies and improve customer service. These issues have resulted in a revenue deficiency that does not provide the Company with a reasonable opportunity to earn a reasonable return on its investment.

Q. HAS TGS TAKEN REASONABLE ACTIONS TO MANAGE COSTS?

A. Yes, it has. 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. In addition, the Company's continued success relies in part on being efficient and cost-conscious and on its employees operating safely and in a responsible manner. The Company has taken, and continues to take, steps to ensure that resources are used wisely and that costs are reasonably managed. 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. For example, the Company was recognized as number one in Customer Satisfaction with Residential Natural Gas Service in the South among Large Utilities in the J.D. Power 2021 Gas Utility Residential Customer Satisfaction Study, receiving top rankings in the following study factors: Price, Corporate Citizenship, and Communications.

Q. PLEASE PROVIDE EXAMPLES OF THE COMPANY'S IMPROVEMENTS IN CUSTOMER SERVICE ACTIVITIES.

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

1. Electronic Bill Statement Growth - Approximately 44% of ONE Gas customers receive electronic bill statements, which results in savings in postage and materials.

2. Enhanced Customer Communications - proactively putting information in customers' hands such as improved education 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.

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

5. Energy Assistance - in late 2020, TGS implemented an Energy Assistance Portal for the Company's Energy Assistance Partners, which are agencies that distribute available utility bill assistance to customers in need. Previously, the Energy Assistance partners were required to call TGS to

submit pledges or receive copies of bills or notices. With the updated portal, Energy Assistance partners are able to submit pledges online and retrieve the necessary documentation. This portal expedited the processing of Energy Assistance efforts, which has prevented disconnects and increased customer satisfaction with the Energy Assistance experience.

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

7. Web Site Enhancements - Enhanced search functionality for customers to more easily find what they are looking for, implemented a new blog section that features up-to-date information for customers including answers to recently asked questions, financial assistance information and community involvement, refreshed and updated content on the TGS website including more accessible and clear navigation regarding how to make payments, and added additional "banner" alerts featured on the TGS homepage to share information on payment assistance and payment options for customers impacted by the winter storm and COVID-19 pandemic.

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 GENERALLY DESCRIBE THE RELIEF REQUESTED IN THIS SOI.

A. The Company's cost of service demonstrates a total annual net revenue deficiency of $12,995,128 for the proposed WNSA. The Company proposes to eliminate this annual earnings deficiency and to have its rates set at a level that provides TGS a return on equity of 10.25%. TGS is requesting recovery of necessary operating and maintenance costs it incurred as a result of COVID-19 in 2020 and 2021, consistent with the Regulatory Asset Notice issued in April 2020.[1] TGS is also seeking to

[1] 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.

recover necessary operating and maintenance costs it incurred as a result of Winter Storm Uri in 2021, consistent with the Regulatory Asset Determination Order in Case OS-21-00007061, the Regulatory Asset Notice issued on February 13, 2021, and Notice to Gas Utilities issued on June 17, 2021. In addition, TGS seeks recovery of compensation and benefit costs, which are supported by GURA § 104.060, which is addressed by Company witnesses Jeff D. Branz and Ms. Borgstadt. 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 WTSA, NTSA and BSSA into a single, new service area known as the West North Service Area. The Company is proposing a small and large residential rate design based on individual customer usage characteristics, as explained by Company witness Paul H. Raab. In addition, TGS seeks a finding that it has correctly reflected changes to utility rates to account for all the impacts of the lowered federal corporate income tax rate consistent with the Accounting Order issued in GUD No. 10695. Finally, TGS is requesting a prudence determination for the capital investment made since the last WTSA, NTSA, and BSSA rate cases.

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

A. The proposed rate increase will result in changes to the average monthly bills for the 257,052 residential customers in the incorporated areas of the proposed WNSA and the 26,606 residential customers in the environs areas of the proposed WNSA, as shown in the table below.[2]

				Change	
Line No.	Description	Current	Recommended	Dollars	%
	(a)	(b)	(c)	(d)	(e)
1	**Residential - Small**				
2	WTSA Incorporated and Environs	$35.50	$39.89	4.39	12.4%
3	NTSA Incorporated	$44.59	$39.89	-4.70	(10.5)
4	NTSA Environs	$51.78	$39.89	-11.89	(23.0)%
5	BSSA Incorporated and Environs	$31.21	$39.89	8.68	27.8%
6	**Residential - Large**				
7	WTSA Incorporated and Environs	$51.01	$58.02	7.01	13.7%
8	NTSA Incorporated	$82.35	$58.02	-24.33	(29.5)%
9	NTSA Environs	$87.13	$58.02	-29.11	(33.4)%
10	BSSA Incorporated and Environs	$50.91	$58.02	7.11	14.0%

The proposed rates for all rate classes are identified in Mr. Raab's direct testimony and are reflected in the tariffs in Section XII of my testimony. In addition to proposed gas sales, transportation, and cost of gas tariffs, the Company's filing includes other rate schedules such as a weather normalization clause, a rate case expense recovery rider, and a pipeline integrity testing expense rider. In addition, the Company proposes revised service fees and updated language in its transportation tariffs and rules of service.

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

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

A. The Company is proposing two residential rates. The small residential rate benefits customers with lower-than-average usage. It combines a lower monthly customer charge of $20.00 and a higher volumetric rate of $0.41173 per Ccf. The large residential rate benefits residential customers with higher-than-average usage. It combines a $35.00 monthly customer charge and a much lower volumetric rate of $0.00264 per Ccf. Importantly, the proposed rate design substantially mitigates the potential rate increase for low-usage residential customers as compared to a traditional rate design that applies the same customer charge and usage charge to all customers within the residential class. 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 customers will, in fact, experience an overall rate decrease as shown in Exhibit PHR-5 to Mr. Raab's testimony. At the same time, the proposed rate design ensures that higher-use customers will not experience significantly higher bill impacts during the winter months. For example, the large residential rate, which has a higher customer charge but lower volumetric charge, helps to levelize monthly charges for higher-use customers throughout the year. In addition, this rate design approach minimizes bill impacts associated with proposed consolidation and creation of the WNSA.

If the proposed residential rate design is approved, the Company 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."[3] The customer will have the option to contact the Company and choose the alternate residential rate based on their own preference, provided that they remain on the rate they choose for a full year. The Company is excited to propose a rate design that recognizes the differing usage characteristics of residential customers and allows customers who desire it some amount of choice in how they are billed for gas service.

Q. 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 eighteen years.

IV. CONSOLIDATION REQUEST

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING CONSOLIDATION OF SERVICE AREAS IN THIS SOI?

A. TGS proposes to consolidate three of its existing service areas, the WTSA, NTSA, and the BSSA, to form a new, combined service area called the West North Service Area. As explained by Company witness Shantel Norman, the proposed consolidation aligns with operational realities already in place under the Company's functional operating model.

[3] 16 Tex. Admin. Code ("TAC") § 7.45(2)(A)(ii).

Q. HAS THE COMMISSION APPROVED PRIOR CONSOLIDATION REQUESTS FOR TGS?

A. Yes. TGS's consolidation requests have been approved by the Commission since 2016, allowing TGS to reduce the number of regulatory service areas from ten to five. Specifically:

- in GUD No. 10488, the Commission approved 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 consolidated to establish the Central Texas Service Area; and
- in GUD No. 10928, the Commission approved consolidation of the Central Texas Service Area and Gulf Coast Service Area to establish the Company's existing Central Gulf Service Area.

Q. HAS THE COMMISSION PREVIOUSLY ADDRESSED ADMINISTRATIVE EFFICIENCIES RESULTING FROM CONSOLIDATION?

A. Yes. In GUD Nos. 10506 and 10928, the Administrative Law Judges ("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.[4] The ALJs concluded that with

[4] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Areas (EPSA), Permian Service Area (PSA) and Dell City Service Area (DCSA)*, GUD No. 10506 consol., First Amended Proposal for Decision ("PFD") at 12 (Sept. 16, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to*

consolidation, rate changes would be implemented uniformly and consistently, which is more economical, efficient, and cost-effective for TGS and its customers.[5]

Consistent with the ALJs' reasoning, the proposed WNSA consolidation will reduce the number of cost-of-service analyses and rate cases 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 WNSA consolidation will reduce the number of tariffs administered by both the Company and the Company's regulators from 86 tariffs for the three service areas combined to 41 tariffs.[6]

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 WNSA consolidation, the proposed consolidated rates had differing impacts on different customer groups. On page 10 of my testimony, I provide the bill impacts which

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Increase Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area, GUD No. 10928 consol., PFD at 15 (Jul. 6, 2020).

[5] *Id*.

[6] Nine of the 41 tariffs are individual Tapping Fee tariffs that apply to discrete areas within the WNSA, have been in place for approximately 10 to 20 years depending on the tariff, and are not affected by proposed consolidation.

demonstrate that, depending on the level of existing rates in the WTSA, NTSA, or BSSA, there are different rate impacts under consolidation. TGS's consolidation request is reasonable as consolidation will lead to more consistent or equal cost impacts on customers because there will be a larger, single group of customers in the WNSA instead of three separate customer bases in three separate service areas supporting three separate costs of service.

The request is also consistent with and supported by prior consolidation dockets. 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.[7] The ALJs 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]

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

[7] GUD No. 10506, First Amended PFD at 12; GUD No. 10928, PFD at 14, 16.
[8] GUD No. 10506, First Amended PFD at 12-13; GUD No. 10928, PFD at 14-15.

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 ALJ in GUD No. 10928 also included this analysis in the PFD supporting consolidation.[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.

V. 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

[9] GUD No. 10506, First Amended PFD at 13 (emphasis in original).
[10] GUD No. 10928, PFD at 16.

("USOA"), as supplemented by Commission order or State law. 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:

- 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 2021 that its Chief Executive Officer and Chief Financial Officer have concluded that ONE Gas' disclosure controls and procedures were effective as of the end of the periods covered by these reports based on the evaluation of the controls and procedures required by Rules 13(a)-15(b) of the Securities Exchange Act of 1934, as amended. There have been no changes in ONE Gas' internal controls over financial reporting during 2021 that have materially affected, or are reasonably likely to materially affect, its internal controls over financial reporting.

Q. ARE THE ONE GAS BOOKS AND RECORDS SUBJECT TO AUDIT?

A. Yes, as a publicly traded company, ONE Gas is responsible for the fair presentation of its consolidated financial statements and is required to establish and maintain disclosure controls and procedures and internal controls over financial reporting. In connection with these requirements, ONE Gas must evaluate the effectiveness of its disclosure controls and procedures and internal controls over financial reporting and present a report in its Form 10-K filed with the Securities and Exchange Commission ("SEC") on its conclusions about the effectiveness of these controls, as of the end of the period covered by the financial statements. ONE Gas' evaluation of the effectiveness of our internal control over financial reporting is based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In connection with the evaluation, ONE Gas' Internal Audit Department annually reviews the design and tests the operating effectiveness of the Company's internal controls over financial reporting. The Company's most recent report is included as part of ONE Gas' Annual Report on Form 10-K filed with the SEC on February 24, 2022. The report concluded that our disclosure controls and procedures and our internal control over financial reporting were effective at December 31, 2021. 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.

The independent public accounting firm of PricewaterhouseCoopers LLP ("PWC") performs an integrated audit of the books and records of ONE Gas and ONE Gas' internal controls over financial reporting. The objective of these audits is to express an opinion as to whether the financial statements are free of material misstatements and whether effective internal control over financial reporting was maintained in all material respects. The most recent audit report is included with the ONE Gas financial statements filed with the SEC as part of ONE Gas' Annual Report on Form 10-K on February 24, 2022. 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 and that ONE Gas maintained, in all material respects, effective internal control over financial reporting at December 31, 2021, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Q. IN YOUR OPINION, DOES THE INFORMATION CONTAINED WITHIN THE COMPANY'S BOOKS AND RECORDS, AS WELL AS THE SUMMARIES AND EXCERPTS THEREFROM, QUALIFY FOR THE PRESUMPTION SET FORTH IN COMMISSION RULE § 7.503?

A. Yes, it does. As I have testified, the Company's system of internal controls and its adherence to the FERC USOA, as modified, fully comply with Commission Rule § 7.503. Accordingly, the Company is entitled to the presumption that costs contained within the books and records have been reasonably and necessarily incurred.

B. Commission Rule § 7.501

Q. ARE YOU FAMILIAR WITH THE REQUIREMENTS OF COMMISSION RULE § 7.501?

A. Yes, I am. Commission Rule § 7.501 requires the separate presentation in a rate proceeding of evidence related to certain types of financial transactions, and in some cases, exclusion of these costs from rates. These types of transactions include lobbying and 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, 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 to remove these items from the cost of service.

Q. PLEASE STATE THE AMOUNT OF PROFITS OR LOSSES FROM MERCHANDISING ACTIVITIES, AS REQUIRED BY COMMISSION RULE § 7.501(1).

A. The Company has not incurred profits or losses from merchandising activities in the proposed WNSA, and no such profits or losses are included in the Company's cost of service.

Q. PLEASE STATE THE AMOUNT OF INCOME TAX SAVINGS OR DEFERRALS, AS REQUIRED BY COMMISSION RULE § 7.501(2).

A. The amount of accumulated deferred income taxes ("ADIT") applicable to the proposed WNSA is $(50,432,867) as shown on Schedule B-9 and discussed in the testimony of Company witness Janet M. Simpson.

Q. PLEASE STATE THE AMOUNT OF INVESTMENT TAX CREDIT AMORTIZATION, AS REQUIRED BY COMMISSION RULE § 7.501(3).

A. The amount of investment tax credit amortization applicable to the proposed WNSA is $0.

Q. PLEASE STATE THE AMOUNT OF LOBBYING AND LEGISLATIVE ADVOCACY EXPENSE, AS REQUIRED BY COMMISSION RULE § 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. WHAT LEVEL OF EXPENSE FOR ADVERTISING IS INCLUDED IN THE REQUESTED COST OF SERVICE?

A. Schedule G-14 shows that the Company's cost of service for the proposed WNSA includes $24,840 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. 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. Actual advertising expense represents only 0.02% of gross receipts. Accordingly, the advertising expense included in the Company's cost of service is within the permissible limit.

D. Statutory Affiliate Standard

Q. PLEASE DESCRIBE THE COMMISSION'S TREATMENT OF THE ALLOCATED ONE GAS COSTS INCLUDED IN TGS'S COST OF SERVICE PRIOR TO THE CREATION OF UIC IN 2017.

A. In addition to approving the Company's request to recover allocated corporate costs in multiple cases, the Commission has also stated that TGS is not an affiliate of ONE Gas, did not incur any affiliate expenses during the test year, and that the Commission does not need to address whether the statutory standard for affiliate costs has been met. In 2017, ONE Gas created UIC, which is a captive insurance company. Therefore, since that time, TGS has affiliate costs subject to review under the statutory affiliate standard, which have been included in TGS rate cases since 2017. The testimony of Company witness Mark W. Smith provides a detailed explanation of UIC, and Ms. Borgstadt supports the schedules that reflect TGS's test year UIC costs.

Q. PLEASE DESCRIBE THE COMMISSION'S AFFILIATE STANDARD.

A. Under GURA § 104.055(b), the Commission "may not allow a gas utility's payment to an affiliate for the cost of a service, property, right, or other item or for an interest expense to be included as capital cost or as expense related to gas utility service except to the extent that the regulatory authority finds the payment is reasonable and necessary for each item or class of items as determined by the regulatory authority." Accordingly, the Commission must make "(1) a specific finding of the reasonableness and necessity of each item or class of items allowed; and (2) a finding that the price to the gas utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person for the same item or class of items."

Q. 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 Mr. Smith, 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 Mr. Smith's 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. In addition, TGS requested recovery of UIC affiliate costs in GUD Nos. 10739, 10766 and 10928, which were resolved through settlement agreements approved by the Commission.

VI. OVERVIEW OF COST OF SERVICE CALCULATION

Q. HOW DID THE COMPANY CALCULATE THE REQUESTED RATES FOR THE PROPOSED WNSA?

A. In calculating the requested rates, the Company used the cost of providing service to the entire proposed WNSA so that rates within each customer class in the incorporated and unincorporated areas will be consistent across the combined service area. Exhibit G to the SOI contains the cost of service schedules that, taken together, show the calculation of the Company's revenue requirement in the proposed WNSA. 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 statements of intent.[11]

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, 2021.

Q. ARE THE COSTS REFLECTED IN SCHEDULE A AND INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT REASONABLE AND NECESSARY?

A. Yes, the proposed revenue requirement reflects costs that are reasonable and necessary to provide safe and reliable service and operate the Company's system within the proposed WNSA as demonstrated by the schedules included with the SOI, the supporting testimony and workpapers.

[11] *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); GUD No. 10506, 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); GUD No. 10928, Final Order (Aug. 4, 2020).

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, is multiplied by the rate of return, calculated in Schedule E, to derive the required return of $45,791,339. Likewise, when federal income taxes from Schedule F 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 $140,273,448. A comparison of this revenue requirement to adjusted revenues, from Schedule G, demonstrates that the Company's current rates in the proposed WNSA produce a level of revenues that is $12,807,673 lower (before gross-up for additional uncollectible expense and Texas franchise tax) than the Company's cost of providing service in the proposed WNSA. After gross-up for additional uncollectible expense and Texas franchise tax, the revenue deficiency on a system wide basis within the proposed WNSA is $12,995,128.

VII. 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; (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. Plant in Service refers to the Company's investment in the infrastructure necessary to provide safe and reliable service within the proposed WNSA. Gross Plant in Service includes the original cost of any intangible, transmission, distribution and general plant. In addition to Gross Plant in Service, 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 Plant in Service account (FERC Plant Account 101). Instead, this plant is shown as "completed construction not classified" and is often referred to as "CCNC." Net Plant in Service 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 Plant in Service 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 CCNC AND CONSTRUCTION WORK IN PROGRESS ("CWIP").

A. CCNC is different from CWIP. Title 16 TAC § 7.115(9) defines CWIP as funds expended by a gas utility which are irrevocably committed to construction projects not yet completed or placed into service. When funds are committed to a project, those funds are recorded in CWIP accounts. Once a project is placed in service, however, those funds will be classified as CCNC. Unlike CWIP dollars, which relate to projects that are not completed and are typically not included in rate base, the dollars in the CCNC account relate to completed construction projects that are used and useful in the provision of utility service.

Q. IS IT APPROPRIATE TO INCLUDE CCNC IN RATE BASE?

A. Yes. As I mentioned, CCNC represents utility plant that has been placed in service. From an accounting perspective, the dollars associated with the utility plant classified as CCNC have not yet been transferred to FERC Plant Account 101, the Plant in Service Account. As CCNC represents plant that is in service, it is appropriate for CCNC to be included in rate base. The Company's proposal for CCNC is consistent with the treatment of CCNC that has been approved in prior proceedings.[12]

Q. PLEASE EXPLAIN THE CALCULATION OF THE GROSS PLANT IN SERVICE AND CCNC BALANCES SHOWN ON SCHEDULE B.

A. The adjusted Gross Plant in Service balance of $701,122,648 on Schedule B is the sum of the adjusted plant balances shown on Schedule C through the test year ended December 31, 2021 for: (1) Direct proposed WNSA plant; (2) the proposed WNSA's allocated portion of TGS Division plant balances, and (3) allocated ONE Gas corporate plant balances. The adjusted CCNC balance of $66,151,145 on

[12] *Petition for 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); *Statement of Intent of Texas Gas Service Company to Change Rates Within the Unincorporated Areas of the Galveston Service Area and South Jefferson County Service Area*, GUD No. 10488, Final Order (May 3, 2016); GUD No. 10506, Final Order.

Schedule B is the sum of the adjusted CCNC balances shown on Schedule C-1 through the test year ended December 31, 2021 for: (1) Direct proposed WNSA balances; (2) the proposed WNSA's allocated portion of TGS Division balances; and (3) allocated ONE Gas Corporate CCNC balances.

Q. PLEASE EXPLAIN HOW THE PER BOOK BALANCE OF PLANT IN SERVICE WAS CALCULATED.

A. The Per Book Plant in Service balance as of December 31, 2021 of $706,866,431 on Schedule C (line 4) results from three component parts: (1) $671,761,746, the per book balance of proposed WNSA Direct Plant in Service; (2) $4,960,600, the proposed WNSA's allocated portion of TGS Division per book Plant in Service; and (3) $30,144,085, the proposed WNSA's allocated portion of ONE Gas Corporate per book Plant in Service. Ms. Borgstadt sponsors the TGS Division and ONE Gas Corporate amounts and the reasonableness of these amounts.

Q. PLEASE DESCRIBE THE TWO DIRECT PLANT WORKPAPERS.

A. WKP C.a Direct Plant contains the per book balance and adjustments for all Direct plant excluding plant associated with Fort Bliss. WKP C.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 Direct Operating Expense section of my testimony.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE PER BOOK PLANT IN SERVICE BALANCES?

A. Yes, the following adjustments were made on WKP C.a Direct Plant and WKP C.a.1 Fort Bliss to the per book proposed WNSA Direct Plant in Service balance:

a) add $1,030,487 in plant additions for a cathodic protection project that was incorrectly coded to another service area;

b) add $3,784 to adjust for miscoded retirements, offset by a matching adjustment to reserves;

c) an adjustment of $95,051 to remove $164,558 in miscoded plant additions and transfers and to adjust Rule 8.209 accruals from prior years by $69,507, explained in the Other Rate Base section of my testimony;

d) remove $4,519,657 in plant that will retire once new amortization rates are implemented, offset by a matching adjustment to reserves; and

e) a $257 adjustment to capitalized meal and hotel costs, described in the testimony Ms. Borgstadt.

The total amount of adjustments to the proposed WNSA Direct per book Plant in Service balance equals $(3,580,695). The Company also adjusted TGS Division and ONE Gas Corporate per book Plant in Service balances as identified and sponsored by Ms. Borgstadt.

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

A. The adjusted Plant in Service balance of $701,122,648 on Schedule C (line 4) results from three components: (1) $668,181,052, the adjusted proposed WNSA Direct Plant in Service balance; (2) $4,590,059, the proposed WNSA's allocated portion of the adjusted TGS Division Plant in Service balance; and (3) $28,351,537, the proposed WNSA's allocated portion of the adjusted ONE Gas Corporate Plant in Service balance. Ms. Borgstadt sponsors the TGS Division and ONE Gas Corporate allocated amounts and their reasonableness.

Q. PLEASE EXPLAIN THE CALCULATION OF THE PER BOOK CCNC BALANCE ON SCHEDULE C-1.

A. Similar to Plant in Service described above, the CCNC per book balance of $66,158,611 on Schedule C-1 (line 4) results from three component parts at December 31, 2021: (1) $65,582,603, the per book balance of proposed WNSA Direct CCNC; (2) $64,654, the proposed WNSA's allocated portion of the adjusted TGS Division Plant in Service balance; and (3) $511,353, the proposed WNSA's allocated portion of ONE Gas Corporate per book CCNC. Ms. Borgstadt sponsors and supports the reasonableness of the TGS Division and ONE Gas Corporate amounts.

Q. WERE ANY ADJUSTMENTS MADE TO PER BOOK CCNC BALANCES?

A. Yes, Direct CCNC was reduced by $293,748 for miscoded additions and transfers. Ms. Borgstadt explains and supports adjustments made to TGS Division and ONE Gas Corporate CCNC per book balances.

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, 2021 of $(130,678,349) on Schedule D contains: (1) $(116,959,260), the per book proposed WNSA Direct

Reserve balance; (2) $(1,070,073), the proposed WNSA allocated portion of the TGS Division reserve balance; and (3) $(12,649,016), the proposed WNSA allocated portion of the ONE Gas Corporate reserve balance. Adjustments were made to the per book proposed WNSA Direct Reserve balance to remove plant additions, transfers or retirements mistakenly coded to the proposed WNSA, to remove plant that will retire once new amortization rates are implemented, and to rebalance reserves as recommended by Dr. White. Total adjustments to the proposed WNSA Direct per book reserves equal $4,727,391. Ms. Borgstadt explains 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 PLANT IN SERVICE BALANCE.

A. The total adjusted test year net Plant in Service balance shown on Schedule B is $636,595,444. This is the sum of the adjusted test year balances for Plant in Service of $701,122,648 plus CCNC of $66,151,145 and Reserves of $(130,678,349).

Q. IS ALL OF THE COMPANY'S ADJUSTED PLANT IN SERVICE INCLUDED IN THIS SOI USED AND USEFUL IN PROVIDING SERVICE?

A. Yes, all plant in service included in this SOI is used and useful in providing service as supported by my testimony and that of Ms. Norman and Ms. Borgstadt.

1. Cloud Computing Service Costs

Q. ARE CLOUD COMPUTING IMPLEMENTATION COSTS INCLUDED IN NET PLANT?

A. Yes, the Company included cloud computing implementation costs as Corporate capital investment, in Account 391.99, as shown on Workpaper C.c., which is discussed in Ms. Borgstadt's testimony. That balance is amortized over 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 Account 165, and expensed over the life of the service agreement, and are found in Workpaper B-2.b.1. which is discussed in Ms. Borgstadt's testimony.

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. ARE CAPITALIZED CLOUD COMPUTING IMPLEMENTATION COSTS APPROPRIATE TO INCLUDE IN THIS RATE CASE AND FUTURE FILINGS?

A. Yes. 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 implementation costs support Information Technology efforts, which provide critical services employees use in their efforts to provide service safely and reliably to customers, including those in the proposed WNSA. The National Association of Regulated Utility Commissioners ("NARUC") issued a

November 2016 resolution[13] 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. In addition, TGS included cloud computing costs in GUD No. 10928 and they were approved for recovery, as was the treatment of those costs in future GRIP filings.[14]

Q. ARE THERE ANY ACCOUNTING STANDARDS REGARDING CLOUD COMPUTING THAT IMPACT RECOVERY IN RATES?

A. Yes. Accounting Standards Update 2018-15[15] ("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 requesting authorization for regulatory purposes to continue to include cloud computing implementation investment in 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 3 to 5 years. TGS is requesting authorization for regulatory purposes to continue to amortize cloud computing implementation costs over the same 13-year life as on-premise software to maintain consistency in regulatory treatment and not increase expenses that are ultimately paid by the customer.

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[13] Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements (Adopted Nov. 16, 2016), https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476.

[14] GUD No. 10928, Final Order at Findings of Fact ("FoF") 70.

[15] Financial Accounting Series - Accounting Standards Update, No. 2018-15 at 22 (Aug. 2018) https://asc.fasb.org/imageRoot/22/118236022.pdf.

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 shareholders, they are appropriately included in rate base. As reflected on Schedule B, "Other Rate Base Items" include:

- Materials and Supplies Inventory;
- Prepayments, which are addressed by Ms. Borgstadt;
- Amounts deferred in accordance with Commission Rule 8.209;
- Pension and Other Post Employment Benefits ("OPEB") Regulatory Asset;
- Prepaid Pension Asset;
- Cash Working Capital ("CWC"); and
- Requested Regulatory Assets.

Q. REFERRING TO SCHEDULE B-1, PLEASE EXPLAIN THE CALCULATION OF THE MATERIALS AND SUPPLIES INVENTORY BALANCE.

A. The Materials and Supplies Inventory balance consists of the average monthly balances of proposed WNSA Direct Materials and Supplies Inventory and Stores Load as well as ONE Gas Measurement Assets ("OMA"). Direct Materials are investments 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 TGS and the TGS service areas. 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 GUD Nos. 10488, 10506, 10526, 10656, 10739, 10766, 10928, and past Commission decisions,[16] a thirteen-month average was used and results in a $5,675,575 balance to be included in rate base. An average 13-month balance normalizes the fluctuations 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 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.

[16] 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; *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, Final Order at FoF 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).

Q. WHY IS IT APPROPRIATE TO INCLUDE OMA AS PART OF THE "MATERIALS AND SUPPLIES INVENTORY" BALANCES INCORPORATED INTO RATE BASE?

A. The OMA inventory balance includes investments such as meters, automatic meter readers, electronic receiver transmitters, and regulators, held at a centralized meter shop. These inventories are necessary for the provision of utility service to TGS and the TGS service areas 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.

The Company calculated a thirteen-month average for OMA inventory, which normalizes fluctuations in the account during the test year. These assets are allocated to TGS based on the Texas customer count. These assets are further allocated to the proposed WNSA based on the service area customer count. The allocation methodology follows the corporate allocation method, which is discussed further in Ms. Borgstadt's testimony.

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

A. The Company has included a thirteen-month average of prepayments of $3,292,141. This asset is included on Schedule B, line 6 and detailed on Schedule B-2. Ms. Borgstadt addresses prepayments in her direct testimony.

Q. WHAT AMOUNTS HAVE BEEN DEFERRED AND REFLECTED WITHIN RATE BASE IN ACCORDANCE WITH COMMISSION RULE 8.209?

A. Schedule B-3, reflects the Company's deferred costs associated with its Distribution Integrity Management Program ("DIMP") as of December 31, 2021. 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 regulatory asset accounts in which to record any expenses incurred by the operator in connection with the acquisition, installation or operation (including related depreciation) of facilities that are subject to the requirements of this section." Rule 8.209 sets out minimum requirements for development and implementation of a risk-based program for removal and replacement of distribution facilities. Rule 8.209(j) also allows each regulatory asset to include the "interest on the balance in the designated distribution facility replacement accounts based on pretax cost of capital last approved for the utility by the Commission."

Pursuant to Rule 8.209, the Company began deferring these DIMP-related expenses on January 1, 2012. The amount associated with the Company's deferral for the proposed WNSA is $1,843,921[17] and includes monthly deferred DIMP costs for the proposed WNSA from January 2021 through December 2021. Ms. Norman also addresses the Company's DIMP-related activities in her direct testimony.

[17] Please see Schedule B-3 for additional detail.

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.[18] In addition, the proposed WNSA cities, among other cities in other TGS service areas, have also approved the Company's request to recover deferred amounts related to Rule 8.209.[19]

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. WERE ANY ADJUSTMENTS MADE TO THE PER BOOK RULE 8.209 BALANCE?

A. Yes. The Company made two adjustments related to Rule 8.209. First, the Company removed calendar year 2020 accruals for NTSA and BSSA from the Rule 8.209 balance and reflected them in net plant. In the regular course of activity, Rule 8.209 balances for each year are included in rate base in the following year's filings, and when the rates from those filings go into effect, the included Rule 8.209 amounts are moved out of the Rule 8.209 Balance and recorded to plant in service on the Company's books. In this instance, the Rule 8.209 amounts included in the

[18] 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; GUD No. 10928, Final Order.
[19] In 2019, 2020 and 2021, cities in the WNSA approved the recovery of Rule § 8.209 amounts in the Company's Cost of Service Adjustment ("COSA") filings and the Company's GRIP filings.

Company's 2021 BSSA and NTSA filings were not moved out of the Rule 8.209 balance and into plant in service prior to December 31, 2021, which is the test year end for this filing. Consequently, an adjustment was required in this rate case to correctly reflect the test year Rule 8.209 balance and plant in service balance.

Second, the Company reduced both the Rule 8.209 balance and plant in service balance to reflect revised Rule 8.209 accruals for the change in the federal income tax rate. This adjustment is necessary because Rule 8.209 provides for an interest accrual at the pretax cost of capital last approved by the Commission. The pretax cost of capital last approved by the Commission for the WTSA in GUD No. 10506 was calculated in 2016 using a 35% federal income tax rate. Effective January 1, 2018, the federal income tax rate was reduced to 21%. While the Commission has not approved a new or different pretax cost of capital, in TGS's IRA filings since 2018, the Company has proposed, and the Commission has approved, an adjustment to reflect the impact of the 21% federal income tax rate on the pretax cost of capital. A similar adjustment to the calculation of Rule 8.209 accruals would be consistent with the practice for IRA filings. To accomplish this adjustment, in this filing, the Company has recalculated the 2018, 2019, 2020, and 2021 Rule 8.209 accruals for the WTSA using a 21% federal tax rate rather than a 35% tax rate, and has reduced Rate Base by the difference. The difference associated with 2021 Rule 8.209 accruals was deducted from the Rule 8.209 Balance. The difference associated with 2018, 2019, and 2020 Rule 8.209 accruals was deducted from plant in service, because those prior year Rule 8.209 amounts were reclassified to plant in service following the rate filings for those years.

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

A. The Company has included $896,913 for a Pension and OPEB regulatory asset, as shown on Schedule B-4. GURA §104.059 states that if a gas utility establishes one or more reserve accounts for the purpose of tracking changes in the costs of pensions and OPEB, the gas utility shall periodically record in a reserve account any differences between the annual amount of pension and OPEB approved and included in the gas utility's then current rates and the annual amount of pension and OPEB costs as determined by actuarial studies. A shortage in a reserve account exists if the amount of pension and OPEB under Subsection (b)(1) is less than the amount determined under Subsection (b)(2). If the gas utility establishes reserve accounts for the costs of pensions and OPEB, the regulatory authority at a subsequent general rate proceeding shall add any shortage to the gas utility's rate base, with the shortage amortized over a reasonable time.

In the most recent rate cases for the BSSA and NTSA, there were no approved regulatory assets. In the most recent rate case for the WTSA (GUD No. 10506), a regulatory asset of $1,019,339 was approved and was completely amortized as of January 2021. In addition, since the rate cases mentioned above, 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, 2021, those deferrals total to $896,913, 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 $19,113,633. This asset is included on Schedule B, line 10 and detailed on Schedule B-5. Mr. Smith addresses the prepaid pension asset in his 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. Company witness Timothy S. Lyons calculated the CWC amount of $(3,535,483) shown on Schedule B, line 11 and detailed in Schedule B-6, and he supports the reasonableness of his calculation in his testimony.

Q. WHAT AMOUNT HAS BEEN INCLUDED IN RATE BASE FOR A REQUESTED REGULATORY ASSET?

A. The Company has included a requested regulatory asset amount totaling $1,788,715. This amount is included on Schedule B, line 8, and detailed on Schedule B-11, and is comprised of the following:

- unamortized balance of regulatory assets from GUD No. 10506;
- over-collection of rate case expenses from GUD Nos. 10739 and 10766;
- deferred Regulatory Expense at December 31, 2021 not included in prior cases;
- deferred Winter Storm Uri O&M at December 31, 2021;
- COVID-19 related O&M; and
- GRIP charges from July and a portion of August 2021 for City of El Paso customers.

Q. WHAT IS THE PURPOSE OF A REGULATORY ASSET?

A. Deferral of costs provides a means of accumulating costs for future recovery over a specific period of time and enables the Company and the Commission to identify, segregate and review the costs related to a specific event that have been deferred to determine whether they are appropriate for recovery and over what period of time. If approved for recovery, the Commission can establish a regulatory asset which is amortized over the recovery period.

Q. PLEASE EXPLAIN THE UNAMORTIZED BALANCE OF REGULATORY ASSETS FROM GUD NO. 10506.

A. In GUD No. 10506, the Commission approved the recovery of a regulatory asset of $530,567 representing regulatory expenses incurred as part of prior regulatory proceedings, with a six-year amortization period and an annual amortization expense of $88,428. As of December 2021, the remaining balance was $66,321, which is appropriate to continue to recover in the base rates set in this rate case. The Company calculated an adjustment to reflect the continued amortization of this balance until December 31, 2022, which brings the balance to zero. If rates are implemented prior to December 31, 2022, TGS requests that any remaining balance of this previously approved regulatory asset be recovered over a six-year period in base rates. Six years is an appropriate amortization period because that is the amount of time that the base rates will remain in effect assuming the Company makes the maximum number of IRA filings.

Q. PLEASE EXPLAIN THE OVER-COLLECTION OF RATE CASE EXPENSES FROM GUD NOS. 10739 AND 10766.

A. In GUD Nos. 10739 and 10766, the Commission approved the recovery of associated rate case expenses in the amounts of $65,492 and $128,751, respectively. The rate case expenses were ordered to be surcharged to customers through a volumetric rate until the total amount was recovered. Because volumes are not known until after they are billed, it is difficult to terminate the surcharge at the precise moment when the balance is exactly zero. Ordinarily TGS terminates the surcharge with a small balance remaining, and simply writes off the small balance. In this instance, however, the surcharges were terminated with a small over-collection of rate case expenses of $31 and $109, respectively. It is appropriate for TGS to return the over-collection to the customers by including it in the requested regulatory asset to be amortized over six years.

Q. PLEASE EXPLAIN THE DEFERRED REGULATORY EXPENSE AT DECEMBER 31, 2021.

A. In 2018, following the passage of the Tax Cuts and Jobs Act of 2017 ("TCJA"), the City of El Paso incurred legal and consulting expenses as it reviewed the impact of the Act on TGS's West Texas rates. The City of El Paso ordered TGS to reimburse these regulatory expenses, totaling $22,250 which the Company did. TGS deferred these regulatory expenses and seeks to recover them via this requested regulatory asset to be amortized over a period of six years.

Q. PLEASE EXPLAIN THE INCLUSION OF WINTER STORM URI O&M REGULATORY ASSET.

A. The Commission issued a Notice to Local Distribution Companies ("LDCs") on February 13, 2021 ("February Notice").[20] In the February Notice, the Commission authorized LDCs to create a regulatory asset to record "extraordinary expenses associated with the weather event including but not being limited to gas cost and other costs related to the procurement and transportation of gas supply" costs incurred during Winter Storm Uri. Based on the Commission's February Notice, TGS created a regulatory asset for extraordinary storm costs, excluding costs recovered as a part of securitization in Case No. OS-21-00007061, for review and recovery during a future rate proceeding.

Q. DESCRIBE COSTS INCLUDED IN THE WINTER STORM URI REGULATORY ASSET.

A. The costs included in the Winter Storm Uri regulatory asset were extraordinary expenses TGS incurred related to the winter storm and efforts TGS made to continue to operate its system and provide service during the storm. The costs include direct service area overtime labor and contractor labor; supplies and expenses; meals and travel; and stores issuances and stores overhead totaling $62,540. In addition to these costs, a portion of the 2021 short-term incentive compensation ("STI") in the amount of $142,619 is included in the proposed Winter Storm Uri regulatory asset as well as $208,711 in recognition awards, given to

[20] Notice of Authorization for Regulatory Asset Accounting for Local Distribution Companies Affected by the February 2021 Winter Weather Event (Feb. 13, 2021), https://www.rrc.texas.gov/media/4u1fpycl/2021_nto_gas-services_state-disaster-waiver_gasutilityassetaccountingwinter-2021_2-13-2021.pdf.

certain employees at the supervisor level and below that were directly involved in maintaining and providing service during Winter Storm Uri. Both of those items are discussed in detail in the testimonies of Ms. Borgstadt and Mr. Branz. This regulatory asset does not include any of the costs the Commission approved for TGS in Case No. OS-21-00007061 in February 2022. TGS requests to amortize the balance in the Winter Storm Uri regulatory asset over a period of six years. In addition, recovery of those costs through a regulatory asset benefits customers because it results in a lower annual revenue requirement because only one sixth of the Uri-related STI is included in annual expenses through the amortization of the regulatory asset.

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.

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

A. The COVID-19 regulatory asset includes costs for items such as sanitizing spray services, changing air filters monthly, personal protective equipment such as masks, hand-sanitizing stations, and social distancing signage totaling $608,467. Ms. Norman describes the nature of these costs in more detail in her testimony.

Q. IS IT REASONABLE FOR THE COMPANY TO RECOVER THESE COSTS IN THIS RATE CASE?

A. Yes, these costs were incurred to follow recommended Centers for Disease Control and Prevention and Occupational Safety and Health Administration guidelines to ensure the safety of both employees and customers as TGS personnel performed their jobs to allow the Company to continue to provide service to customers. The costs are also the types of costs mentioned in the Commission's notice authorizing recovery through a regulatory asset.

Q. PLEASE EXPLAIN THE UNCOLLECTED GRIP CHARGES FROM THE CITY OF EL PASO.

A. On March 12, 2021, TGS filed its 2020 IRA for the incorporated and environs areas of the WTSA with an effective date after suspension of June 28, 2021. On June 21, 2021, the City of El Paso acted through a Motion that stated the rates in the Company's filing complied with the GRIP statute (GURA § 104.301) and also denied TGS's requested IRA for customers within the City of El Paso. A copy of the City's June 21, 2021 Motion is attached as Exhibit SLM-1. The City of El Paso gave no explanation for the denial in its Motion or to the Company. TGS appealed the Motion to the Commission, and the Commission approved TGS's requested IRA within the City of El Paso, as it had done for the WTSA environs IRA filing.[21] As a result of the City of El Paso's Motion, TGS was unable to recover the 2020

[21] *Petition for Review of Municipal Rate Action of the City of El Paso Regarding Texas Gas Service Company, a Division of ONE Gas, Inc.'s Interim Rate Adjustment for Calendar Year 2020*, Case No. 00006942, Final Order (Aug. 3, 2021); *see Application of Texas Gas Service Company for Test Year 2020 Annual Interim Rate Adjustment for the Unincorporated Areas of the West Texas Service Area*, Case No. 00006161, Interim Order (Jun. 22, 2021).

IRA charges from incorporated El Paso customers from June 28, 2021 to August 2, 2021, totaling $744,266. This amount should be recovered from customers within the City of El Paso because the City found the rates in compliance with the GRIP statute in its Motion, which the Commission confirmed on appeal and these revenues are not recoverable from any other source.

Q. WHAT ARE THE POTENTIAL CONSEQUENCES OF TGS NOT BEING PERMITTED TO RECOVER THESE GRIP CHARGES FROM EL PASO CUSTOMERS?

A. If TGS is not permitted to recover these revenues from El Paso customers, there is a risk that a city may, without consequence and with harm to the utility, improperly deny a utility's IRA filing simply to delay and ultimately avoid the implementation of proper IRA charges.[22] After the GRIP statute was implemented in 2003, there was disagreement over the extent of the review involved in a GRIP filing. Ultimately, after a Texas Supreme Court decision in 2011, it is clear that a GRIP filing is an administrative filing subject to a ministerial review to confirm the utility complied with the statutory requirements.[23] The City of El Paso's Motion was a surprise to the Company, particularly because the Motion first found that TGS complied with the GRIP statute. TGS's request to recover the GRIP amounts through a regulatory asset is simply a way to keep TGS whole when it has fully complied with the GRIP requirements, as confirmed by the City of El Paso and the Commission.

[22] On June 22, 2022, the City of El Paso denied the Company's GRIP filing made on March 10, 2022. A copy of the City's Motion is attached hereto as Exhibit SLM-7.
[23] *Atmos Energy Corp. v. Cities of Allen*, 353 S.W.3d 156 (Tex. 2011).

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 shareholders. Because a rate of return is applied to the Company's rate base to determine the dollars needed to cover the Company's debt service and provide an opportunity to earn a reasonable return, funds supplied 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. Specifically, Lines 12 and 13 are the balances at the test year end for customer deposits and customer advances, respectively. In addition, the ADIT balance shown on line 14 of Schedule B represents funds available to the Company as a result of lower current income tax expenses due to timing differences between book and taxable income. Lastly, the EDIT balance shown on line 15 of Schedule B represents the remaining EDTI balance resulting from the remeasurement of ADIT due to the federal tax rate decrease from the TCJA. These funds are also deducted from the rate base calculation. Ms. Simpson explains and sponsors the ADIT balance in her testimony. Company witness Jeffrey J. Husen explains and sponsors the EDIT balance in his testimony.

Q. PLEASE EXPLAIN THE AMOUNTS SHOWN ON SCHEDULE B FOR THE BALANCES OF CUSTOMER DEPOSITS, CUSTOMER ADVANCES, ADIT, AND EDIT.

A. The amounts reflected in Rate Base on Schedule B are equal to the proposed WNSA per book balances of customer deposits and customer advances as of December 30, 2021. Customer Deposits (line 12) are $(7,838,323). Customer Advances (line 13) are $(3,132,466). The ADIT balance (line 14) is $(50,432,867). The EDIT balance (line 14) is $(14,871,247). These balances are treated for ratemaking purposes as offsets to the Company's invested capital or rate base.[24]

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 $589,395,955. This total amount includes all the component parts described above. Ms. Borgstadt's testimony provides details for Corporate and Division rate base items.

Q. ARE THE RATE BASE ADJUSTMENTS DISCUSSED IN YOUR TESTIMONY NECESSARY TO CALCULATE A COST OF SERVICE THAT INCLUDES ONLY THOSE AMOUNTS TO BE COLLECTED THROUGH BASE RATES THAT ARE REASONABLE AND NECESSARY FOR PROVIDING SERVICE TO CUSTOMERS IN THE PROPOSED WNSA?

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 proposed WNSA customers, which are appropriately recovered through base rates.

[24] 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. 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.

VIII. 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.[25] 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 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

[25] Oversight and Safety Division - Gas Services, Natural Gas Rate Review Handbook at 38-39 (Sept. 2017).

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,[26] the Act added Code Section 274(a)(4) precluding employers from deducting for tax purposes qualified transportation fringe benefits such as qualified parking. In December 2020,[27] the IRS issued a final regulation under Internal Revenue Code Sec. 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 Method are shown on Schedule F. The Company used a federal income tax rate of 21% to comply with the TCJA, which lowered the federal corporate tax rate from 35% to 21%. Ms. Simpson and Mr. Husen further discuss issues related to the TCJA in their direct testimonies. The adjusted test year federal income tax expense included in the Company's revenue requirement is $9,629,801.

IX. EXCESS DEFERRED INCOME TAX

Q. PLEASE EXPLAIN THE CHANGES TO THE FEDERAL CORPORATE INCOME TAX RATE THAT BECAME EFFECTIVE IN 2018.

A. Effective January 1, 2018, the TCJA lowered the federal corporate income tax rate to 21% from 35%. In response, the Commission issued an Accounting Order in

[26] 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.

[27] Qualified Transportation Fringe, Transportation and Commuting Expenses Under Section 274, 85 Fed. Reg. 81391 (Effective Dec. 16, 2020), https://www.federalregister.gov/documents/2020/12/16/2020-27505/qualified-transportation-fringe-transportation-and-commuting-expenses-under-section-274.

GUD No. 10695 on February 27, 2018, that reflects the Commission's directives regarding changes to utility rates to account for the change in the federal corporate income tax rate.[28]

Q. PLEASE DESCRIBE YOUR UNDERSTANDING OF THE COMMISSION'S DIRECTIVES IN THE ACCOUNTING ORDER.

A. I understand the Commission's Accounting Order to require gas utilities to reduce base rates and existing GRIP rates to reflect rates that would be set using a 21% federal tax rate; to refund amounts collected from customers through base rates and GRIP rates that were set using the 35% tax rate; and to present the issue of EDIT for consideration in a SOI or other proceeding.

Q. HAS THE COMPANY COMPLIED WITH THE DIRECTIVE TO REFLECT THE LOWER FEDERAL CORPORATE INCOME TAX RATE IN BASE RATES AND GRIP RATES FOR THE WTSA, NTSA AND BSSA?

A. Yes. Consistent with the requirements in the Accounting Order, the Company filed administrative Notices of Intent to Reduce Gas Utility Rates pursuant to Section 104.111 in the incorporated and environs areas of the WTSA that addressed the requirements in the Accounting Order to (1) decrease then-existing base rates and then-existing GRIP rates to reflect the difference between the current approved cost of service and the cost of service that would have resulted had base rates or GRIP rates been based on the 21% federal tax rate (Ordering Paragraph 2); and (2) refund to customers the amount the utility collected through base rates and GRIP rates for revenues collected from January 1, 2018, through the effective date of new base

[28] On March 20, 2018, the Commission issued an Order Nunc Pro Tunc in *Regulatory Accounting Related to Federal Income Tax Changes*, GUD No. 10695, correcting a clerical error in the original Accounting Order.

rates or new GRIP rates that reflect the 21% federal tax rate (Ordering Paragraph 3). In the incorporated and environs areas of the NTSA, TGS filed Statements of Intent to change base rates that reflected the 21% federal tax rate and provided for refunds to customers of the amount collected through base rates or GRIP rates for revenues collected from January 1, 2018, through the effective date of the new base rates.[29] Similarly, in the incorporated and environs areas of the BSSA, TGS filed Statements of Intent to change base rates that reflected the 21% federal tax rate and provided for refunds to customers of the amount collected through base rates or GRIP rates for revenues collected from January 1, 2018, through the effective date of the new base rates.[30] TGS was required to file either a SOI or a filing under GURA § 104.111 by September 1, 2018, to lower existing rates and issue a refund to customers (Ordering Paragraph 4), which it did in all three areas.

Q. HOW DID THE COMPANY REDUCE EXISTING BASE RATES AND GRIP RATES FOR THE WTSA INCORPORATED CUSTOMERS?

A. On March 26, 2018, the Company made a filing with the WTSA cities under GURA § 104.111 to lower rates that were set in a rate case based on a 2015 test year and in a test-year 2016 GRIP filing and to issue a refund to customers within the WTSA cities. Effective June 26, 2018, TGS reduced rates by $4,262,007. In addition, TGS refunded $9.01 per customer, totaling $2,162,424, to account for the tax rate reduction from January 1, 2018 through June 26, 2018.

[29] GUD No. 10739, Final Order.
[30] GUD No. 10766, Final Order.

Q. HOW DID THE COMPANY REDUCE EXISTING BASE RATES AND GRIP RATES FOR THE WTSA ENVIRONS CUSTOMERS?

A. On March 28, 2018, the Company made a filing with the Commission under GURA § 104.111 to lower existing rates set in GUD No. 10506 and in GUD No. 10612 and to issue a refund to customers within the WTSA environs, which the Commission docketed as GUD No. 10713. Effective June 26, 2018, TGS reduced rates by $326,181. In addition, TGS refunded $9.01 per customer, totaling $177,370, to account for the tax rate reduction from January 1, 2018 through June 26, 2018.

Q. HOW DID THE COMPANY REDUCE EXISTING BASE RATES FOR THE NTSA ENVIRONS?

A. On June 20, 2018, the Company made a SOI filing with the Commission to change existing rates incorporating the 21% federal tax rate and to issue a refund to customers within the NTSA environs, which the Commission docketed as GUD No. 10739. Effective November 13, 2018, the Commission approved new base rates reflecting a federal tax rate of 21%. In addition, TGS refunded $43.29 per customer, totaling $69,488, to account for the tax rate reduction from January 1, 2018 through November 28, 2018.

Q. HOW DID THE COMPANY REDUCE BASE RATES IN THE NTSA INCORPORATED AREA TO ACCOUNT FOR THE CHANGE IN THE FEDERAL TAX RATE?

A. On June 20, 2018, the Company made a SOI filing with the NTSA cities to change existing rates incorporating the 21% federal tax rate and to issue a refund to customers within the NTSA cities. In October 2018, TGS reached a settlement with the cities resulting in new base rates reflecting a federal tax rate of 21%, effective November 28, 2018. In addition, the cities approved a refund of $575,228, to account for the tax rate reduction from January 1, 2018 through July 26, 2018. At the direction of the cities, TGS applied $202,795 of the refund to reduce recoverable rate case expenses to zero. TGS refunded $25.90 per customer, totaling $372,433, to account for the remaining refund.

Q. HOW DID THE COMPANY REDUCE EXISTING BASE RATES FOR THE BSSA ENVIRONS?

A. On August 30, 2018, the Company made a SOI filing with the Commission to change existing rates incorporating the 21% federal tax rate and to issue a refund to customers within the BSSA environs, which the Commission docketed as GUD No. 10766. Effective February 5, 2019, the Commission approved new base rates reflecting a federal tax rate of 21%. In addition, TGS refunded $12.11 per customer, totaling $5,560, to account for the tax rate reduction from January 1, 2018 through February 28, 2018.

Q. HOW DID THE COMPANY REDUCE BASE RATES IN THE BSSA INCORPORATED AREAS TO ACCOUNT FOR THE CHANGE IN THE FEDERAL TAX RATE?

A. On August 30, 2018, the Company made a SOI filing with the BSSA cities to change existing rates incorporating the 21% federal tax rate and to issue a refund to customers within the BSSA cities. In December 2018, TGS reached a settlement with the cities resulting in new base rates reflecting a federal tax rate of 21%, effective December 31, 2018. In addition, TGS refunded $28.25 per customer, totaling $145,623, to account for the tax rate reduction from January 1, 2018 through December 31, 2018.

Q. HAS THE COMPANY COMPLETED THE REQUIRED REFUNDS TO CUSTOMERS IN THE WTSA, NTSA AND BSSA?

A. Yes. All required refunds were completed in 2018 and early 2019, consistent with the requirements of the Accounting Order.

Q. PLEASE DESCRIBE MORE SPECIFICALLY THE REQUIREMENTS IN THE ACCOUNTING ORDER REGARDING EXCESS DEFERRED TAXES.

A. Utilities subject to the Commission's original jurisdiction must accrue regulatory liabilities on their books as of the date of the Commission's Accounting Order to reflect the excess deferred tax reserve, including any associated gross up in taxes, caused by the reduction to 21% for the federal corporate income tax rate (Ordering Paragraph 1(C)).

For EDIT, the utility shall present that issue "for consideration in setting the cost of service rates of the gas utility during the next SOI or other rate proceeding." In addition, the amortization of the entire regulatory liability for EDIT shall be consistently calculated using a methodology set forth under the Act (Ordering Paragraph 7).

Q. PLEASE DESCRIBE HOW EDIT WAS PRESENTED IN THE NTSA AND BSSA STATEMENTS OF INTENT.

A. The NTSA and BSSA statements of intent reflected the impact of the change in the corporate tax rate on ADIT, reducing the balance of ADIT and giving rise to EDIT.

Both the new balance of ADIT and the balance of EDIT were deducted from rate base as sources of cost-free capital.

For EDIT, the Company proposed to flow the EDIT back to customers through a separate rider, Rate Schedule EDIT-Rider, with the flow back of protected balances over ten years and the flow back of unprotected balances calculated according to the Average Rate Assumption Method ("ARAM"), which is a methodology set forth under the Act, as required by Ordering Paragraph 7 in the Commission's Accounting Order. The Commission and city regulators approved the EDIT-Riders for NTSA and BSSA customers, and TGS made annual EDIT refunds under each of the riders starting in 2019 through 2022.

Q. PLEASE DESCRIBE HOW EDIT WAS TREATED BY THE CITY OF EL PASO, TEXAS.

A. On June 26, 2018, the City of El Paso passed an ordinance ordering TGS to make a filing with the City of El Paso to address its EDIT, no later than 30 days after the federal income tax return for 2017 was filed with the IRS. The Company complied and proposed to flow the EDIT back to customers through a separate tariff rider, Rate Schedule EDIT-Rider, calculated according to the ARAM which is a methodology set forth under the Act, as required by Ordering Paragraph 7 in the Commission's Accounting Order. The City of El Paso approved the EDIT-Rider for customers within the City's jurisdiction on February 4, 2019, and TGS made annual EDIT filings and refunds under the rider starting in 2019 through 2022.

Q. PLEASE DESCRIBE THE STATUS OF EDIT ISSUES IN THE REMAINING INCORPORATED AREAS OF THE WTSA AND THE WTSA ENVIRONS.

A. The remaining cities of the WTSA and the Commission have not yet had an opportunity to take action on EDIT for the WTSA customers in their jurisdiction. This case is TGS's first opportunity to address the issue in a rate case for these areas.

Q. PLEASE DESCRIBE HOW EDIT IS INCLUDED IN THIS SOI, INCLUDING HOW TGS IS PRESENTING EDIT FOR CONSIDERATION IN SETTING NEW RATES.

A. This SOI continues to reflect the impact of the change in the corporate tax rate by reflecting the balance of ADIT based on a 21% federal tax rate and separately reflecting the unamortized balance of EDIT. Both the balance of ADIT and the balance of EDIT are deducted from rate base as sources of cost-free capital. Ms. Simpson addresses the ADIT calculations in her testimony, while Mr. Husen addresses the EDIT calculations.

The Company proposes to withdraw the separate tariff rider, Rate Schedule EDIT-Rider, and instead flow the EDIT back to customers through base rates, as discussed further in Mr. Husen's testimony.

Q. WHAT IS THE AMOUNT OF THE AMORTIZATION TO BE FLOWED BACK ANNUALLY THROUGH THE BASE RATES?

A. The test year EDIT amortization of $1,422,666 is shown on Schedule G-24.

Q. IS TGS REQUESTING A FINDING FROM THE COMMISSION THAT IT HAS COMPLIED WITH THE COMMISSION'S ACCOUNTING ORDER?

A. Yes. TGS requests a finding that its WTSA Section 104.111 environs filing was reasonable and accurate.

X. OPERATING REVENUE AND EXPENSES

Q. PLEASE DESCRIBE SCHEDULE G.

A. Schedule G presents a summary of all revenues and expenses, other than federal income tax expense. Page 1 is a summary of the adjustments to revenues and expenses, which are identified in greater detail in Schedules G-1 through G-24. Pages 2 and 3 reflect the same information as Page 1, organized by FERC account number. The total amounts on page 1, line 27 of Schedule G equal the total operating amounts shown on page 3, line 92 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 Teresa Serna. The expense adjustments detailed on Schedules G-4 through G-24 are discussed in the remainder of my testimony or in the testimony of Ms. Borgstadt.

Q. DO THE ADJUSTED EXPENSES SHOWN ON SCHEDULE G, COLUMN (C) INCLUDE ALLOCATED EXPENSES?

A. Yes. In addition to expenses that are directly charged to the proposed WNSA, the Company incurs "allocable" expenses for Shared Services provided to customers in the proposed WNSA from various TGS and ONE Gas departments. A portion of these reasonable and necessary expenses must be allocated to the proposed WNSA to determine the total cost TGS incurs to provide service to proposed WNSA customers. For example, during the test year, personnel from various departments provided management, accounting, human resources, customer service and engineering services to the proposed WNSA and generated a variety of expenses that are directly charged or causally allocated to the proposed WNSA. Lastly, there are ONE Gas Corporate level costs allocated through Distrigas for necessary business functions such as treasury, investor relations and executive management that support operations in the proposed WNSA. The proposed WNSA's portion of test year costs charged to the allocable cost centers described above are included in the proposed WNSA's per book costs on Schedule G, column (a). The Company's allocation methodologies are discussed by Ms. Borgstadt.

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 amount reflects the deferred annual Pension and OPEB expense that has occurred since GUD No. 10506 was filed. 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, penalties, out of period accruals and legislative activities. Expenses associated with COVID-19 were removed and included in the requested regulatory asset discussed in the rate base section of my testimony. Additionally, meals over $25 per person, exclusive of taxes and tip amounts, hotel stays over $175 per night, exclusive of taxes, were removed. Ms. Borgstadt 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 proposed WNSA interest on customer deposits has been calculated by applying the current Commission-required interest rate of 0.06%[31] to the adjusted balance of proposed WNSA customer deposits as shown on Schedule B-7 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.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO UNCOLLECTIBLE EXPENSE ON SCHEDULE G-12.

A. Schedule G-12 presents the calculation of adjusted uncollectible expense relating to the proposed WNSA adjusted base revenues and other revenues. This adjusted

[31] Railroad Commission of Texas, Bulletin No. 1180, Sec. 6(B)(1), May 31, 2022 (citing to Historical PUC Interest Rates, https://www.puc.texas.gov/industry/electric/reports/HRates/HistRates.pdf).

expense level is calculated by multiplying the adjusted base revenues and other revenues by a three-year average uncollectibles ratio. The uncollectibles ratio is non-gas-cost-related Direct write-offs for the proposed WNSA divided by total proposed WNSA non-gas-cost revenue. The use of a three-year average is consistent with Commission decisions from prior TGS dockets, including GUD Nos. 9770, 9988, 10217, 10285, 10488, 10506, 10526, 10656, and 10928, as well as other gas utilities in Texas.[32] Test year uncollectible expense is then subtracted from the adjusted uncollectible expense level to obtain the adjustment to the test year amount. In addition, the uncollectible expense ratio is used on Schedule A to gross-up the revenue deficiency for the additional uncollectible expense associated with the requested increase in rates.

The adjusted expense on Schedule G-12 excludes uncollectible expense relating to gas cost revenues because the Company proposes to recover gas-cost-revenue-related bad debt expense through its cost of gas tariffs in the proposed WNSA.

Q. PLEASE DESCRIBE THE CALCULATIONS ASSOCIATED WITH ADVERTISING EXPENSE ON SCHEDULE G-14.

A. Commission Rule § 7.5414 states that actual expenditures for advertising will be allowed as a cost of service item for rate-making purposes provided that the total sum of such expenditures shall not exceed one-half of 1% of the gross receipts of the utility for utility services rendered to the public. Schedule G-14 demonstrates that total adjusted advertising expense included in the proposed revenue

[32] *See e.g.,* GUD No. 10170, Final Order at FoF 33 (Dec. 4, 2012) (stating that use of a three-year average for uncollectible expense was approved in GUD Nos. 9762 and 9869).

requirement is $25,535 and is less than the allowable amount of $1,110,736. The disallowed expenses of civic and charitable expenses and membership dues are addressed above under Commission Rule § 7.501.

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 plant in service. In addition, depreciation expense on the Company's December 31, 2021 DIMP deferral balance, pursuant to Commission Rule 8.209, is included and is calculated using the proposed WNSA depreciation rates for mains and services. The proposed WNSA Direct plant depreciation rates were developed in the 2022 depreciation study conducted by Dr. White for this rate case. Dr. White describes the depreciation study and the resulting rates in his direct testimony.[33] Test year depreciation expense is subtracted from total adjusted depreciation expense to calculate the adjustment to test year expense reflected on Schedule G-15. The balances of proposed WNSA transportation and major work equipment ("TWE") are excluded from depreciable plant for purposes of computing adjusted depreciation expense on Schedule G-15. 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 depreciation for TWE equipment is included as part of the TWE clearing adjustment on Schedule G-19. Ms. Borgstadt co-sponsors Schedule G-15

[33] The 2022 study was based on asset balances at December 31, 2021.

and supports the depreciation expense related to the TGS Division and Corporate Plant.

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 plant in service included in rate base by an effective property tax rate. The effective tax rate is computed by dividing the property taxes paid during the test year period by net plant in service as of January 1, 2020. Net plant in service as of January 1, 2020 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.

Q. PLEASE EXPLAIN THE ADJUSTMENT FOR TEXAS FRANCHISE TAX ON SCHEDULE G-17.

A. TGS's Texas franchise tax is recorded as a part of the income tax accrual on the Company's books that is excluded from the per book test year numbers for the proposed WNSA. Instead, the Company calculates separate, stand-alone proposed WNSA federal income tax and Texas franchise tax amounts in this filing. Schedule G-17 shows the adjustment to calculate the proposed WNSA stand-alone Texas franchise tax amount by multiplying TGS's franchise tax rate (for the 2020 return due in 2021) by the proposed WNSA's "As Adjusted Base (Non-Gas) Revenue" less "Taxes Other Than Federal Income Tax - Revenue Related" less "Bad Debt Expense, not included in Purchased Gas Costs." The Texas franchise tax is a necessary cost of providing utility service and is appropriately included in the proposed WNSA rates.

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 proposed WNSA stores costs that were under-cleared relative to the proposed WNSA costs incurred during the test year. TGS accounts for stores costs through a clearing account. Costs are accumulated in the stores load clearing account on the balance sheet and then cleared to capital and expense accounts based on a percentage load applied to all requisitions for materials and supplies. Because the percentage load is based on estimated usage and costs, the amount cleared may be more or less than the costs incurred during any given twelve-month period. During the test year, the amounts cleared from the proposed WNSA stores clearing account were less than the proposed WNSA actual cost incurred during the test year. Thus, an adjustment to increase the test year amount cleared is necessary to include a portion of these actual costs in the Company's cost of service. This adjustment is shown on Schedule G-18, lines 1 through 3. The second category of adjustments relates to the level of costs that was charged into the proposed WNSA stores clearing account during the test year. As shown on lines 4 through 7, adjustments were made to reflect the difference between proposed WNSA adjusted and test year payroll and payroll-related costs applicable to the stores function. The combination of these two categories of adjustments is an increase to overall test year stores clearing as shown on line 8. The two adjustments to stores clearing have been multiplied by the percentage of stores load charged to expense accounts in the proposed WNSA 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. In this case, the amounts cleared for proposed WNSA TWE during the test year were more than the proposed WNSA actual costs incurred. Thus, an adjustment to decrease the test year amount cleared is necessary to reduce 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 proposed WNSA 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 proposed WNSA 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 proposed WNSA 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. An adjustment was made to Test Year Expense in the amount of the difference between proforma Annual Regulatory Amortization Expense and Test Year Regulatory Amortization Expense. Rate case expenses associated with the filing of the instant 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 pipeline integrity testing expense to include in base rates if the Company's request for a rider is not approved. Pipeline integrity testing 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 pipeline integrity testing expense. Ms. Norman explains and supports the reasonableness and necessity of the pipeline integrity testing costs, and I address the appropriateness of recovering the pipeline integrity testing expense through a rider in the Proposed Rate Schedules section of my testimony. If the rider is approved, the adjustment shown on Schedule G-23 should be removed from the Company's base revenue requirement.

Q. PLEASE EXPLAIN THE EDIT ADJUSTMENT REFLECTED ON SCHEDULE G-24.

A. Schedule G-24 reflects the annual EDIT amortization credit to include in base rates if the Company's request to discontinue the EDIT rider is approved, which is detailed in Section IX of my testimony and in the direct testimony of Mr. Husen.

XI. CURRENT RATE SCHEDULES AND TARIFFS

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

A. On March 30, 2016, TGS filed a SOI requesting to increase rates within three previously existing service areas: (1) the incorporated and environs areas of the El Paso Service Area ("EPSA") comprised of Anthony, El Paso, Clint, Horizon City, San Elizario, Socorro, and Vinton and their environs, (2) the incorporated and environs areas of the Dell City Service Area ("DCSA") comprised of Dell City and its environs, and (3) the environs areas of the Permian Service Area ("PSA") comprised of the environs of Andrews, Barstow, Crane, McCamey, Monahans, Pecos, Pyote, Thorntonville, Wickett and Wink. In that case, TGS also requested consolidation of the EPSA, DCSA and PSA to create the WTSA. The SOI was docketed at the Commission as GUD No. 10506. The Commission approved the consolidation request and new rates for the WTSA on September 27, 2016. On October 27, 2016, TGS filed an SOI with the PSA Cities requesting to decrease rates within the incorporated areas of the PSA to reflect the rates approved in GUD No. 10506 and their approval of consolidation. The PSA cities approved the consolidation request and new rates in November 2016 and February 2017.[34]

Q. HAS THE COMPANY FILED IRAS IN THE EXISTING WTSA?

A. Yes. Pursuant to GURA § 104.301 and Commission Rule § 7.7101 (the "GRIP rule"), the Company filed the following IRA adjustments with the WTSA incorporated and environs areas:

Incorp. & Environs IRA Filing Date	GUD No. for Environs Filing	Plant Investment Period	Environs Final Order Issue Date[35]
March 15, 2017	10612	January 1 to December 31, 2016	June 6, 2017
March 15, 2018	10710	January 1 to December 31, 2017	June 5, 2018
March 15, 2019	10830	January 1 to December 31, 2018	June 18, 2019
March 13, 2020	10955	January 1 to December 31, 2019	June 16, 2020
March 12, 2021	Case Nos. 00006161 and 00006942	January 1 to December 31, 2020	June 22, 2021 and August 3, 2021
March 11, 2022	Case No. 00008972	January 1 to December 31, 2021	TBD

[34] The PSA Cities approved as follows: Barstow, Crane, Pecos, and Pyote approved the SOI filing via operation of law effective December 1, 2016; Monahans issued Ordinance No. 1234 dated November 8, 2016; Thorntonville issued Ordinance No. 2016 B-1 dated November 17, 2016; Wickett issued Ordinance No. 180 dated November 16, 2016; Andrews issued Ordinance No. 1590 dated November 10, 2016; McCamey issued Ordinance No. 2016-05 dated November 14, 2016; Wink issued Ordinance No. 364 dated February 6, 2017.

[35] Please see Exhibit SLM-3 for incorporated approval dates.

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING WTSA?

A. As shown in Exhibit SLM-2, the rates in effect for customers in the existing WTSA are the base rates approved in GUD No. 10506 and the IRAs addressed above.

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

A. On June 20, 2018, TGS filed an SOI requesting to increase rates within the NTSA comprised of the incorporated and environs areas of Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Millsap, Mineral Wells, Weatherford and Willow Park ("NTSA Cities") and the environs of Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas. The SOI was docketed at the Commission as GUD No. 10739. The NTSA Cities approved the settlement agreement in October, November and December 2018,[36] and the Commission approved on October 3, 2018.

Q. HAS THE COMPANY REQUESTED RATE CHANGES WITH THE NTSA CITIES SINCE THE SOI IN 2018?

A. Yes. A COSA Clause tariff has been in effect for the NTSA Cities since November 28, 2018. Pursuant to the terms of the COSA Clause, the Company filed a COSA adjustment with the NTSA Cities on April 30, 2019 that included capital

[36] The NTSA Cities approved as follows: Aledo issued Ordinance No. 2018-103 dated November 15, 2018; Breckenridge issued Ordinance No. 18-18 dated November 6, 2018; Bryson issued Ordinance No. O-2018-02 dated November 12, 2018; Graford issued Ordinance No. 2018-6 dated November 13, 2018; Graham issued Ordinance No. 1076 dated November 1, 2018; Hudson Oaks issued Ordinance No. 2018-21 dated December 13, 2018; Jacksboro issued Ordinance No. O-21-18 dated October 22, 2018; Millsap issued Ordinance No. 18-04-01 dated December 4, 2018; Mineral Wells issued Ordinance No. 2018-21 dated November 6, 2018; Weatherford issued Ordinance No. 945-2018-60 dated December 11, 2018; Willow Park issued Ordinance No. 783-18 dated November 13, 2018.

investment and expenses from a test year ending December 31, 2018. The Company has continued to file annual COSA adjustments with the NTSA Cities, most recently on April 29, 2022, that included capital investment and expenses from a test year ending December 31, 2021.

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING NTSA INCORPORATED AREAS?

A. As shown in Exhibit SLM-2, the rates in effect for customers in the incorporated areas of the NTSA are the rates that the NTSA Cities approved as part of the COSA in 2021.

Q. HAS THE COMPANY FILED IRAS IN THE NTSA ENVIRONS?

A. Yes. Pursuant to the GRIP statute and GRIP rule, the Company filed the following IRAs for the NTSA environs:

GUD No.	IRA Filing Date	Plant Investment Period	Final Order Issue Date
10875	July 12, 2019	January 1 to December 31, 2018	October 22, 2019
10990	July 10, 2020	January 1 to December 31, 2019	October 20, 2020
Case No. 00006940	July 9, 2021	January 1 to December 31, 2020	October 12, 2021

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING NTSA ENVIRONS?

A. As shown in Exhibit SLM-2, the rates in effect for customers in the NTSA environs are base rates approved in GUD No. 10739 and the IRAs addressed above.

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

A. On August 30, 2018, TGS filed an SOI requesting to change rates within the incorporated and environs areas of the BSSA comprised of Borger and Skellytown

("BSSA Cities") and their environs. The SOI was docketed at the Commission as GUD No. 10766. The BSSA Cities approved the settlement agreement in December 2018,[37] and the Commission approved on February 5, 2019.

Q. HAS THE COMPANY FILED IRAS IN THE EXISTING BSSA?

A. Yes. Pursuant to the GRIP statute and GRIP rule, the Company filed the following IRA adjustments with the BSSA incorporated and environs areas:

Incorp. & Environs IRA Filing Date	Case No. for Environs Filing	Plant Investment Period	Environs Final Order Issue Date[38]
August 28, 2020	00004435	January 1 to December 31, 2018	December 8, 2020
July 30, 2021	00007053	January 1 to December 31, 2019	October 26, 2021
September 28, 2021	00007778	January 1 to December 31, 2020	January 11, 2022

Q. WHAT RATES ARE CURRENTLY IN EFFECT IN THE EXISTING BSSA?

A. As shown in Exhibit SLM-2, the rates in effect for customers in the existing BSSA are the base rates approved in GUD No. 10766 and the IRAs addressed above.

Q. IF THE COMPANY'S REQUEST REGARDING CONSOLIDATION IS APPROVED, WHAT TARIFFS WILL BE IN EFFECT FOR CUSTOMERS IN THE WTSA, NTSA, AND BSSA?

A. If the Company's request to consolidate the incorporated and unincorporated areas of the WTSA, NTSA and BSSA to create the WNSA is approved, the proposed rate schedules and tariffs would be applicable to the entire WNSA, as shown in Exhibit A to the SOI filing. For customers in the NTSA Cities, the Company's consolidation request will result in a rate reduction. To ensure uniform rate implementation within the NTSA Cities and the other service areas affected by the

[37] The BSSA Cities approved as follows: Borger issued Resolution No. R-024-18 dated December 18, 2018; Skellytown issued Ordinance No. 2018-12-11 dated December 11, 2018.
[38] Please see Exhibit SLM-3 for incorporated approval dates.

consolidation request, the Company did not file an SOI with the NTSA Cities on June 30, 2022. Instead, upon receiving approval of the requested consolidation and determining the resulting WNSA rates, the Company plans to file a request with the NTSA Cities to implement the resulting rate reduction at the same time rates from the related SOI proceedings are implemented throughout the WNSA.

If the Company's consolidation request is not approved, the Company requests that new rate schedules and tariffs are approved for the existing WTSA, NTSA and BSSA, which are also provided with the SOI filing. The Company will make a separate SOI filing for the NTSA Cities.

XII. PROPOSED RATE SCHEDULES AND TARIFFS

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

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

- Rate Schedules 10, 15, 20, 30, 40, 70, C-1, and CNG-1, for gas sales service;
- Rate Schedules 1Z, 1Y, 2Z, 3Z, 4Z, 7Z, C-1-ENV, and CNG-1-ENV for gas sales service;
- Rate Schedules 1-INC and 1-ENV for the cost of gas clause;
- Rate Schedules T-1, T-1-ENV, T-TERMS for transportation service;
- Rate Schedule WNA for weather normalization adjustment;
- Rate Schedules PIT and PIT-Rider for recovery of annually approved pipeline integrity testing expenses;[39]
- Rate Schedules RCE and RCE-ENV for recovery of approved rate case expenses in this filing;
- Rate Schedule UGC for incorporated El Paso only to recover uncollected GRIP charges as a result of the City of El Paso's denial of TGS's 2020 IRA;

[39] The Company proposes a new PIT and PIT-Rider for the incorporated and environs areas of the BSSA. The PIT and PIT-Rider are currently in effect in the incorporated and environs areas of the WTSA and NTSA.

- Incorporated and environs Rules of Service;
- Rate Schedule PSF for recovery of the annual fee to support the pipeline safety functions of the Commission;
- Rate Schedule EDR for the economic development rate for incorporated Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro, and Vinton;
- Rate Schedule URI-Rider for the Winter Storm Uri Surcharge for 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 only as a result of Case No. 7061;
- Rate Schedule E5 for service to the United States Government for all purposes at Fort Bliss; and
- Rate Schedules TF-Agua Dulce, TF-Burbridge Acres-OS, TF-Burbridge Acres-IS, TF-Cotton Valley, TF-Haciendas del Valle; TF-Jones, TF-ENV-Panorama Vlg, TF-Poole, TF-Westway for the recovery of approved tapping fees.

The rate schedules for the proposed WNSA accurately reflect all the changes requested by the Company in this filing. Exhibit SLM-4 provides the existing rate schedules in redline format to identify the changes the Company proposes for the proposed consolidated 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 consolidation rate case for the incorporated and environs of the WTSA, GUD No. 10506, and merged applicability for the NTSA and BSSA. Next, the tariffs and rate schedules approved in recent TGS rate cases (GUD Nos. 10656, 10739, 10766, and 10928) were reviewed to identify applicable tariff provisions and language to include in the proposed WNSA tariffs. Should consolidation be approved in this SOI, the overall number of tariffs that must be maintained and administered will be reduced to 41. Without consolidation, the proposed rate and tariff changes in this case will affect 86 rate schedules.

A. Gas Sales Service Tariffs

Q. PLEASE DESCRIBE THE PROPOSED WNSA GAS SALES RATE SCHEDULES.

A. Rate Schedules 10, 20, 30, 40, 1Z, 2Z, 3Z and 4Z are based on the existing WTSA gas sales rate schedules and incorporate approved changes from GUD Nos. 10656, 10739, 10766, and 10928 with revisions made to:

1. include all WTSA Cities, NTSA Cities and BSSA Cities in the "Territory" section in the incorporated tariffs and to include all WTSA environs, NTSA environs and BSSA environs in the "Territory" section in the environs tariffs;
2. add language to the residential tariffs, Rate Schedules 10 and 1Z, to designate them for Small Residential Service;
3. add a reference to the Pipeline Safety and Regulatory Program Fees, Rate Schedule PSF, under "Other Adjustments;"
4. add a reference to the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, under "Other Adjustments;" and
5. add residential builders to the "Applicability" section in Rate Schedules 10 and 1Z.

Additional material differences between the proposed WNSA gas sales tariffs and the gas sales tariffs currently in effect for the WTSA, NTSA, and BSSA incorporated and environs areas are the:

1. addition of the Large Residential Service, Rate Schedules 15 and 1Y;
2. addition of the Unmetered Gas Light Service, Rate Schedules 70 and 7Z;
3. addition of the Compressed Natural Gas Service, Rate Schedules CNG-1 and CNG-1-ENV;
4. withdrawal of the School and Municipal Service in the BSSA, Rates Schedules 48 and 4H;

5. withdrawal of the Commercial Air Conditioning Service in the WTSA, Rate Schedules 21 and 2A;

6. withdrawal of the Public Authority Air Conditioning Service in the WTSA, Rate Schedules 41 and 4A;

7. withdrawal of the Municipal Water Pumping Service in the WTSA, Rate Schedules 42 and 4B;

8. withdrawal of the Standby Service in the WTSA, Rate Schedule SS;

9. removal of references to riders proposed to be withdrawn such as the EDIT Credit, Rate Schedule EDIT-Rider; and

10. addition of references to proposed new tariffs such as the Rate Case Expense Surcharge Riders, Rate Schedules RCE-INC and RCE-ENV, and the Uncollected GRIP Charges Rider, Rate Schedule UGC.

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

Q. PLEASE EXPLAIN THE TWO PROPOSED RESIDENTIAL TARIFFS BASED ON CUSTOMER USAGE OF NATURAL GAS.

A. As discussed by Mr. Raab, the Company proposes a rate design that includes a Small Residential Rate and a Large Residential Rate to be assigned to residential customers depending upon customer usage. The revisions to Rate Schedules 10 and 1Z and the addition of Rate Schedules 15 and 1Y reflect the Company's request.

Q. PLEASE EXPLAIN THE TARIFF REVISION TO INCLUDE RESIDENTIAL BUILDERS UNDER THE RESIDENTIAL RATE SCHEDULES 10 AND 1Z RATHER THAN THE COMMERCIAL RATE SCHEDULES 20 AND 2Z.

A. After gas sales service begins for a newly constructed home, while the house is for sale, the residential builder pays for the gas service. Because a residential builder is a commercial customer, they have historically paid commercial rates for this service. TGS proposes to charge residential builders a residential rate for gas service to these homes because they are single family dwelling places. This change will also add administrative efficiency because the rate will not need to be changed from commercial to residential when the home is sold. This revision is consistent with the tariffs proposed and approved in GUD Nos. 10739 and 10928.

Q. PLEASE DESCRIBE THE PROPOSED UNMETERED GAS LIGHT SERVICE TARIFFS, RATE SCHEDULES 70 AND 7Z.

A. Proposed Rate Schedules 70 and 7Z provide for unmetered service to customers using natural gas for gas lighting only. TGS currently serves no gas lighting customers in the proposed WNSA, but includes these tariffs as an option for future customers and for consistency with other TGS service areas. The proposed tariffs are consistent with the unmetered gas light tariffs proposed and approved in GUD No. 10928.

Q. PLEASE DESCRIBE THE PROPOSED C-1 AND C-1-ENV GAS SALES RATE SCHEDULES FOR ELECTRICAL COGENERATION SERVICE.

A. Proposed Rate Schedules C-1 and C-1-ENV are based on the existing WTSA tariffs with revisions made to:

1. include all WTSA Cities, NTSA Cities and BSSA Cities in the “Territory” section in the incorporated tariff, Rate Schedule C-1, and to include all WTSA environs, NTSA environs and BSSA environs in the “Territory” section in the environs tariff, Rate Schedule C-1-ENV;

2. add a reference to the Pipeline Safety and Regulatory Program Fees, Rate Schedule PSF, under “Other Adjustments;”

3. add a reference to the Rate Case Expense Surcharge Rider, Rate Schedules RCE-INC and RCE-ENV, under “Other Adjustments;”

4. add a reference to the Winter Storm Uri Surcharge Rider, Rate Schedule URI-Rider, under “Other Adjustments;” and

5. remove a condition referencing standby service.

Currently, there are no sales customers receiving service under the electrical cogeneration tariffs. There are, however, transportation customers receiving cogeneration service under Rate Schedule T-1. The Company proposes to retain the electrical cogeneration sales tariffs, Rate Schedules C-1 and C-1-ENV, for future customer use.

Q. PLEASE DESCRIBE THE PROPOSED CNG-1 AND CNG-1-ENV GAS SALES RATE SCHEDULES FOR COMPRESSED NATURAL GAS SERVICE, RATE SCHEDULES CNG-1 AND CNG-ENV-1.

A. Proposed Rate Schedules CNG-1 and CNG-1-ENV provide for compressed natural gas service to be used as motor fuel for non-residential customers. Ms. Serna discusses the revenue adjustment related to this proposed tariff change.

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

A. Proposed Rate Schedules 1-INC and 1-ENV are based on the existing cost of gas clauses in the WTSA while incorporating approved changes from GUD Nos. 10656, 10739 and 10928 with revisions to:

1. include all WTSA Cities, NTSA Cities and BSSA Cities in the "Applicability" section in the incorporated tariff and to include all WTSA, NTSA and BSSA environs areas in the environs tariff;

2. withdraw the cost of gas clauses for Dell City in the WTSA, Rate Schedules 1-INC-DC and 1-ENV-DC;

3. add clarifying language to section B.10 in the incorporated and environs tariffs and revise section B.3 in the incorporated and environs tariff to make consistent with recently approved cost of gas clauses in GUD Nos. 10656, 10739, 10766, and 10928;

4. include language for the use of financial instruments in sections B.3, B.6, B.8, H, and I.5 in the incorporated tariff to make consistent with the recently approved cost of gas clause in GUD No. 10928;

5. add clarifying language to section B.3 in the incorporated and environs tariffs to include other renewable sources of natural gas;

6. add clarifying language to section E, Interest on Funds, in the incorporated and environs tariffs to make consistent with recently approved cost of gas clauses in GUD Nos. 10656, 10739, 10766, and 10928;

7. add section F, Surcharge or Refund Procedures, to the incorporated and environs tariffs to make consistent with recently approved cost of gas clauses in GUD Nos. 10656, 10739, 10766, and 10928;

8. add language to section I in the incorporated and environs tariffs to make consistent with the recently approved cost of gas clause in GUD No. 10928; and

9. add section B.5 for a Customer Rate Relief charge for NTSA and BSSA customers, authorized by the Commission's Financing Order in Case No. OS-21-00007061.

The proposed cost of gas clauses require the following additional revisions compared to those currently in effect for the incorporated and environs customers in the NTSA and BSSA:

1. add section G, Non-Utility Transactions, and FERC intervention cost language in sections B.1, B.6, B.8, B.9 and I.4 to make consistent with the cost of gas clauses in the existing WTSA; and

2. revise sections B, D, E, and I to make the language consistent with the cost of gas clauses in the existing WTSA.

In addition to the revisions above, the proposed cost of gas clauses include a number of non-substantive language revisions to make the language of the tariffs consistent with the cost of gas clauses that are in effect in the Company's other service areas.

B. Transportation Service Tariffs

Q. PLEASE DESCRIBE THE PROPOSED WNSA TRANSPORTATION SERVICE TARIFFS.

A. Proposed Rate Schedules T-1 and T-1-ENV are based on the existing WTSA transportation rate schedules, while incorporating approved changes from GUD Nos. 10656, 10739, 10766 and 10928 with revisions made to:

1. include all WTSA Cities, NTSA Cities and BSSA Cities in the "Availability" section in the incorporated tariff and to include all WTSA, NTSA and BSSA environs areas in the environs tariff; and
2. add a reference to the Pipeline Safety and Regulatory Program Fees, Rate Schedule PSF, under "Additional Charges."

Additional material differences between the proposed WNSA transportation tariffs and the tariffs currently in effect for the WTSA, NTSA and BSSA incorporated and environs areas are the addition of the:

1. Compressed Natural Gas service rates; and
2. Electrical Cogeneration service rates for the NTSA and BSSA.

Q. DOES THE COMPANY PROPOSE ANY ADDITIONAL CHANGES TO THE TRANSPORTATION TARIFFS?

A. Yes, the Company also proposes Rate Schedule T-TERMS, which is consistent with the approved Rate Schedule T-TERMS in GUD Nos. 10656, 10739, 10766 and 10928 with revisions made to:

1. include all WTSA, NTSA and BSSA incorporated and environs areas in the "Requirements for Transportation Service" section;
2. include definitions for commercial, electrical cogeneration, and industrial service under "Definitions" to provide clarity and match the terminology in the proposed WNSA Rules of Service, which are consistent with the tariffs proposed and approved in GUD No. 10928;

3. add Section 1.3 to clarify Customer and Company rights and responsibilities;
4. add additional clarifying language to Rate Schedule T-TERMS in Section 1.6 (d) to address potential upstream pipeline costs beyond the control of the Company;
5. add Section 1.8 regarding Liability Limitations; and
6. make an administrative correction to Rate Schedule T-TERMS in Section 1.5 (d).

C. Tariff Riders

Q. HOW HAS THE COMPANY REVISED THE WEATHER NORMALIZATION CLAUSE FOR THE PROPOSED WNSA?

A. Existing Rate Schedule WNA provides a mechanism whereby incorporated and environs customer bills are adjusted up or down each billing cycle to reflect differences in actual weather compared to normal weather, as defined in the rate case and discussed in the testimony of Ms. Serna. Revisions have been made to Rate Schedule WNA to:

1. include all WTSA, NTSA and BSSA incorporated and environs areas in the "Applicability" section;
2. add Large Residential Service, Rate Schedules 15 and 1Y, to the "Applicability" section; and
3. reflect updated weather factors for each class consistent with Ms. Serna's weather normalization calculation in this case.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL FOR THE RECOVERY OF PIPELINE INTEGRITY TESTING EXPENSES.

A. Proposed Rate Schedules PIT and PIT-Rider provide a mechanism for recovery of costs incurred to comply with the Commission's Pipeline Integrity Assessment and Management Plan Rule, Rule § 8.101, and other future Commission rules related to integrity management plans, through a surcharge similar to the PIT-Rider previously approved by the Commission in GUD Nos. 9988, 10506, 10526, 10656, 10739, and 10928. To continue the treatment approved by the Commission in previous cases, the Company requests implementation of revised Rate Schedules PIT and PIT-Rider, applicable to all gas sales and standard transportation customers in the proposed WNSA, to recover pipeline integrity testing 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 PIPELINE INTEGRITY TESTING COSTS THROUGH A RIDER?

A. Yes. In GUD No. 9988, the Commission ordered that PIT expense in the Company's then EPSA be recovered via a rider rather than in base rates, finding that a rider is the "best mechanism for recovery of these expenses and is reasonable."[40] It is reasonable and appropriate to recover pipeline integrity testing costs via an annual rider because the annual amount of pipeline integrity testing costs varies greatly from year to year depending upon the testing schedule, making it challenging to determine an appropriate amount of expense to be included in base rates. Finally, a PIT rider has operated successfully and effectively in both the WTSA and the NTSA since the last rate case in each of those areas. Nevertheless, if the proposed Rate Schedule PIT is not approved, pipeline integrity testing

[40] GUD No. 9988, Final Order at FoF 22.

expenses should be included in the calculation of base rates, as discussed in the Direct Operating Expense section of my testimony.

Q. PLEASE DESCRIBE THE PROPOSED REVISIONS TO RATE SCHEDULES PIT AND PIT-RIDER FOR THE RECOVERY OF PIPELINE INTEGRITY TESTING EXPENSES.

A. Proposed Rate Schedules PIT and PIT-Rider are based on the existing WTSA rate schedules with revisions made to:

1. update references to the West North Service Area;
2. include all WTSA, NTSA and BSSA incorporated and environs areas in the "Territory" and "Applicability" sections;
3. update language for clarity and consistency with Rate Schedules PIT and PIT-Rider approved in GUD No. 10928;
4. add Large Residential Service, Rate Schedules 15 and 1Y, to the "Territory" and "Applicability" sections;
5. add Compressed Natural Gas Service, Rate Schedules CNG-1 and CNG-1-ENV to the "Territory" and "Applicability" sections; and
6. include electronic transmission of notifications to customers and regulatory authorities in the "Notice to Affected Customers" section of Rate Schedule PIT.

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 SLM-5.

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 IS THE COMPANY REQUESTING?

A. The Company is requesting approval of rate case expense riders, Rate Schedules RCE and RCE-ENV, to enable the Company to recover via surcharge all rate case expenses determined to be reasonable.

Q. PLEASE DESCRIBE THE PROPOSED UNCOLLECTED GRIP CHARGES TARIFF.

A. If recovery through base rates is not approved, proposed Rate Schedule UGC provides a mechanism for the recovery of GRIP charges that TGS was denied recovery of from incorporated El Paso customers from June 28, 2021 to August 2, 2021. This occurred as a result of the City of El Paso's Motion denying the Company's 2021 IRA, which TGS appealed to the Commission. The Commission approved TGS's requested IRA within the City of El Paso, as it had done in the corresponding IRA filings for the environs areas.[41] These charges are not recoverable from any other source and should be recovered from customers. Proposed Rate Schedule UGC provides for a one-time charge to all customers in the incorporated areas of the City of El Paso served under rate schedules that are subject to IRAs. If Rate Schedule UGC is approved, then the related requested regulatory asset discussed in the Other Rate Base section of my testimony should be eliminated.

Q. PLEASE EXPLAIN THE COMPANY'S WITHDRAWAL OF RATE SCHEDULE EDIT-RIDER FOR THE FLOW BACK OF EDIT.

A. The Company proposes to withdraw Rate Schedule EDIT-Rider, which provided a mechanism for the flow back to customers of the annual amortization of EDIT, via an annual one-time bill credit. As explained in Section IX of my testimony and in the direct testimony of Mr. Husen, recent private letter rulings from the IRS necessitate the flow back of EDIT through base rates rather than a rider.

D. Rules of Service

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RULES OF SERVICE FOR THE WNSA.

A. The Company developed proposed Rules of Service for the WNSA by starting with the existing WTSA incorporated and environs Rules of Service, which were updated and approved in 2016. The proposed Rules of Service were revised to reflect revisions approved in GUD Nos. 10656, 10739, 10766, and 10928. The proposed Rules of Service have also been extensively updated and reordered in

[41] Case No. 6942, Final Order; *see* Case No. 00006161, , Interim Order.

order to more closely conform to the Commission's Quality of Service Rules. Sections impacted by these conforming revisions include:

1. § 4.6 and 4.7, Conditions of Service;
2. § 5.2, Initiation of Service (previously § 5.7);
3. § 6, Refusal of Service (previously § 5.6);
4. § 7, Discontinuance of Service (previously §§ 17 and 18);
5. § 8, Security Deposits (previously § 10);
6. § 9, Billing and Payment of Bills (previously §§ 13 and 20);
7. § 10, Facilities and Equipment (previously §§ 7, 15 and 16);
8. § 11, Extension of Facilities (previously § 8);
9. § 12, Meters (previously §§ 6 and 12);
10. § 13, Gas Measurement (previously § 11); and
11. § 15, Service Fees and Deposit Amounts (previously §§ 15 and 21).

Additional material differences between the proposed WNSA Rules of Service and existing WTSA, NTSA, and BSSA Rules of Service include:

1. including the incorporated and environs areas of the WTSA, NTSA and BSSA in § 1.1 Tariff Applicability;
2. updating § 1.3, Definitions, to include all definitions of terminology in the Rules of Service consistent with approved Rules of Service in GUD Nos. 10739, 10766 and 10928, as well as adding a definition for "master meter" and expanding the definition for "excess flow valve" to establish consistency with terminology used across all proposed WNSA tariffs;
3. revisions to § 4.4 to remove a reference to the Company's previous filed curtailment plans and § 4.4(iv) to include curtailment language consistent with the new Commission Rule 7.455;
4. revisions to § 4.5 to include a reference to the tariffs on the TGS website;
5. revisions to § 4.6 to allow for electronic provision of general information to new customers;

6. revisions to § 4.9 to add language regarding force majeure situations to the limitation of liability provision;

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

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

9. revisions to the table in § 13.1 (previously § 11.1) to include all WNSA atmospheric and standard serving pressures; and

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

Finally, TGS proposes to withdraw the rules of service addenda WTSA-Env 7-45; WTSA-Env 7-46; WTSA-EFV; NTSA-Env 7-46 and BSSA-Env 7-46, as these provisions have been included within the proposed WNSA Rules of Service in Sections 7.5, 7.7 and 8.3(f) and a separate rules of service addendum is no longer necessary. The proposed changes provide clarity regarding the Company's current policies and procedures. Creating consistent Rules of Service will lead to more consistent application and more efficient administration of the Company's tariffs, which benefits all the Company's customers.

Q. WHAT REVISIONS HAS THE COMPANY MADE TO ITS SERVICE FEES AND DEPOSITS AS REFLECTED IN SECTION 15 OF THE PROPOSED RULES OF SERVICE?

A. Exhibit SLM-6 identifies the current and proposed service fees. The proposed service fees are similar to those approved for the Company's other service areas in GUD Nos. 10488, 10506, 10526, 10656, 10739, 10766, and 10928. 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 Ms. Serna sponsors.

E. Miscellaneous Tariffs

Q. ARE THERE ANY ADDITIONAL COMPANY TARIFFS YOU WISH TO ADDRESS?

A. Yes. The Company proposes no changes to Rate Schedule PSF, "Pipeline Safety and Regulatory Fees," which describes the recovery of the annual fee to support the pipeline safety functions of the Commission. In addition, the Company proposes to withdraw Rate Schedule COSA, "Cost of Service Adjustment Clause," and Rate Schedule ORD-NTX, "City Ordinance Listing" for the NTSA. Finally, there are a number of tariffs for which no substantive changes are proposed but which require a number of conforming revisions for clarity and consistency and to update references to the West North Service Area, add references to proposed new tariffs, and correct or update references to existing tariffs. These tariffs include:

- Rate Schedule 1-INC-R, for collection of franchise fees for incorporated areas within Weatherford;
- Rate Schedule EDR for the economic development rate for incorporated Anthony, Clint, El Paso, Horizon City, San Elizario, Socorro, and Vinton;
- Rate Schedule URI-Rider for the Winter Storm Uri Surcharge for the incorporated and unincorporated areas of the WTSA only, authorized by the Commission's Regulatory Asset Determination Order Case No. OS-21-00007061;
- Rate Schedule E5 for service to the United States Government for all purposes at Fort Bliss; and
- Rate Schedules TF-Agua Dulce, TF-Burbridge Acres-OS, TF-Burbridge Acres-IS, TF-Cotton Valley, TF-Haciendas del Valle, TF-Jones, TF-ENV-Panorama Vlg, TF-Poole, TF-Westway for the recovery of approved tapping fees.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

MOTION
June 21, 2021

That the City Council finds after review of the revised GRIP filing made by Texas Gas Service Company, a division of ONE Gas, Inc. on March 22, 2021, that rates identified in the filing comply with the provisions of the "GRIP" statute, TEXAS UTILITIES CODE §104.301.

1. That pursuant to Texas Utilities Code §104.301, the Interim Rate Adjustment Request filed Texas Gas Service Company, a division of ONE Gas, Inc., on March 14, 2021 and revised on March 22, 2021 is hereby denied.

2. Texas Gas Service Company is ordered to reimburse the City's expenses in reviewing this request within 30 days after it is invoiced.

Approved this 21st day of June 2021

CITY OF EL PASO

Oscar Leeser, Mayor

ATTEST:

Laura D. Prine

Laura D. Prine
City Clerk

APPROVED AS TO FORM:

Karla M. Nieman
City Attorney

		Current Rates						
Customer Class		**BSSA Incorporated Rates**	**BSSA Environs Rates**	**NTSA Incorporated Rates**	**NTSA Environs Rates**	**WTSA Incorporated Rates**	**WTSA Environs Rates**	**Proposed WNSA Rates**
Residential								
Customer Charge		$16.48	$16.48	$15.44	$24.50	$23.53	$23.53	
Volumetric Charge (per Ccf)	All Usage	$0.21548	$0.21548	$0.67101	$0.59366	$0.09317	$0.09317	
Rate (Small) Customer Charge								$20.00
Rate (Small) Volumetric	All Usage							$0.41173
Rate (Large) Customer Charge								$35.00
Rate (Large) Volumetric	All Usage							$0.00264
Commercial								
Customer Charge		$39.11	$39.11	$47.80	$76.33	$63.58	$63.58	$75.00
Volumetric Charge (per Ccf)	All Usage	$0.29344	$0.29344	$0.68165	$0.60165			$0.06808
	First 500					$0.08223	$0.08223	
	Over 500					$0.06223	$0.06223	
Commercial Transportation								
Customer Charge		$254.11	$254.11	$250.00	$286.33	$424.58	$424.58	$500.00
Volumetric Charge (per Ccf)	All Usage	$0.29344	$0.29344	$0.57978	$0.57978			$0.06808
	First 500					$0.08223	$0.08223	
	Over 500					$0.06223	$0.06223	
Commercial Air Conditioning (Withdrawing)								
Customer Charge						$63.58	$63.58	
Volumetric Charge (per Ccf)	Usage Rates (October - April)							
	First 500					$0.08223	$0.08223	
	Over 500					$0.06223	$0.06223	Reclass to Commercial
Volumetric Charge (per Ccf)	Usage Rates (May-September)							
	First 500					$0.06223	$0.06223	
	Over 500					$0.04223	$0.04223	
Industrial								
Customer Charge		$0.00	$0.00	$308.59	$509.26	$857.20	$857.20	$850.00
Volumetric Charge (per Ccf)	All Usage			$0.62874	$0.55395			$0.08875
	First 500					$0.12458	$0.12458	
	Over 500					$0.10458	$0.10458	
Industrial Transportation								
Customer Charge				$250.00	$509.26	$424.58	$424.58	$1,050.00
Volumetric Charge (per Ccf)	All Usage			$0.55395	$0.55395			$0.08875
	First 500					$0.12458	$0.12458	
	Over 500					$0.10458	$0.10458	
Public Authority								
Customer Charge		$49.07	$49.07	$101.32	$160.93	$195.79	$195.79	$200.00
Volumetric Charge (per Ccf)	All Usage	$0.23148	$0.23148	$0.61329	$0.54101			$0.11113
	First 500					$0.11461	$0.11461	
	Over 500					$0.09461	$0.09461	
Public Authority Transportation								
Customer Charge		$254.07	$254.07	$250.00	$325.93	$495.79	$495.79	$500.00
Volumetric Charge (per Ccf)	All Usage	$0.23148	$0.23148	$0.54101	$0.54101			$0.11113
	First 500					$0.11461	$0.11461	
	Over 500					$0.09461	$0.09461	
Public Authority Air Conditioning (Withdrawing)								
Customer Charge						$195.79	$195.79	
Volumetric Charge (per Ccf)	Usage Rates (October - April)							
	First 500					$0.11461	$0.11461	Reclass to Public Authority
	Over 500					$0.09461	$0.09461	
Volumetric Charge (per Ccf)	Usage Rates (May-September)							
	First 500					$0.08461	$0.08461	
	Over 500					$0.06461	$0.06461	
Electrical Cogeneration								
Customer Charge						$424.58	$424.58	$700.00
Volumetric Charge (per Ccf)	Usage Rates (October - April)							
	First 5,000					$0.05696	$0.05696	$0.05260
	Next 95,000					$0.04696	$0.04696	$0.04260
	Next 300,000					$0.03696	$0.03696	$0.03260
	Over 400,000					$0.02696	$0.02696	$0.02260
Volumetric Charge (per Ccf)	Usage Rates (May-September)							
	First 5,000					$0.04695	$0.04695	$0.04259
	Next 95,000					$0.03694	$0.03694	$0.03258
	Next 300,000					$0.02695	$0.02695	$0.02259
	Over 400,000					$0.01694	$0.01694	$0.01258
Electrical Cogeneration Transportation								
Customer Charge						$424.58	$424.58	$700.00
Volumetric Charge (per Ccf)	Usage Rates (October - April)							
	First 5,000					$0.05696	$0.05696	$0.05260
	Next 95,000					$0.04696	$0.04696	$0.04260
	Next 300,000					$0.03696	$0.03696	$0.03260
	Over 400,000					$0.02696	$0.02696	$0.02260
Volumetric Charge (per Ccf)	Usage Rates (May-September)							
	First 5,000					$0.04695	$0.04695	$0.04259
	Next 95,000					$0.03694	$0.03694	$0.03258
	Next 300,000					$0.02695	$0.02695	$0.02259
	Over 400,000					$0.01694	$0.01694	$0.01258
School and Municipal (Withdrawing)								
Customer Charge		$56.80	$56.80					Reclass to Public Authority
Volumetric Charge (per Ccf)	All Usage	$0.3765100	$0.3765100					
School and Municipal Transportation (Withdrawing)								
Customer Charge		$261.80	$261.80					Reclass to Public Authority Transporation
Volumetric Charge (per Ccf)	All Usage	$0.3765100	$0.3765100					
Municipal Water Pumping (Withdrawing)								
Customer Charge						$768.75	$768.75	
Volumetric Charge (per Ccf)	All Usage							Reclass to Public Authority
	First 500					$0.06111		
	Over 500					$0.05111		
Compressed Natural Gas								
Customer Charge								$150.000
Volumetric Charge (per Ccf)	All Usage							$0.076
Compressed Natural Gas Transportation (Reclassed from Commercial)								
Customer Charge						$424.58	$424.58	$450.00
Volumetric Charge (per Ccf)	All Usage							$0.07626
	First 500					$0.08223	$0.08223	
	Over 500					$0.06223	$0.06223	
Compressed Natural Gas Transportation (Reclassed from Public Authority)								
Customer Charge						$495.79	$495.79	$450.00
Volumetric Charge (per Ccf)	All Usage							$0.07626
	First 500					$0.11461	$0.11461	
	Over 500					$0.09461	$0.09461	

GRIP Period	WTSA Incorporated:	GRIP Period	Date of City Ordinances
2016		2016	June 13, 2017
2017		2017	Cities did not act
2018		2018	
2019		2019	April 28, 2020 - June 22, 2020
2020	Case No. 00006942	2020	August 3, 2021
2021		2021	TBD
WTSA	**WTSA Unincorporated:**		
GRIP Period	**GUD No.**	**GRIP Period**	**Date of Final IRA Order**
2016	10612	2016	June 6, 2017
2017	10710	2017	June 5, 2018
2018	10830	2018	June 18, 2019
2019	10955	2019	June 16, 2020
	Case No.		
2020	00006161	2020	June 22, 2021
2021	00008972	2021	TBD
GRIP Period	**BSSA Incorporated:**	**GRIP Period**	**Date of City Ordinances**
2018		2018	Cities did not act
2019		2019	
2020		2020	
BSSA	**BSSA Unincorporated:**		
GRIP Period	**Case No.**	**GRIP Period**	**Date of Final IRA Order**
2018	00004435	2018	December 8, 2020
2019	00007053	2019	October 26, 2021
2020	00007778	2020	January 11, 2022
	NTSA Unincorporated:		
GRIP Period	**GUD No.**	**GRIP Period**	**Date of Final IRA Order**
2018	10875	2018	October 22, 2019
2019	10990	2019	October 20, 2020
	Case No.		
2020	00006940	2020	October 12, 2021

Exhibit SLM-4 is Voluminous and will be provided in electronic format.

PUBLIC NOTICE
_____ WNSA 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 ___ through March ____ under the Pipeline Integrity Testing ("PIT") Rider applicable to the West-North Service Area incorporated and environs areas 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 Unincorporated Areas of Canutillo, Fabens, Jermyn, Palo Pinto, Perrin, Possum Kingdom, Punkin Center and Whitt, Texas. 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 customer classes within the WNSA is set forth in the table below:

Customer Class	PIT Rate per Ccf	Average Monthly Bill Impact	Number of Customers
Small Residential			
Large Residential			
Commercial			
Industrial			
Public Authority			
Compressed Natural Gas			
Electrical Cogeneration			
Commercial and Cogen. Transportation			
Industrial Transportation			
Public Authority Transportation			

Persons with specific questions or who want more information about this filing may contact the Company at 1-800-700-2443. A copy of the filing will be available for inspection during normal business hours at one of the Company's offices at 4600 Pollard in El Paso, Texas or 114 S. Main in Weatherford, Texas or 712 N. Florida in Borger, Texas, or on the Company's website at https://www.texasgasservice.com/RateInformation/WestNorth.

	BSSA, NTSA, WTSA, WNSA Incorporate and Environs	
Fee or Deposit	**Current Fee**	**Proposed Fee**
Connect	$35.00	$35.00
Reconnect	$35.00	$35.00
Connect Fee - Read Only	$10.00	$15.00
Special Handling	$6.00	$15.00
Expedited Service/Overtime/After Hours	$67.50	$65.00
Regular Labor Rate	$45.00	$48.00
No Access Fee (Door Tag)	$10.00	$15.00
Meter Test Up to 1500 CFH	$80.00	$150.00
Meter Test Over 1500 CFH	$100.00	$200.00
Orifice Meters	$100.00	$200.00
Payment Re-processing Fee (Returned Check Fee)	$25.00	$25.00
Collection Fee (All Classes)	$12.00	$15.00
Special Read	$10.00	$18.00
Meter Exchange without ERT (Customer Request)	$100.00	Discontinue
Meter Exchange (Customer Request)		$150.00
Unauthorized Consumption (Plus Expenses)	$20.00	$30.00
Meter Removal Fee	$50.00	$25.00
Account Research per hour Fee	$25.00	$20.00
Excess Flow Valve Installation Fee	$400.00	$400.00
Minimum Deposit Residential	$75.00	$75.00
Minimum Non Residential Deposit	$250.00	$250.00
Meter Tampering (Residential)	$100.00	$150.00

MOTION

June 22, 2022

That the **CITY OF EL PASO**, after review of the Interim Rate Adjustment filed by Texas Gas Service Company, a division of ONE Gas, Inc., on March 10, 2022, **FINDS**:

1. That the Interim Rate Adjustment Request filed by Texas Gas Service Company, a division of ONE Gas, Inc., for the Incorporated Areas of the West Texas Service Area, including the City of El Paso, on March 10, 2022 is hereby **DENIED**.

2. That Texas Gas Service Company, a division of ONE Gas, Inc., is **ORDERED** to reimburse the City's expenses in reviewing this request within 30 days after it is invoiced.

3. That the City Attorney's Office, in consultation with the City Manager, is authorized to file an intervention in any Appeal filed by Texas Gas Service Company from the Action of the City Council of the City of El Paso.

This Motion is intended to grant broad authority to the City Attorney's Office to take all action necessary to address these matters, including but not limited to, the initiation and response to any, litigation, complaints, appeals, administrative or judicial proceedings or process regarding this matter.

APPROVED on June 22nd, 2022.

CITY OF EL PASO

Oscar Leeser

Oscar Leeser, Mayor

ATTEST:

Laura D. Prine

Laura D. Prine
City Clerk

APPROVED AS TO FORM:

Donald C. Davie

Donald C. Davie
Assistant City Attorney

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.

DocuSigned by:
Stacey L. McTaggart
35B4599DD95D454...

Stacey L. McTaggart

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey L. McTaggart on this 16th day of June 2022.

DocuSigned by:
Christine Marie Bell
1C45AAFD08DC44A...

Notary Public in and for the State of Texas

NOTARY PUBLIC STATE OF TEXAS
CHRISTINE MARIE BELL
Notary ID
130547096
My Commission Expires
2/19/2024

CASE NO. 00009896

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	**§ § § § § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

STACEY R. BORGSTADT

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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EXHIBIT SRB-1	List of Prior Testimony
EXHIBIT SRB-2	Schedule of Utility Insurance Company Premiums
EXHIBIT SRB-3	Cost Allocation Manual

DIRECT TESTIMONY OF STACEY R. BORGSTADT

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Stacey R. Borgstadt. My business address is 15 East Fifth Street, Tulsa, Oklahoma.

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

A. I am employed by ONE Gas, Inc. ("ONE Gas") as the Director of Rates and Regulatory Analysis.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Master's Degree in Business Administration with a concentration in information systems from Lindenwood University in 2001 and a Bachelor of Science Degree in accounting from Missouri Valley College in 1996. From June 1996 to August 1998, I served as a corporate accountant for Dollar Rent-A-Car. From August 1998 to January 2004, I served in the internal audit departments of Enterprise Rent-A-Car, Cornerstone Propane and Dollar Rent-A-Car. I worked as a Senior Audit Associate at KPMG LLP from January 2004 to November 2005.

I began my employment with ONEOK, Inc. ("ONEOK") on November 21, 2005, as a project leader in the Internal Audit Department. I began serving as Manager of Rates and Regulatory Analysis in October 2007 while at ONEOK and retained that position with ONE Gas after its separation from ONEOK. I was promoted to Director of Corporate Rates and Regulatory in January 2020.

Q. PLEASE DISCUSS YOUR DUTIES AND RESPONSIBILITIES AS CORPORATE RATES AND REGULATORY DIRECTOR.

A. My responsibilities include assisting the Divisions of ONE Gas, which include Texas Gas Service Company ("TGS" or the "Company"), Kansas Gas Service, and Oklahoma Natural Gas by overseeing the Corporate Regulatory team with their preparation and analysis of ONE Gas ("Corporate") and TGS Division ("Shared Services") costs for purposes of regulatory filings and related activities.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony in proceedings before the Oklahoma Corporation Commission ("OCC"), the Kansas Corporation Commission ("KCC") and the Railroad Commission of Texas ("Commission") regarding the same general subject matter that I am testifying to in this case. I have also testified before the Public Utility Regulation Board of the City of El Paso. A list of the dockets in which I have filed written testimony is provided as Exhibit SRB-1.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony:

1. Provides an overview of ONE Gas' organizational structure, which includes Shared Services at the corporate level and Direct TGS service areas;

2. Explains and supports ONE Gas' cost allocation methodology, including causal allocations and the ONE Gas Distrigas ("Distrigas") formula;
3. Supports the reasonableness of certain rate base adjustments, including Corporate and Division capital investments and prepayments, and depreciation and amortization expense allocated to the proposed West North Service Area ("WNSA");
4. Explains and supports TGS's operating expense adjustments for Shared Services and Corporate, including adjustments for rent and lease operating expense, injuries and damages, the Distrigas allocation, and miscellaneous operating expenses;
5. Explains and supports adjustments associated with payroll, overtime, and payroll related taxes and benefits; and
6. Supports recovery of incentive compensation.

Q. HOW DOES YOUR TESTIMONY RELATE TO OTHER COMPANY WITNESSES IN THE RATE CASE?

A. My testimony relates to Company witness Stacey McTaggart's testimony as she supports the proposed WNSA Direct service area rate base and expense adjustments, whereas I support allocated Corporate and TGS Division rate base and expense adjustments. My testimony also relates to Company witness Jeff Branz's testimony that addresses employee compensation and benefits.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring the following schedules:

RATE BASE:	
Schedule B-2 (Prepays)	Co- Sponsor with Stacey L. McTaggart
Schedule C (Plant)	Co-Sponsor with Stacey L. McTaggart
Schedule C-1 (CCNC)	Co-Sponsor with Stacey L. McTaggart
Schedule D (Reserves)	Co-Sponsor with Stacey L. McTaggart
OPERATING INCOME:	
Schedule G (Summary of Operating Revenue & Expense Adj)	Co-Sponsor with Stacey L. McTaggart and Teresa Serna
Schedule G-4 (Base Payroll)	Sponsoring
Schedule G-5 (Overtime Payroll)	Sponsoring
Schedule G-6 (Benefits & Payroll Related Taxes)	Sponsoring
Schedule G-8 (Incentive Compensation)	Sponsoring
Schedule G-9 (Miscellaneous Adjustments)	Co-Sponsor with Stacey L. McTaggart
Schedule G-10 (Rents and Leases)	Co-Sponsor with Stacey L. McTaggart
Schedule G-13 (Inj & Dam)	Sponsoring
Schedule G-14 (Advertising)	Co-Sponsor with Stacey L. McTaggart
Schedule G-15 (Depr Amort)	Co-Sponsor with Stacey L. McTaggart
Schedule G-21 (Distrigas Allocation)	Sponsoring
Schedule G-22 (Causal Allocation)	Sponsoring

The schedules I address in my testimony are for the Company's proposed WNSA, which consolidates the West Texas Service Area ("WTSA"), North Texas Service Area ("NTSA") and Borger Skellytown Service Area ("BSSA") into a new regulatory service area. In addition to schedules that support the Company's consolidation request for the proposed WNSA, TGS is also providing stand-alone schedules for the WTSA, NTSA, and BSSA.

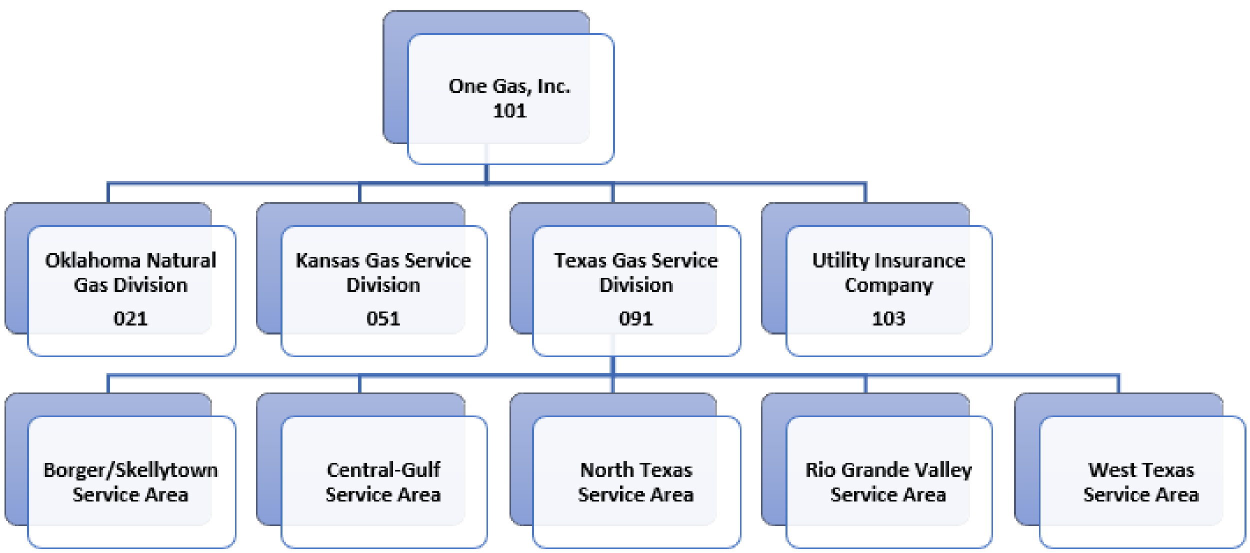
Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

III. 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, that together serve more than 2.2 million customers, and an affiliate company, Utility Insurance Company ("UIC"), a wholly-owned captive insurance subsidiary. Company witness Mark W. Smith discusses UIC in more detail in his testimony.



Q. ARE CERTAIN CENTRALIZED SERVICES PROVIDED TO TGS'S DIRECT SERVICE AREAS?

A. Yes, both ONE Gas and TGS Division provide certain necessary, centralized services for TGS's direct service areas. Providing certain consolidated or centralized services reduces operational redundancies and helps achieve economies of scale. These common centralized services are more efficiently provided at the TGS Division or Corporate level and are considered "Shared Services" costs because company personnel provide support to all ONE Gas Operating Divisions, including TGS's service areas. The activities performed through these cost centers are subject to cost assignment using the methodology set forth below.

Q. HAS THE COMPANY INCLUDED THE COSTS ASSOCIATED WITH PROVIDING SHARED SERVICES TO THE PROPOSED WNSA IN THE REVENUE REQUIREMENT?

A. Yes. The Company has included these costs in the filing. As described in my testimony below, during the test year, services were provided to the proposed WNSA by TGS Division and ONE Gas employees, and the costs associated with those services are allocated to the WNSA and included in the requested revenue requirement.

Q. IS A PORTION OF UIC PREMIUMS FOR ONE GAS AND TGS INCLUDED IN THE COMPANY'S REQUESTED REVENUE REQUIREMENT FOR THE PROPOSED WNSA?

A. Yes. A portion of UIC premiums for ONE Gas and TGS is included as allocated costs to the proposed WNSA. A complete list containing the UIC premiums included in operations and maintenance ("O&M") expense allocated to the proposed WNSA is attached to my testimony as Exhibit SRB-2. Mr. Smith provides testimony describing UIC and its services, and Ms. McTaggart discusses the Company's compliance with the associated affiliate standard.

IV. 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 or service areas, cost responsibility for these services must be reasonably allocated among the various ONE Gas business entities and TGS's service areas. These allocations are accomplished by applying ONE Gas' cost allocation methodology.

Q. PLEASE DESCRIBE ONE GAS' COST ALLOCATION METHODOLOGY.

A. The costs incurred by ONE Gas or any of its business entities can be described as either direct or indirect. A direct cost can be fully attributed to a specific business entity or service area, so those costs are directly assigned to that specific business entity or service area. Conversely, indirect costs are costs that cannot be attributed to a specific business entity or service area, so those costs must be allocated in accordance with principles of cost causation. For instance, if costs cannot be directly assigned, but a specific unit of 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 according to a formula that has been previously approved or accepted in Texas, Kansas, Oklahoma and other jurisdictions. This formula is known as Distrigas.

Q. PLEASE EXPLAIN "DIRECT COSTS."

A. Direct costs are those costs that can be identified and directly assigned to the service area, TGS Division, or Corporate. Costs are directly assigned for services such as meter reading, leak surveys, field customer service, fleet expenses, certain information technology ("IT") services, line location services, facilities management, and labor and benefits costs for Property Accounting employees for each ONE Gas Division for which the employee has accounting responsibility.

Q. PLEASE EXPLAIN "INDIRECT COSTS" AND HOW THE INDIRECT COSTS ARE ALLOCATED.

A. Indirect costs are those costs incurred to provide services that cannot be directly assigned to a business entity or service area; thus, these costs are considered shared costs. 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 measurements such as participation level, activity level, output level, or resource consumption. Indirect costs that cannot be charged directly or cannot be associated with an identifiable causal relationship are allocated through Distrigas. Examples of indirect costs include customer information center services, credit and collections, and TGS general accounting. Employee health and welfare benefits for active employees are examples of indirect costs allocated on a causal basis as measured by output level (allocated by employee headcount for each respective business entity). Other examples of causal allocation factors include a percentage of customer count for the Billing Control Group and invoice processing volume by business entity for Accounts Payable. Costs are then further allocated to the TGS service areas based on the ratio of customers in each service area to the total number of TGS customers in all TGS service areas.

Q. PLEASE DESCRIBE THE SERVICES AND COSTS ALLOCATED THROUGH DISTRIGAS.

A. ONE Gas provides many services that benefit all its business entities, including TGS. Those Corporate service operating costs are recorded on ONE Gas' financial books and are then allocated to the various ONE Gas business entities using the Distrigas factor.

A general summary of Corporate services is provided below. A complete list containing a more detailed explanation of each Corporate service and associated allocation can be found in the Corporate Allocation Manual ("CAM") attached to my testimony as Exhibit SRB-3.

- Human Resources - Provides professional development and training programs for active employees.
- IT - Supports ONE Gas' business entities by developing and administering disaster recovery, data backup and recovery, cyber-security, data center and support of all ONE Gas, and Company technology.
- Finance and Accounting - Supports ONE Gas' business entities by administering processes related to corporate accounting, financial reporting, tax, credit, risk and insurance, internal audit, financial planning, and business development.
- General Counsel - Supports ONE Gas' business entities by administering processes related to legal aspects of day-to-day business activities.
- Corporate Communications - Supports ONE Gas' business entities by administering processes related to corporate communications efforts directed to employees and external stakeholders.
- Corporate Services - Supports ONE Gas' various business entities by developing and administering programs and processes that facilitate

general day-to-day business activities such as purchasing, facilities, business continuity and environmental safety, and health initiatives.

Finally, as noted in the CAM, certain miscellaneous costs such as rent and utilities impacting all business entities are also allocated. All costs allocated to TGS, including UIC premiums, are then further allocated to the TGS service areas based on the ratio of customers in each service area to the total number of TGS customers in all TGS service areas.

Q. WOULD THE SAME TYPES OF SERVICES AS THOSE PROVIDED BY TGS DIVISION AND ONE GAS BE REQUIRED IF THE PROPOSED WNSA WERE A STAND-ALONE BUSINESS?

A. Yes, these services would need to be provided even if the proposed WNSA was a standalone business. The WNSA would likely have to independently provide these services if the services were not provided by TGS Division or Corporate. However, having these services performed centrally is efficient, allows for economies of scale and allows for the costs of those services to be spread across the business and service areas for which the services are provided. These services are necessary for the operation of any gas utility business, regardless of whether the service is performed centrally or on a decentralized basis at the service area level.

Q. PLEASE DESCRIBE THE HISTORY OF THE DISTRIGAS ALLOCATION METHODOLOGY.

A. The Distrigas method was first approved in 1987 by the Federal Energy Regulatory Commission ("FERC") in a rate proceeding for a natural gas transmission company, Distrigas of Massachusetts Corporation.[1] The formula used by Distrigas

[1] *Distrigas of Mass. Corp.*, 41 FERC ¶ 61205 (F.E.R.C. 1987).

of Massachusetts Corporation was a slight modification of the old Massachusetts formula (a three-part formula consisting of gross plant, gross revenues, and labor) which, prior to the acceptance of the Distrigas method, was widely accepted by numerous regulatory agencies across the country. In its opinion, FERC accepted the Modified Distrigas method (a three-part formula consisting of gross plant, net revenues, and labor) as a reasonable and acceptable methodology for allocating costs for ratemaking purposes.

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED USING THE DISTRIGAS METHOD.

A. The Distrigas Method ONE Gas uses ensures that ONE Gas allocates Corporate costs to each Division on a consistent basis by applying the same cost-causation principles and methodology. This method uses a three-factor formula comprised of: (1) gross plant and investments; (2) operating income (income before interest expense and income taxes); and (3) labor expense. As with the Modified Distrigas Method, the factors are individually calculated and then a simple average is calculated using the three component percentages.

Distrigas utilizes gross plant and investments rather than just gross plant in the event that ONE Gas invests in business(es) that are not directly operated by ONE Gas.[2] These modifications further refine the Distrigas Method to fairly and reasonably allocate the costs to the ONE Gas business entities, including TGS.

[2] Currently, ONE Gas has no investment in businesses that are not operated by ONE Gas. ONE Gas also uses operating income rather than net revenues as an allocator to eliminate the cost of gas component.

Q. HAS THE SAME COST ALLOCATION METHODOLOGY BEEN APPLIED IN PRIOR ONE GAS PROCEEDINGS?

A. Yes, it has. This methodology has been used since 1994 to allocate Corporate costs. It is important for 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 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; and most recently the Central-Gulf Service Area in GUD No. 10928.[3]

Additionally, the OCC has approved the use of the cost allocation method used by ONE Gas in prior rate cases.[4] This methodology is also currently used in Kansas. The KCC accepted ONEOK's allocation methodology in a settled 2005 Kansas Gas Service rate case and ONE Gas' allocation methodology in the 2016 Kansas Gas Service rate case.

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[3] *Appeal of Texas Gas Service Company from the Actions of the Cities of Lockhart, Luling, Cuero, Gonzales, Nixon, Shiner and Yoakum; and, Statement of Intent Filed to Increase Rates in the Unincorporated Areas of the South Texas Service Area,* GUD No. 9770, Final Order at Findings of Fact ("FoF") 36 (Apr. 24, 2008); *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 at FoF 23-24 (Dec. 14, 2010).
[4] *In the Matter of the Application of Oklahoma Natural Gas Company, a Division of ONEOK, Inc., for Review and Change or Modification in its Rates, Charges, Tariffs and Terms and Conditions of Service,* Cause No. PUD 200400610, Order No. 512287, Final Order at 113 of 134 (Oct. 4, 2005).

Q. IS ONE GAS' COST ALLOCATION METHODOLOGY A REASONABLE METHODOLOGY TO ALLOCATE CORPORATE COSTS?

A. Yes, it is. As mentioned above, ONE Gas' cost allocation methodology allows ONE Gas to allocate Corporate costs to each of its Divisions on a consistent basis by applying the same cost-causation principles and methodologies. Furthermore, this methodology has been previously approved as a reasonable means of allocating Corporate costs by this Commission, the FERC,[5] the OCC, and accepted by the KCC.

V. RATE BASE ADJUSTMENTS

Q. WHAT IS RATE BASE?

A. Rate base is the Company's invested capital that is used and useful in providing safe and reliable gas utility service to its customers. The Company's rate base is summarized on Schedule B and is classified into three components: (1) Net Plant in Service ("PIS"); (2) Other Rate Base Items; and (3) Non-Investor Supplied Funds. Ms. McTaggart further discusses Direct rate base and its three components in her 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 to the provision of utility service to TGS and the proposed WNSA but are not reflected in the proposed WNSA Direct costs; thus, an adjustment is necessary to include these investments in rate base to determine the revenue requirement. This is the same approach TGS

[5] 41 FERC ¶ 61205.

took in prior statements of intent, which the Commission approved in GUD Nos. 9770 and 9988; TGS's last fully litigated rate case in GUD No. 10506; and TGS's settled cases GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928.[6]

Q. WHICH RATE BASE ITEMS DO YOU ADDRESS?

A. I address the rate base items for capital costs that are allocated from ONE Gas or TGS Division to the proposed WNSA. These rate base items include prepayments, materials and supplies, net PIS, construction completed not classified ("CCNC"), and accumulated reserves for depreciation and amortization. Schedule B contains a summary of all Rate Base items.

Q. PLEASE DISCUSS THE RATE BASE ADJUSTMENTS ASSOCIATED WITH PREPAYMENTS.

A. Prepayments are a component of rate base and are defined as amounts paid for in advance of the goods or services being received in the future. ONE Gas and TGS Division prepayments allocated to the proposed WNSA represent advances for items such as annual equipment and software maintenance agreement fees;

[6] GUD No. 9770, Final Order at FoF 27; GUD No. 9988, Final Order at FoF 10; *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order at FoF 46 (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 at FoF 110 (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 44 (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 at FoF 39 (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 at FoF 34 (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order at FoF 33 (Feb. 5, 2019); and S*tatement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS") to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928 consol., Final Order at FoF 52 (Aug. 4, 2020).

software license fees; insurance policy premiums for general liability; automobile and workers' compensation; and other miscellaneous prepaid items. ONE Gas and TGS Division prepayments are provided on Schedule B-2 and Workpapers B-2.a.1 and B-2.b.1. Prepayments are included in rate base because they reflect an investment ONE Gas and TGS made for the provision of utility service, and 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 testimony of Mr. Smith, ONE Gas formed a wholly-owned captive insurance subsidiary, UIC, in 2017 to provide insurance to ONE Gas and its Divisions. Some UIC premiums are included in Corporate and TGS Division costs that are allocated to the proposed WNSA. A complete list containing UIC premiums included in rate base is attached to my testimony as Exhibit SRB-2. Ms. McTaggart explains 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 2022.

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 required costs for services that are necessary for TGS to operate safely, reliably, and efficiently. As such, prepayments are appropriately included in rate base, and this is the same approach TGS has taken in prior statements of intent, which the Commission has previously approved.[7]

Q. NEXT, PLEASE EXPLAIN THE ONE GAS AND TGS DIVISION CAPITAL INVESTMENT, ALLOCATED TO THE PROPOSED WNSA, SHOWN ON SCHEDULES C, C-1, AND D.

A. ONE Gas' net PIS (gross plant less accumulated reserves), allocated from Corporate to TGS, is $36,750,870. The TGS Division net PIS is $8,125,875. The proposed WNSA allocated share of these amounts is 44.1009%, or $19,791,049, based on the number of customers in the proposed WNSA relative to the total number of TGS customers. Net PIS costs are shown on Workpapers C.b, C.c, C-1.b, C-1.c, D.b, and D.c.

Q. PLEASE DESCRIBE ANY SIGNIFICANT CORPORATE OR TGS DIVISION CAPITAL INVESTMENTS MADE SINCE THE LAST RATE CASE AND REFLECTED ON SCHEDULES C AND C-1.

A. Corporate and TGS Division capital expenditures made since the last rate case and reflected on Schedules C and C-1 primarily consist of investments in a new

[7] GUD No. 9770, Final Order; GUD No. 9988, Final Order; 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; and GUD No. 10928, Final Order.

Customer Information Center ("CIC") and computer software and hardware. Examples of those investments include:

- The purchase and renovation of a manufacturing facility into functional office space to adequately accommodate operation of TGS's CIC located in El Paso. The previous CIC facility was not large enough to accommodate the employees necessary to perform daily operations and resulted in two to four employees sharing office space originally made for one employee. The old location also had unsafe employee parking conditions resulting in employees parking in the street and surrounding neighborhoods. The new facility renovation process included replacing the building's electrical system; repairing plumbing systems; installing fire system equipment; and adding a generator system for emergency response needs. Additional technological renovations included installing hardware such as digital screens and camera systems into conference rooms; servers, uninterruptible power supplies, 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.

- Enhancements made to ONE Gas' interactive voice response ("IVR") system in order to improve customer experience. These enhancements include: (1) providing customers the option to complete a post call and field survey which links survey information to customer accounts; (2) routes Spanish calls to Spanish speaking customer service representatives ("CSRs"); (3) provides customers a call back option when CSRs are servicing other customers in order to reduce wait time and help manage periods of high inbound call volumes; and (4) the creation of an application for emergency calls routed through the IVR and an application for calls routed through the emergency toll free numbers.

- Improvements made to ONE Gas' Banner application to increase the efficiency and productivity of CSRs. Banner is ONE Gas' billing system, which contains records of ONE Gas' approximately 2.2 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.

- Updates and additions to technology infrastructure such as data centers, disaster recovery, storage, servers, networking, backups, and cyber security protection.

Q. WERE THE TGS DIVISION AND CORPORATE PROJECTS AND RELATED CAPITAL EXPENDITURES PRUDENT, REASONABLE AND NECESSARY?

A. Yes, they were. Corporate capital and TGS Division investment are necessary for the provision of service in the TGS service areas. These expenditures provide critical services supporting all employees in their efforts to provide service safely and reliably to customers in the proposed WNSA. ONE Gas made these investments, including investment in technology systems and software, to provide the highest level of stability, reliability, and security. If a technology system becomes unavailable, operations may be impaired. Additionally, ONE Gas and TGS maintain office and training spaces for employees to adequately and safely provide reliable gas service to customers Thus, it is necessary to provide reliable technology systems, infrastructure, and office/training facilities to minimize disruption to customers and employees, who provide either indirect support or direct service to customers, through leak detection, emergency response, customer billing, dispatching and scheduling of service calls, to protect sensitive customer information, enhance cybersecurity, improve website functionality, and maintain office/training facilities. Company witness Shantel Norman testifies regarding the overall reasonableness, necessity, and prudence of the capital investment costs TGS is requesting in this case.

Q. DID YOU MAKE ANY ADJUSTMENTS TO ONE GAS AND TGS DIVISION PIS, CCNC OR ACCUMULATED RESERVE?

A. Yes. The Company has made adjustments to remove Corporate and TGS Division costs for activities such as: (1) plant additions, transfers or retirements mistakenly coded to the proposed WNSA, (2) plant that will retire once new amortization rates are implemented; (3) costs for meals greater than $25 per person, exclusive of taxes and tip amounts, and hotel stays greater than $175 per night, exclusive of taxes;[8] (4) duplicative Vertex sales tax; and (5) aviation. These adjustments are reflected in Workpapers C.b, C.c, C-1.b, C-1.c, D.b, and D.c.

Q. DID THE COMPANY MAKE ANY OTHER ADJUSTMENTS TO ONE GAS AND TGS DIVISION ACCUMULATED RESERVES ON WORKPAPER D.b?

A. The Company has made an adjustment to the Accumulated Reserve to account for the differences between the recorded reserve and computed reserve calculated in Company witness Dr. Ronald E. White's Depreciation study. This adjustment transferred reserve dollars from all TGS Direct depreciable 390.1 accounts to TGS Division amortizable accounts, so there is enough reserve in the amortizable accounts for when those assets retire. Ms. McTaggart explains and sponsors the adjustments made to Direct per book reserve balances.

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[8] GUD No. 10928, Final Order at FoFs 71-72.

VI. 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 $87,002,138, of which $38,368,726 is allocated to the proposed WNSA. Workpaper G.a.2.a provides a summary showing the TGS allocated test year amount along with an O&M expense factor calculation applied to the adjustments.

Q. DESCRIBE THE MISCELLANEOUS ADJUSTMENTS SHOWN ON SCHEDULE G-9.

A. Schedule G-9 contains miscellaneous adjustments to remove expenses not currently allowed for regulatory recovery such as civic activities, sponsorships, charitable contributions, and legislative activities. Additional adjustments include the removal of royalty fees, an adjustment to account for the known and measurable change in insurance costs, and an adjustment to remove COVID expenses that have been included in Schedule G-20, Regulatory Asset Amortization, to be recovered through a regulatory asset, over a six-year period. Ms. McTaggart addresses the Regulatory Asset Amortization, including COVID 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 2018 through December 2021 (4 years). Next, injuries and damages expense for the twelve months ended December 2021 was subtracted from the average claims paid (4-year average) to determine the additional adjustment to test year expense. Mr. Smith 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 and 10506, the Commission found that it is reasonable to normalize this expense over a four-year period. The Commission also approved this treatment in TGS rate cases in GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928, all of which were resolved through settlement agreements.

Q. PLEASE EXPLAIN HOW THE DEPRECIATION AND AMORTIZATION EXPENSE ADJUSTMENT ON SCHEDULE G-15 IS CALCULATED.

A. Adjusted depreciation or amortization expense is calculated by multiplying the proposed depreciation/amortization rates by depreciable PIS. Test year depreciation expense is subtracted from total adjusted depreciation expense to calculate the adjustment to test year expense reflected on Schedule G-15. Most Corporate plant depreciation rates and amortization periods were developed in Dr. White's 2015 depreciation study, approved in TGS's last fully litigated rate case in GUD No. 10506, and approved in TGS's settled cases in GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928.[9] Corporate depreciation rates and amortization periods are consistent throughout ONE Gas and its Divisions. The KCC[10] and OCC[11] have also approved these depreciation rates. For certain new investments in accounts that were not considered in the 2015 depreciation study, initial depreciation rates were determined based on previous company experience and the judgment of those responsible for developing and managing these assets. The Company proposes to continue the use of existing depreciation rates for ONE Gas plant.

Dr. White conducted a 2021 depreciation study to determine the proposed depreciation rates for TGS Division plant. If approved, the Company will use the new depreciation rates for TGS Division plant going forward. Dr. White describes in his testimony the depreciation study and resulting depreciation rates requested in this case.

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[9] GUD No. 10488, Final Order at FoF 45; GUD No. 10506, Final Order at FoF 77; GUD No. 10526, Final Order at FoF 43; GUD No. 10656, Final Order at FoF 30; GUD No. 10739, Final Order at FoF 39; GUD No. 10766, Final Order at FoF 37; and GUD No. 10928, Final Order at FoF 68.

[10] *In the Matter of the Application of Kansas Gas Service, a Division of ONE Gas, Inc. for Adjustment of its Natural Gas Rates in the State of Kansas,* Docket No. 16-KGSG-491-RTS, Order Approving Unanimous Settlement Agreement at FoF 14 (Nov. 29, 2016).

[11] *Application of Oklahoma Natural Gas Company, a Division of ONE Gas, Inc., for Approval of its Performance Based Rate Change Plan Calculations for the Twelve Months Ending December 31, 2016, Energy Efficiency True-Up and Utility Incentive Adjustments for Program Year 2016, and Changes or Modifications to its Tariffs,* Cause No. PUD 201700079, Order No. 666781, Final Order Approving Joint Stipulation and Settlement at 9 of 11(Aug. 9, 2017).

Q. WHY IS IT APPROPRIATE TO USE EXISTING DEPRECIATION RATES AND AMORTIZATION PERIODS APPROVED BY THE COMMISSION TO CALCULATE THE DEPRECIATION AND AMORTIZATION EXPENSE FOR CORPORATE ASSETS?

A. These depreciation rates were subject to a comprehensive review in seven different Texas rate cases and are already being utilized by TGS statewide, including the WTSA, NTSA and BSSA. If the regulatory authority were to establish parameters for Corporate assets in the proposed WNSA that are different from those utilized in other Texas jurisdictions and ONE Gas Divisions, ONE Gas and TGS would have two sets of depreciation/amortization periods for the exact same assets. This difference would require ONE Gas to modify its current accounting system to track assets, accumulated reserve, and depreciation/amortization specifically for the proposed WNSA, which would be a complicated and costly process.

Q. PLEASE EXPLAIN THE DISTRIGAS ALLOCATION ADJUSTMENT REFLECTED ON SCHEDULE G-21.

A. Schedule G-21 and Workpaper G-21.a provide the monthly per book Distrigas allocation to TGS, along with the factors used to calculate the allocation percentages. An adjustment to reflect the known and measurable change in the Distrigas allocation factor as of the first quarter of 2022 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.

VII. PAYROLL, OVERTIME, 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. Mr. Branz discusses base pay and its components in his testimony.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO BASE PAYROLL PROVIDED ON SCHEDULE G-4.

A. Schedule G-4 contains adjustments to payroll expense to annualize the changes in salary or hourly wages for services that employees provided to the proposed WNSA as well as employees whose costs are allocated through Shared Services during the test year. Adjusted base salaries were calculated by annualizing test year payroll at December 31, 2021. 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 2021 Common Salary Review increase, to determine the allocable base payroll adjustment that was multiplied by allocation factors and by the payroll O&M expense ratio to determine the adjusted O&M expense amount applicable to the proposed WNSA. 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.

Q. PLEASE DESCRIBE THE EXPENSE ADJUSTMENT SHOWN ON SCHEDULE G-5.

A. Schedule G-5 contains adjustments to overtime expense for hourly employees who are based in the proposed WNSA, as well as TGS Division and Corporate employees whose costs are allocated through Shared Services. The adjusted hourly base payroll calculated on Schedule G-4 was multiplied by the test year overtime percentage (which is test year overtime as a percentage of test year hourly base pay) to determine annualized overtime payroll. Total test year overtime payroll was then subtracted from the annualized overtime payroll to determine the allocable overtime payroll adjustment. This adjustment was multiplied by allocation factors and the payroll O&M expense ratio to determine the adjusted O&M overtime payroll expense amount applicable to the proposed WNSA. 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.

Q. DESCRIBE THE BENEFITS AND PAYROLL TAXES ADJUSTMENT SHOWN ON SCHEDULE G-6.

A. Schedule G-6 contains the adjustment to recognize the change in benefits and payroll tax based on the annualization of the labor increases for employees performing work in the proposed WNSA as well as TGS Division and Corporate employees whose costs are allocated through Shared Services. The adjustment includes a cost per payroll dollar for payroll taxes and for those benefits that vary based on labor cost. Benefits that vary based on labor cost include pension, other post-employment benefits, and medical reserve. The benefit cost per payroll dollar was calculated based on the most recently available data for payroll tax and benefits costs. These calculations are shown on Workpaper G-6.b. Additional benefits such as profit-sharing amounts, 401(k) company match, tuition reimbursement, and employee assistance programs, are reflected on Schedule G-6 and Workpaper G-6.b and represent test year actual amounts. The proforma base and overtime payroll from Schedules G-4 and G-5, respectively, were then multiplied by the calculated benefit and payroll tax per payroll dollar ratios that were developed on Workpaper G-6.b to determine the annualized benefits and payroll tax. The total test year benefits and payroll tax were then subtracted from the annualized benefits and payroll tax to determine the allocable benefits and payroll tax adjustment. This amount was then multiplied by allocation factors and the payroll O&M expense ratio to determine the adjusted O&M expense amount applicable to the proposed WNSA. 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.

VIII. 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).[12] These executive officers are known as the Named Executive Officers ("NEOs") in ONE Gas' Notice of Annual Meeting and Proxy Statement. Mr. Branz also addresses how TGS meets the requirements of GURA § 104.060 to support TGS's request for incentive compensation cost recovery, provides testimony in support of the reasonableness and necessity of TGS's requested incentive compensation costs, and describes the nature of the ONE Gas incentive compensation plans and the role these plans have in ONE Gas' overall compensation philosophy.

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 (except for a portion of incentive costs included in the Winter Storm Uri Regulatory Asset, addressed below). TGS is seeking recovery of short-term incentive ("STI") and long-term incentive ("LTI") compensation costs for

[12] https://www.sec.gov/divisions/corpfin/ecfr/17cfr229.402a.pdf.

direct employees, TGS Division employees and ONE Gas employees, excluding incentive compensation related to financial metrics for NEOs.

Q. DESCRIBE THE ADJUSTMENT MADE TO STI COMPENSATION TO EXCLUDE COSTS RELATED TO FINANCIAL METRICS FOR NEOS.

A. The STI attributable to financial metrics for NEOs, including FICA, 401(k) company match, and profit-sharing amounts associated with STI, allocated to the proposed WNSA is $175,865. The Company removed the $175,865 amount consistent with GURA § 104.060. Mr. Branz discusses the STI metrics in his direct testimony.

Q. WERE ANY ADDITIONAL ADJUSTMENTS MADE TO COMPENSATION AS A RESULT OF WINTER STORM URI?

A. Yes. There were two adjustments made to compensation costs as a result of Winter Storm Uri. As explained in Mr. Branz's testimony, ONE Gas leadership determined that Winter Storm Uri was an unprecedented weather event outside the normal operating conditions measured by the STI metrics, specifically the Emergency Response Time ("ERT") metric, and excluded the ten-day period of February 13-22, 2021 from its ERT calculation. This adjustment resulted in an ERT payout of 4.69% of STI and contributed to a total STI payout of 101% for non-officer employees. Employees at the officer level (vice-president) and above did not receive an ERT payout. TGS made an adjustment to reduce the STI paid to non-officer employees on Schedule G-8 to reflect an ERT payout percent of 0%.

The next adjustment was to remove the costs for a recognition award. Mr. Branz explains that certain TGS employees who were directly involved in providing service during Winter Storm Uri received a one-time recognition award. Rather than recover that amount through base rates, TGS proposes recovery of the recognition award amount through the Winter Storm Uri regulatory asset, contained on Schedules B-11 and G-20.

Q. DESCRIBE THE ADJUSTMENT MADE TO LTI COMPENSATION FOR PERFORMANCE STOCK UNITS.

A. The total Performance Stock Unit per book amount in the test year allocated to the proposed WNSA is $720,849 of which $321,367 was attributable to financial metrics for NEOs. Removing that amount results in TGS requesting recovery of $399,482. As discussed by Mr. Branz, Performance Stock Units 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 Performance Stock Units consistent with GURA § 104.060.

Q. WAS AN ADJUSTMENT MADE TO LTI COMPENSATION FOR RESTRICTED STOCK UNITS?

A. No. As discussed in Mr. Branz's direct testimony, Restricted Stock Units are **not** based on the financial performance of ONE Gas. Therefore, no adjustment was made for LTI costs related to Restricted Stock Units.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Texas Gas Service Company, a Division of ONE Gas, Inc.
WNSA ISOS RTCS TYE December 31, 2021

STACEY BORGSTADT – LIST OF PRIOR TESTIMONY

Line	Jurisdiction	Docket	Company	Year
1	Oklahoma Corporation Commission	Cause No. PUD 200900110	Oklahoma Natural Gas	2009
2	City council of the City of Austin	Ordinance no. 2009618-074	Texas Gas Service	2009
3	City Council of the City of El Paso and the Public Utility Regulation Board		Texas Gas Service	2009
4	Railroad Commission of Texas	GUD No. 9988	Texas Gas Service	2010
5	Oklahoma Corporation Commission	Cause No. PUD 201100034	Oklahoma Natural Gas	2011
6	Oklahoma Corporation Commission	Cause No. PUD 201200029	Oklahoma Natural Gas	2012
7	Kansas Corporation Commission	Docket No. 12-KGSG-835-RTS	Kansas Gas Service	2012
8	Oklahoma Corporation Commission	Cause No. PUD 201300032	Oklahoma Natural Gas	2013
9	Railroad Commission of Texas	GUD No. 10488	Texas Gas Service	2015
10	Railroad Commission of Texas	GUD No. 10526	Texas Gas Service	2016
11	Municipalities of Rio Grande Valley		Texas Gas Service	2017
12	Railroad Commission of Texas	GUD No. 10656	Texas Gas Service	2017
13	Railroad Commission of Texas	GUD No. 10739	Texas Gas Service	2018
14	Railroad Commission of Texas	GUD No. 10766	Texas Gas Service	2018
15	Railroad Commission of Texas	GUD No. 10928	Texas Gas Service	2019

CORPORATE UIC PREMIUMS ALLOCATED TO PROPOSED WNSA
TEST YEAR ENDING DECEMBER 31, 2021

LINE NO.	POLICY TYPE	DECEMBER[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]
1	UIC Auto Liability	$ 950	$ 855	$ 760	$ 665	$ 570	$ 475	$ 380	$ 285	$ 190	$ 95	$ -	$ 2,563	$ 2,330
2	UIC Excess Liability	794,540	715,086	635,632	556,178	476,724	397,270	317,816	238,362	158,908	79,454	-	1,014,849	922,590
3	UIC Property	22,636	16,977	11,318	5,659	-	95,227	86,570	77,913	69,256	60,599	51,942	43,285	34,628
4	UIC Workers Compensation	35,590	32,031	28,472	24,913	21,354	17,795	14,236	10,677	7,118	3,559	-	73,007	66,370
5	UIC Cyber	-	-	160,413	145,830	131,247	116,664	102,081	87,498	72,915	58,332	43,749	29,166	14,583
6	**CORPORATE UIC PREMIUMS**	**$ 853,716**	**$ 764,949**	**$ 836,595**	**$ 733,245**	**$ 629,895**	**$ 627,431**	**$ 521,083**	**$ 414,735**	**$ 308,387**	**$ 202,039**	**$ 95,691**	**$ 1,162,870**	**$ 1,040,501**
7	TGS Distrigas Allocation %	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%	27.15%
8	**CORPORATE UIC PREMIUMS ALLOCATED TO TGS**	**$ 231,784**	**$ 207,684**	**$ 227,136**	**$ 199,076**	**$ 171,016**	**$ 170,348**	**$ 141,474**	**$ 112,601**	**$ 83,727**	**$ 54,854**	**$ 25,980**	**$ 315,719**	**$ 282,496**
9	WNSA Allocation %	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%
10	**CORPORATE UIC PREMIUMS ALLOCATED TO WNSA**	**$ 102,219**	**$ 91,590**	**$ 100,169**	**$ 87,794**	**$ 75,420**	**$ 75,125**	**$ 62,391**	**$ 49,658**	**$ 36,924**	**$ 24,191**	**$ 11,457**	**$ 139,235**	**$ 124,583**

Footnotes:

[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.b.1_Prepayments - ONE GAS Corp Prepayments Detail (CONFIDENTIAL)". Filter on "UIC" in the "Line Description" column to identify the UIC premiums contained in "WKP B-2.b.1_Prepayments - ONE GAS Corp Prepayments Detail (CONFIDENTIAL)".

TGS DIVISION UIC PREMIUMS ALLOCATED TO PROPOSED WNSA
TEST YEAR ENDING DECEMBER 31, 2021

LINE NO.	POLICY TYPE	DECEMBER[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]
1	UIC Auto Liability	$ 1,810	$ 1,629	$ 1,448	$ 1,267	$ 1,086	$ 905	$ 724	$ 543	$ 362	$ 181	$ -	$ 3,014	$ 2,740
2	UIC Excess Liability	2,334,617	2,101,158	1,867,696	1,634,234	1,400,772	1,167,310	933,848	700,386	466,924	233,462	-	2,857,624	2,597,840
3	UIC Property	191,404	143,553	95,702	49,737	-	585,838	532,580	479,322	426,064	372,806	319,548	266,290	213,032
4	UIC Workers Compensation	74,140	66,726	59,312	51,898	44,484	37,070	29,656	22,242	14,828	7,414	-	92,455	84,050
5	**TGS DIVISION UIC PREMIUMS**	**$ 2,601,971**	**$ 2,313,066**	**$ 2,024,158**	**$ 1,737,136**	**$ 1,446,342**	**$ 1,791,123**	**$ 1,496,808**	**$ 1,202,493**	**$ 908,178**	**$ 613,863**	**$ 319,548**	**$ 3,219,383**	**$ 2,897,662**
6	WNSA Allocation %	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%
7	**TGS DIVISION UIC PREMIUMS ALLOCATED TO WNSA**	**$ 1,147,492**	**$ 1,020,083**	**$ 892,672**	**$ 766,093**	**$ 637,850**	**$ 789,901**	**$ 660,106**	**$ 530,310**	**$ 400,515**	**$ 270,719**	**$ 140,924**	**$ 1,419,777**	**$ 1,277,895**

Footnotes:

[1] The UIC premium amounts contained in this exhibit are included in the 13 month avergage, calculated in "WKP B-2.a.1_Prepayments - TGS Division Detail (CONFIDENTIAL)". Filter on "UIC" in the "Vendor" column to identify the UIC premiums contained in "WKP B-2.a.1_Prepayments - TGS Division Detail (CONFIDENTIAL)".

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 STACEY R. BORGSTADT

BEFORE ME, the undersigned authority, on this day personally appeared Stacey R. Borgstadt who having been placed under oath by me did depose as follows:

1. "My name is Stacey R. Borgstadt. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as a Director of Rates and Regulatory Analysis for ONE Gas, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Stacey R. Borgstadt

SUBSCRIBED AND SWORN TO BEFORE ME by the said Stacey R. Borgstadt on this 16th day of June 2022.

Notary Public in and for the State of Oklahoma

KATHLEEN HILL
NOTARY
14000359
EXP. 01/13/26
PUBLIC
STATE OF OKLAHOMA

CASE NO. 00009896

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	**§ § § § § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JEFF D. BRANZ

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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LIST OF EXHIBITS

EXHIBIT JDB-1	ONE Gas, Inc. Schedule 14(a) 2022 Proxy Statement
EXHIBIT JDB-2	Willis Towers Watson 2022 General Rate Case Total Compensation Study for TGS (CONFIDENTIAL)
EXHIBIT JDB-3	Willis Towers Watson 2020 Long-Term Incentives Policies and Practices Survey Report U.S. (Excerpt) - LTI Prevalence (CONFIDENTIAL)
EXHIBIT JDB-4	ONE Gas, Inc. 2021 Annual Employee Short-Term Incentive Plan (CONFIDENTIAL)
EXHIBIT JDB-5	ONE Gas, Inc. 2021 Annual Officer Short-Term Incentive Plan (CONFIDENTIAL)
EXHIBIT JDB-6	ONE Gas, Inc. 2021 Amended and Restated Equity Compensation Plan (CONFIDENTIAL)
EXHIBIT JDB-7	ONE Gas, Inc. 2021 New Hire Welcome Presentation (Excerpt) (CONFIDENTIAL)
EXHIBIT JDB-8	ONE Gas, Inc. 2021 Open Enrollment Guide (CONFIDENTIAL)
EXHIBIT JDB-9	ONE Gas Inc. 2019 Ben Val Study (CONFIDENTIAL)

DIRECT TESTIMONY OF JEFF D. BRANZ

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeff D. Branz. 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 and Benefits. Texas Gas Service Company ("TGS" or the "Company") is a Division of ONE Gas.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Master of Arts Degree in Organizational Dynamics with an emphasis in Human Resources from the University of Oklahoma in 2006 and a Bachelor of Science Degree in Accounting from Oral Roberts University in 1988. I am a certified executive coach, and I practiced as a certified public accountant early in my career (although my license is now inactive due to my current role). I began my employment with ONE Gas in June 2016, as the Director of Compensation and Benefits. Prior to joining ONE Gas, I worked as a Director of Total Rewards at WPX Energy from January 2012 to June 2016. From April 1991 to December 2011, I served in various management roles including Director or Manager of Benefits, Benefits Accounting, Compensation, Payroll, Organizational Development, People Strategies, Human Resource Information Systems, Wellness and HR Business Partner Consulting for Williams Companies and MAPCO. From 1988 to 1991, I worked as a Senior Auditor for Deloitte and Touche.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE RAILROAD COMMISSION OF TEXAS ("COMMISSION")?

A. Yes, I filed testimony before this Commission in Gas Utilities Docket Nos. 10739, 10766, and 10928. I have also testified before the Oklahoma Corporation Commission and the Kansas Corporation Commission.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECTION?

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.

II. PURPOSE OF TESTIMONY

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 Gas Utility Regulatory Act ("GURA") § 104.060. I also discuss short-term incentives ("STI") and a recognition award paid to certain employees related to Winter Storm Uri. Company witnesses Stacey McTaggart and Stacey Borgstadt also address aspects of these issues in their direct testimonies.

III. <u>ONE GAS COMPENSATION PHILOSOPHY</u>

Q. PLEASE EXPLAIN ONE GAS' EMPLOYEE COMPENSATION PROGRAM.

A. ONE Gas' employee compensation program is designed to attract, engage, motivate and retain employees. The compensation program includes a combination of a fixed component in the form of base pay and the variable components of incentive compensation, which are comprised of STI and long-term incentives ("LTI"), if applicable. When determining or setting compensation, ONE Gas' objective is to pay its employees on average at the 50th percentile of the market for total compensation compared to peer companies. As a result, individual pay is differentiated and may be below, at or above the 50th percentile depending on an employee's level of experience, knowledge, and performance. In this way, ONE Gas aims to pay its employees at a reasonable level that is not too high or too low compared to peer companies. The compensation program is reviewed at least annually through an Annual Salary Review process to determine if changes or revisions are necessary for ONE Gas to remain competitive with the marketplace.

Q. WHY DOES ONE GAS SPLIT EMPLOYEE COMPENSATION INTO FIXED AND VARIABLE COMPONENTS?

A. ONE Gas structures its compensation plan to be consistent with market demands, and all companies that ONE Gas competes with for employee talent have both fixed and variable components of compensation. Variable compensation requires that both individual employees and ONE Gas meet certain performance criteria to realize an incentive award. Variable pay plans provide ONE Gas with opportunities to attract, retain, engage, reward, and motivate qualified workers to operate safely and efficiently in our communities. In this way, the compensation plan incentivizes employees who work safely and productively in the field, office or remotely, which benefits TGS customers, communities, employees, and ONE Gas shareholders.

Q. DO ANY STATE LAWS SPECIFICALLY ADDRESS HOW REGULATORS MUST REVIEW THE REASONABLENESS OF ONE GAS' COMPENSATION PLAN?

A. Yes. 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 rates." Section 104.060(a) defines "employee compensation and benefits" to include base salaries, wages, incentive compensation, and benefits. Section 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. IS ONE GAS' COMPENSATION APPROACH CONSISTENT WITH GURA § 104.060?

A. Yes. While I am not a lawyer, I have read and understand the statute, and ONE Gas' compensation approach is consistent. ONE Gas participates in national and industry-specific independent compensation studies to determine proper pay ranges

[1] Named Executive Officers are those employees whose compensation is required to be disclosed under 17 C.F.R. Section 229.402(a).

and LTI and STI targets for each position. These studies may be specific to the energy industry, targeted to certain business units within the energy industry or from a general industry perspective. Pay information is submitted and reviewed on at least an annual basis, allowing ONE Gas to maintain relevant and competitive pay ranges. ONE Gas relies on the studies to establish pay ranges that are competitive with its peers. Most positions are matched to multiple studies that are conducted by independent third-party human resources compensation consulting firms.

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF § 104.060 OF GURA WITH RESPECT TO TGS'S INCENTIVE COMPENSATION COST RECOVERY IN THIS FILING.

A. My understanding of the significance is that the statute's focus on the use of market studies means that all of the incentive compensation costs TGS seeks to recover in this case must be presumed to be reasonable and necessary costs. I also read the statute to mean that those costs should be recovered because TGS's compensation and benefit expense are consistent with market compensation studies issued not earlier than three years before the initiation of this proceeding to establish rates. The statute confirms ONE Gas' position that market compensation studies are an important and reasonable source for both the gas utility and regulatory authorities to rely on to determine reasonable base pay and incentive compensation amounts, as well as recovery of those costs. TGS's employee compensation and benefits expenses are consistent with these market compensation studies and must be presumed reasonable by regulators under GURA § 104.060.

Q. WHAT ARE SOME OF THE STUDIES USED TO MONITOR MARKET-BASED PAY RELATED TO ONE GAS EMPLOYEES?

A. Some of the studies used to monitor market-based pay include:

- Willis Towers Watson ("WTW") General Industry Mid-Management, Profession, and Support;
- WTW Energy Services Mid-Management, Professional and Support;
- WTW Energy Services Executive Compensation;
- WTW American Gas Association Compensation;
- CompData Utilities;
- Mercer Energy Total Compensation; and
- Mercer Benchmark.

Several of these recent studies and study excerpts are included in my testimony exhibits.

Q. DOES ONE GAS DETERMINE AND MONITOR EXECUTIVE COMPENSATION SIMILAR TO THE MANNER IN WHICH IT DETERMINES AND MONITORS OTHER EMPLOYEE COMPENSATION?

A. Yes, ONE Gas uses a market-based pay process for both executives and other non-executive employees. The Executive Compensation Committee of ONE Gas' Board of Directors and its independent executive compensation consultant, Meridian Compensation Partners, LLC, review executive market data of ONE Gas' peers. The compensation peers are selected because of their similarities to ONE Gas, including their business, size of their operations and the skills and experience required of their senior management. A list of peer companies included in the review is contained in ONE Gas' 2022 Proxy Statement on page 48, which is included as Exhibit JDB-1. As it does for all positions, ONE Gas strives to pay experienced executives at the median level of total compensation for peer companies. The WTW 2022 General Rate Case Total Compensation Study for TGS ("Compensation Study") provided as Confidential Exhibit JDB-2 on page 6 states, "[e]xecutive positions examined are, on average, within the same +/-10% competitive range of the market median as the other ONE Gas employee groups."

Q. HOW SHOULD ONE GAS' COMPENSATION PACKAGE BE VIEWED?

A. The compensation ONE Gas offers employees should be viewed as a comprehensive compensation package. On a combined basis, considering base salaries and incentive compensation, the Company is *generally at or below* comparable energy company industry levels. The Compensation Study provided in Confidential Exhibit JDB-2 illustrates that employee groups (non-exempt, professional, etc.) at ONE Gas and TGS have salaries and incentives valued below the market median. Specifically, WTW found TGS's pay competitiveness is estimated to be at the low end of the competitive market range for base salary, total cash compensation, and total direct compensation. WTW's assessment included the review of small and large utility peers as well as the general industry.

Q. DOES ANY DATA DEMONSTRATE THAT ONE GAS MUST OFFER INCENTIVE COMPENSATION OPPORTUNITIES TO ATTRACT AND RETAIN EMPLOYEES?

A. Yes. The utility industry continues to provide incentive compensation to employees. This has been a consistent form of compensation to attract, engage, reward, motivate, and retain employees for many years. The points below indicate that almost all public utilities rely upon some form of incentive compensation as part of their overall compensation structure:

- The WTW 2020 Long-Term Incentives Policies and Practices Survey Report U.S. excerpt - LTI Prevalence found that 66% of the 100 energy companies responding granted restricted LTI and 93% granted performance-based LTI (Confidential Exhibit JDB-5);
- Every company in the large and small peer group studied by WTW offers STI and LTI; and
- Both CenterPoint and Atmos, gas utilities in the state of Texas and within ONE Gas' peer group, offer 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 quality work; (4) increased turnover costs; and (5) difficulty attracting and retaining employees. It is even more important to offer competitive compensation packages with today's tight labor market to help ensure a stable workforce to deliver safe and reliable services to our customers. Without some form of incentive compensation, highly motivated and high-performing employees will seek employment opportunities where employees with their skill sets are provided an opportunity to earn compensation beyond base pay. A comprehensive compensation package, including incentive compensation, helps to create an engaged, skilled, safe and high performing workforce.

Q. WHAT CONSEQUENCES WOULD RESULT IF ONE GAS WERE TO ELIMINATE INCENTIVE COMPENSATION AND INCREASE BASE PAY ACCORDINGLY?

A. Compensating employees based solely on base pay would place ONE Gas and TGS at a competitive disadvantage. The Company's ability to attract, engage, motivate, and retain highly skilled employees has a very real and direct effect on the quality of the service provided 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 local firms and businesses that offer incentive compensation. Providing employees the opportunity to earn incentive compensation in addition to their base pay is an integral component of ONE Gas' ability to attract, engage, motivate and retain talented employees.

Q. ARE TGS'S REQUESTED INCENTIVE COMPENSATION COSTS REASONABLE AND NECESSARY?

A. Yes, they are. The incentive costs TGS seeks to recover, and which are presumed reasonable and necessary under the law, include STI and LTI for TGS Direct and Division employees as well as ONE Gas employees who perform activities that are necessary for TGS to provide service to customers in the proposed West North Service Area. 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 customer service representatives, field personnel who ensure the safety of customer premises, and employees whose work is critical to TGS's ability to meet required safety and regulatory requirements. All non-bargaining unit employees are eligible to earn incentive compensation through their performance.

Q. ARE THERE ANY UNIQUE ASPECTS OF ONE GAS THAT SUPPORT THE REASONABLENESS AND NECESSITY OF THE INCENTIVE COMPENSATION COSTS TGS IS REQUESTING IN THIS CASE?

A. Yes, as I stated previously, ONE Gas is a fully regulated entity and operates only regulated local distribution companies, including TGS. Due to ONE Gas' fully regulated nature, all of the work performed by ONE Gas and TGS employees is focused on serving customer interests and operating a safe and reliable system. Because efforts from all employees are directed towards meeting customer needs, the compensation costs TGS incurs are reasonable and necessary for the provision of service.

IV. <u>COMPENSATION COMPONENTS</u>

Q. WHAT ARE THE COMPENSATION COMPONENTS?

A. Compensation is comprised of several components, including base pay and incentive programs commonly known as STI and LTI. STI and LTI are commonly referred to as at-risk pay. STI is awarded to all employees based on first meeting specific company metrics and then meeting individual performance standards. STI provides meaningful incentives for employees to operate with an emphasis on safety and customer service along with ONE Gas' financial performance. LTI is only awarded to a select group of employees. ONE Gas also offers benefits such as health and welfare, well-being, and retirement plans, which are considered part of the overall employee total rewards package.

Q. PLEASE EXPLAIN BASE PAY.

A. Base pay is designed to compensate employees based on the skills and competencies required for their position, proficiency level, experience, consistent performance level, and the overall value the employee brings to the position. Other components considered when determining base pay include workforce availability in the marketplace, employer needs, location, cost of labor, and economic conditions. Base pay is reviewed at least annually for all employees resulting in pay increases, if applicable, by December to remain competitive with the marketplace. This process is known as the Annual Salary Review.

Q. WHAT INCENTIVE COMPENSATION PROGRAMS DOES ONE GAS OFFER TO ITS EMPLOYEES?

A. ONE Gas has two incentive compensation programs: (1) the Annual Employee Incentive Plan, which is known as STI, 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.

V. SHORT TERM INCENTIVE PLAN

Q. PLEASE EXPLAIN ONE GAS' STI PLAN.

A. The Annual Employee Incentive Plan provides an annual, lump-sum cash amount based on specific employee and ONE Gas performance criteria, established each year by the Executive Compensation Committee of the ONE Gas Board of Directors. 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. Typically, 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, unless other factors justify an adjustment to the award. Lastly, an individual's STI award may increase or decrease based on their individual work performance.

STI provides employees with an incentive to achieve high quality and safe delivery of service to our customers, which also affects ONE Gas' performance. 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 JDB-2, page 7, identifies that every company in the large and small utility peer groups has a short-term at-risk compensation program. The details of ONE Gas' STI Plan are set forth in Confidential Exhibits JDB-4 and JDB-5.

Q. WHAT PERFORMANCE METRICS ARE INCLUDED IN THE STI PLAN?

A. ONE Gas performance metrics included in the STI Plan are total recordable incident rate ("TRIR"), preventable vehicle incident rate ("PVIR"), days away, restricted or transferred ("DART"), emergency response time ("ERT"), and diluted earnings per share ("EPS"). Typically, an STI award is made if at least threshold levels for these metrics are attained. However, the STI Plan does provide for discretion in the amount of the STI award payment as shown in Confidential Exhibit JDB-4 on page 4. Employee performance also affects individual STI awards up or down.

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 JDB-2, page 10, reflects that all peer companies offer employees the opportunity to earn STI incentives above the 100% target threshold. For this reason, offering employees payouts that range from 0% to 150% helps ONE Gas maintain compensation that is competitive with the median of the market. In fact, up to 55% of the peer companies ONE Gas competes with for employees offer a maximum incentive payout at the 200% level.

Q. WHAT CONSEQUENCES COULD RESULT IF THE ONE GAS STI PLAN DID NOT INCLUDE OPPORTUNITIES FOR EMPLOYEES TO BE AWARDED AT A LEVEL GREATER THAN THE 100% TARGET?

A. If ONE Gas did not offer the opportunity for STI awards to exceed the 100% target, it would risk losing a motivational element in the plan design. By structuring a STI plan that offers additional compensation for exceeding performance targets, ONE Gas is able to reward employees when their own efforts help ONE Gas exceed the target for the safety, operational, and financial goals in the plan. Likewise, if 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 set 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. For example, related to the chart below, a customer service center representative's performance would be assessed based on various factors that impact how effectively and efficiently information is professionally delivered to customers.

Each employee's performance is a key factor in calculating their STI compensation. Individual performance is ranked at five levels: (a) does not meet expectations; (b) needs improvement; (c) meets expectations; (d) exceeds expectations; or (e) far exceeds expectations. If an employee does not meet expectations or needs improvement, their incentive compensation will be limited or eliminated altogether. Conversely, there may be some employees who receive a larger incentive if they exceed performance expectations. This is reasonable as employees should be rewarded for the ways in which their actions exceed performance expectations related to the overall safety, operational efficiency, and quality of service delivered to our customers, as well as the financial health of ONE Gas. Rewarding employees for actions that contribute to a safe environment while providing quality and efficient service to our customers and the Company, promotes positive behavior, a strong customer experience, and is reasonable to recover in rates.

Q. CAN YOU PROVIDE PAYOUT EXAMPLES FOR EMPLOYEES IN THE STI PLAN?

A. Below are actual examples of employee STI payouts for a Field Technician and a Customer Service Representative II, which are employees who regularly interact with and serve customers. The Field Technician in the example below had $46,259 in base wages and a 4% incentive target. The Customer Service Representative II had $31,200 in base wages and a 4% incentive target. ONE Gas performance resulted in a company modifier of 101%. Both employees earned an individual performance modifier of 95%. The individual modifiers are based on the employee's performance throughout the year. The calculations are as follows:

Field Technician - Pipeline/Field Support								
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$46,259	x	4%	x	95%	x	101%	=	**$1,775**
Customer Service Rep II - Information Center								
Base Wages Earned	**x**	**STI Incentive Target**	**x**	**Individual Modifier**	**x**	**Company Modifier**	**=**	**STI**
$31,200	x	4%	x	95%	x	101%	=	**$1,197**

As the examples demonstrate, the Field Technician and the Customer Service Representative II must meet individual performance metrics and ONE Gas must (through the company modifier) have 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 GOALS 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 and reliable service; (b) practice safe driving and operating behaviors; and (c) be good stewards of expenses by encouraging decisions that help manage the Company's costs.

The combination of these criteria is key to safely providing reliable service to our customers at reasonable rates, as well as providing a balanced approach for attracting, engaging, motivating, and retaining a high-performing employee workforce appropriate for the needs and requirements of ONE Gas, TGS, and its customers. In this way, the metrics in the STI plan encourage employee actions and performance that come together to provide benefits to customers, employees and shareholders rather than creating a situation in which certain types of metrics benefit only one stakeholder group. In fact, utilizing safety metrics in the STI plan has moved ONE Gas into first quartile performance thus benefiting ONE Gas, TGS, and its customers, as discussed in the testimony of Company witness Shantel Norman.

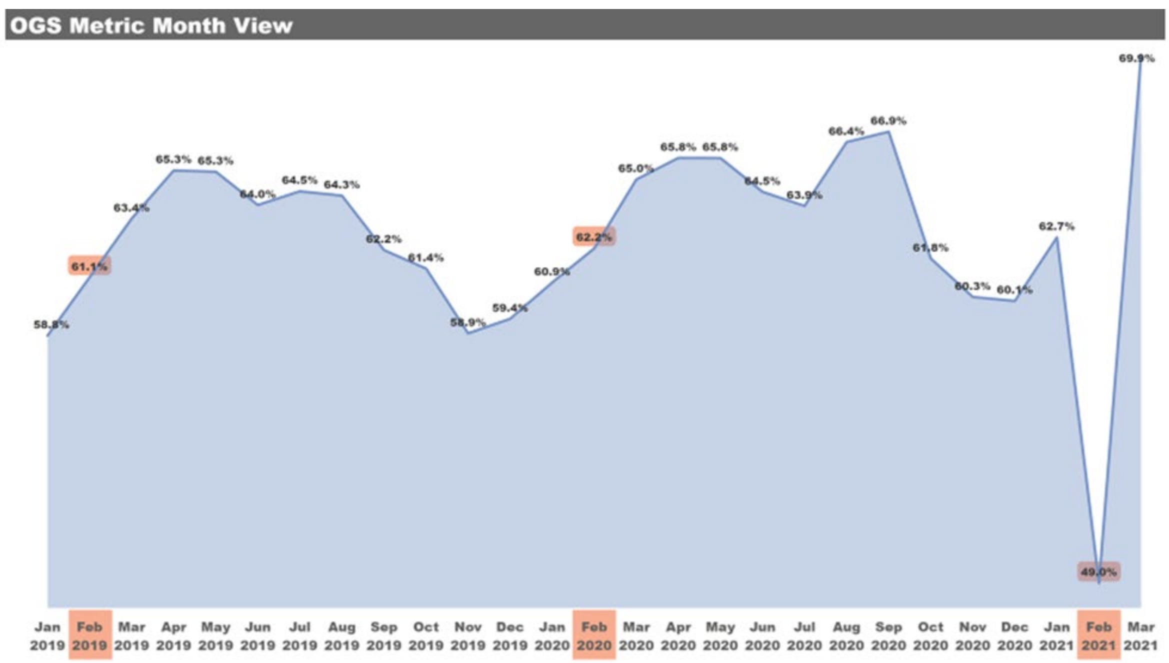
Q. DID ONE GAS EVALUATE ANY FACTORS RELATED TO THE STI METRICS AND 2021 AWARD?

A. Yes. ONE Gas evaluated the ERT metric performance and Winter Storm Uri, specifically the ERT performance data from February 13-22, 2021. As Ms. Norman testifies, Winter Storm Uri was an unprecedented event that impacted all of the areas TGS serves and significantly disrupted normal operations. The ERT metric is a measure of the percentage of emergency orders that are safely responded to within 30 minutes after being notified of an emergency. ONE Gas completed 5,983 emergency orders during February 13-22, 2021. Comparatively, for the same time period in 2020, ONE Gas completed 2,406 emergency orders. The ERT metric performance for the emergency orders responded to in less than 30 minutes during the ten-day period in 2021 I mention above was 38.4%, compared to 62.5% in the same ten-day period in 2020. As Ms. Norman testifies, ONE Gas' and TGS's priority during Winter Storm Uri was maintaining service to human needs customers and providing safe and reliable service during unprecedented weather conditions. ONE Gas leadership determined that Winter Storm Uri was a significant statewide disaster that was not consistent with normal operating conditions and was a factor to consider when measuring employee performance under the ERT metric. Accordingly, ONE Gas calculated the overall ERT metric percentage without the February 13-22, 2021 time period for all employees other than vice-president level and above.

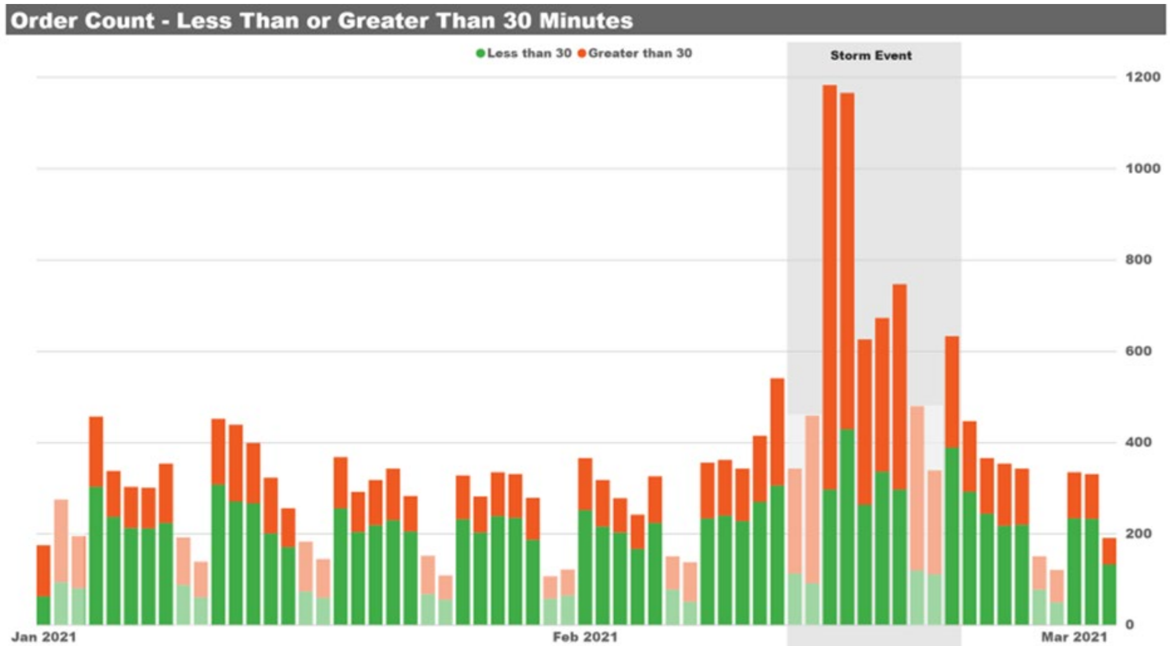
Q. CAN YOU ILLUSTRATE THE IMPACT OF THE STORM ON THE ERT METRIC?

A. Yes. The graphs below show how the ten-day severe weather event affected monthly and daily performance of the metric. Graph 1 shows the ONE Gas monthly ERT metrics from January 2019-March 2021 where a fairly consistent trend line is present until February 2021. Graph 2 tracks the order count and the emergency calls responded to in less than or greater than 30 minutes where the number of emergency calls significantly increased and affected the response time.

Graph 1



Graph 2



Q. WHAT WERE THE PERCENTAGES FOR ERT AND TOTAL STI AWARD IN 2021?

A. For non-officers, by excluding the ten-day period, the ERT metric percentage met the threshold target of 64%. As a result, the total 2021 STI award payout was 101% for non-officers. For the officer level, the ten-day period was included within the ERT metric and the total STI award percentage was 96.3%. Ms. Borgstadt's testimony addresses the test year STI calculations requested for recovery in this rate case, and Ms. McTaggart supports the requested recovery of Winter Storm Uri-related compensation costs through a regulatory asset.

VI. RECOGNITION AWARD

Q. PLEASE EXPLAIN THE ONE-TIME RECOGNITION AWARD INCLUDED IN THIS RATE CASE.

A. Recognition awards are a form of compensation designed to provide recognition to individual employees who perform one-time or short-term quality acts or service in an exceptional manner and above day-to-day responsibilities. The awards are typically low-value amounts and recognize a commitment to high performance on special tasks or situations. ONE Gas leadership approved a one-time recognition award for certain employees who directly impacted ONE Gas' ability to maintain service to customers during Winter Storm Uri. ONE Gas lost service to fewer than 900 of its 2.2 million customers during Winter Storm Uri and maintained service to 99.9% of TGS customers. The few outages that did occur lasted less than 24 hours in most cases. The employees who received the award often worked directly in the harsh winter conditions to maintain gas service to customers. For example, to ensure that critical regulator stations did not freeze, field operations employees stayed near the regulator stations in their vehicles to allow for constant monitoring of pressure levels.

Q. WHICH COMPANY EMPLOYEES WERE ELIGIBLE TO RECEIVE THE RECOGNITION AWARD?

A. Only employees involved in responding to Winter Storm Uri were eligible to receive the award. Thus, any employees that were on vacation or otherwise unable to work during Winter Storm Uri did not receive the award. Moreover, the recognition award only applied to the supervisor level and below.

Q. WHAT WAS THE AMOUNT OF THE RECOGNITION AWARD?

A. The recognition award to each employee was $2,000 or less. The portion of the company-wide award included for recovery in this case is approximately $208,000. As discussed by Ms. Borgstadt and Ms. McTaggart, TGS is proposing to include this amount in the Winter Storm Uri regulatory asset to be amortized over six years.

Q. IS IT REASONABLE TO RECOVER THESE COSTS IN THIS RATE CASE?

A. Yes. The recognition award is directly related to compensating employees for their significant efforts to maintain and provide gas service to customers during the storm. It is reasonable to recognize, in addition to our other forms of compensation, the extraordinary efforts of employees who directly impacted the Company's ability to provide safe and reliable service to our customers during Winter Storm Uri.

VII. <u>LONG TERM INCENTIVE PLAN</u>

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. 133 non-officers received an LTI grant in February 2021. The payout that vested in February 2021, included 81 non-officers. ONE Gas' LTI plan is included as Confidential Exhibit JDB-6 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 2021, ONE Gas granted two forms of LTI compensation: Restricted Stock Units and Performance Stock Units. A higher ratio of Performance Stock Units to Restricted Stock Units is granted to participants with more direct ability to impact the overall performance of ONE Gas. The grant values were based on position and base salary utilizing compensation survey data. In addition to position and base salary, employee high performance, employee high potential, long-term value to ONE Gas, criticality of the job or a unique skill set and our desire to retain quality employees are considered in determining employee eligibility. LTI awards cliff vest three years after the grant to encourage long-term improvements, safe operations, and financial awareness in key employees and to provide an incentive to remain employed with ONE Gas.

The Long-Term Incentives Policies and Practices Survey Report U.S. provided in Confidential Exhibit JDB-3, at pages 1-3, identifies that Performance plans are the most prevalent form of LTI, followed by Restricted Stock Units for the Energy Services sector. For that reason, these costs are presumed reasonable and necessary under GURA § 104.060.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN RESTRICTED STOCK UNITS AND PERFORMANCE STOCK UNITS.

A. Restricted Stock Units are granted for a term of three years from the date of the grant, with the participant being vested and entitled to receive one share of ONE Gas common stock for each restricted stock unit granted after three years of employment following the grant date. Restricted Stock Units are time-based equity and are <u>not</u> based on the financial performance of ONE Gas; rather, it is a form of compensation that depends entirely on an employee's tenure with ONE Gas. Restricted Stock Units are designed to encourage the retention of key employees, reducing turnover costs and retaining experienced employees who contribute to the overall success and stability of the organization.

Performance Stock Units also cliff vest three years from the date of the grant, at which time the employee is entitled to receive a percentage of the Performance Stock Units granted in shares of ONE Gas common stock. The number of shares of common stock awarded will range from 0% to 200% of the number of units granted based upon ONE Gas' performance as measured by its three-year total shareholder return ("TSR") compared with a designated peer group of utility peer companies established each year by the ONE Gas Board of Directors' Executive Compensation Committee over the same three-year measurement period. If the ONE Gas TSR equals the 50th percentile of the TSR earned by the peer companies over the measurement period, participants will receive 100% of the Performance Stock Units granted. A performance scale calibrates the potential number of performance stock units earned, with a 25th percentile TSR performance compared to the peer group equating to an award of 50% of the Performance Stock Units granted and a 90th percentile performance compared to the peer group equating to a payment of 200% of the Performance Stock Units granted. If the ONE Gas TSR falls below the 25th percentile TSR of the peer group, participants will not receive an award for any of the Performance Stock Units granted at the start of the measurement period. This measurement is commonly referred to as relative TSR. As I explain below, relative TSR is a common measure of long-term performance associated with utility performance plans such as the ONE Gas Performance Stock Units.

Q. WHAT IS THE PURPOSE OF OFFERING 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, engage, and motivate key employees, including executives, and encourage them to make operational decisions that create value for customers, employees, and other stakeholders. Generally, participants who receive LTI are those employees who are in a position to significantly contribute to the operational and financial stability of ONE Gas.

Q. IS IT APPROPRIATE FOR PERFORMANCE STOCK UNITS TO BE LINKED TO FINANCIAL GOALS?

A. Yes, linking the award of ONE Gas Performance Stock Units to financial goals is a consistent standard across the marketplace. The most common financial metric used to evaluate company performance in an LTI plan is TSR, with 67.7% of energy companies using that metric according to the WTW 2020 Long-Term Incentives Policies and Practices Survey Report U.S. excerpt - LTI Prevalence provided in Confidential Exhibit JDB-3. 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 shareholder's 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, motivate, and retain quality executives and key employees. This encourages employees to continuously improve performance, which directly benefits customers through a focus on safe, reliable and efficient service at reasonable rates. Retaining key employees also improves system and operations knowledge and reduces the need (and cost) to recruit, hire and train employees to replace employees who might leave ONE Gas or TGS if we did not compensate them competitively in the market.

VIII. 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). See Confidential Exhibit JDB-7 and Confidential Exhibit JDB-8 for information related to ONE Gas benefits. These benefit programs are offered to employees, who may elect to participate in certain benefits at varying levels.

Q. HAS ONE GAS TAKEN ANY MEASURES TO HELP MANAGE ITS HEALTH BENEFIT COSTS?

A. Yes. ONE Gas' goal is to provide benefits that are competitive in the marketplace and allow ONE Gas to attract, retain, engage, and motivate, a quality workforce. ONE Gas compares the benefits it offers employees with that of peer companies to ensure market competitiveness and the ability to attract, engage, motivate, and retain employees. Having a quality workforce is key to providing safe, reliable and efficient service to the Company's customers. ONE Gas contracts with market standard health care vendors to provide reliable service to our employees and their dependents while helping ONE Gas to control health care costs. ONE Gas has a process for auditing vendor administration fees and participant eligibility to ensure efficient administration and has performance guarantees in place to help ensure high quality vendor management. ONE Gas continues to partner with a pharmacy benefit manager to help control pharmacy cost. The Company expanded the virtual visit option for medical and mental health visits which in turn reduced cost to the plan while allowing safe and reliable health care to our participants. ONE Gas has regular governance meetings with healthcare vendors and provides assistance to employees to identify quality providers, review medical bills, and provide second opinions.

In addition, employees' dependents over age 18 are required to identify whether they use tobacco products. Those who do pay a premium surcharge. ONE Gas also offers a tobacco cessation program for employees and dependents over age 18 who wish to stop smoking or using tobacco products. The tobacco surcharge, in turn reduces ONE Gas health claim costs. ONE Gas contracts with health carriers to provide several programs to ensure early detection of potential health concerns to produce quality outcomes and help manage health care trends.

Q. WHY IS IT IMPORTANT THAT ONE GAS' BENEFIT PROGRAMS ARE COMPARABLE WITH ITS INDUSTRY PEERS?

A. ONE Gas provides competitive benefits because it competes with other utilities and local companies and businesses for talented employees to meet its goal of providing safe, reliable service to customers at a reasonable cost. Additionally, most of our employees have transferable skills, meaning they can go work in the broader energy industry or a completely unrelated industry. We compete with the broader marketplace to attract, engage, motivate, and retain employees that will support our business of providing natural gas to our customers safely and reliably. Part of that attraction, engagement, motivation, and retention is that ONE Gas' pay and benefits must be competitive in the industry and local market.

Q. IN YOUR OPINION, DOES GURA § 104.060 SUPPORT THE COMPANY'S REQUEST TO RECOVER BENEFIT COSTS?

A. Yes. In addition to referring to base pay and wage issues, the statute also mentions 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 JDB-9 for an independent study showing the value of ONE Gas' benefits is comparable to peer companies and slightly above the median value.

IX. <u>CONCLUSION</u>

Q. ARE COMPENSATION PLAN COSTS INCURRED BY ONE GAS REASONABLE?

A. Yes. The Company targets the median (50th percentile) of the local market and peer groups in the locations in which it operates to set pay and benefits. By reducing or eliminating any element of our total direct compensation, we would not be competitive in the market. Competitive pay and benefit plans are a necessary cost of doing business in order to attract, motivate, and retain qualified employees, which benefits the customer and communities by ensuring the delivery of safe, reliable, and efficient service.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 14A

Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934

Filed by the Registrant ☒ Filed by a Party other than the Registrant ☐

Check the appropriate box:

☐ Preliminary Proxy Statement

☐ **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**

☒ Definitive Proxy Statement

☐ Definitive Additional Materials

☐ Soliciting Material under § 240.14a-12

ONE Gas, Inc.
(Name of Registrant as Specified In Its Charter)

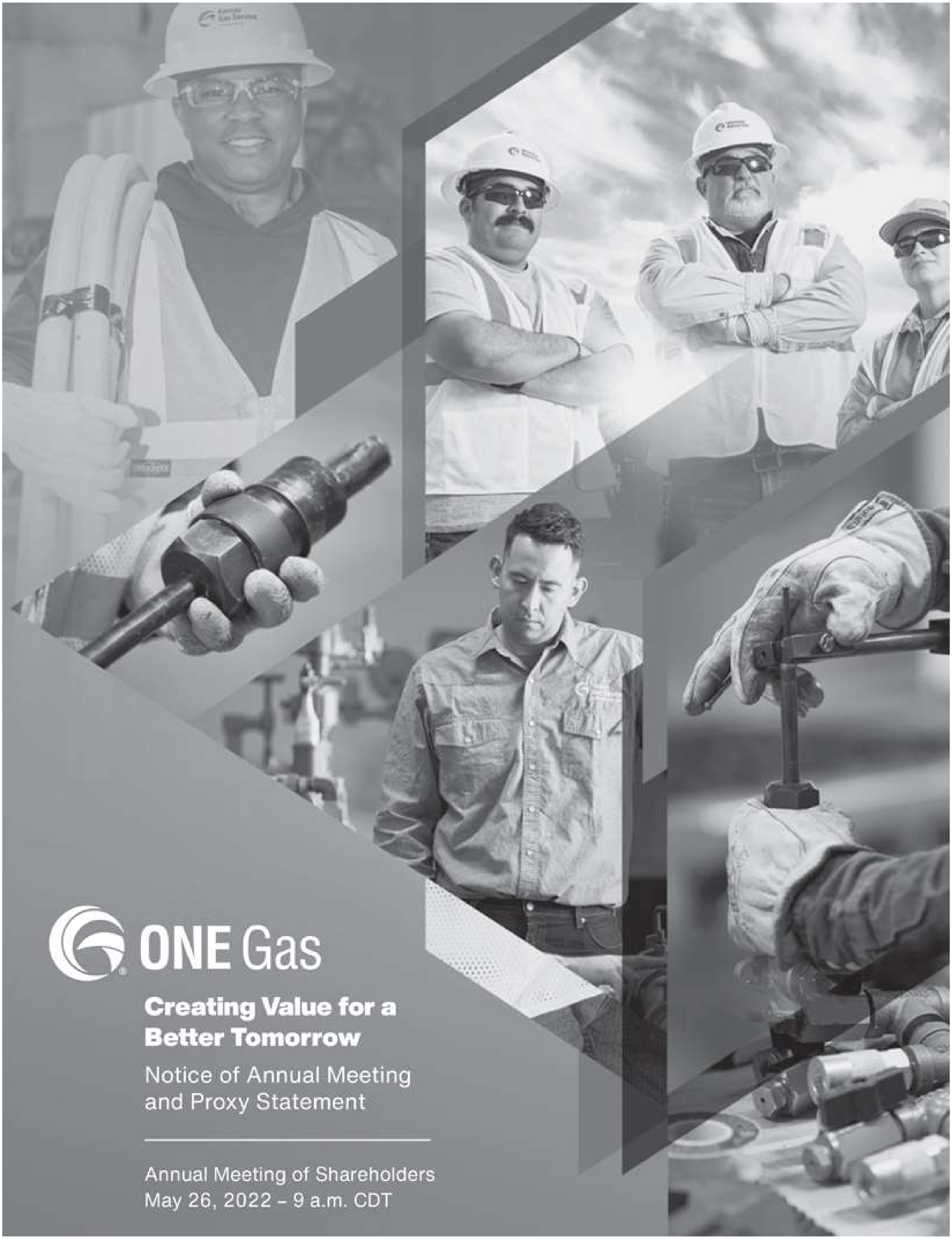
NOT APPLICABLE
(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check all boxes that apply):

☒ No fee required

☐ Fee paid previously with preliminary materials

☐ Fee computed on table in exhibit required by Item 25(b) per Exchange Act Rules 14a-6(i)(1) and 0-11.


ONE Gas
Creating Value for a Better Tomorrow
Notice of Annual Meeting and Proxy Statement
Annual Meeting of Shareholders
May 26, 2022 – 9 a.m. CDT

ONE Gas

Mission, Vision, Strategy and Core Values

Mission – Why we exist
We deliver natural gas for a better tomorrow

Vision – What we want to be
To be a premier natural gas distribution company creating exceptional value for our stakeholders

Strategy – How we get there
- Safe & reliable energy
- High-performing workforce
- Capital demand growth
- Energy transition solutions
- Customer affordability

Core Values – Our Compass

SAFETY
We are committed to operating safely and in an environmentally responsible manner.

ETHICS
We are accountable to the highest ethical standards and are committed to compliance.

INCLUSION & DIVERSITY
We embrace an inclusive and diverse culture that encourages collaboration. Every employee makes a difference and contributes to our success.

SERVICE
We provide exceptional service and make continuous improvements in our pursuit of excellence.

VALUE
We create value for all stakeholders, including our customers, employees, investors and communities.

April 6, 2022

Dear Shareholder:

You are cordially invited to attend the 2022 Annual Meeting of Shareholders of ONE Gas, Inc. on Thursday, May 26, 2022, at 9:00 a.m. (Central Daylight Time) to be held in a virtual-only meeting format with no physical location. We adopted a virtual-only meeting format to leverage technology and provide a safe and convenient experience to all shareholders regardless of location. Information on how to virtually attend and participate in the annual meeting is provided under "About the 2022 Annual Meeting" in the accompanying proxy statement. You will not be able to attend the 2022 Annual Meeting in person.

The matters to be considered and voted on at the meeting are set forth in the accompanying Notice of Annual Meeting of Shareholders and are described in the accompanying proxy statement. A copy of our 2021 annual report to shareholders is also enclosed. A report on our 2021 performance will be presented at the meeting.

Whether or not you attend the virtual Annual Meeting, it is important that your shares be represented and voted at the meeting. Therefore, proxies are being solicited so that each shareholder has an opportunity to vote by proxy. You can authorize a proxy over the internet or by telephone. Instructions for using these convenient services are included in the proxy statement and the proxy card. Of course, if you prefer, you may vote by mail by signing, dating and returning the enclosed proxy card in the enclosed postage-paid envelope.

If your shares are held by a broker, bank or other holder of record, unless you provide your broker, bank or other holder of record with your instructions on how to vote your shares, your shares will not be voted in the election of directors or in certain other important proposals as described in the accompanying proxy statement. Consequently, please provide your voting instructions to your broker, bank or other holder of record in a timely manner in order to ensure that your shares will be voted. As always, we encourage you to vote your shares prior to the annual meeting.

Regardless of the number of shares you own, your vote is important. I urge you to submit your proxy as soon as possible so that you can be sure your shares will be voted.

Thank you for your investment in ONE Gas and your continued support.

Sincerely,

John W. Gibson.

JOHN W. GIBSON
Chairman of the Board

ONE Gas

ONE GAS, INC. NOTICE OF 2022 ANNUAL MEETING OF SHAREHOLDERS

Date and time: May 26, 2022, at 9:00 a.m. Central Daylight Time

Place (online): To register and participate in the live online Annual Meeting, please visit www.proxydocs.com/ogs. Please note you will need the control number included in your proxy card, voter instruction form or Notice of Internet Availability to register for and to access the Annual Meeting. Registration to participate is due by Wednesday, May 25, 2022, at 3:00 p.m. Central Daylight Time.

Items of business:

(1) To consider and vote on the election of eight director nominees named in the accompanying proxy statement to serve on our Board of Directors;

(2) To consider and vote on the ratification of the selection of PricewaterhouseCoopers LLP as the independent registered public accounting firm of ONE Gas, Inc. for the year ending December 31, 2022;

(3) To consider and vote on our executive compensation on a non-binding, advisory basis; and

(4) To consider and vote on such other business as may come properly before the meeting or any adjournment or postponement of the meeting.

These matters are described more fully in the accompanying proxy statement.

Record date: March 28, 2022. Only shareholders of record at the close of business on the record date are entitled to receive notice of, and to vote at, the annual meeting.

Proxy voting:

YOUR VOTE IS IMPORTANT

Please vote your shares at your earliest convenience. Registered holders may vote (a) by internet prior to the Annual Meeting at www.proxydocs.com/ogs; (b) by internet during the Annual Meeting at www.proxydocs.com/ogs; (c) by toll-free telephone by calling 866-883-3382; or (d) by mail by completing your proxy card and returning it in the enclosed postage-paid envelope. If you hold your shares through an account with a brokerage firm, or in the name of a bank, trustee or other holder of record, please follow the instructions you receive from them to vote your shares. You may revoke your proxy at any time by following the procedures set forth in the accompanying proxy statement.

Voting your shares promptly, via the internet, by telephone, or by signing, dating and returning the enclosed proxy card will ensure the presence of a quorum at the meeting and will save the expense of additional solicitation. Submitting your proxy now will not prevent you from voting your shares at the meeting, if you desire to do so, as your proxy is revocable at your option.

Important Notice Regarding Internet Availability of Proxy Materials for the Shareholder Meeting to be held on May 26, 2022. This notice of Annual Meeting, proxy statement, form of proxy and our 2021 annual report to shareholders are being distributed and made available on or about April 6, 2022. This proxy statement and our 2021 annual report to shareholders are also available on our website at www.ONEGas.com.

Additionally, you may access this proxy statement and our 2021 annual report at www.proxydocs.com/ogs.

By order of the Board,

Brian K. Shore

Brian K. Shore
Corporate Secretary

Tulsa, Oklahoma
April 6, 2022

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This proxy statement describes important issues affecting our company and is furnished in connection with the solicitation of proxies by our Board for use at our 2022 Annual Meeting of Shareholders to be held at the time and place set forth in the accompanying notice.

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GLOSSARY OF TERMS

The abbreviations, acronyms and terms used in this Proxy Statement are defined as follows:

401(k) Plan	ONE Gas, Inc. 401(k) Plan
Board	ONE Gas, Inc. Board of Directors
CCO	Chief Commercial Officer
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIC	Change in control
COO	Chief Operating Officer
DART	Days Away, Restricted or Transferred Incident Rate calculated by multiplying the total number of recordable injuries and illnesses, or one or more restricted days that resulted in an employee transferring to a different job within the company by 200,000, and then dividing that number by the total number of hours worked by all employees
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
ECP	The ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018), as approved by our shareholders on May 24, 2018
EPA	Environmental Protection Agency
EPS	Diluted earnings per share
ERT	Emergency Response Time calculated as the time between the creation of an emergency order and the arrival of a first company responder to the scene expressed as the percentage of emergency orders with a response time of 30 minutes or less
ESG	Environmental, Social and Governance
ESP Plan	ONE Gas, Inc. Employee Stock Purchase Plan
Exchange Act	Securities Exchange Act of 1934, as amended
LTI	Long-term equity incentive
Meridian	Meridian Compensation Partners, LLC, the independent consultant to the Executive Compensation Committee
NEO	Named executive officer
NQDC Plan	ONE Gas, Inc. Nonqualified Deferred Compensation Plan
NYSE	New York Stock Exchange
ONE Gas, the company, we, our or us	ONE Gas, Inc.
ONE Gas PAC	ONE Gas, Inc. Political Action Committee
ONEOK	ONEOK, Inc. and its subsidiaries
ONEOK Plan	ONEOK, Inc. 401(k) Plan
OSHA	Occupational Safety and Health Administration
Profit Sharing Plan	ONE Gas, Inc. Profit Sharing Plan
PSU	Performance stock unit
PVIR	Preventable Vehicle Incident Rate calculated by multiplying the number of total vehicle incidents by 1,000,000, and then dividing that number by the total number of business use miles driven

Qualified Pension Plan	ONE Gas, Inc. Retirement Plan
RSU	Restricted stock unit
SEC	United States Securities and Exchange Commission
SERP	Supplemental Executive Retirement Plan
STI	Annual short-term cash incentive
TRIR	Total Recordable Incident Rate calculated by multiplying the number of recordable cases by 200,000, and then dividing that number by the number of hours worked by all employees
TSR	Total shareholder return

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

Any statements in this proxy statement that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements made under the provision of the “Safe Harbor” section of the Private Securities Litigation Reform Act of 1995. Forward-looking statements may include words such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecast,” “goal,” “guidance,” “intend,” “may,” “might,” “outlook,” “plan,” “potential,” “project,” “scheduled,” “should,” “will,” “would” and other words and terms of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations and “Forward-Looking Statements,” in our 2021 Annual Report on Form 10-K and other filings with the SEC. All forward-looking statements included in this document are based on information available to us on the date hereof. We will not undertake and specifically decline any obligation to update any forward-looking statements, except as required under applicable law.

SUMMARY PROXY INFORMATION

To assist you in reviewing the company's 2021 performance and voting your shares, we would like to call your attention to key elements of our 2022 proxy statement and our 2021 annual report to shareholders. The following is only a summary. Please review the full proxy statement and our 2021 annual report to shareholders for complete information about these topics.

PROXY STATEMENT SUMMARY

The following summary provides highlights contained in this proxy statement. You should carefully read and consider the information contained in the proxy statement as this summary does not contain all the information you should consider before voting.

INFORMATION ABOUT THE ANNUAL MEETING OF SHAREHOLDERS

- **Date:** Thursday, May 26, 2022
- **Time:** 9:00 a.m., Central Daylight Time
- **Meeting Registration Link:** **www.proxydocs.com/ogs**. Virtual Meeting Only – No Physical Location. You must register by May 25, 2022, at 3:00 p.m. Central Daylight Time to attend

ITEMS OF BUSINESS

- Election of eight director nominees to serve a one-year term
- Ratification of the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2022
- Approval, on a non-binding, advisory basis, of our executive compensation
- Other business as may come properly before the meeting, or any adjournment or postponement of the meeting

RECORD DATE

- March 28, 2022

INTERNET ACCESS TO PROXY MATERIALS

- Please visit **www.proxydocs.com/ogs** for online access to our proxy materials including this proxy statement and the company's 2021 annual report.

HOW TO VOTE

The vote of every shareholder is important. The Board appreciates the cooperation of shareholders in directing proxies to vote at the meeting. To make it easier for you to vote, internet and telephone voting are available. Of course, if you prefer, you may vote by mail by completing your proxy card and returning it in the enclosed postage-paid envelope.

HOW TO VOTE IF YOUR SHARES ARE HELD BY A BROKER, BANK OR OTHER HOLDER OF RECORD

- This proxy statement and our 2021 annual report to shareholders should have been forwarded to you by your bank, broker or other holder of record, together with a voting instruction card. You have the right to direct your bank, broker or other holder of record how to vote your shares by using the voting instruction card you received from your bank, broker or other holder of record, or by following any instructions provided by your bank, broker or other holder of record for voting via the internet or telephone.

SHAREHOLDER ACTIONS – MATTERS TO BE VOTED UPON

- **Election of Directors (Proposal 1).** You will find in this proxy statement important information about the qualifications and experience of each of the eight director nominees, each of whom is a current director. The Corporate Governance Committee performs an annual assessment of the performance of the Board to ensure that our directors have the skills and experience to effectively oversee our company. All of our directors have proven leadership, sound judgment, integrity and a commitment to the success of our company, and our Board recommends that shareholders **vote in favor** of each nominee for election.
- **Ratification of our Independent Registered Public Accounting Firm (Proposal 2).** You will also find in this proxy statement important information about our independent registered public accounting firm, PricewaterhouseCoopers LLP. We believe PricewaterhouseCoopers LLP continues to provide high-quality service to our company, and our Board recommends that shareholders **vote in favor** of ratification.
- **Advisory Vote on Executive Compensation (Proposal 3).** Our shareholders have the opportunity to cast a non-binding, advisory vote on our executive compensation program. In evaluating this “say-on-pay” proposal, we recommend that you review our Compensation Discussion and Analysis in this proxy statement, which explains how and why the Executive Compensation Committee arrived at decisions with respect to our 2021 executive compensation. Our Board recommends that shareholders **vote in favor** of our executive compensation program.

PROPOSALS, BOARD RECOMMENDATIONS, VOTES REQUIRED AND EFFECT OF ABSTENTIONS AND BROKER NON-VOTES

Each of the proposals, how the Board recommends that you vote, how you may vote, and votes required for each proposal, together with how abstentions and broker non-votes will be treated for each proposal, are set forth in the following table:

	Proposal	How does the Board recommend that I vote?	Votes required to adopt proposal	Broker discretionary voting allowed	Effect of abstentions	Effect of broker non-votes
ONE	**Election of Directors**	**For**	Majority of the votes cast by shareholders present online or by proxy at the Annual Meeting (i.e., more shares voted “FOR” election than “AGAINST” election)	**No**	No Effect	No Effect
TWO	**Ratification of our Independent auditor**	**For**	The vote of the holders of a majority of the stock having voting power present online or represented by proxy at the Annual Meeting	**Yes**	Same effect as a vote against	Not applicable
THREE	**Advisory vote on Executive Compensation**	**For**	The vote of the holders of a majority of the stock having voting power present online or represented by proxy at the Annual Meeting	**No**	Same effect as a vote against	No effect

DIRECTOR NOMINEES

The following table summarizes information about the eight director nominees. As noted, six of our eight directors have been determined to be independent in accordance with the NYSE independence standards and our director independence guidelines.

Director Nominees

Name	Age	Director since	Occupation	Independent	Committee memberships/ positions
Robert B. Evans	73	2014	Retired, President and Chief Executive Officer of Duke Energy Americas	Yes	B**, C, D
John W. Gibson	69	2014	Retired, Chief Executive Officer of ONEOK	No	A*
Tracy E. Hart	60	2018	President and Chief Executive Officer, Tarlton Corporation	Yes	B, C, D
Michael G. Hutchinson	66	2014	Retired, partner at Deloitte & Touche	Yes	A, B*, C, D**
Robert S. McAnnally	58	2021	President and Chief Executive Officer of ONE Gas, Inc.	No	A
Pattye L. Moore	64	2014	Retired Board Chair, Red Robin Gourmet Burgers	Yes	A, B, C*, D
Eduardo A. Rodriguez	66	2014	President of Strategic Communication Consulting Group	Yes	A, B, C, D*
Douglas H. Yaeger	73	2014	Retired, Chairman, President and Chief Executive Officer of The Laclede Group, Inc. (now known as Spire Inc.)	Yes	B, C**, D

Committee memberships/positions key:

A - Executive Committee
B - Audit Committee
C - Executive Compensation Committee
D - Corporate Governance Committee
** - Committee chair*
*** - Committee vice chair*

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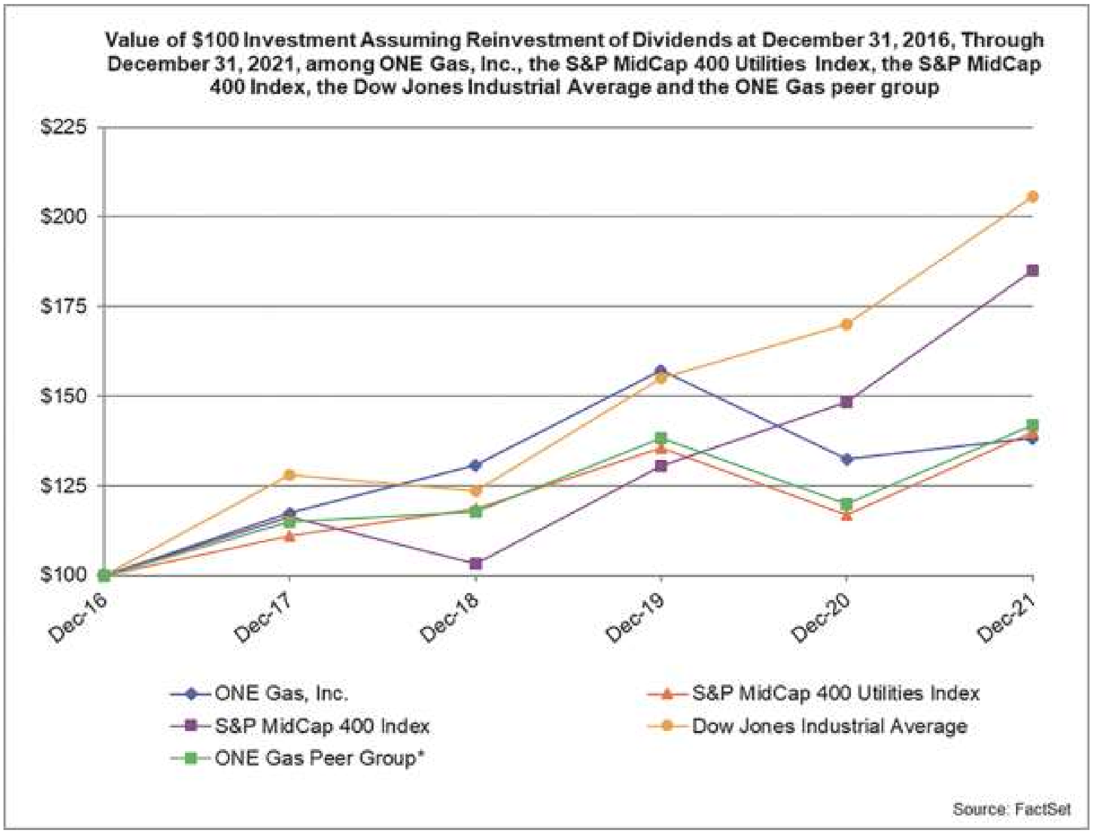
BUSINESS HIGHLIGHTS

2021 Results

5-Year Results

- **Financial Performance.** In 2021, we generated net income of $206 million, or $3.85 per diluted share compared with 2020 net income of $196 million, or $3.68 per diluted share. Operating income in 2021 was $310 million, compared with operating income of $304 million in 2020.
- **Dividend.** During 2021, we paid cash dividends of $2.32 per share. We paid total aggregate dividends to our shareholders of $124 million in 2021. In January 2022, we declared a dividend of 62 cents per share ($2.48 per share on an annualized basis), an increase of 4 cents per share compared with the previous cash dividend of 58 cents per share.
- **Total Shareholder Return.** The market price of our common stock was $77.59 per share at December 31, 2021, an increase of approximately 130 percent from the closing price of $33.63 on February 3, 2014, our first day of "regular way" trading, and an increase of 1 percent from the closing price of $76.77 on December 31, 2020.

  We generated TSR of approximately 38 percent from December 31, 2016, through December 31, 2021. This return exceeded the returns over the same period of 8 of 13 companies in our peer group, but was below the returns of Dow Jones Industrial Average (106 percent), the S&P MidCap 400 Index (85 percent), and the S&P MidCap Utilities Index (40 percent).
- **Safety Improvements.** Driving safely, personal injury prevention and public safety continue to be a priority at ONE Gas. We are a leader amongst our peers with outstanding performance in DART. We achieved a 6 percent improvement in TRIR as compared to last year. ONE Gas' DART, TRIR, and PVIR all performed within the American Gas Association's last reported first quartile results. ONE Gas was awarded the Safety Achievement Award for Excellence in Employee Safety by the American Gas Association for the fourth consecutive year, which recognizes ONE Gas for having the fewest number of lost workdays due to injury.

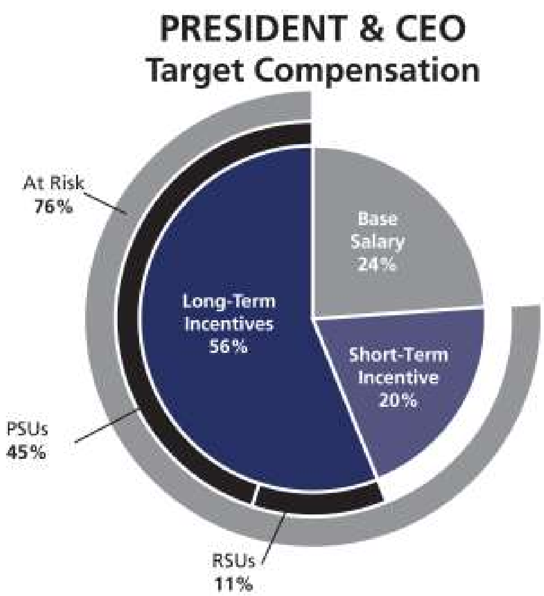


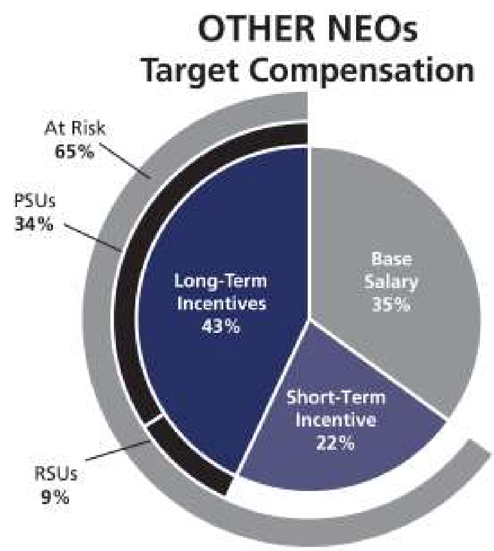
* The ONE Gas peer group used in this graph is the same peer group that will be used in determining our level of performance under our 2021 performance units at the end of the three-year performance period and is comprised of the following companies: Alliant Energy Corporation; Atmos Energy Corporation; Avista Corporation; CenterPoint Energy Inc.; Chesapeake Utilities Corporation; CMS Energy Corporation; New Jersey Resources Corporation; NiSource Inc.; Northwest Natural Holding Company; NorthWestern Corporation; South Jersey Industries; Southwest Gas Corporation; and Spire Inc.

COMPENSATION HIGHLIGHTS

- **Compensation Philosophy.** Our Executive Compensation Committee (referred to as the “Executive Compensation Committee” or the “Committee”) determines executive compensation based on a comprehensive review of quantitative and qualitative factors designed to reward the accomplishment of long-term sustainable business goals. Our executive compensation program is designed to attract, engage, motivate, reward and retain highly effective key executives who drive our success and who are leaders in the industry. Our pay for performance programs align the long-term interests of our executive officers with those of our stakeholders. Additional information can be found in the Compensation Discussion and Analysis beginning on page 36.
- **Program Design.** The Executive Compensation Committee references market data when determining all elements of compensation and targets the median level of total compensation. Our compensation program provides a competitive total compensation opportunity by establishing a pay mix that balances short- and long-term performance specifically consisting of significant equity-based (at-risk) compensation. A significant portion of total compensation is linked to performance which we believe creates long-term stakeholder value and discourages unnecessary or excessive risk taking. Our performance-based STI program provides for cash awards based on achievement of the company’s annual financial and operational goals as well as individual performance of each NEO. We encourage alignment of our NEOs’ interests with those of our stakeholders through LTI awards, of which are approximately 80 percent PSUs and 20 percent RSUs. Our NEOs receive no perquisites or other personal benefits. We have market-competitive stock ownership guidelines for our NEOs and our non-management directors which provides them with a significant stake in our long-term success and aligns their interest with stakeholder interests.
- **Say-On-Pay.** Our say-on-pay vote in 2021 was 97 percent in agreement with our compensation paid to our NEOs. In reviewing our compensation program during 2021, our Executive Compensation Committee determined to continue applying the same principles as have been historically applied in determining the nature and amount of our executive compensation.

- **Link between Executive Compensation and Performance.** On June 27, 2021, Pierce H. Norton retired as President and CEO of ONE Gas. He was succeeded by Robert S. McAnnally on June 28, 2021. Mr. McAnnally has been with ONE Gas for six years. He joined the company as the Senior Vice President of Operations and was promoted to COO in 2020. In 2021, consistent with our executive compensation philosophy, a significant majority of the CEO's and other NEO's total direct compensation was incentive-based and at-risk, as illustrated by the following charts:





The compensation of our other NEOs further reflects both our 2021 performance and our pay-for-performance compensation philosophy:

Named Executive Officer	2021 Base Salary	2021 STI Award	2021 LTI Award(1)	2021 Total Direct Compensation
Robert S. McAnnally(2)	$650,000	$405,369	$1,500,000	$2,555,369
Pierce H. Norton(3)	$800,000	$375,724	$2,200,000	$3,375,724
Caron A. Lawhorn	$435,000	$294,000	$500,000	$1,229,000
Curtis L. Dinan(4)	$500,000	$314,000	$700,000	$1,514,000
Joseph L. McCormick	$360,000	$243,000	$450,000	$1,053,000
Mark A. Bender	$312,500	$174,000	$325,000	$811,500

(1) Represents the grant date value approved by the Committee. The values displayed in the Summary Compensation Table represent the accounting value of the PSUs.

(2) Mr. McAnnally's base salary increased 49.4 percent increase, his STI target increased from 65 to 85 percent, and he received an off-cycle LTI award of $975,000, associated with his promotion to President and CEO on June 28, 2021.

(3) Mr. Norton, retired as our President and CEO effective June 27, 2021. Mr. Norton earned approximately half of his base salary prior to his retirement date. His 2021 STI payment was pro-rated accordingly.

(4) Mr. Dinan received a 14.9 percent increase in base salary and an off-cycle LTI award of $200,000 associated with his promotion to COO on June 28, 2021.

CORPORATE RESPONSIBILITY

For more than 100 years, our business has built a legacy of safely delivering reliable and affordable natural gas to our customers. We are committed to a clear mission – to deliver natural gas for a better tomorrow. For more information about our approach to corporate responsibility, visit our website at https://esg.onegas.com, the contents of which are expressly not incorporated herein by this reference.

The Board has overall responsibility for overseeing our corporate sustainability strategy and associated disclosures. We understand that delivering a sustainable energy future requires a sharp focus on ensuring the resiliency and reliability and reducing environmental impact of our delivery systems. As a result, we established an Environmental, Social and Governance (“ESG”) Steering Committee led by our CFO, which includes representatives from most functional areas, including other members of our senior management team. The primary purpose of the ESG Steering Committee is to provide vision, leadership, direction and oversight of our ESG programs, processes and disclosures. We continue to focus on integrating sustainable business practices and providing transparency into our strategy, while creating long-term shareholder value.

Our core values–safety, ethics, inclusion and diversity, service and value–are the foundation for all we do and guide our sustainability strategy, which is reviewed and validated annually as part of our enterprise risk management and strategic planning processes.

SAFETY AND HEALTH

Safety is our number one core value and at the foundation of everything we do. By monitoring the integrity of our assets and promoting the safety and health of our employees, customers and communities, we are investing in the long-term sustainability of our businesses.

We maintain safe and reliable operations by tightening and modernizing our system through pipeline replacement. This helps us maintain safe and reliable operations while decreasing leaks and emissions from our systems.

Our nearly 3,600 employees drive our safety culture and are committed to a goal of zero fatalities and zero incidents. We continue to refine our training, engineering controls, work procedures and other preventive safety and health programs as we strive for zero harm. The key to reducing safety incidents is to stop the accident before it happens, which is why we continue to enhance our preventive safety programs, such as near-miss reporting, vehicle-safety monitoring, risk assessment and others.

Our COO chairs our Environment, Safety, Health and Compliance (“ESH&C”) Steering Committee and includes other management team members and senior operations personnel. The primary purpose of the ESH&C Steering Committee is to provide vision, leadership, direction and oversight of our ESH&C programs, processes and management systems. These efforts relate to the protection of our employees, the environment and the communities we serve, as well as systems focused on the safe design and operation of our natural gas distribution system.

2021 Safety and Health Performance

- Since 2013 we have experienced a 67% reduction in our TRIR.
- Since 2013 strains and sprains, our employees’ most prevalent type of injury, has declined by 79%.
- Since 2013 we have experienced a 87% reduction in our DART.
- Since 2013 we have experienced a 7% reduction in our PVIR.

ENVIRONMENTAL PERFORMANCE

We recognize the importance of responsible environmental stewardship in creating long-term value for our stakeholders. We are committed to reducing negative environmental impacts and providing cleaner energy sources for our customers that are reliable and affordable. As part of our commitment, we have continued to make progress on emissions reductions through various programs, including pipeline replacement and system integrity projects, end-use energy conservation programs, and providing compressed natural gas for alternative fuel vehicles. We anticipate a 55% reduction in emissions due to leaks from mains and services through 2035, from a 2005 baseline, factoring in projected system growth. We are also pursuing projects to bring renewable natural gas (“RNG”) to our customers and are participating in studies related to the utilization of hydrogen as a fuel source. In addition, we participate in several organizations to identify and implement best practices that advance social responsibility, economic vitality, and environmental stewardship.

2021 Environmental Updates and Highlights

- In 2021, we continued to execute our energy efficiency and conservation programs in Oklahoma and Texas. These programs offer residential and commercial customers rebates on natural gas appliances and energy-efficient home improvements.
- We exceeded our EPA Natural Gas STAR Methane Challenge program emissions reduction goal in 2021. As a founding member, we’ve committed to annually replacing a minimum of 2% of our highest emitting materials – a target we’ve exceeded each year since we began the program in 2016.

- For the first time, we submitted our emissions data to Our Nation's Energy Future (ONE Future), a group of natural gas companies working together to voluntarily reduce methane emissions across the natural gas value chain to one percent or less by 2025. In November 2021, ONE Future released its results, reporting a methane intensity for all ONE Future members of 0.42%, well below the 1% methane intensity target. The methane intensity for the natural gas distribution sector, of which ONE Gas is a part, was 0.118%, beating the goal of 0.225% by 46%.

COMMUNITY INVESTMENT

We are committed to being active members of the communities where we operate. We invest in the areas where we have operations and where our employees live and work not only because it is the right thing to do–it's smart business. By contributing financially and through company-sponsored volunteer work, we can help build stronger communities and create a better quality of life for our employees, customers and the general public.

We accomplish this in several ways, including grants from the ONE Gas Foundation, corporate sponsorships to nonprofit organizations and community volunteer efforts. Primary philanthropic focus areas are Community Enrichment and Assistance, including public spaces and disaster recovery; Education and Workforce Development; and Community Collaboration, including diversity and economic development. In 2021, we gave priority consideration to grant requests that involve natural gas safety partnerships, workforce development and classroom enrichment projects involving Science, Technology, Engineering, the Arts and Mathematics (STEAM) programs.

2021 Community Investment Updates and Highlights

- In 2021, we contributed approximately $3.6 million to nonprofit organizations through the ONE Gas Foundation and corporate sponsorships. The time our employees invested in community volunteering was significantly limited due to the ongoing safety protocols related to the pandemic.

HUMAN CAPITAL MANAGEMENT

Culture and Employee Engagement

Every ONE Gas employee makes a difference and contributes to our success. We actively recruit and retain a high-performing workforce and create a safe, ethical and inclusive culture where top talent wants to work. Our programs and policies help attract and develop diverse talent and support our employees' physical, social, emotional and financial well-being. Our holistic approach inspires employees to make healthy personal and professional lifestyle choices.

2021 Human Capital Updates and Highlights

- In 2021, we again had high participation in our annual employee engagement survey, with 89% of employees providing feedback. Employee engagement scores were in the top quartile of Gallup's Overall Company Database.

INCLUSION AND DIVERSITY

To build a better tomorrow for everyone, we have created a culture that embraces inclusion and diversity and encourages collaboration. Our CEO chairs our Inclusion and Diversity Council, including five permanent members and 17 rotating members from various functional areas, backgrounds and experiences. The Council advises and advocates for inclusion and diversity in alignment with the Company's vision and mission. This includes identifying opportunities and guiding the execution of the inclusion and diversity strategy. Members are natural advocates who share our vision with their local teams.

All employees are welcomed and encouraged to join Employee Resource Groups ("ERGs"). These voluntary cohort groups are based on shared characteristics, interests or experiences. ERGs help us recruit diverse talent, share valuable education on diverse topics, provide professional and leadership development opportunities for members and promote community involvement.

To promote a diverse workforce, we take active steps, including monitoring the diversity of our workforce across roles and leadership levels. We also require leaders to utilize diverse teams when interviewing talent. Our annual employee engagement survey focuses on company values, including Inclusion and Diversity, using Gallup's Inclusiveness Index. Also, we have instituted a Managing Bias course that provides conscious inclusion training to employees.

POLITICAL ADVOCACY AND CONTRIBUTIONS

We do not contribute corporate funds to political candidates or political action committees as a company. We also do not contribute corporate funds to so-called 501(c)(4) social welfare organizations for lobbying. Employee and director contributions to the ONE Gas PAC support various parties including other political action committees and candidates seeking federal or state offices who support the energy industry and business interests. A steering committee made up of senior management representatives and a contributions committee of employees from across our operating areas and business functions oversee all ONE Gas PAC contributions to political candidates.

OUTSTANDING STOCK AND VOTING

VOTING

Only shareholders of record at the close of business on March 28, 2022, are entitled to receive notice of and to vote at the annual meeting. As of that date, 54,089,817 shares of our common stock were outstanding. Each outstanding share entitles the holder to one vote on each matter submitted to a vote of shareholders at the meeting. No other class of our stock is entitled to vote on matters to come before the meeting.

Shareholders of record may vote online or by proxy at the annual meeting. All properly submitted proxies received prior to the commencement of voting at the annual meeting will be voted in accordance with the voting instructions contained on the proxy. Shares for which signed proxies are properly submitted without voting instructions will be voted:

(1) **FOR** the election of the eight director nominees named in this proxy statement to serve on our Board for a one-year term;

(2) **FOR** the ratification of the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2022; and

(3) **FOR** the advisory proposal to approve our executive compensation.

While we know of no other matters that are likely to be brought before the meeting, in the event any other business properly comes before the meeting, proxies will be voted in the discretion of the persons named in the proxy. The persons named as proxies were designated by our Board.

To vote shares held “in street name” through a bank, broker or other holder of record, a shareholder must provide voting instructions to his or her bank, broker or other holder of record. Brokerage firms, banks and other holders of record are required to request voting instructions for shares they hold on behalf of their customers and others. We encourage you to provide instructions to your bank, broker or other holder of record on how to vote your shares. If your shares are held “in street name,” to be able to vote those shares online at the annual meeting, you must obtain a legal proxy, executed in your favor, from the holder of record of those shares as of the close of business on March 28, 2022.

The rules of the NYSE determine whether proposals presented at shareholder meetings are routine or non-routine. If a proposal is routine, a broker or other entity holding shares for an owner in street name may vote for the proposal without receiving voting instructions from the owner under certain circumstances. If a proposal is non-routine, the broker or other entity may vote on the proposal only if the owner has provided voting instructions. A “broker non-vote” occurs when the broker or other entity is unable to vote on a proposal because the proposal is non-routine and the owner does not provide any voting instructions. Under the rules of the NYSE, Proposals 1 and 3 are considered to be non-routine, and Proposal 2 is considered to be routine. Accordingly, if you do not provide voting instructions to your brokerage firm or other entity holding your shares, your brokerage firm or other entity holding your shares will not be permitted under the rules of the NYSE to vote your shares on Proposals 1 and 3 and will be permitted under the rules of the NYSE to vote your shares on Proposal 2 at its discretion.

Please provide your voting instructions to your broker, bank or other holder of record so that your shares may be voted.

Representatives of our stock transfer agent, Equiniti Trust Company d/b/a EQ Shareowner Services, will be responsible for tabulating and certifying the votes cast at the annual meeting.

QUORUM

The holders of a majority of the shares entitled to vote at the annual meeting, present online or by proxy, constitute a quorum for the transaction of business at the annual meeting. In determining whether we have a quorum, we count abstentions and broker non-votes as present.

If a quorum is not present at the scheduled time of the meeting, the shareholders who are present online or by proxy may adjourn the meeting until a quorum is present. If the time and place of the adjourned meeting are announced at the time the adjournment is taken, no other notice will be given. However, if the adjournment is for more than 30 days, or if a new record date is set for the adjourned meeting, a notice will be given to each shareholder entitled to receive notice of, and to vote at, the meeting.

MATTERS TO BE VOTED UPON

At the annual meeting, the following matters will be voted upon:

(1) the election of eight director nominees named in this proxy statement to serve a one-year term;

(2) the ratification of the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the year ending December 31, 2022;

(3) to consider and vote on our executive compensation on a non-binding, advisory basis; and

(4) such other business as may properly come before the meeting, or any adjournment or postponement of the meeting.

VOTES REQUIRED

Proposal 1 — Election of Directors. Our bylaws provide for majority voting for directors in uncontested elections. We expect that the election of directors at our 2022 annual meeting will be uncontested. Under the majority voting standard, to be elected a nominee must receive a number of "For" votes that exceeds 50 percent of the votes cast with respect to that director's election. Abstentions and broker non-votes, if any, do not count as votes cast with respect to the election of directors.

Our corporate governance guidelines require that if an uncontested nominee for director does not receive more "For" than "Against" votes, he or she must promptly tender his or her resignation to our Board. The Board (excluding the director who tendered the resignation) will then evaluate the resignation in light of the best interests of our company and our shareholders in determining whether to accept or reject the resignation, or whether other action should be taken. The Board will announce publicly its decision regarding any tendered resignation.

Proposal 2 — Ratification of Selection of PricewaterhouseCoopers LLP as our Independent Registered Public Accounting Firm for the Year ending December 31, 2022. In accordance with our bylaws, approval of this proposal requires the affirmative vote of a majority of the voting power of the shareholders present online or by proxy and entitled to vote on this proposal at the meeting. Abstentions will have the same effect as votes against this proposal.

***Proposal 3* — Advisory Vote on Executive Compensation.** In accordance with our bylaws, approval of this proposal requires the affirmative vote of a majority of the voting power of the shareholders present online or by proxy and entitled to vote on this proposal at the meeting. Abstentions will have the same effect as votes against this proposal and broker non-votes do not count as entitled to vote for purposes of determining the outcome of the vote on this proposal. The vote on this proposal is advisory and non-binding on the company and our Board.

REVOKING A PROXY

Any shareholder may revoke his or her proxy at any time before it is voted at the meeting by (1) notifying our corporate secretary in writing (the mailing address of our corporate secretary is Corporate Secretary, ONE Gas, Inc., 15 East Fifth Street, Tulsa, Oklahoma 74103), (2) authorizing a later proxy via the internet or by telephone, (3) returning a later dated proxy card, or (4) voting online at the meeting. A shareholder's presence without voting at the annual meeting will not automatically revoke a previously delivered proxy and any revocation during the meeting will not affect votes previously taken.

If your shares are held in a brokerage account or by a bank or other holder of record, you may revoke any voting instructions you may have previously provided in accordance with the revocation instructions provided by the broker, bank or other holder of record.

PROXY SOLICITATION

Solicitation of proxies will be primarily by mail and telephone. We have engaged Morrow Sodali LLC, 333 Ludlow Street, 5th Floor, South Tower, Stamford, CT 06902, to solicit proxies for a fee of $10,000 plus out-of-pocket expenses. In addition, certain of our officers, directors and employees may solicit proxies on our behalf in person or by mail, telephone, fax or email, for which such persons will receive no additional compensation. We will pay all costs of soliciting proxies. We will also reimburse brokerage firms, banks and other custodians, nominees and fiduciaries for their reasonable expenses for forwarding proxy materials to our shareholders.

GOVERNANCE OF THE COMPANY

Our Board and management are committed to maintaining strong corporate governance practices that allocate rights and responsibilities among our Board, management and our shareholders in a manner that benefits the long-term interests of our shareholders. Our corporate governance practices are designed not just to satisfy regulatory and stock exchange requirements but also to provide for effective oversight and management of our company.

Our Corporate Governance Committee engages in a regular process of reviewing our corporate governance practices, including comparing our practices with those recommended by various corporate governance authorities, the expectations of our shareholders and the practices of other leading public companies. Our Corporate Governance Committee also regularly reviews our corporate governance practices in light of proposed and adopted laws and regulations, including the rules of the SEC and the rules and listing standards of the NYSE.

CORPORATE GOVERNANCE GUIDELINES

Our Board has adopted corporate governance guidelines that address key areas of our corporate governance, including: director qualification standards, including the requirement that a majority of our directors be “independent” under the applicable independence requirements of the NYSE; director responsibilities; director access to management; director compensation; management succession; evaluation of the performance of our Board; ESG oversight; and the structure and operation of our Board. Our Board periodically reviews our corporate governance guidelines and may revise the guidelines from time to time as conditions warrant. The full text of our corporate governance guidelines is published on and may be printed from our website at www.ONEGas.com and is also available from our corporate secretary upon request.

CODE OF BUSINESS CONDUCT AND ETHICS

Our Board has adopted a code of business conduct and ethics that applies to our directors, officers (including our principal executive and financial officers, controller and other persons performing similar functions) and all other employees. We require all directors, officers and employees to adhere to our code of business conduct and ethics in addressing the legal and ethical issues encountered in conducting their work for our company. Our code of business conduct and ethics requires that our directors, officers and employees avoid conflicts of interest, comply with all applicable laws and other legal requirements, conduct business in an honest and ethical manner and otherwise act with integrity and in our company’s best interests. All directors, officers and employees are required to report any conduct that they believe to be an actual or apparent violation of our code of business conduct and ethics.

The full text of our code of business conduct and ethics is published on and may be printed from our website at www.ONEGas.com and is also available from our corporate secretary upon request. We intend to disclose on our website any future amendments to, or waivers of, our code of business conduct and ethics, as required by the rules of the SEC and the NYSE.

DIRECTOR INDEPENDENCE

Our corporate governance guidelines provide that a majority of our Board will be “independent” under the applicable independence requirements of the NYSE. These guidelines and the rules of the NYSE provide that, in qualifying a director as “independent,” the Board must make an affirmative determination that the director has no material relationship with our company, either directly or as a partner, shareholder or officer of an organization that has a relationship with our company. In making this determination with respect to each director serving on the Executive Compensation Committee, under the rules of the NYSE, the Board is required to consider all factors specifically relevant to determine whether the director has a relationship to our company which is material to that director’s ability to be independent from management in connection with the duties of a member of that committee.

Our Board has also adopted director independence guidelines that specify the types of relationships the Board has determined to be categorically immaterial. Directors who meet these standards are considered to be “independent.” The full text of our director independence guidelines is published on and may be printed from our website at www.ONEGas.com and is also available from our corporate secretary upon request.

Our Board has determined affirmatively that members Robert E. Evans, Tracy E. Hart, Michael G. Hutchinson, Pattye L. Moore, Eduardo A. Rodriguez and Douglas H. Yaeger have no material relationship with our company, and each qualifies as “independent” under our corporate governance guidelines, our director independence guidelines and the rules of the NYSE. In determining whether certain of our directors qualify as “independent” under our director independence guidelines, our Board considered the receipt by certain directors or their immediate family members (or entities of which they are members, directors, partners, executive officers, or counsel) of natural gas service from us at regulated rates on terms generally available to all of our customers (and, in the case of an entity, in an amount that is less than the greater of $1 million or 2 percent of the entity’s gross revenue for its last fiscal year). In each case, the Board determined these relationships to be in the ordinary course of business at regulated rates or on substantially the same terms available to non-affiliated third parties and to be immaterial in amounts to both our company and the director.

ANTI-HEDGING AND ANTI-PLEDGING POLICIES

An employee designated as an insider, including the NEOs, may not engage in any hedging strategies involving ONE Gas securities that allow a person to lock in much of the value of stockholdings, often in exchange for all or part of the potential upside appreciation in the stock, including, but not limited to:

- purchasing ONE Gas stock on margin;
- selling ONE Gas stock short;
- entering into zero cost collars, prepaid variable forward sale contracts, equity swaps or exchange funds; or
- buying or selling puts or calls or other derivative instruments.

Insiders are prohibited from holding ONE Gas securities in a margin account or otherwise pledging ONE Gas securities as collateral for a loan. ONE Gas may grant exceptions to the prohibition against pledging on a limited case-by-case basis, provided that the insider must submit a request for approval to the CEO. There is no exception to the prohibition against pledging with respect to the CEO. Any request is subject to pre-clearance under the Securities/Insider Trading Policy. However, there is no assurance that an exception will be granted and there were none granted to any insiders in 2021.

BOARD LEADERSHIP STRUCTURE

During 2021, our Board was led by John W. Gibson, who was the Chairman of the Board, and Eduardo A. Rodriguez, who was both our lead independent director and the chair of the Corporate Governance Committee. In addition, our Audit Committee and Executive Compensation Committee are each led by a chair and vice chair, each of whom is an independent director.

Our corporate governance guidelines provide that our Board retains the right to exercise its discretion in combining or separating the offices of the Chairman of the Board and CEO. Our Board reviews the issue as a part of its succession planning process. The Board believes that it is advantageous for the Board to maintain flexibility to determine on a case-by-case basis and, if necessary, change the Board leadership structure in order to meet our needs at any time, based on the individuals then available and the circumstances then presented.

The Board believes that maintaining Mr. Gibson’s continuing service as non-executive Chairman of the Board provides the most effective leadership model for our Board and our company at this time. In making this determination, the Board considered the advantages to our company of maintaining the continuity of Mr. Gibson’s effective leadership as Chairman of the Board based on, among other factors, his strong leadership skills, his extensive knowledge and experience regarding operations and the industries and markets in which we compete, as well as his ability to promote communication and to synchronize strategic objectives and activities between our Board and our senior management. The Board also believes this leadership structure continues to ensure significant independent oversight of management, as Messrs. Gibson and McAnnally are the only members of the Board who are not independent directors. In addition, our Board has an ongoing practice of holding executive sessions of the independent members of the Board as part of each regularly scheduled in-person Board meeting.

LEAD INDEPENDENT DIRECTOR

Our corporate governance guidelines vest the lead independent director who, under these guidelines, is also chair of our Corporate Governance Committee, with various key responsibilities, including but not limited to:

- presiding as the chair at all meetings of the Board at which the Chairman of the Board is not present;
- presiding at all executive sessions of the independent directors;
- serving as liaison between the Chairman of the Board and the independent directors;
- approving information sent to the Board;
- approving meeting agendas for the Board; and
- approving meeting schedules to assure that there is sufficient time for discussion of all agenda items.

In addition, the lead independent director has the authority to call meetings of the independent directors and, if requested by major shareholders, will be reasonably available for consultation and direct communication with such shareholders. The Lead Independent Director may also perform duties otherwise assigned to the Chairman of the Board when the offices of the Chairman of the Board and the CEO are combined.

SUCCESSION PLANNING

A key responsibility of the CEO and the Board is ensuring that an effective process is in place to provide continuity of leadership over the long term at all levels in our company. Each year, succession-planning reviews are held at every significant organizational level of the company, culminating in a full review of senior leadership talent by our independent directors. During this review, the CEO, the Chairman of the Board and the independent directors discuss future candidates for senior leadership positions, including all NEOs, succession timing for those positions and development plans for the highest-potential candidates. This process ensures continuity of leadership over the long term, and it forms the basis on which our company makes ongoing leadership assignments. It is a key success factor in managing the long-term planning and investment lead times of our business.

In addition, we have a written CEO emergency succession plan pursuant to which the CEO maintains in place at all times, and reviews with the non-management directors, a confidential plan for the timely and efficient transfer of responsibilities in the event of an emergency or sudden incapacitation or departure of the CEO.

OUR BOARD AND CORPORATE STRATEGY

Our Board is actively involved in overseeing, reviewing and guiding our corporate strategy. Our Board formally reviews our company's business strategy, including the risks and opportunities facing our company and its business, at an annual strategic planning session. Our Board regularly discusses corporate strategy throughout the year with management formally as well as informally and during executive sessions of the Board as appropriate. As discussed in "Risk Oversight" below, our Board views risk management and oversight as an integral part of our strategic planning process, including mapping key risks to our corporate strategy and seeking to manage and mitigate risk. Our Board also views its own composition as a critical component to effective strategic oversight. Accordingly, our Board and relevant Board committees consider our business strategy and the company's regulatory, geographic and market environments when assessing board composition, director succession, executive compensation and other matters of importance.

SHAREHOLDER ENGAGEMENT

Our Board believes that accountability to shareholders is a mark of good corporate governance and that regular shareholder engagement is important to our company's success. Our company frequently engages with shareholders on a variety of topics, with particular focus on matters relating to our company's publicly disclosed strategy and financial performance. Our company also engages with shareholders to discuss matters relating to ESG, compensation and other current and emerging issues that the Board and our management understand are important to our shareholders. In addition to this direct engagement, our company also maintains a number of complementary mechanisms that allow our shareholders to effectively communicate to our Board and management, including:

- maintaining an investor relations page on our website;
- regularly attending investor conferences;
- conducting an annual advisory vote to approve executive compensation;
- if requested by major shareholders, ensuring the lead independent director is available for consultation and direct communication;
- permitting shareholders to submit prospective candidates for nomination by our Board for election at the annual meeting of shareholders in accordance with our corporate governance guidelines and bylaws;
- permitting shareholders to nominate candidates for election at the annual meeting of shareholders in accordance with our bylaws; and
- providing shareholders the ability to attend and voice opinions at the annual meeting of shareholders.

RISK OVERSIGHT

We have integrated a comprehensive Enterprise Risk Management ("ERM") process as part of strategy setting and driving performance throughout the company, which includes identifying, aggregating, monitoring, measuring, assessing and managing risks that could affect our ability to fulfill our business objectives or execute our corporate strategy. These risks generally relate to strategic, operational, financial, regulatory compliance and human resources issues. Our ERM approach is overseen by our CFO and is designed to enable our Board to establish a mutual understanding with management of the effectiveness of our risk-management practices and capabilities, to review our risk exposure and to elevate certain key risks for discussion at the Board level. Management and our Board believe that risk management is an integral part of our annual strategic planning process, which addresses, among other things, the risks and opportunities facing our company.

Not all risks can be dealt with in the same way. Some risks may be easily perceived and controllable, and other risks are unknown; some risks can be avoided or mitigated by particular behavior, and some risks are unavoidable as a practical matter. For some risks, the potential adverse impact would be minor and, as a matter of business judgment, it may not be appropriate to allocate significant resources to avoid the adverse impact. In other cases, the adverse impact could be significant, and it is prudent to expend resources to seek to avoid or mitigate the potential adverse impact. In some cases, a higher degree of risk may be acceptable because of a greater perceived potential for reward. Management is responsible for identifying risks and controls related to our significant business activities; mapping the risks to our corporate strategy; and developing programs and recommendations to determine the sufficiency of risk identification, the balance of potential risk to potential reward and the appropriate manner in which to control and mitigate risk. Much of this work is led by our ESH&C Steering Committee, which is chaired by our COO, and includes other members of the management team and senior operations personnel. The ESH&C Steering Committee's primary purpose is to provide vision, leadership, direction, and oversight of our ESH&C programs, processes, and management systems for the protection of the employees, the environment, and the communities we serve, as well as the systems focused on the safe design and operation of our system.

The Board implements its risk oversight responsibilities by having management provide periodic briefing and informational sessions on the significant voluntary and involuntary risks that our company faces and how our company is seeking to control and mitigate those risks. In some cases, as with risks associated with ESG, risk oversight is addressed as part of the full Board's engagement with the CEO and management. ESG risks are also evaluated at the management level through our ESG Steering Committee. The ESG Steering Committee is chaired by our CFO, and includes other members of the management team and senior management personnel. The ESG Steering Committee is charged with providing oversight and guidance to the company on emerging ESG issues and considering how to implement ESG matters consistent with our overall strategy.

The Board annually reviews a management assessment of the various operational and regulatory risks facing our company, their relative magnitude and management's plan for mitigating these risks. The Board also reviews risks related to our company's business strategy at its annual strategic planning meeting and at other meetings as appropriate. The Board receives cybersecurity updates at every regular Board meeting and participated in a cybersecurity drill in 2021.

In certain cases, a Board committee is responsible for oversight of specific risk topics. For example, the Audit Committee oversees risk issues associated with our overall financial reporting and disclosure process and legal compliance, as well as reviewing policies and procedures on risk-control assessment and accounting risk exposure, including our companywide risk control activities. Our general counsel provides compliance and ethics reports to the Audit Committee at every regular committee meeting. The Audit Committee meets with our executive officers and meets with our Director–Audit Services, as well as with our independent registered public accounting firm, in separate executive sessions at each of its in-person/virtual meetings during the year, at which time risk issues are discussed regularly.

In addition, our Executive Compensation Committee oversees risks related to our compensation program, as discussed in greater detail elsewhere in this proxy statement, and our Corporate Governance Committee oversees risks related to our governance practices and policies.

BOARD AND COMMITTEE MEMBERSHIP

Our business, property and affairs are managed under the direction of our Board. Members of our Board are kept informed of our business through discussions with our CEO and other officers, by reviewing materials provided to them periodically and in connection with Board and committee meetings, and by participating in meetings of the Board and its committees.

During 2021, the Board held eight regular meetings (one virtual, four in-person and three telephonic meetings) and 11 special meetings primarily related to Winter Storm Uri, all of which were held virtually. All of our incumbent directors who served on the Board during 2021 attended all of the meetings of the Board and Board committees on which they served.

Our corporate governance guidelines provide that members of our Board are expected to attend our Annual Meeting of Shareholders. Based on the nature of the convening method of the Annual Meeting of Shareholders, members of our Board may attend the meeting in person or by conference telephone or videoconference software. All members of the Board attended the 2021 Annual Meeting of Shareholders.

The Board has four standing committees: the Audit Committee, the Executive Compensation Committee, the Corporate Governance Committee and the Executive Committee. The table below provides the current membership of our Board and each of our Board committees. Our Board has determined affirmatively that each member of our Audit Committee, Executive Compensation Committee and Corporate Governance Committee is "independent" under our corporate governance guidelines, our director independence guidelines and the rules of the NYSE.

Director	Board	Audit	Executive Compensation	Corporate Governance	Executive
Robert B. Evans	Member	Vice Chair	Member	Member	
John W. Gibson	Chair				Chair
Tracy E. Hart	Member	Member	Member	Member	
Michael G. Hutchinson	Member	Chair	Member	Vice Chair	Member
Robert S. McAnnally	Member				Member
Pattye L. Moore	Member	Member	Chair	Member	Member
Eduardo A. Rodriguez	Member	Member	Member	Chair	Member
Douglas H. Yaeger	Member	Member	Vice Chair	Member	
Number of meetings in 2021	19	7	5	5	0

Our Board has adopted written charters for each of its Audit, Executive Compensation, Corporate Governance and Executive Committees. Copies of the charters of each of these committees are available on and may be printed from our website at www.ONEGas.com. Copies are also available from our corporate secretary upon request. The responsibilities of our Board committees are summarized below. From time to time the Board, in its discretion, may form other committees.

THE AUDIT COMMITTEE

2021 Meetings: 7

The Audit Committee represents and assists our Board with oversight of the integrity of our financial statements and internal controls, our compliance with legal and regulatory requirements, the independence, qualifications and performance of our independent registered public accounting firm and the performance of our internal audit function. The responsibilities of the Audit Committee include:

- appointing, compensating and overseeing our independent auditor;
- reviewing the scope, plans and results relating to the external audits of our financial statements;
- reviewing the scope, plans and results relating to internal audits;
- monitoring and evaluating our financial condition;
- monitoring and evaluating the integrity of our financial reporting processes and procedures;
- assessing our significant financial risks and exposures and reviewing internal control processes and evaluating any deficiencies in connection with such risks and exposures, including, but not limited to, internal controls over financial reporting and disclosure controls and procedures;
- reviewing policies and procedures on risk-control assessment and accounting risk exposure, including our companywide risk control activities;
- considering compliance programs and policies, approaches to risk assessment and risk management, and internal controls that support the company's ESG goals and objectives; and
- monitoring our compliance with our policies on ethical business conduct.

Our independent registered public accounting firm reports directly to our Audit Committee. All members of our Audit Committee are "independent" under the independence requirements of the NYSE and the SEC applicable to audit committee members. The Board has determined that Robert E. Evans, Tracy E. Hart, Michael G. Hutchinson, Eduardo A. Rodriguez and Douglas H. Yaeger (five of the six committee members) are each an audit committee financial expert under the applicable rules of the SEC and all members of the Audit Committee are financially literate. No member of our Audit Committee serves on the audit committees of more than two other public companies.

THE EXECUTIVE COMPENSATION COMMITTEE

2021 Meetings: 5

Our Executive Compensation Committee is responsible for establishing and periodically reviewing our executive compensation policies and practices. This responsibility includes:

- evaluating, in consultation with our Corporate Governance Committee, the performance of our CEO, and recommending to our Board the compensation of our CEO and our other senior executive officers;
- reviewing and approving, in consultation with our Corporate Governance Committee, the annual objectives of our CEO;
- reviewing our executive compensation program to ensure the attraction, retention and appropriate compensation of executive officers in order to motivate their performance in the achievement of our business objectives and to align their interests with the long-term interests of our shareholders;
- assessing the risks associated with our compensation program;
- approving, subject to ratification by the full Board, executive officer compensation and personnel policies, programs and plans;
- considering compensation and incentive structures, policies and procedures and related matters that support the company's ESG goals and objectives; and
- reviewing and making recommendations to the full Board on director compensation.

Our Executive Compensation Committee meets periodically during the year to review our executive and director compensation policies and practices. Executive officer salaries and STI and LTI compensation are determined annually by the Committee. The scope of the authority of the Committee is not limited except as set forth in its charter and by applicable law. The Committee has the authority to delegate duties to subcommittees of the Committee, or to other standing committees of the Board, as it deems necessary or appropriate. The Committee may not delegate to a subcommittee any authority required by any law, regulation or listing standard to be exercised by the Committee as a whole. All members of our Executive Compensation Committee are "independent" under the independence requirements of the NYSE applicable to compensation committee members.

The compensation group in our corporate human resources department supports, in consultation with our CEO, the Executive Compensation Committee in its work.

During 2021, the Executive Compensation Committee engaged Meridian, as an independent executive compensation consultant to assist the Committee in its evaluation of the amount and form of compensation paid in 2021 to our CEO, our other executive officers and our directors. Meridian reported directly to the Executive Compensation Committee. For more information on executive compensation and the role of this consultant, see "Compensation Discussion and Analysis—How We Determine Pay—Role of the Independent Executive Compensation Consultant" at page 38.

THE CORPORATE GOVERNANCE COMMITTEE	Our Corporate Governance Committee is responsible for overseeing our company's governance, including the selection of directors and the Board's practices and effectiveness. These responsibilities include: • identifying and recommending qualified director candidates, including qualified director candidates suggested by our shareholders in written submissions to our corporate secretary in accordance with our corporate governance guidelines and our bylaws or in accordance with the rules of the SEC; • making recommendations to the Board with respect to electing directors and filling vacancies on the Board; • adopting an effective process for director selection and tenure by making recommendations on the Board's organization and practices and by aiding in identifying and recruiting director candidates; • reviewing and making recommendations to the Board with respect to the organization, structure, size, composition and operation of the Board and its committees; • overseeing evaluation of the Board and management; • in consultation with our Chairman of the Board, and CEO and the Executive Compensation Committee, overseeing management succession and development, including all NEOs; • coordinating with the Board and management with respect to oversight of shareholder engagement initiatives; • reviewing annually directorships held by directors and executive officers; • considering governance programs and policies and approaches to legislative affairs activities and political action committees that support the Company's ESG goals and objectives; and • reviewing, assessing risk and making recommendations with respect to other corporate governance matters. All members of the Corporate Governance Committee are "independent" under the independence requirements of the NYSE.
2021 Meetings: 5	

THE EXECUTIVE COMMITTEE	In the intervals between meetings of our Board, the Executive Committee may, except as otherwise provided in our bylaws and applicable law, exercise the powers and authority of the full Board in the management of our property, affairs and business. The function of this committee is to act on major matters where it deems action appropriate, providing a degree of flexibility and ability to respond to time-sensitive business and legal matters without calling a special meeting of our full Board. The Executive Committee reports to the Board at its next meeting on any actions taken by the committee.
2021 Meetings: 0	

DIRECTOR NOMINATIONS

Our corporate governance guidelines provide that the Board is responsible for nominating candidates for Board membership and for the delegation of the screening process to the Corporate Governance Committee of the Board. This committee, with recommendations and input from our Chairman of the Board, CEO and the directors, evaluates the qualifications of each director candidate and assesses the appropriate mix of skills, qualifications and characteristics required of Board members in the context of the perceived needs of the Board at a given point in time. The Corporate Governance Committee is responsible for recommending to the full Board candidates for nomination by the Board for election as members of our Board.

Our corporate governance guidelines provide that candidates for nomination by the Board must be committed to devote the time and effort necessary to be productive members of the Board and that, in nominating candidates, the Board will endeavor to establish director diversity in personal background, race, gender, age and nationality. The guidelines also provide that the Board will seek to maintain a mix that includes, but is not limited to, the following areas of core competency: accounting and finance; investment banking; business judgment; management; industry knowledge; crisis response; international business; leadership; applicable ESG matters; strategic vision; law; and corporate relations.

The Corporate Governance Committee's charter provides that it has the responsibility, in consultation with the Chairman of the Board and CEO, to search for, recruit, screen, interview and recommend to the Board candidates for the position of director as necessary to fill vacancies on the Board or the additional needs of the Board and to consider management and shareholder recommendations for candidates for nomination by the Board. In carrying out this responsibility, the Corporate Governance Committee evaluates the qualifications and performance of incumbent directors and determines whether to recommend them for re-election to the Board. In addition, this committee determines, as necessary, the portfolio of skills, experience, diversity, perspective and background required for the effective functioning of the Board considering our business strategy and our regulatory, geographic and market environments.

Our corporate governance guidelines contain a policy regarding the Corporate Governance Committee's consideration of prospective director candidates recommended by shareholders for nomination by our Board. Under this policy, and in accordance with our bylaws, any shareholder who wishes to recommend a prospective candidate for nomination by our Board for election at our 2023 annual meeting should send a letter of recommendation to our corporate secretary at our principal executive offices by no later than December 7, 2022. The letter should include the name, address and number of shares owned by the recommending shareholder (including, if the recommending shareholder is not a shareholder of record, proof of ownership of the type referred to in Rule 14a-8(b)(2) of the proxy rules of the SEC), the prospective candidate's name and address, a description of the prospective candidate's background, qualifications and relationships, if any, with our company and all other information requested by our Board for determining whether the prospective candidate meets the independence standards under the rules of the NYSE and our director independence guidelines. A signed statement from the prospective candidate should accompany the letter of recommendation indicating that he or she consents to being considered as a nominee of the Board and that, if nominated by the Board and elected by the shareholders, he or she will serve as a director. The Corporate Governance Committee will evaluate prospective candidates recommended by shareholders for nomination by our Board in light of the various factors set forth above.

Neither the Corporate Governance Committee, the Board, nor our company itself discriminates in any way against prospective candidates for nomination by the Board on the basis of age (subject to the mandatory retirement age set forth in the company's bylaws), sex, sexual orientation, gender identity or expression, race, ethnicity, national origin, religion, or other personal characteristics. There are no differences in the manner in which the Corporate Governance Committee or the Board evaluates prospective candidates based on whether the prospective candidate is recommended by a shareholder or by the Corporate Governance Committee, provided that the recommending shareholder furnishes to our company a letter of recommendation containing the information described above along with the signed statement of the prospective candidate referred to above.

In addition to having the ability to recommend prospective candidates for nomination by our Board, under our bylaws, shareholders may themselves nominate candidates for election at an annual meeting of shareholders. Any shareholder who desires to nominate candidates for election as directors at our 2023 annual meeting must follow the procedures set forth in our bylaws. Under these procedures, notice of a shareholder nomination for the election of a director must be received by our corporate secretary at our principal executive offices not less than 120 calendar days before the first anniversary of the date that our proxy statement was released to shareholders in connection with our 2022 Annual Meeting of Shareholders (i.e., notice must be received no later than December 7, 2022). If the date of the 2023 annual meeting is more than 30 days from the first anniversary date of the 2022 meeting, our corporate secretary must receive notice of a shareholder nomination by the close of business on the tenth day following the earlier of (i) the day on which notice of the date of the meeting is mailed to shareholders or (ii) the day on which public announcement of the meeting date is made. In accordance with our bylaws, a shareholder notice must contain certain information about the candidate the shareholder desires to nominate for election as a director, including: (a) the name, age, business address and residence address of such person; (b) the principal occupation or employment of such person; (c) the class or series and number of our shares that are owned beneficially or of record by such person and any affiliates or associates of such person; (d) the name of each nominee holder of our shares owned beneficially but not of record by such person or any affiliates or associates of such person, and the number of our shares held by each such nominee holder; (e) whether and the extent to which any derivative instrument, swap, option, warrant, short interest, hedge or profit interest or other transaction has been entered into by or on behalf of such person, or any affiliates or associates of such person, with respect to our shares; (f) whether and the extent to which any other transaction, agreement, arrangement or understanding (including any short position or any borrowing or lending of our shares) has been made by or on behalf of such person, or any affiliates or associates of such person, the effect or intent of any of the foregoing being to mitigate loss to, or to manage risk or benefit of stock price changes for, such person, or any affiliates or associates of such person, or to increase or decrease the voting power or pecuniary or economic interest of such person, or any affiliates or associates of such person, with respect to our shares; (g) such person's written and executed representation and agreement (in the form provided by the corporate secretary upon written request) that such person (1) is not and will not become a party to any agreement, arrangement or understanding with, and has not given any commitment or assurance to, any person or entity as to how such person, if elected as a director of the company, will act or vote on any issue or question, (2) is not and will not become a party to any agreement, arrangement or understanding with any person or entity other than the company with respect to any direct or indirect compensation, reimbursement or indemnification in connection with service or action as a director of the company that has not been disclosed to the company in such representation and agreement and (3) in such person's individual capacity, would be in compliance, if elected as a director of the company, and, if elected as a director, will comply with, all applicable publicly disclosed confidentiality, corporate governance, conflict of interest, Regulation FD, code of conduct and ethics, and stock ownership and trading policies and guidelines of the company; (h) such person's completed written questionnaire with respect to the background and qualification of such individual and the background of any other person or entity on whose behalf, directly or indirectly, the nomination is being made (which form of questionnaire shall be promptly provided by the corporate secretary to the requesting shareholder upon written request) and (i) all other information relating to such person that would be required to be disclosed in connection with a solicitation of proxies for the election of such person as a director, or would be otherwise required to be disclosed in connection with such solicitation, in each case pursuant to Regulation 14A under the Exchange Act, (including without limitation such person's written consent to being named in the proxy statement as a nominee and to serving as a director if elected).

In addition, as to the shareholder giving the notice and the beneficial owner, if any, on whose behalf the nomination is made, the notice must set forth: (a) the name and address, as they appear on the company's books, of such shareholder, and the name and address of such beneficial owner, if any, and any other shareholders known by such shareholder to be supporting such nominee(s); (b) the class and number of our shares that are owned beneficially and of record by such person and any affiliates or associates of such person; (c) the name of each nominee holder of our shares owned beneficially but not of record by such person or any affiliates or associates of such person, and the number of such shares held by each such nominee holder; (d) whether and the extent to which any derivative instrument, swap, option, warrant, short interest, hedge or profit interest or other transaction has been entered into by or on behalf of such person, or any affiliates or associates of such person, with respect to our shares; (e) whether and the extent to which any other transaction, agreement, arrangement or understanding (including any short position or any borrowing or lending of our shares) has been made by or on behalf of such person, or any affiliates or associates of such person, the effect or intent of any of the foregoing being to mitigate loss to, or to manage risk or benefit of stock price changes for, such person, or any affiliates or associates of such person, or to increase or decrease the voting power or pecuniary or economic interest of such person, or any affiliates or associates of such person, with respect to our shares; (f) a representation that the shareholder giving notice intends to appear online or by proxy at the annual meeting or special meeting to nominate the persons named in its notice; (g) a description of all agreements, arrangements and understandings between such person or any affiliate or associate of such person, and any other person or persons (including their names) in connection with the nomination by such shareholder; and (h) all other information that would be required to be disclosed by such person as a participant in a solicitation of proxies for the election of directors in a contested election, or would be otherwise required to be disclosed in connection with such solicitation, in each case pursuant to Regulation 14A under the Exchange Act. This information must be supplemented by such shareholder and beneficial owner, if any, not later than ten (10) days after the record date for the meeting to disclose all such information as of the record date.

At the request of the company, each proposed nominee must submit to the corporate secretary such other information as the company may reasonably require, including such information as may be necessary or appropriate in determining the eligibility of such proposed nominee to serve as an independent director of the company or that could be material to a reasonable shareholder's understanding of the independence, or lack thereof, of such nominee.

DIRECTOR COMPENSATION

The Executive Compensation Committee's independent compensation consultant, Meridian, annually advises the Executive Compensation Committee on matters related to non-management director compensation including competitive market data for the company's peer group. The Executive Compensation Committee reviews and discusses the director compensation information provided by Meridian and makes a recommendation to the full Board with respect to non-management director compensation. The Executive Compensation Committee's philosophy with respect to non-management director compensation is to target at or below the market median. The components of non-management director compensation include an annual cash retainer, additional annual cash retainers for the Chairman of the Board, the chairs of the Audit, Executive Compensation and Corporate Governance Committees and an annual stock retainer. No separate per meeting fees are paid to the non-management directors.

Compensation for each of our non-management directors for their service on our Board is paid on an annual meeting date basis. Based on the market information provided by Meridian in November 2020 and February 2021, indicating that our non-management director compensation was below market median compared to our peers, the Executive Compensation Committee recommended, and the full Board approved, increases in the cash retainer of 12 percent and the stock retainer of 5 percent for non-management director compensation. For the period of May 27, 2021, through May 25, 2022, non-management director compensation consists of $95,000 in an annual cash retainer and a $115,000 stock retainer. The chairs of our Audit, Corporate Governance and Executive Compensation Committees receive an additional annual cash retainer of $15,000, and our lead independent director, receives an additional annual cash retainer of $20,000. Our Chairman of the Board receives an additional annual cash retainer of $100,000 for his service.

All directors are reimbursed for reasonable expenses incurred in connection with attendance at Board and committee meetings.

The CEO, as the sole management director, receives no compensation for his service as a director.

Our Board has established minimum share ownership guidelines for members of our Board. The guidelines provide that within five years after joining the Board, each non-management director will own shares of the company's common stock having a value, at a minimum, of five times the annual cash retainer for service on the Board (excluding annual retainers for service as a chair of a Board committee or for service as Chairman of the Board or as the lead independent director) as established from time to time by the Board. Shares that count toward this ownership guideline include shares owned outright in the director's name, shares held in trust for the director's benefit or the benefit of the director's immediate family, and phantom shares held in the director's account under any company deferred compensation plan for non-employee directors or any similar plan or arrangement. Shares that do not count toward this ownership guideline include unexercised stock options and shares of restricted stock for which restrictions have not yet lapsed (unvested restricted stock). A non-management director will not be allowed to sell shares of the company's common stock (using established pre-clearance procedures) unless such director's holdings of the company's common stock meet the established minimum ownership guideline. Ms. Moore and Messrs. Evans, Gibson, Hutchinson, Rodriguez and Yaeger have each satisfied the minimum share ownership guidelines. Ms. Hart has until July 23, 2023, to satisfy the minimum share ownership guidelines.

The following table sets forth the compensation paid to our non-management directors in 2021:

Director Compensation for 2021

Director	Fees Earned or Paid in Cash(1)	Stock Awards(1)(2)(3)	Nonqualified Deferred Compensation Earnings(4)	All Other Compensation(5)	Total
Robert B. Evans	$ 95,000	$115,000	$ -	$ -	$210,000
John W. Gibson	$195,000	$115,000	$4,020	$25,000	$339,020
Tracy E. Hart	$ 95,000	$115,000	$ -	$ -	$210,000
Michael G. Hutchinson	$110,000	$115,000	$ -	$ -	$225,000
Pattye L. Moore	$110,000	$115,000	$ -	$ 5,000	$230,000
Eduardo A. Rodriguez	$130,000	$115,000	$ -	$ 2,500	$247,500
Douglas H. Yaeger	$ 95,000	$115,000	$ -	$ -	$210,000

(1) Non-management directors may defer all or a part of their annual cash and stock retainers under our Deferred Compensation Plan for Non-Employee Directors. During the year ended December 31, 2021, $499,750 of the total amount payable for directors' fees were deferred under this plan at the election of four of our directors. Deferred amounts are treated, at the election of the participating director, either as phantom stock or as a cash deferral. Phantom stock deferrals are treated as though the deferred amount is invested in our common stock at the fair market value on the date the deferred amount was earned. Phantom stock earns the equivalent of dividends declared on our common stock and is reinvested in phantom shares of our common stock based on the closing price of our common stock on the payment date of each common stock dividend. The shares of our common stock reflected in a non-management director's phantom stock account are issued to the director under our ECP on the last day of the director's service as a director or a later date selected by the director. Cash deferrals earn interest at a rate equal to Moody's Bond Indices Corporate AAA on the first business day of the plan year, plus 100 basis points, which, at January 4, 2021, was 3.28 percent. The following table sets forth, for each non-management director, the amount of director compensation deferred during 2021 and cumulative deferred compensation as of December 31, 2021.

Director	Board Fees Deferred to Phantom Stock in 2021 (a)	Dividends Earned on Phantom Stock and Reinvested in 2021 (b)	Total Board Fees Deferred to Phantom Stock at December 31, 2021 (a)	Total Shares of Phantom Stock Held at December 31, 2021 (c)	Board Fees Deferred to Cash in 2021 (d)	Total Board Fees Deferred to Cash at December 31, 2021 (d)
Robert B. Evans	$ -	$ -	$ -	-	$ -	$ -
John W. Gibson	$115,000	$33,597	$828,640	15,616	$195,000	$1,592,759
Tracy E. Hart	$ 46,000	$ 4,449	$170,727	2,275	$ -	$ -
Michael G. Hutchinson	$ -	$ -	$ -	-	$ -	$ -
Pattye L. Moore	$115,000	$33,597	$828,640	40,123	$ -	$ -
Eduardo A. Rodriguez	$ 28,750	$ 3,701	$129,250	2,538	$ -	$ -
Douglas H. Yaeger	$ -	$ -	$ -	-	$ -	$ -

(a) Reflects the value of the annual cash and stock retainers (based on the average of our high and low stock price on the NYSE on the grant date) deferred to phantom stock by a director under our Deferred Compensation Plan for Non-Employee Directors.

(b) Dividend equivalents paid on phantom stock are reinvested in additional shares of phantom stock based on the closing price of our common stock on the NYSE on the date the dividend equivalent was paid.

(c) Includes 24,507 shares of phantom stock held by Ms. Moore and 709 shares of phantom stock held by Mr. Rodriguez as a result of the separation from ONEOK.

(d) Mr. Gibson deferred board fees in the amount of $195,000 to cash in 2021. The total amount deferred to cash reflects the balance in Mr. Gibson's cash deferral account. Cash deferrals earn interest at a rate equal to Moody's Bond Indices Corporate AAA on the first business day of the plan year, plus 100 basis points which, at January 4, 2021, was 3.28 percent.

(2) The amounts in this column reflect the aggregate grant date fair value, computed in accordance with Financial Accounting Standards Board's Accounting Standards Codification Topic 718, Compensation-Stock Compensation ("ASC Topic 718"), with respect to stock awards received by directors for service on our Board. Since the shares are issued free of any restrictions on the grant date, the grant date fair value of these awards is based on the average of our high and low stock price on the NYSE on the date of grant. The following table sets forth the number of shares and grant date fair value of such shares of our common stock issued to our non-management directors during 2021 for service on our Board.

Director	Shares Awarded in 2021	Aggregate Grant Date Fair Value
Robert B. Evans	1,535	$115,000
John W. Gibson	1,535	$115,000
Tracy E. Hart	1,535	$115,000
Michael G. Hutchinson	1,535	$115,000
Pattye L. Moore	1,535	$115,000
Eduardo A. Rodriguez	1,535	$115,000
Douglas H. Yaeger	1,535	$115,000

(3) For the aggregate number of shares of our common stock and phantom stock held by each member of our Board at March 1, 2022, see "Stock Ownership–Holdings of Officers and Directors" at page 34.

(4) Reflects above-market earnings on Board fees deferred to cash under our Deferred Compensation Plan for Non-Employee Directors which provides for payment of interest on cash deferrals at a rate equal to Moody's Bond Indices Corporate AAA on the first business day of the plan year, plus 100 basis points, which, at January 2, 2021, was 3.28 percent.

(5) Reflects charitable contributions made by our company or the ONE Gas Foundation, Inc., on behalf of members of our Board as follows: (a) matching contributions up to $5,000 per year to non-profit organizations of his or her choice pursuant to our Matching Grants Program for Directors of ONE Gas through our Community Investment Program; and (b) matching contributions to the United Way pursuant to our annual United Way contribution program.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

During 2021, Mesdames Hart and Moore and Messrs. Evans, Hutchinson, Rodriguez and Yaeger served on our Executive Compensation Committee. No member of the Executive Compensation Committee was an officer or employee of the company or its subsidiary during 2021, and no member of this committee was formerly an officer of the company or its subsidiary. In addition, during 2021, none of our executive officers served as a member of a compensation committee or Board of any other entity of which any member of our Board was an executive officer.

Ms. Moore currently serves as the Chair of the ONEOK Executive Compensation Committee, and Mr. Rodriguez serves as Vice Chair of the ONEOK Executive Compensation Committee.

EXECUTIVE SESSIONS OF THE BOARD

The non-management members of our Board meet in regularly scheduled executive sessions without any members of management present. Our Chairman of the Board presides during the non-management executive sessions of the Board. During 2021, the non-management members of our Board met in executive session during each regularly scheduled in-person meeting of the Board held during the year. We intend to continue this practice of regularly scheduled meetings of the non-management members of our Board.

Our corporate governance guidelines provide that our lead independent director, who is the chair of our Corporate Governance Committee, presides as the chair at executive session meetings of the independent members of our Board. The independent members of the Board meet in regularly scheduled executive sessions without any members of management or non-independent directors present in connection with each regularly scheduled in-person meeting of the Board. During 2021, the independent members of our Board met in executive session during each regularly scheduled in-person meeting of the Board held during the year. We intend to continue this practice of regularly scheduled meetings of the independent members of our Board.

COMMUNICATIONS WITH DIRECTORS

Our Board believes that it is management's role to speak for our company. Directors refer all inquiries regarding our company from institutional investors, analysts, the news media, customers or suppliers to our CEO or his designee. Our Board also believes that any communications between members of the Board and interested parties, including shareholders, should be conducted with the knowledge of our CEO. Interested parties, including shareholders, may contact one or more members of our Board, including non-management directors and non-management directors as a group, by writing to the director or directors in care of our corporate secretary at our principal executive offices. A communication received from an interested party or shareholder will be forwarded promptly to the director or directors to whom the communication is addressed. A copy of the communication also will be provided to our CEO. We will not, however, forward sales or marketing materials, materials that are abusive, threatening or otherwise inappropriate, or correspondence not clearly identified as interested party or shareholder correspondence.

COMPLAINT PROCEDURES

Our Board has adopted procedures for the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, or auditing matters and complaints or concerns under our code of business conduct and ethics. These procedures allow for the confidential and anonymous submission by employees of concerns regarding questionable accounting or auditing matters and matters arising under our code of business conduct and ethics. The full text of these procedures, known as our whistleblower policy, is published on and may be printed from our website at www.ONEGas.com and is also available from our corporate secretary upon request.

PROPOSAL 1 – ELECTION OF DIRECTORS

ELECTION BY MAJORITY VOTE

Our amended and restated certificate of incorporation provides for the annual election of directors. Our Board of Directors currently consists of eight members, each of whose terms will expire at the 2022 annual meeting. As described above, Mr. Norton resigned from the Board effective June 27, 2021, and Mr. McAnnally was elected to the Board effective June 28, 2021. Accordingly, the eight current members of our Board of Directors named in this proxy statement will stand for re-election at the annual meeting for one-year terms.

The Board believes that its current membership reflects a balanced Board with deep experience and diverse expertise.

Our bylaws provide that, in the case of uncontested elections (i.e., elections where the number of nominees is the same as the number of directors to be elected), director nominees are elected by the vote of a majority of the votes cast with respect to that nominee. Abstentions and broker non-votes with respect to the election of a director do not count as votes cast. Our corporate governance guidelines provide that any uncontested nominee for director who fails to receive the requisite majority vote at an annual or special meeting held for the purpose of electing directors where the election is uncontested must, promptly following certification of the shareholder vote, tender his or her resignation to the Board. The Board (excluding the director who tendered the resignation) will evaluate any such resignation in light of the best interests of the company and our shareholders in determining whether to accept or reject the resignation, or whether other action should be taken. In reaching its decision, the Board may consider any factors it deems relevant, including the director’s qualifications, the director’s past and expected future contributions to the company, the overall composition of the Board and whether accepting the tendered resignation would cause the company to fail to comply with any applicable rule or regulation (including the NYSE listing requirements and the federal securities laws). The Board will act on the tendered resignation and publicly disclose its decision and rationale within 90 days following certification of the shareholder vote.

The persons named in the accompanying proxy card intend to vote such proxy in favor of the election of each of the nominees named below, who are all currently directors, unless the proxy provides for a vote against the director. Although the Board has no reason to believe that the nominees will be unable to serve as directors, if a nominee withdraws or otherwise becomes unavailable to serve, the persons named as proxies will vote for any substitute nominee designated by the Board, unless contrary instructions are given on the proxy. Except for these nominees, no other person has been recommended to our Board as a potential nominee or otherwise nominated for election as a director.

BOARD DIVERSITY

Our Board recognizes the importance of diversity on the Board. Diversity brings different perspectives to Board discussions and deliberations. During 2021, the Board included two female directors (25%) and one Hispanic director (12.5%). In terms of age, three age decades are represented on our board, and the difference in age between our oldest and youngest board members is 15 years. Average director tenure is slightly over six years. Ms. Moore and Messrs. Gibson and Rodriguez served on the ONEOK board of directors prior to our separation from ONEOK. Considering their tenure on the ONEOK board of directors, our average board tenure is over nine years.

BOARD QUALIFICATIONS

Our corporate governance guidelines provide that our Corporate Governance Committee will evaluate the qualifications of each director candidate and assess the appropriate mix of skills and characteristics required of Board members in the context of the perceived needs of the Board at a given point in time. Each director also is expected to:

- exhibit high standards of integrity, commitment and independence of thought and judgment;
- use his or her skills and experiences to provide independent oversight to the business of our company;
- be willing to devote sufficient time to carrying out his or her duties and responsibilities effectively;
- devote the time and effort necessary to learn the business of the company and the Board;
- represent the long-term interests of all shareholders; and
- participate in a constructive and collegial manner.

In addition, our corporate governance guidelines provide that, in nominating candidates, the Board will endeavor to establish director diversity in personal background, sex, sexual orientation, gender identity or expression, race, ethnicity, age and national origin, and to maintain a mix that includes, but is not limited to, the following areas of core competency: accounting and finance; investment banking; business judgment; management; industry knowledge; crisis response; international business; leadership; applicable ESG matters; strategic vision; law; and corporate relations.

The Board believes that each member of our Board possesses the necessary integrity, skills and qualifications to serve on our Board and that their individual and collective skills and qualifications provide them with the ability to engage management and each other in a constructive and collaborative fashion and, when necessary and appropriate, challenge management in the execution of our business operations and strategy.

The following table summarizes the Board’s skills and qualifications as an easy reference:

Skills, Attributes and Experience	John Gibson	Robert Evans	Tracy Hart	Michael Hutchinson	Pattye Moore	Robert McAnnally	Eduardo Rodriguez	Douglas Yaeger
Executive Management	●	●	●	●	●	●	●	●
Operations	●	●	●			●	●	●
Industry Knowledge	●	●		●		●	●	●
Acquisitions and Divestitures	●		●					
Strategic and Financial Planning	●		●		●	●	●	
Risk Management and Oversight	●		●					
Safety	●	●	●			●	●	●
Compliance	●	●				●		●
Corporate Governance	●	●	●	●	●		●	●
Executive Compensation	●				●		●	●
Marketing	●				●			
Corporate Development	●	●						
Regulatory Compliance							●	
Legal						●	●	
Financial and Operational Analysis	●	●	●	●		●		●
Public Accounting				●				
Construction Management	●		●					
Engineering Management	●							
Accounting and Financial Expertise	●	●	●	●			●	●
Demographic Background								
Board Tenure (years)	8	8	3	8	8	1	8	8
Age (years)	69	73	60	66	64	58	66	73
Gender (male/female)	M	M	F	M	F	M	M	M
Race/Ethnicity								
Hispanic/Latino							●	
Caucasian/White	●	●	●	●	●	●		●

Certain information with respect to the eight nominees for election at the annual meeting, is set forth below. This information includes their names, ages, a brief description of their recent business experience, including present occupations and employment, certain directorships that each person holds and the year in which each person became a director of the company. All eight director nominees currently serve as directors of the company.

None of the director nominees are being proposed for election pursuant to any agreement or understanding between the nominees and the company or any other person(s).

There are no family relationships between or among any of the director nominees and executive officers.

RECOMMENDATION OF THE BOARD

Your board unanimously recommends a vote **FOR** each nominee.

DIRECTOR NOMINEES

Set forth below is certain information with respect to each nominee for election as a director, each of whom is a current director. In light of the experience, skills and qualifications of each of the nominees for election as a director as detailed below, our Board has concluded that each nominee should continue as a member of our Board.

ROBERT B. EVANS
Retired President and Chief Executive Officer, Duke Energy Americas

Age: 73
Director Since: 2014
Independent: Yes

Committee Member: Audit (Vice Chair), Corporate Governance, Executive Compensation

Current Public Company Directorships:
Targa Resources Corp. (since 2016)
Targa Resources GP LLC (since 2007)
New Jersey Resources Corp. (since 2009)

Prior Public Company Directorships:
Sprague Resources, LP (2013 to 2018)

Prior Experience: Mr. Evans served as President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 until his retirement in March 2006. He served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans was president of Duke Energy Gas Transmission, a business unit of Duke Energy, beginning in 1998 until he was named President and Chief Executive Officer in 2002, a position in which he served until 2004. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of Marketing and Regulatory Affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998.

Skills and Qualifications: Mr. Evans has extensive experience with the natural gas transmission business and wholesale natural gas trading business of Duke Energy and Targa Resources Partners and his current and previous directorships for other energy companies brings executive management, corporate development, operations, finance, customer perspectives, safety, compliance, risk management and corporate governance to the Board.

JOHN W. GIBSON
Retired Chief Executive Officer, ONEOK and ONEOK Partners GP, L.L.C.

Position:
Chairman of the Board

Age: 69
Director Since: 2014
Independent: No

Committee Member: Executive (Chair)

Current Public Company Directorships:
ONEOK, Chairman of the Board (since 2011)

Prior Public Company Directorships:
ONEOK Partners, GP, L.L.C. (2007 to 2017)
BOK Financial Corp (2008 to 2018)
Matrix Service Company (2016 to 2020)

Prior Experience: Mr. Gibson served as Chief Executive Officer of ONEOK from January 2007 to January 2014. He was appointed Chairman of the Board of ONEOK in May 2011 and served as President from 2010 through 2011. Mr. Gibson served as Chief Executive Officer and as Chairman of the Board of ONEOK Partners, GP, L.L.C., the sole general partner of ONEOK Partners, L.P. from 2007 until it was acquired by ONEOK in June 2017. Mr. Gibson was instrumental in the separation of ONE Gas from ONEOK into a stand-alone, 100 percent regulated, publicly traded natural gas distribution company. In connection with the separation, Mr. Gibson retired as Chief Executive Officer of ONEOK and of ONEOK Partners GP, L.L.C. effective January 31, 2014. He joined ONEOK in 2000 as President of Energy where he served in a variety of leadership positions. Prior to joining ONEOK, Mr. Gibson was Executive Vice President of Koch Energy, Inc., a subsidiary of Koch Industries. He spent 18 years with Phillips Petroleum Company in a variety of domestic and international positions in its natural gas, natural gas liquids and exploration and production businesses. His career began in the energy industry in 1974 as a refinery engineer with Exxon Company, USA.

Skills and Qualifications: Mr. Gibson has extensive industry experience and brings strategic and financial planning, acquisitions and divestitures, operations, executive management, corporate development, compliance and risk management. His current and previous directorships bring valuable experience in corporate governance, executive compensation, marketing and financial matters.

TRACY E. HART
President and Chief Executive Officer, Tarlton Corporation

Age: 60
Director Since: 2018
Independent: Yes

Committee Member: Audit, Corporate Governance, Executive Compensation

Current Public Company Directorships: None

Prior Public Company Directorships: None

Prior Experience: Ms. Hart has served as President and Chief Executive Officer and on the board of Tarlton Corporation, a St. Louis based general contracting and construction management firm since joining the company in 1990. Ms. Hart also serves as President and Chief Executive Officer of Waterhout Construction Company, a Tarlton wholly-owned subsidiary. She is the first woman to become president of a major general contracting company in St. Louis, and one of a few nationally. Ms. Hart serves on the Executive Committee of Midwest BankCentre's Legal Board of Directors.

In 2008, Ms. Hart was elected the first woman chairperson of the Associated General Contractors of St. Louis, having served on the board since 1996. She also is the first woman to be named chairperson of the AGC Natural Quality in Construction Committee. Ms. Hart has received much recognition as a successful business leader including being awarded the University of Missouri-St. Louis Trailblazer Award for her accomplishments. Ms. Hart holds numerous positions in the community, including her position as a board member of the St. Louis Regional Chamber, and service on the Board of Trustees at St. Louis Children's Hospital. In 2019, Ms. Hart was appointed as a Commissioner of the St. Louis Economic Development Partnership, the economic development entity for St. Louis city and county, and became chairperson in 2020.

Skills and Qualifications: Ms. Hart has extensive executive management and construction management experience, leadership skills and directorships, and brings valuable experience in finance, operations, strategic and financial planning, acquisitions and divestitures, corporate governance, and risk management. Her years of service to her community in varying positions brings social responsibility, community engagement, and inclusion and diversity experience.

MICHAEL G. HUTCHINSON
Retired Partner, Deloitte & Touche

Age: 66
Director Since: 2014
Independent: Yes

Committee Member: Audit (Chair), Corporate Governance (Vice Chair), Executive Compensation, Executive

Current Public Company Directorships: None

Prior Public Company Directorships:
Whiting Petroleum Corporation (2019 to 2020)
Westmoreland Coal Company (2012 to 2019)
CoBiz Financial, Inc. (2017 to 2018)
ONEOK Partners GP, L.L.C. (2015 to 2017)

Prior Experience: Mr. Hutchinson retired as a partner from Deloitte & Touche in 2012. His Deloitte career spanned nearly 35 years, leading the energy and natural resources practice in Colorado for more than 10 years, while at the same time managing more than 150 professionals in the Denver audit and enterprise risk management practice. Mr. Hutchinson was elected to the board of Whiting Petroleum Corporation on September 1, 2019, and served as a member of its Audit Committee until it emerged from bankruptcy in September 2020. Mr. Hutchinson served on the board of Westmoreland Coal Company from 2012 through March 2019 and served as its interim Chief Executive Officer from November 2017 until conclusion of the company's restructuring process in March 2019. Mr. Hutchinson served on the board of CoBiz Financial, Inc. and as its audit committee chair until it was acquired in September 2018. In 2015, Mr. Hutchinson joined the board of ONEOK Partners GP, L.L.C., the general partner of ONEOK Partners, L.P., and served as vice chair of its Audit Committee until the acquisition of ONEOK Partners, L.P. by ONEOK, Inc. in June 2017.

Skills and Qualifications: Mr. Hutchinson has extensive experience with accounting principles, financial controls and evaluating financial statements of public companies in the energy sector, particularly from an auditor's perspective and his current and previous directorships brings extensive management experience and corporate governance to the Board.

ROBERT S. McANNALLY
President and Chief Executive Officer, ONE Gas

Position: Management Director

Age: 58
Director Since: 2021
Independent: No

Committee Member: Executive

Current Public Company Directorships: None

Prior Public Company Directorships: None

Prior Experience: Mr. McAnnally has served as President and Chief Executive Officer of ONE Gas since June 28, 2021. Mr. McAnnally joined the company in 2015 as senior vice president of operations responsible for the operation of its three natural gas utilities – Oklahoma Natural Gas Company, Kansas Gas Service and Texas Gas Service. He was promoted to COO in 2020, assuming additional responsibilities for the company's administrative functions, including human resources and information technology. Before joining ONE Gas, Mr. McAnnally was an officer of Energen Corporation, serving first as vice president of external affairs and strategic planning, then as senior vice president of customer service and marketing for its utility subsidiary, Alagasco. Before joining Energen, Mr. McAnnally practiced law, representing clients in the utility, financial and corporate sectors.

Mr. McAnnally serves on the Board of Directors of the American Gas Association. He served as the Chair of the Board of Trustees of the American Gas Foundation and remains an active trustee. Mr. McAnnally is also involved in several other industry associations and charitable organizations.

Skills and Qualifications: Mr. McAnnally has extensive experience in executive management, operations, strategic and financial planning, safety and compliance. In addition, Mr. McAnnally has legal and financial and operational analysis experience.

PATTYE L. MOORE
Business Strategy Consultant, Pattye Moore & Associates LLC

Age: 64
Director Since: 2014
Independent: Yes

Committee Member: Executive Compensation (Chair), Corporate Governance, Audit, Executive

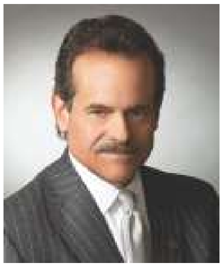
Current Public Company Directorships:
ONEOK, Inc. (since 2002)

Prior Public Company Directorships:
Red Robin Gourmet Burgers (2007 to 2019)

Prior Experience: Ms. Moore served on the Board of Red Robin Gourmet Burgers from 2007 until her retirement on December 31, 2019, served as the non-executive Chairman of the Board from 2010 through October 2019 and served as interim Chief Executive Officer from April 2019 through October 2019. Since 2002, Ms. Moore has served on the board of ONEOK and is the Chair of its Executive Compensation Committee. Ms. Moore also serves as a director of privately-held QuikTrip Corporation. In addition, Ms. Moore is a business strategy consultant, speaker and the author of *Confessions from the Corner Office*, a book on leadership instincts, published by Wiley & Sons in 2007. Ms. Moore served on the board of Sonic Corp. from 2000 through January 2006 and was the President of Sonic from January 2002 to November 2004. She held numerous senior management positions during her 12 years at Sonic.

Skills and Qualifications: Ms. Moore has extensive leadership skills, executive management, management development, marketing and brand development, and strategic planning experience. Ms. Moore's current and previous directorships bring corporate governance and executive compensation experience to the Board. Ms. Moore also has extensive experience as a member of the board of numerous non-profit organizations, including serving as Chairman of the Board of the National Arthritis Foundation. Ms. Moore is a National Association of Corporate Directors ("NACD") Board Leadership Fellow and was named to the NACD 2017 Directorship 100 List.

EDUARDO A. RODRIGUEZ
President, Strategic Communications Consulting Group



Position: Lead Independent Director

Age: 66
Director Since: 2014
Independent: Yes

Committee Member: Corporate Governance (Chair), Audit, Executive Compensation, Executive

Current Public Company Directorships:
ONEOK, Inc. (since 2004)

Prior Public Company Directorships: None

Prior Experience: Mr. Rodriguez is President of Strategic Communication Consulting Group in El Paso, Texas. Mr. Rodriguez serves as a member of the ONEOK board and as Vice Chair of its Executive Compensation Committee and Vice Chair of its Corporate Governance Committee. Mr. Rodriguez previously served as Executive Vice President of Hunt Building Corporation, a privately held company engaged in construction and real estate development. He also served as a member of the board of Hunt Building Corporation. Prior to his three years with Hunt Building Corporation, Mr. Rodriguez spent 20 years in the electric utility industry at El Paso Electric Company, at the time during which it was a publicly traded, investor-owned utility, where he served in various senior-level executive positions, including General Counsel, Senior Vice President for Customer and Corporate Services, Executive Vice President and as Chief Operating Officer.

Skills and Qualifications: Mr. Rodriguez has extensive senior management, operational, entrepreneurial and legal experience in a variety of industries and brings valuable experience in strategic planning, corporate governance, regulatory compliance, utility operations, and executive compensation to the Board. Mr. Rodriguez has practiced law for more than 40 years and is a licensed attorney in the states of Texas and New Mexico, and is admitted to the United States District Court for the Western District of Texas.

DOUGLAS H. YAEGER
Retired Chairman, President and Chief Executive Officer, Laclede Group, Inc. (now Spire Inc.)

Age: 73
Director Since: 2014
Independent: Yes

Committee Member: Executive Compensation (Vice Chair), Audit, Corporate Governance

Current Public Company Directorships: None

Prior Public Company Directorships:
The Laclede Group, Inc. (1999 to 2012)

Prior Experience: Mr. Yaeger served as Chairman, President and Chief Executive Officer of The Laclede Group, Inc. (now known as Spire Inc.) and Laclede Gas Company from 1999 until his retirement on February 1, 2012. He served as President and Chief Operating Officer from 1997 to 1999 and as Executive Vice President–Operations and Marketing from 1995 to 1997. Mr. Yaeger served Senior Vice President–Operations, Gas Supply and Technical Services from 1992 to 1995. Mr. Yaeger joined Laclede in 1990 as Vice President–Planning. Prior to this time, he held roles as Executive Vice President of Mississippi River Transmission Corporation and Executive Vice President of Arkla Energy Marketing Company.

Mr. Yaeger served on the board and Executive Committee of the American Gas Association and is a past Chairman of its Audit Committee. He also served as Chairman of the Missouri Energy Development Association and the Southern Gas Association.

Skills and Qualifications: Mr. Yaeger has extensive executive management experience in a variety of sectors in the oil and natural gas industry as a result of his service at Laclede. Mr. Yaeger brings extensive industry, financial, compliance, safety, corporate governance, operating and executive compensation experience to the Board.

PROPOSAL 2 – RATIFY THE SELECTION OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR THE YEAR ENDING DECEMBER 31, 2022

RATIFICATION OF THE SELECTION OF PRICEWATERHOUSECOOPERS LLP AS OUR INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2022

Our Board has ratified the selection by our Audit Committee of PricewaterhouseCoopers LLP to serve as our independent (consistent with SEC and NYSE policies regarding independence) registered public accounting firm for 2022. In carrying out its duties in connection with the 2022 audit, PricewaterhouseCoopers LLP had unrestricted access to our Audit Committee to discuss audit findings and other financial matters.

Representatives of PricewaterhouseCoopers LLP will be present at the annual meeting to answer appropriate questions. They also will have the opportunity to make a statement if they desire to do so.

Approval of this proposal to ratify the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm requires the affirmative vote of a majority of the voting power of the shareholders present online or by proxy and entitled to vote on this proposal at the meeting. Abstentions will have the effect of a vote against the proposal.

RECOMMENDATION OF THE BOARD

Your board unanimously recommends a vote **FOR** the ratification of the selection of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2022.

AUDIT AND NON-AUDIT FEES

Audit services provided by PricewaterhouseCoopers LLP during the 2022 fiscal year included an integrated audit of our consolidated financial statements and internal control over financial reporting, review of our unaudited quarterly financial statements, consents for and review of documents filed with the SEC, and performance of certain agreed-upon procedures.

The following table presents fees billed for services rendered by PricewaterhouseCoopers LLP for the years ended December 31, 2021, and 2020:

	2021	2020
	(Thousands of Dollars)	
Audit fees(1)	$1,419.9	$1,456.7
Audit related fees(2)	$6.3	$6.3
Tax fees	$-	$-
Total	$1,426.2	$1,463.0

(1) Audit fees include audit services provided for the audits of the annual financial statements and internal controls as required by Section 404 of the Sarbanes-Oxley Act of 2002, and reviews of unaudited quarterly financial information and consents related to the Registration Statements filed with the SEC by us.

(2) Audit related fees include subscriptions to research software for technical accounting guidance.

AUDIT COMMITTEE POLICY ON SERVICES PROVIDED BY THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Consistent with SEC and NYSE policies regarding auditor independence, the Audit Committee has the responsibility for appointing, setting compensation for and overseeing the work of our independent auditor. In furtherance of this responsibility, the Audit Committee has established a policy with respect to the pre-approval of audit and permissible non-audit services provided by our independent auditor. Prior to engagement of PricewaterhouseCoopers LLP as our independent auditor for the 2022 audit, a plan was submitted to and approved by the Audit Committee setting forth the audit services expected to be rendered during 2022. The plan included audit services which are comprised of work performed in the audit of our financial statements and to attest and report on our internal controls over financial reporting, as well as work that only the independent auditor can reasonably be expected to provide, including:

- quarterly review of our unaudited financial statements;
- comfort letters;
- statutory audits;
- performance of certain agreed-upon procedures;
- attest services; and
- consents and assistance with the review of documents filed with the SEC.

Audit fees are budgeted, and the Audit Committee requires the independent auditor and management to report actual fees versus budgeted fees periodically during the year by category of service.

The Audit Committee has adopted a policy that provides that fees for audit, audit related and tax services that are not included in the independent auditor's annual services plan, and for services for which fees are not determinable on an annual basis, are pre-approved if the fees for such services will not exceed $75,000. In addition, the policy provides that the Audit Committee may delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated must report, for informational purposes only, any pre-approval decisions to the Audit Committee at its next scheduled meeting.

2022 REPORT OF THE AUDIT COMMITTEE

The purpose of the Audit Committee is to assist the Board with the oversight of the integrity of the company's financial statements and internal controls, the company's compliance with legal and regulatory requirements, the independence, qualifications and performance of the company's independent registered public accounting firm and the performance of the company's internal audit function. The Audit Committee's function is more fully described in its charter, which the Board has adopted. The charter is on and may be printed from our website at www.ONEGas.com and is also available from the company's corporate secretary upon request. The Audit Committee reviews the charter on an annual basis. The Board annually reviews the definition of "independence" for audit committee members contained in the listing standards for the NYSE and applicable rules of the SEC, as well as our director independence guidelines, and has determined that each member of the Audit Committee is independent under those standards. In addition, the Board has determined that all members of the Audit Committee are financially literate, and five of the six committee members are audit committee financial experts.

Management is responsible for the preparation, presentation and integrity of the company's financial statements, accounting and financial reporting principles, internal controls and procedures designed to ensure compliance with accounting standards, applicable laws and regulations. The company's independent registered public accounting firm, PricewaterhouseCoopers LLP, is responsible for performing an independent audit of the company's consolidated financial statements and the company's internal control over financial reporting and expressing an opinion on the conformity of those financial statements with generally accepted accounting principles and on the effectiveness of the company's internal control over financial reporting.

In this context, the Audit Committee has met and held discussions with management and the company's independent registered public accounting firm, PricewaterhouseCoopers LLP, regarding the fair and complete presentation of the company's financial results and management's report on its assessment of the company's internal control over financial reporting. In addition, the Audit Committee reviews the quality of the company's significant accounting policies and presentations in the financial statements. The Audit Committee has discussed the most critical estimates and accounting policies applied by the company in its financial statements, as well as alternative treatments. The Audit Committee has also reviewed both the internal and independent auditors' audit plans and subsequent findings. Management has represented to the Audit Committee that the company's consolidated financial statements were prepared in accordance with generally accepted accounting principles, and the Audit Committee has reviewed and discussed the consolidated financial statements with management and the independent auditor.

The Audit Committee has also reviewed and discussed with both management and the independent registered public accounting firm, management's assessment of the company's internal control over financial reporting. In addition, the Audit Committee has discussed the independent auditor's report on the company's internal control over financial reporting. The Audit Committee has also discussed with the company's independent auditor the matters required to be discussed by the applicable requirements of the Public Company Accounting Oversight Board and the SEC ("Communication with Audit Committees").

In addition, the Audit Committee has discussed with the independent registered public accounting firm, the firm's independence from the company and its management, including the matters in the written disclosures and the letter received from PricewaterhouseCoopers LLP as required by the applicable requirements of the Public Company Accounting Oversight Board (United States) regarding the independent accountant's communications with the Audit Committee concerning independence. No non-audit services were provided by PricewaterhouseCoopers LLP in 2021 or 2020, and did not impact the Audit Committee's determination of PricewaterhouseCoopers LLP's independence, the Audit Committee will also consider in the future whether the provision of non-audit services to the company by PricewaterhouseCoopers LLP is compatible with maintaining that firm's independence. The Audit Committee has concluded that the independent registered public accounting firm is independent from the company and its management. In considering the reappointment of PricewaterhouseCoopers LLP as the company's independent registered public accounting firm, the Audit Committee considered talent and experience on the audit engagement, the appropriateness of fees and the quality and candor of communications with the Audit Committee.

The Audit Committee discussed with the company's internal and independent auditors the overall scope and plans for their respective audits. The Audit Committee meets with both the internal and independent auditors, with and without management present, to discuss the results of their examinations, the assessments of the company's internal control over financial reporting and the overall quality of the company's financial reporting.

Based on the review and discussions referred to above, the Audit Committee recommended to the Board, and the Board approved, the inclusion of the audited financial statements of the company as of and for the year ended December 31, 2021, in the company's Annual Report on Form 10-K for the year ended December 31, 2021, for filing with the SEC.

Respectfully submitted by the members of the Audit Committee of the Board:

Michael G. Hutchinson, Chair
Robert B. Evans, Vice Chair
Tracy E. Hart, Member
Pattye L. Moore, Member
Eduardo A. Rodriguez, Member
Douglas H. Yaeger, Member

STOCK OWNERSHIP

HOLDINGS OF MAJOR SHAREHOLDERS

The following table sets forth the beneficial owners of 5 percent or more of our common stock known to us at March 1, 2022.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class(5)
Common Stock	BlackRock, Inc. 55 E. 52nd Street New York, NY 10055	6,548,818(1)	12.20%(1)
Common Stock	The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	5,824,796(2)	10.87%(2)
Common Stock	American Century Investment Management, Inc. 4500 Main Street, 9th Floor Kansas City, MO 64111	4,284,402(3)	8.00%(3)
Common Stock	T. Rowe Price Associates, Inc. 100 E. Pratt Street Baltimore, MD 21202	3,160,604(4)	5.80%(4)

(1) Based upon Schedule 13G filed with the SEC on January 27, 2022, in which BlackRock, Inc. reported that, as of December 31, 2021, BlackRock, Inc. beneficially owned in the aggregate 6,548,818 shares of our common stock. Of such shares, BlackRock, Inc. reported it had sole dispositive power with respect to 6,548,818 shares and sole voting power with respect to 6,224,118 shares.

(2) Based upon Schedule 13G filed with the SEC on February 10, 2022, in which The Vanguard Group, Inc. reported that, as of December 31, 2021, The Vanguard Group, Inc. directly and through its wholly-owned subsidiaries, Vanguard Fiduciary Trust Company and Vanguard Investments Australia, Ltd., beneficially owned in the aggregate 5,824,796 shares of our common stock. Of such shares, The Vanguard Group, Inc. reported it had sole dispositive power with respect to 5,711,741 shares, shared dispositive power with respect to 113,055 shares, sole voting power with respect to 0 shares, and shared voting power with respect to 66,012 shares.

(3) Based upon Schedule 13G filed with the SEC on February 4, 2022, in which American Century Investment Management, Inc., reported that, as of December 31, 2021, American Century Investment Management, Inc. directly and through its wholly-owned subsidiary, American Century Companies, Inc., American Century Capital Portfolios, Inc. controlled by the Stowers Institute for Medical Research, beneficially owned in the aggregate 4,284,402 shares of our common stock with respect to which American Century Investment Management, Inc. had sole voting power with respect to 4,052,270 shares, and sole dispositive power with respect to 4,284,402 shares.

(4) Based upon Schedule 13G filed with the SEC on February 14, 2022, in which T. Rowe Price Associates, Inc. reported that as of December 31, 2021, T. Rowe Price Associates, Inc. beneficially owned in the aggregate 3,160,604 shares of our common stock. Of such shares, T. Rowe Price Associates, Inc. reported it had sole dispositive power with respect to 3160,604 shares and sole voting power with respect to 867,191 shares.

(5) The percent of voting securities owned is based on the number of outstanding shares of our common stock on December 31, 2021.

HOLDINGS OF OFFICERS AND DIRECTORS

The following table sets forth the number of shares of our common stock beneficially owned as of March 1, 2022, by (1) each director and nominee for director, (2) each of the executive officers named in the Summary Compensation Table for 2021 under the caption "Compensation Discussion and Analysis" in this proxy statement, and (3) all directors and executive officers as a group.

Name of Beneficial Owner	Shares of ONE Gas Common Stock Beneficially Owned(1)	ONE Gas Directors' Deferred Compensation Plan Phantom Stock(2)	Total Shares of ONE Gas Common Stock Beneficially Owned Plus ONE Gas Directors' Deferred Compensation Plan Phantom Stock	ONE Gas Percent of Class(3)
Robert B. Evans	13,818	-	13,818	*
John W. Gibson	272,694	15,616	288,310	*
Tracy E. Hart	3,781	2,275	6,056	*
Michael G. Hutchinson	13,518	-	13,518	*
Robert S. McAnnally	26,782	-	26,782	*
Pattye L. Moore	500	40,123	40,623	*
Eduardo A. Rodriguez	9,716	2,538	12,254	*
Douglas H. Yaeger	23,818	-	23,818	*
Curtis L. Dinan	139,137	-	139,137	*
Caron A. Lawhorn	138,105	-	138,105	*
Joseph L. McCormick	68,395	-	68,395	*
Mark A. Bender	22,455	-	22,455	*
All directors and executive officers as a group	749,064	60,552	809,616	1.50

* Less than 1 percent.

(1) Includes shares of common stock held by members of the family of the director or executive officer for which the director or executive officer has sole or shared voting or investment power, shares of common stock held in our Direct Stock Purchase and Dividend Reinvestment Plan, shares held through our 401(k) Plan and shares held through our ESP Plan. There are no shares issuable pursuant to grants of RSUs or PSUs within 60 days of March 1, 2022.

The following table sets forth for the persons indicated and the number of shares of our common stock that are held on the person's behalf by the trustee of our 401(k) Plan as of March 1, 2022. Our Profit Sharing Plan was merged into our 401(k) Plan on December 30, 2021.

Executive Officer/Director	Stock Held by 401(k) Plan
Robert B. Evans	-
John W. Gibson	-
Michael G. Hutchinson	-
Robert S. McAnnally	-
Pattye L. Moore	-
Eduardo A. Rodriguez	-
Douglas H. Yaeger	-
Curtis L. Dinan	5,470
Caron A. Lawhorn	1,194
Joseph L. McCormick	3,211
Mark A. Bender	-
All directors and executive officers as a group	14,860

(2) Represents shares of phantom stock credited to a director's account under our Deferred Compensation Plan for Non-Employee Directors. Each share of phantom stock is equal to one share of our common stock. Phantom stock has no voting or other shareholder rights, except that dividend equivalents are paid on phantom stock and reinvested in additional shares of phantom stock based on the closing price of our common stock on the NYSE on the date the dividend equivalent was paid. Shares of phantom stock do not give the holder beneficial ownership of any shares of our common stock because they do not give such holder the power to vote or dispose of any shares of our common stock.

(3) The percent of our voting securities owned is based on our outstanding shares of common stock on March 1, 2022.

COMPENSATION DISCUSSION AND ANALYSIS

The Compensation Discussion and Analysis contains a detailed description of our executive compensation philosophy and the elements of compensation that we provide to our NEOs.

Our NEOs for the fiscal year ended December 31, 2021, are as follows:

Robert S. McAnnally	**President and CEO (Effective June 28, 2021)**
Pierce H. Norton II	**Former President and CEO (Retired from the company effective June 27, 2021)**
Caron A. Lawhorn	**Senior Vice President and CFO**
Curtis L. Dinan	**Senior Vice President and COO**
Joseph L. McCormick	**Senior Vice President, General Counsel and Assistant Secretary**
Mark A. Bender	**Senior Vice President, Administration and Chief Information Officer**

Mr. McAnnally was appointed to serve as our President and CEO on June 28, 2021, succeeding Mr. Norton upon his retirement from our company. He joined the company in 2015 as the Senior Vice President of Operations and was promoted to Senior Vice President and COO in 2020.

Mr. Dinan was appointed to serve as our Senior Vice President and COO upon Mr. McAnnally's promotion. Mr. Dinan previously served as our Senior Vice President and CCO. With this appointment, Mr. Dinan assumed responsibility for the company's operations and safety functions along with his current leadership role of commercial activities, corporate development, rates and regulatory, government affairs, community relations, and customer service. He has been with the company since its inception in 2014. Mr. Dinan served as Senior Vice President and CFO until 2020 when he transitioned to Senior Vice President and CCO.

EXECUTIVE SUMMARY

ONE Gas continued to proactively address the safety and health of our workforce in 2021 related to the COVID-19 global pandemic. To help prevent the spread of COVID-19 in our workplace and communities, we continued to ask employees to work remotely where possible. We maintained a cross-functional task force to ensure information technology infrastructure and equipment were in place to seamlessly provide a connected remote work environment and enhance our facilities to enable safely distanced work environments. For those employees not able to work from home, we continued to execute a multi-tiered response and safety plan using guidelines from the Centers for Disease Control and Prevention, Occupational Safety and Health Administration ("OSHA") and third-party experts. This plan was created with specific procedures to serve our customers and community proactively and safely with minimal disruption of service. We continue to monitor this plan and make necessary adjustments based on the risk level of the virus-related activity in our operating areas. Our senior leadership has been key in implementing these precautionary measures to protect business critical operations as well as maintain our commitment to the safety and health of our employees and the communities in which we serve and do business.

In early 2021 winter storm Uri, a historic winter storm, impacted supply, demand, and market pricing for natural gas in all ONE Gas service territories. The governors of Kansas, Oklahoma, and Texas, declared states of emergency, and certain regulatory agencies issued emergency orders that impacted the utility and natural gas industries. Under the guidance of our senior leadership and the collective efforts of our employees, we lost service to fewer than 900 of our 2.2 million customers during this unprecedented cold weather event. The few outages that did occur lasted less than 24 hours in most cases. This extraordinary performance was the result of many elements coming together: the system improvements since 2014; the dedication of employees to maintain gas service; the goodwill of customers who conserved their usage; and the work of our field operations team who, in the most challenging conditions, worked tirelessly to ensure that our system continued to provide natural gas to our residential customers and critical care facilities. Both during and following winter storm Uri, management's decisions were guided by the Company's core values including safety, ethics, service and value.

Despite the national disasters of COVID-19 and winter storm Uri, ONE Gas did not reassess any of the metrics for our incentive plans. As reflected in the performance highlights below, ONE Gas continued to provide value to our stakeholders.

2021 Performance Highlights

- In 2021, we generated net income of $206 million, or $3.85 per diluted share compared with 2020 net income of $196 million, or $3.68 per diluted share. Operating income in 2021 was $310 million, compared with operating income of $304 million in 2020.
- During 2021, we paid cash dividends of $2.32 per share. We paid total aggregate dividends to our shareholders of $124 million in 2021. In January 2022, we declared a dividend of 62 cents per share ($2.48 per share on an annualized basis), an increase of 4 cents per share compared with the previous cash dividend of 58 cents per share.

- The market price of our common stock was $77.59 per share on December 31, 2021, an increase of approximately 130 percent from the closing price of $33.63 on February 3, 2014, our first day of "regular way" trading, and an increase of 1 percent from the closing price of $76.77 on December 31, 2020.
- We generated TSR of approximately 38 percent from December 31, 2016, through December 31, 2021. This return exceeded the returns over the same period of 8 of 13 companies in our peer group, but was below the returns of Dow Jones Industrial Average (106 percent), the S&P MidCap 400 Index (85 percent), and the S&P MidCap Utilities Index (40 percent).
- Driving safely, personal injury prevention and public safety continue to be a priority at ONE Gas. We lead our peers in DART performance. We achieved a 6 percent improvement in TRIR as compared to last year. ONE Gas' DART, TRIR, and PVIR all performed within the American Gas Association's last reported first quartile results. ONE Gas was awarded the Safety Achievement Award for Excellence in Employee Safety by the American Gas Association for the fourth consecutive year, which recognizes ONE Gas for having the fewest number of lost workdays due to injury.

Our executive compensation programs have features designed to align the interests of executives with stakeholders. The following chart provides an overview of the practices underlying our compensation programs:

What We Do

✓ Emphasize a pay-for-performance focus where the majority of executive compensation is performance-based	✓ Grant an annual incentive that is based on financial, operational and individual performance	✓ Grant 80% of LTI in performance-based equity to align long-term business goals with the interest of stakeholders	✓ Engage an independent executive compensation consultant	✓ Maintain a clawback policy to recoup incentive-based compensation awards under certain circumstances
✓ Enforce share ownership guidelines for executives and directors	✓ Prohibit executives and directors from hedging or pledging activities	✓ Restrict Change-in-Control cash benefits to "double-trigger" vesting	✓ Restrict Change-in-Control acceleration of equity vesting to "double-trigger" vesting	✓ Review tally sheets for NEOs prior to making compensation decisions

What We Don't Do

✗ Enter into employment agreements with executive officers	✗ Provide excise tax gross-ups upon a Change-in-Control	✗ Provide tax gross-ups on other compensation or benefits	✗ Pay dividends on unearned restricted or performance shares until vested	✗ Encourage excessive or imprudent risk-taking
✗ Offer any perquisites to executive officers	✗ Offer incentive programs that have uncapped performance modifiers	✗ Allow unlimited short-term incentive payouts	✗ Allow hedging or pledging of company stock	✗ Use the same metrics in our STI and LTI award programs to incentivize performance

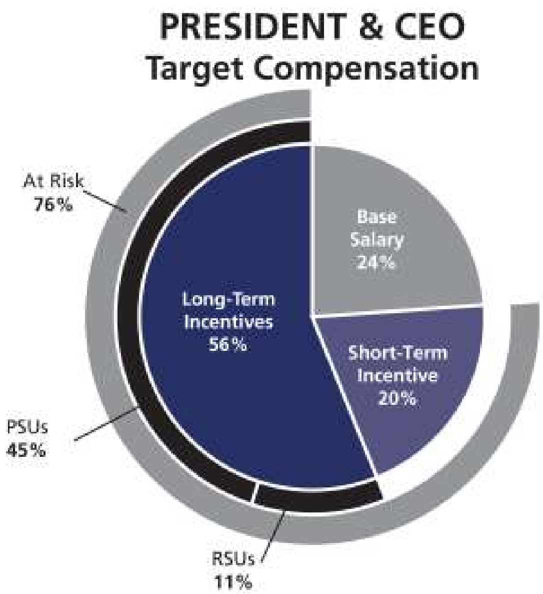
Our Philosophy

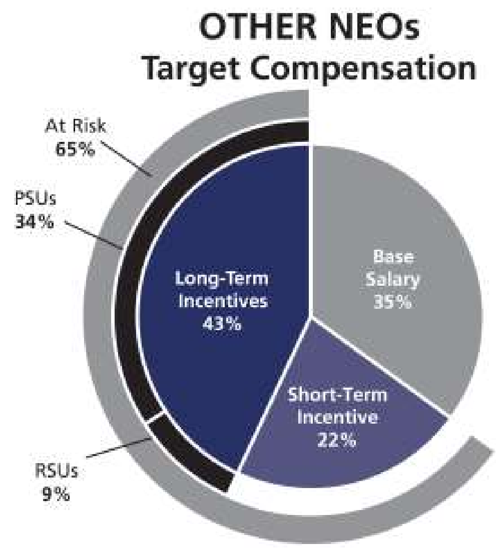
We provide executive compensation programs designed to attract, engage, motivate, reward and retain highly effective executives who drive our success and who are leaders in our industry. We pay for performance in order to align the long-term interests of our executive officers with those of our stakeholders while also rewarding behaviors that drive collaboration, execution, teamwork, and safety within our culture.

The majority of our executives' pay is in the form of variable compensation that is "at-risk" based on performance. At-risk components include annual STI cash awards and LTI awards which include PSUs and RSUs.

We believe our executive compensation programs provide executive officers with a balanced mix of market-competitive base salaries, STI awards tied to achieving financial and operational targets, and LTI awards that promote long-term sustainable business results.

The Committee evaluates market benchmark data while considering our compensation philosophy in determining the allocation of these elements to NEOs. On December 31, 2021, 76 percent of the CEO's total target compensation was "at risk" and an average of 65 percent was "at risk" for the other NEOs.





We generally seek to pay executives within a competitive range of the market median of target total compensation. However, we may target pay opportunities above or below the median based on, but not limited to, experience, company performance, sustained individual performance and internal pay equity.

HOW WE DETERMINE PAY

Role of the Executive Compensation Committee and the Board

The Committee, which is comprised of independent directors, reviews our executive compensation programs, market benchmark data and approves individual base salaries, STI awards and LTI grants for each NEO. The Committee also certifies the achievement of STI and LTI performance levels for the respective performance periods and approves the associated incentive program metrics, including company and individual target opportunities.

In making individual compensation decisions, the Committee reviews recommendations from the CEO with respect to all NEOs other than himself. The Committee reviews and discusses these recommendations in executive session with its independent executive compensation consultant and reaches its own decision with respect to the compensation of the CEO and the other NEOs. The Committee then submits its compensation decisions with respect to the CEO and the other NEOs to the Board for ratification.

Role of the 2021 Shareholder Advisory Vote to Approve 2020 Executive Compensation

In 2021, we received a favorable advisory vote on our 2020 executive compensation, with 97 percent of the company's shares voting in favor. The Committee therefore determined shareholders were supportive of the company's pay programs and there was not a need to materially change the executive compensation practices. The Committee will continue to monitor compensation practices, future advisory votes and other shareholder feedback to align executive compensation with the interests of the company and our stakeholders.

Role of the Independent Executive Compensation Consultant

The Committee again engaged Meridian as the independent executive compensation consultant to advise them on matters related to executive and non-employee director compensation. This includes assessing the peer group and competitive market data, consulting on the company's STI and LTI programs, informing the Committee of emerging practices, trends and changes in regulatory and corporate governance matters and reviewing the executive and non-employee director compensation programs and policies. The Committee regularly meets with its independent executive compensation consultant with and without management and has the sole authority to approve its fees and terms of engagement. Meridian reports directly to the Committee and does not provide any services or advice to management, although it may meet from time to time with members of management as necessary to support its work on behalf of the Committee.

As required by the Committee's charter, the Committee annually reviews the independence of its executive compensation consultant, considering the factors set forth by the SEC and in the NYSE listing standards. For 2021, the Committee found that Meridian continues to meet the SEC rules and NYSE listing standards for independence.

Role of Executive Officers and Management

Annually, our executive officers present the year's strategic and financial plan to the Board for approval. Based on the approved plan, the company's executive officers recommend the measures, weightings, target, threshold and maximum company performance goals for the annual STI plan. Management also advises the Committee of their assessment of the challenges facing the company, economic trends related to the business and the overall economy. Following each fiscal year, the CEO reviews the company's actual performance relative to the approved STI goals and the performance of each executive, excluding himself, and recommends an STI award to the Committee for each executive officer, including the NEOs, other than himself. The CEO also makes recommendations for base salary adjustments, STI target opportunities and LTI awards for the executive officers, including the NEOs, other than himself.

The company's compensation department supports both the Committee and management by providing analysis and research regarding our executive compensation programs.

The Use of Tally Sheets

When making compensation decisions, the Committee reviews comprehensive tally sheets for the executive officers including the NEOs. The tally sheets, prepared by management and reviewed by the Committee's independent executive compensation consultant, list components of the NEOs' compensation such that the Committee can review the total compensation of the NEOs under different scenarios and wealth accumulation as part of its due diligence in considering and approving compensation.

MARKET BENCHMARKING

The Committee's independent executive compensation consultant provides a competitive assessment of our executive compensation programs and the compensation of our executive officers, including the NEOs, using publicly available information from our peer group. Independent market salary survey data is utilized when public data is not available. The assessment includes annual base salaries, STI targets, LTI awards and total compensation opportunities.

With input from its independent executive compensation consultant, the Committee considers the following selection criteria to identify the peer group:

- Primary focus of the company is a utility company; and
- Similar character in areas such as revenue, market capitalization and number of customers.

After considering these criteria and recommendations from both its independent executive compensation consultant and management, the companies listed below were chosen by the Committee to comprise the peer group utilized for making 2021 pay decisions and reviewing overall executive compensation programs. The Committee evaluates the composition of the peer group at least annually and makes appropriate changes, as necessary. The peer group will remain the same for the 2022 executive compensation benchmarking.

Alliant Energy Corporation • Atmos Energy Corporation • Avista Corporation • IDACORP Inc. • New Jersey Resources Corporation
Northwest Natural Holding Company • NorthWestern Corporation • Pinnacle West Capital Corporation • PNM Resources Inc.
Portland General Electric Company • South Jersey Industries, Inc. • Southwest Gas Corporation • Spire, Inc.

The Committee assessed the market competitiveness of our NEOs' compensation based on the data provided by its independent executive compensation consultant. This data included the market benchmarks at the 25th, 50th and 75th percentiles for consideration for the following compensation components: base salary, STI target, target total cash compensation, target annualized grant date value of LTI awards and total target compensation.

ELEMENTS OF OUR EXECUTIVE COMPENSATION PROGRAM FOR 2021

This section describes each component of compensation we pay to our executives. Information regarding how compensation is determined is found in the section "How We Determine Pay" set forth above.

	Compensation Element	Objective	Type of Compensation
Fixed Pay	Base Salary	Provides continuous income to appropriately motivate and retain our executives based on a competitive market analysis and consideration for experience, performance and internal equity.	Annual cash compensation
At-Risk	STI Awards	Aligns executive efforts with the interests of stakeholders through key measures of the company's financial and operational performance. Awards can be modified based on individual performance.	Annual cash compensation, earned based on performance against pre-established company goals and individual performance
	RSUs	Promotes the alignment of executive interests with those of our stakeholders to support long-term equity ownership and retention.	Time-based RSUs that cliff vest in three years
	PSUs	Aligns executive interests and performance with our stakeholders by rewarding sustained share price performance as well as promotes retention.	Performance-based stock units that cliff vest based on relative TSR over a three-year period
Other	Benefits	Provides a safety net to protect against financial burdens that can result from illness, injury, disability or death.	Includes medical, dental, disability, life insurance and accidental death which are the same as for the broader employee base
	Retirement	Provide for basic retirement needs. Attracts and retains executives.	Can include 401(k), pension plans, NQDC Plan, SERP, and ESP Plan

2021 PERFORMANCE AND COMPENSATION DECISIONS

Base Salary

The majority of compensation delivered to our NEOs is based on performance. Base salaries for our NEOs are set at competitive levels that enable the company to attract, engage, motivate, reward and retain our leadership team. This balanced approach aligns with our pay-for-performance compensation philosophy. The Committee considered the results of the market benchmarking analysis, the CEO's recommendation, each NEO's individual experience and sustained performance, internal equity and the compensation practices of our peer group to determine that salaries would remain flat in 2021 due to labor market uncertainties under the COVID-19 pandemic regarding base pay movement. Messrs. McAnnally and Dinan's salary increases were solely related to their promotions to CEO and COO respectively.

Name	Base Salary as of December 31, 2020	Base Salary as of December 31, 2021	Dollar Increase	Percentage Increase
Robert S. McAnnally	$435,000	$650,000	$215,000	49.4%
Pierce H. Norton II(1)	$800,000	$800,000	$0	0.0%
Caron A. Lawhorn	$435,000	$435,000	$0	0.0%
Curtis L. Dinan	$435,000	$500,000	$65,000	14.9%
Joseph L. McCormick	$360,000	$360,000	$0	0.0%
Mark A. Bender	$312,500	$312,500	$0	0.0%

(1) Mr. Norton's base salary did not increase in 2021 and ceased payment on June 27, 2021, in conjunction with the date of his retirement from our company.

Short-Term Incentive

Our 2021 STI awards were based on five measures–one financial measure and four operational measures focused on safety.

Measure	Weighting	Definition
EPS	70%	Based on diluted earnings per share for the year ended December 31, 2021, as computed in accordance with accounting principles generally accepted in the United States.
TRIR	7.5%	The number of OSHA injuries per 100 full-time employees.
DART	7.5%	The number of OSHA injuries per 100 full-time employees that resulted in days away from work, restricted duty or transfer of duties.
PVIR	7.5%	The number of preventable vehicle incidents per 1,000,000 miles driven.
ERT	7.5%	The time that expires between the creation of an emergency order and the arrival of a first company responder to the scene expressed as the percentage of emergency orders with a response time of 30 minutes or less.

We believe that EPS is an appropriate measure to be used in determining short-term incentive compensation since it is:

- transparent and reflects the growth and performance of our operations;
- a measure that aligns the interests of our NEOs with the interests of our stakeholders;
- widely used by financial analysts and the investing public; and
- used by a majority of our peer companies.

Since EPS is a reflection of our financial performance, the Committee has placed a weighting of 70 percent of the overall award on this measure. Safety is our number one core value and is the foundation of everything we do. The four operational STI measures reinforce our commitment to the safety and wellbeing of our employees, customers and communities by focusing on the importance of safe driving, personal injury prevention, public safety and reducing the severity of injuries. In addition to these company measures, an individual performance modifier ranging from 0–125 percent is used to recognize each executive’s individual performance against pre-established goals and objectives that support the company’s continued success such as:

- strategic planning and execution;
- succession planning with a focus on developing, retaining and attracting a high performing workforce;
- communication (internal and external);
- industry and community leadership; and
- commitment to inclusion and diversity.

The Committee also considered each executive’s individual performance as it related to the Company’s handling of winter storm Uri and related matters.

Each NEO has a target opportunity that is established at the beginning of the performance year. The STI target opportunity for Mr. McAnnally was increased to 85% upon promotion to his new role of CEO. The other NEOs remained unchanged in 2021.

Name	2021 STI Target Opportunity as a Percentage of Base Salary
Robert S. McAnnally	85%
Pierce H. Norton II	100%
Caron A. Lawhorn	65%
Curtis L. Dinan	65%
Joseph L. McCormick	65%
Mark A. Bender	55%

For 2021, NEOs could earn up to 150 percent of their STI target opportunity prior to individual performance modifiers if maximum company performance goals are achieved. If threshold company performance goals are achieved, the threshold payout is 50 percent of each NEOs target opportunity. After achievement of the threshold award for any measure, the actual award percentage is interpolated for performance between threshold and target or target and maximum. No annual incentive is earned if the company's performance is below the threshold goal.

Individual awards under our STI plan are calculated using the following formula:

Base Salary earned in 2021	x	STI Target Opportunity	x	Company Performance Modifier	x	Individual Performance Modifier

The Committee engages in a rigorous process with its independent executive compensation consultant and management to determine the annual STI measures and potential awards. At its February 2021 meeting, the Committee established the threshold, target and maximum performance goals for the 2021 STI measures-based on the 2021 strategic and financial plan with consideration given to the company's prior year performance.

Performance Measure	Threshold (50% of Target)	Target (100% of Target)	Maximum (150% of Target)	Percentage Payable at Threshold	Percentage Payable at Target	Percentage Payable at Maximum	2021 Actual Performance	2021 Payout Percent
EPS	$3.55	$3.80	$4.05	35%	70%	105%	$3.85	76.44%
TRIR	1.22	0.99	0.89	3.75%	7.5%	11.25%	0.96	8.63%
DART	0.56	0.40	0.36	3.75%	7.5%	11.25%	0.22	11.25%
PVIR	2.05	1.65	1.55	3.75%	7.5%	11.25%	2.10	0.0%
ERT	64.0%	66.0%	70.0%	3.75%	7.5%	11.25%	62.7%	0.0%
Company Performance Modifier								**96.3%**

Based on business performance relative to the established annual measures, the Committee certified a company performance modifier payout percent of target for the 2021 STI awards. The CEO evaluated the 2021 individual performance of each NEO through our annual performance assessment process. The CEO's recommended individual performance modifiers for the NEOs are reviewed and approved by the Committee. The Committee, together with the Corporate Governance Committee, evaluated Mr. McAnnally's performance in his prior role of COO and his new role of CEO against established goals and objectives to determine his individual performance modifier. The Committee determined that the CEO had met the 2021 goals and assigned a rating of 100 percent for his individual performance. The same process was used for Mr. Norton's time in the CEO position to determine a 100 percent personal modifier related to his STI award. Individual performance modifiers for the other NEOs ranged from 105 percent to 108 percent.

Below are the STI awards, reflecting the actual performance against target and the individual performance modifiers applied for each of our NEOs for the 2021 plan year that were paid in March 2022:

Name	Base Salary earned in 2021(4)	STI Target Opportunity	Company Performance Modifier	Individual Performance Modifier	STI Award
Robert S. McAnnally(1)	$545,151	85%	96.3%	100%	$405,369
Pierce H. Norton II(2)	$390,137	100%	96.3%	100%	$375,724
Caron A. Lawhorn	$435,000	65%	96.3%	108%	$294,000
Curtis L. Dinan(3)	$468,301	65%	96.3%	107%	$314,000
Joseph L. McCormick	$360,000	65%	96.3%	108%	$243,000
Mark A. Bender	$312,500	55%	96.3%	105%	$174,000

(1) Mr. McAnnally's STI award recognizes the base salary earned and applicable STI targets in his prior role of COO and new role of CEO.
(2) Mr. Norton's STI award recognizes the base salary earned up until his retirement from our company on June 27, 2021.
(3) Mr. Dinan's STI award recognizes the base salary earned in his prior role of CCO and his new role of COO.
(4) Base salary earned is calculated using the time in role while earning a specific salary. This may differ slightly from what is stated on the Summary Compensation Table.

Long-Term Incentives

We granted LTI awards to our NEOs under our ECP consisting of PSUs and RSUs in 2021. The grants were awarded as 80 percent PSUs and 20 percent RSUs representing the same value mix as 2020. The Committee believes that this weighting further strengthens executive officers' alignment with our stakeholders by only vesting PSUs based on how well the company performs compared to its peer group.

The overall grant values were determined based on the market benchmarking data provided by our independent executive compensation consultant and the individual performance of each NEO, among other factors.

Name	Value of PSUs	Value of RSUs	Value of 2021 Equity Grant(1)
Robert S. McAnnally(2)	$1,200,000	$ 300,000	$1,500,000
Pierce H. Norton II	$1,760,000	$ 440,000	$2,200,000
Caron A. Lawhorn	$ 400,000	$ 100,000	$ 500,000
Curtis L. Dinan(3)	$ 560,000	$ 140,000	$ 700,000
Joseph L. McCormick	$ 360,000	$ 90,000	$ 450,000
Mark A. Bender	$ 260,000	$ 65,000	$ 325,000

(1) Represents the grant date value approved by the Committee. The values displayed in the Summary Compensation Table represent the accounting value of the PSUs and RSUs may differ.
(2) Mr. McAnnally received an off-cycle grant of $975,000 consisting of $780,000 PSUs and $195,000 RSUs associated with his promotion to CEO on June 28, 2021.
(3) Mr. Dinan received an off-cycle grant of $200,000 consisting of $160,000 PSUs and $40,000 RSUs associated with his promotion to COO on June 28, 2021.

Performance Stock Units

PSUs are payable in common stock based on our TSR relative to the peer group approved by the Committee as shown below over a three-year performance period. In addition to encouraging retention, we believe PSUs provide incentives to our executives that align their interests and performance with those of our stakeholders through increased share ownership. The actual payout of the PSUs can range from 0 percent to 200 percent of the units originally awarded, as set by the Committee, depending upon the company's relative three-year TSR. This structure is aligned with industry practices.

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 PSUs 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 as set forth in the following chart. If the actual TSR percentile rank falls between the stated percentile ranks set forth in the chart, the payout percentage is interpolated between the percentile rank above and below the actual percentile rank. No PSUs are earned if our TSR ranking at the end of the performance period is below the 25th percentile.

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	0%

During the three-year performance period, dividend equivalents are accrued on both RSUs and PSUs. If the vesting provisions are achieved, these will be distributed as actual shares. If any PSUs are forfeited, the dividend equivalents are also forfeited. Dividend equivalents are also applied to the number of PSUs earned based on the company's performance factor.

The Committee approved the peer group for the 2021 PSU grant based on companies that are similar to ONE Gas in having:

- Notable gas utility operations;
- Strong trading correlations with ONE Gas; and
- Similar peer companies.

The peer group for the 2021 PSUs is as follows:

Alliant Energy Corporation • Atmos Energy Corporation • Avista Corporation • CenterPoint Energy, Inc.• Chesapeake Utilities
CMS Energy Corporation. • New Jersey Resources Corporation • NiSource, Inc.• Northwest Natural Holding Company
NorthWestern Corporation • South Jersey Industries, Inc. • Southwest Gas Corporation • Spire, Inc.

Restricted Stock Units

RSUs are payable in common stock after a three-year vesting period, provided the NEO remains employed with the company through the vesting date. As with the PSUs, RSUs promote retention, increase long-term equity ownership and further promote the alignment of our executives' interests with those of our stakeholders. We believe that it is important to have an element of compensation that is focused directly on retaining executives to help minimize the disruption associated with unplanned turnover. During the three-year vesting period, employees receiving a grant, including the NEOs, have their accounts credited with an amount equal to all ordinary cash dividends that would have been paid if shares were issued on the grant date. The dividend equivalents are deemed to be reinvested. If an employee, including an NEO, forfeits any RSUs, the dividend equivalents are also forfeited.

Vesting of 2018 PSUs

The 2018 PSU grants vested in February 2021. The Committee reviewed the company's relative TSR performance during the performance period against the peer group and has determined that its 61 percent TSR result ranks sixth amongst the fourteen peer companies. The Committee certified the performance with a corresponding payout of 122 percent of target. The number of PSUs awarded in 2018 that could have been earned by each NEO based on achievement of the performance criteria at threshold, target and maximum performance levels are set forth in the Grants of Plan-Based Awards for 2018 in our 2019 proxy statement. The amounts shown in the table below represent the target number of PSUs awarded and the actual number of PSUs earned by each NEO for actual performance over the three-year performance period that vested in February 2021.

2018 PSUs

Name	Target number of shares awarded	Number of shares Earned(1)
Robert S. McAnnally	4,694	6,165
Pierce H. Norton II	20,537	26,970
Caron A. Lawhorn	4,694	6,165
Curtis L. Dinan	4,988	6,550
Joseph L. McCormick	4,401	5,779
Mark A. Bender	3,345	4,393

(1) Includes dividends

The peer group previously approved by the Committee for this grant includes the companies below. Two companies were eliminated due to merger activity:

Alliant Energy Corporation • Atmos Energy Corporation • Avista Corporation • CenterPoint Energy, Inc. • Chesapeake Utilities
CMS Energy Corporation • NiSource, Inc. • New Jersey Resources Corporation • Northwest Natural Holding Company
NorthWestern Corporation • Southwest Gas Corporation, Inc.• South Jersey Industries, Inc. • Spire, Inc.

Other Compensation and Benefit Programs

Retirement Benefits, qualified under the Internal Revenue Code:

- The defined contribution 401(k) Plan is available to all of our employees. The company matches 100 percent of employee contributions, up to 6 percent of eligible pay, subject to Internal Revenue Code contribution limits. All of our NEOs participate in this Plan.
- The Qualified Pension Plan is a defined benefit plan that is available to non-bargaining unit employees hired prior to January 1, 2005, and certain other bargaining unit employees, subject to Internal Revenue Code contribution limits. All of our NEOs, with the exception of Mr. McAnnally and Mr. Bender, are participants in the Qualified Pension Plan.

NQDC Plan: We maintain a NQDC Plan that provides our NEOs with the opportunity to defer receipt of specified portions of compensation and to have such deferred amounts treated as if invested in specified investment options. The NQDC Plan allows pre-tax deferrals of income and company matching contributions that may have been lost due to government limitations on our qualified retirement plans. The NQDC Plan provides an important financial planning tool which encourages executive retention. Employees eligible for the NQDC Plan are officers and certain other highly compensated employees designated by the company's Benefit Plan Sponsor Committee. All of our NEOs participate in the NQDC Plan.

SERP: We maintain a SERP that provides for two types of benefits. Part A of the SERP is an "excess" benefit that is intended to make up for the benefits not paid to our NEOs from the Qualified Pension Plan, because of the government limits applicable to qualified plans. The formula in Part A of the SERP is the same as the formula used in our Qualified Pension Plan, but uses only eligible earnings above the qualified plan limits. There are two NEOs who are active participants including Mr. Dinan and Ms. Lawhorn. Mr. Norton was an active participant before his retirement from the company.

Part B of the SERP is a supplemental benefit, or "top hat plan" that uses a different formula than the Qualified Pension Plan. The supplemental benefits are based upon a specified percentage of the highest 36 consecutive months' compensation of the NEO's last 60 months of service. This benefit is offset by any payment received from Part A of the SERP and the Qualified Pension Plan. Only one of our NEOs, Mr. Dinan, is a participant in Part B.

The SERP is closed to new participants and has not been extended to any new participants since 2005.

Profit Sharing Plan: We maintain a Profit Sharing Plan within our 401(k) Plan for employees who are not eligible for the Qualified Pension Plan. The company contributes a discretionary contribution equal to 1 percent of a participant's eligible compensation each quarter. The company may also make an additional discretionary contribution each year based on annual eligible compensation. Eligible compensation is limited to the qualified plan limits. Company contributions and earnings are not taxable until distributed. All NEOs are participants in the 401(k) Plan. Only Messrs. McAnnally and Bender participate in the Profit Sharing Plan.

ESP Plan: Our employees, including NEOs, are eligible to participate in the ESP Plan which offers shares of company common stock on an after-tax basis at a discounted price.

Other Benefits: Our executive officers, including the NEOs, are eligible to participate in employee benefit plans under the same terms and premium structure as generally available to all our employees, including our medical, dental, vision, life, accidental death and dismemberment, travel and accident, and disability plans.

Perquisites: Our executive officers, including the NEOs, receive no perquisites or other personal benefits from the company.

SHARE OWNERSHIP GUIDELINES

Our Board advocates executive share ownership to align executive interests with our stakeholders. These guidelines are mandatory and generally must be achieved by each officer over the course of five years after becoming subject to the guidelines. Our executives are required to hold all shares, net of taxes, awarded under our ECP until the share ownership guideline is met.

An executive's holdings include shares owned in the open market, shares held in trust for the benefit of the executive or the benefit of the executive's immediate family, unvested RSUs, and shares held in qualified plans. PSU shares that have not yet been earned and vested do not count toward an executive's personal holdings for the purpose of determining whether the executive is permitted to sell shares of the company's common stock.

Below are the base salary multiples for share ownership for the NEO positions:

Title	Multiple of Base Salary
President and CEO	6
Senior Vice President and CFO	4
Senior Vice President and COO	4
Senior Vice President, General Counsel and Assistant Secretary	4
Senior Vice President, Administration and Chief Information Officer	3

As of December 31, 2021, all NEOs had met their individual share ownership requirements except for Mr. McAnnally who has until June 28, 2026, to reach the guidelines of the President and CEO position.

RISK CONSIDERATIONS

The Committee engaged its independent executive compensation consultant in the annual review of the risks and rewards associated with our executive compensation program. Our executive compensation program is designed with features that mitigate risk without diminishing the incentive nature of the compensation. The framework below lists a range of compensation program features that might create motivations for excessive risk and our practices that mitigate those risks:

Appropriate Risk	Risk Mitigation
√Multiple incentive performance measures	• Our annual STI program features a balance of financial and operational measures
√Measures aligned with shareholder value	• Our LTI program features multiple vehicles (RSUs and PSUs) and 3-year overlapping performance periods
√Measures developed and reviewed across key stakeholder groups	• Our performance measures, performance goals and capital allocation require multiple approval levels and has oversight; the Committee reviews and approves the STI and performance-based LTI award goals at the beginning of each cycle
√Balanced pay mix	• Our compensation program features an effective balance of STI and LTI compensation components to avoid placing too much value on any one element and is aligned to the market
√Balance of formulaic and discretionary factors	• Our incentive awards incorporate both objective formulaic and subjective discretionary factors; the Committee retains full discretion
√Capped awards	• Our short-term and long-term performance-based payments have capped performance modifiers at 150 percent for short-term and 200 percent for performance-based long-term awards
√Reasonable CIC and severance benefits	• Our CIC and severance benefits are within common norms (cash CIC payments and acceleration of vesting of equity grants are also subject to “double trigger” requirements) and do not provide excessive incentives to seek unwarranted transactions
√Clawback provisions in place	• Our clawback provisions extend beyond current legal requirements
√Meaningful executive share ownership and consistent LTI practices	• Our share ownership guidelines, annual LTI award grants and vesting provisions create sustained and consistent ownership stakes

Based on its review, because of the reasons set forth above, the Committee has concluded that the company’s executive compensation program does not encourage unreasonable risk taking by our executives, and therefore does not produce risks that are reasonably likely to have a material adverse effect on the company.

CLAWBACK PROVISIONS

Awards made under the annual STI plan and ECP are subject to clawback provisions. The clawback provisions permit the Committee to use appropriate discretion to seek recoupment of awards paid to executives in the event of fraud, negligence or intentional misconduct that is determined to be a contributing factor of having to restate all or a portion of the company's financial statements. We believe executives who are responsible for material noncompliance with applicable financial reporting requirements should not benefit monetarily from such noncompliance.

TERMINATION AND CHANGE IN CONTROL BENEFITS

Our NEOs are eligible to participate in a CIC Severance Plan. The participants in the plan are reviewed and approved annually by the Committee and the full Board. The program is designed to encourage NEOs to focus on the best interests of stakeholders by alleviating concerns about possible detrimental impacts to their compensation and benefits under a potential change in control. The program is not intended to provide advantages to NEOs in association with executing a change in control transaction and it requires a double trigger in order to take effect.

The cash severance multiple varies but is no greater than three times the participant's salary and target STI. The cash severance and acceleration of unvested equity requires a double trigger of a CIC of the company followed by a "qualifying" termination of the executive's employment. See page 59 for more information regarding the determination of when a "double trigger" has occurred. Qualifying terminations include involuntary termination without cause or voluntary termination with "good reason." Good reason includes:

- Demotion or material reduction of authority or responsibility;
- Material reduction in base salary;
- Material reduction in annual incentive or LTI targets;
- Relocation of greater than 35 miles; or
- Failure to assume the CIC Severance Plan.

The plan does not provide for additional pension benefits upon a CIC. In addition, the plan does not provide for a tax gross-up feature for "golden parachute" excise taxes but provides plan participants a "best after-tax results" approach to excise taxes in determining the benefit payable to a participant under the plan. Under this approach, the company will reduce the benefits payable to the participant to the extent necessary to avoid triggering the excise tax, but only if doing so would result in a higher after-tax payment to the participant.

The following chart details the benefits received if a NEO were to be terminated or resign for a defined good reason following a change in control as well as an analysis of the benefit to the company and stakeholders:

CIC Benefit	Benefit Description	Benefit to Company and Stakeholders
Cash Severance	2x to 3x sum of base pay and target STI (3x CEO only)	Encourage NEOs to remain engaged and focused during transition
Medical & Dental	Reimbursement of COBRA premiums for coverage of 18 months	Maintain health benefits at minimal cost to the company
Tax Treatment	"Best after-tax results" approach	Enable CIC benefits to be delivered as intended
Long-Term Incentives	Accelerated vesting and paid at target upon termination	Incent NEOs to stay throughout transition process

EMPLOYMENT AGREEMENTS

We do not enter into individual employment agreements with any of our NEOs. Instead, in general, the rights of our NEOs with respect to specific events are covered by our compensation and benefit plans, including our CIC Severance Plan.

INTERNAL REVENUE CODE LIMITATIONS ON DEDUCTIBILITY OF EXECUTIVE COMPENSATION

The Tax Cuts and Jobs Act, enacted on December 22, 2017, substantially modified Section 162(m) of the Internal Revenue Code and, among other things, eliminated the performance-based exception to the $1 million deduction limit effective as of January 1, 2018. As a result, beginning in 2018, compensation paid to certain executive officers in excess of $1 million will generally be nondeductible, whether or not it is performance-based. In addition, beginning in 2018, the executive officers subject to Section 162(m) (the "Covered Employees") will include any individual who served as the CEO or CFO at any time during the taxable year and the three other most highly compensated officers (other than the CEO and CFO) for the taxable year, and once an individual becomes a Covered Employee for any taxable year beginning after December 31, 2016, that individual will remain a Covered Employee for all future years, including following any termination of employment.

The Tax Cuts and Jobs Act includes a transition rule under which the changes to Section 162(m) described above will not apply to compensation payable pursuant to a written binding contract that was in effect on November 2, 2017 and is not materially modified after that date. To the extent applicable to our existing contracts and awards, the Committee may avail itself of this transition rule. However, because of uncertainties as to the application and interpretation of the transition rule, no assurances can be given at this time that our existing contracts and awards, even if in place on November 2, 2017, will meet the requirements of the transition rule. Moreover, to maintain flexibility in compensating executive officers in a manner designed to promote varying corporate goals, the Committee does not limit its actions with respect to executive compensation to preserve deductibility under Section 162(m) if the Committee determines that doing so is in the best interests of the company.

EXECUTIVE COMPENSATION COMMITTEE REPORT

The Committee has met, reviewed and discussed with management the Compensation Discussion and Analysis contained in this proxy statement. Based on this review and discussion, the Committee recommended to the Board the inclusion of the Compensation Discussion and Analysis in this proxy statement.

Pattye L. Moore, Chair
Douglas H. Yaeger, Vice Chair
Robert B. Evans, Member
Tracy E. Hart, Member
Michael G. Hutchinson, Member
Eduardo A. Rodriguez, Member

NAMED EXECUTIVE OFFICER COMPENSATION

The following table reflects the compensation paid to the NEOs in respect to our 2021 fiscal year.

SUMMARY COMPENSATION TABLE FOR 2021

Name and Principal Position	Year	Salary(1)(2)	Stock Awards(3)	Non-Equity Incentive Plan Compensation(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings(5)	All Other Compensation(6)	Total
Robert S. McAnnally	2021	$ 544,943	$ 1,537,575	$ 405,369	$ -	$ 96,286	$ 2,584,173
President and Chief Executive	2020	$ 421,285	$ 948,156	$ 358,000	$ -	$ 75,671	$ 1,803,112
Officer	2019	$ 380,000	$ 449,054	$ 353,000	$ -	$ 71,690	$ 1,253,744
Pierce H. Norton II	2021	$ 390,909	$ 2,437,725	$ 375,724	$ 1,098,395	$ 28,438	$ 4,331,191
Former President and Chief	2020	$ 800,000	$ 2,109,106	$ 997,920	$ 1,442,205	$ 39,558	$ 5,388,789
Executive Officer	2019	$ 800,000	$ 2,007,181	$ 960,800	$ 1,754,310	$ 109,033	$ 5,631,324
Caron A. Lawhorn	2021	$ 435,000	$ 554,074	$ 294,000	$ 332,836	$ 49,441	$ 1,665,351
Senior Vice President and Chief	2020	$ 418,542	$ 448,143	$ 330,000	$ 641,218	$ 46,119	$ 1,884,022
Financial Officer	2019	$ 385,000	$ 449,054	$ 310,000	$ 735,426	$ 42,949	$ 1,922,429
Curtis L. Dinan	2021	$ 468,239	$ 750,207	$ 314,000	$ 290,307	$ 51,098	$ 1,873,851
Senior Vice President and Chief	2020	$ 435,000	$ 448,143	$ 356,000	$ 971,267	$ 48,253	$ 2,258,663
Operating Officer	2019	$ 435,000	$ 449,054	$ 343,000	$ 1,029,458	$ 49,558	$ 2,306,070
Joseph L. McCormick	2021	$ 360,000	$ 498,662	$ 243,000	$ 82,788	$ 59,327	$ 1,243,777
Senior Vice President, General	2020	$ 360,000	$ 448,143	$ 284,000	$ 217,168	$ 57,603	$ 1,366,914
Counsel and Assistant Secretary	2019	$ 355,000	$ 449,054	$ 280,000	$ 231,558	$ 54,412	$ 1,370,024
Mark A. Bender	2021	$ 312,500	$ 360,123	$ 174,000	$ -	$ 59,104	$ 905,727
Senior Vice President and Chief	2020	$ 312,500	$ 316,446	$ 212,000	$ -	$ 57,993	$ 898,939
Information Officer	2019	$ 305,000	$ 316,927	$ 201,000	$ -	$ 56,158	$ 879,085

(1) Mr. McAnnally was promoted to CEO on June 28, 2021, succeeding Mr. Norton's retirement.

(2) Mr. Norton retired on June 27, 2021.

(3) The amounts included in the table relate to RSUs and PSUs granted under our ECP and reflect the aggregate grant date fair value of such awards calculated pursuant to ASC Topic 718. Material assumptions used in the calculation of the value of these equity grants are included in Note 11 to our audited financial statements for the year ended December 31, 2021, included in our Annual Report on Form 10-K filed with the SEC on February 24, 2022.

The aggregate grant date fair value of RSUs for purposes of ASC Topic 718 was determined based on the closing price of our common stock on the grant date. With respect to the PSUs, the aggregate grant date fair value for purposes of ASC Topic 718 was determined using the probable outcome of the performance conditions as of the grant date based on a valuation model that considers the market condition (TSR) and using assumptions developed from the referenced peer companies. The value included for the PSUs is based on 100 percent of the PSUs vesting at the end of the performance period. Using the maximum number of shares issuable upon vesting of the PSUs (200 percent of the units granted), the aggregate grant date fair value of the PSUs would be as follows:

Name	2021	2020	2019
Robert S. McAnnally	$ 2,475,294	$ 726,378	$ 728,046
Pierce H. Norton II	$ 3,995,464	$ 3,418,130	$ 3,254,370
Caron A. Lawhorn	$ 908,105	$ 726,378	$ 728,046
Curtis L. Dinan	$ 1,220,320	$ 726,378	$ 728,046
Joseph L. McCormick	$ 817,344	$ 726,378	$ 728,046
Mark A. Bender	$ 590,277	$ 512,822	$ 513,819

(4) Reflects STI awards earned in 2021, 2020 and 2019 and paid in 2022, 2021 and 2020, respectively, under our annual STI plan. For a discussion of the performance criteria established by the Committee for awards under the 2021 annual STI plan, see "2021 Performance and Compensation Decisions—*Short-Term Incentive*" above on page 41.

Mr. McAnnally's STI award recognizes the base salary earned and applicable STI targets in his prior role of COO and new role of CEO. Mr. Norton's STI award recognizes the base salary earned up until his retirement date of June 27, 2021. Mr. Dinan's STI award recognizes the base salary earned in his prior role of CCO and his new role of COO.

(5) The amounts reflected represent the aggregate change during 2021 in the actuarial present value of the NEOs' accumulated benefits under the Qualified Pension Plan and the SERP. For a description of these plans, see "Pension Benefits" below. The change in the present value of the accrued pension benefit is impacted by variables such as additional years of service, age and the discount rate used to calculate the present value of the change. For 2021, the change in pension value reflects the increase due to additional service and pay for the year, and an increase in present value due to the lower discount rate in effect on the measurement date (2.8 percent as of December 31, 2020, and 3.05 percent as of December 31, 2021). The Qualified Pension Plan was closed to new participants as of December 31, 2004. Ms. Lawhorn and the Messrs. Dinan and McCormick participate in the Qualified Pension Plan. Mr. Norton participated in the Qualified Pension Plan prior to his retirement. The SERP was closed to new participants on January 1, 2014, although no new participants had been added since 2005. Ms. Lawhorn and Mr. Dinan participate in the SERP. Mr. Norton participated in the SERP prior to his retirement.

(6) Reflects (i) the amounts paid as our dollar-for-dollar match of contributions made by the NEO under our NQDC Plan, 401(k) Plan for Employees of ONE Gas, Inc. and Subsidiaries and Profit Sharing Plan and (ii) amounts paid for length of service awards as follows:

Name	Year	Match Under Nonqualified Deferred Compensation Plan(a)	Match Under 401(k) Plan(b)	Profit Sharing Plan(c)	Service Award(d)(e)	Imputed Income LTD(f)	Imputed Income GTL(g)
Robert S. McAnnally	2021	$ 61,940	$ 17,400	$ 14,300	$	$ 492	$ 2,154
	2020	$ 41,897	$ 17,100	$ 14,050	$ 200	$ 510	$ 1,914
	2019	$ 39,382	$ 16,800	$ 13,800	$ -	$ -	$ 1,708
Pierce H. Norton II	2021	$ 7,818	$ 17,400	$ -	$ -	$ 246	$ 2,974
	2020	$ 16,000	$ 17,100	$ -	$ -	$ 510	$ 5,948
	2019	$ 87,558	$ 16,800	$ -	$ 800	$ -	$ 3,875
Caron A. Lawhorn	2021	$ 28,500	$ 17,400	$ -	$ -	$ 492	$ 3,049
	2020	$ 26,613	$ 17,100	$ -	$ -	$ 510	$ 1,896
	2019	$ 24,415	$ 16,800	$ -	$ -	$ -	$ 1,734
Curtis L. Dinan	2021	$ 32,054	$ 17,400	$ -	$ -	$ 492	$ 1,152
	2020	$ 29,580	$ 17,100	$ -	$ -	$ 510	$ 1,063
	2019	$ 31,095	$ 16,800	$ -	$ 600	$ -	$ 1,063
Joseph L. McCormick	2021	$ 38,980	$ 17,400	$ -	$ -	$ 492	$ 2,455
	2020	$ 37,538	$ 17,100	$ -	$ -	$ 510	$ 2,455
	2019	$ 35,188	$ 16,800	$ -	$ -	$ -	$ 2,424
Mark A. Bender	2021	$ 25,555	$ 17,400	$ 14,300	$ -	$ 492	$ 1,357
	2020	$ 25,801	$ 16,275	$ 14,050	$ -	$ 510	$ 1,357
	2019	$ 24,037	$ 16,800	$ 13,800	$ 200	$ -	$ 1,321

(a) For additional information on our NQDC Plan, see "Nonqualified Deferred Compensation for 2021" below on page 57.

(b) Our 401(k) Plan is a tax-qualified plan that covers substantially all of our employees. Employee contributions are discretionary. Subject to certain limits, we match 100 percent of employee contributions to the plan up to a maximum of 6 percent of eligible compensation.

(c) Represents amounts contributed by the company under the Profit Sharing Plan (PSP). Only Messrs. McAnnally and Bender participate in the PSP.

(d) Service awards are amounts paid to employees of the company upon milestone anniversaries with the company beginning upon the employee's fifth anniversary with the company and continuing thereafter for every five years of service with the company.

(e) There are no tax gross-up payments in connection with cash service awards.

(f) Represents the value of imputed income related to long-term disability insurance. ONE Gas provides long-term disability insurance to all employees.

(g) Represents the value of imputed income related to group-term life insurance. ONE Gas provides group-term life insurance to all employees.

The NEOs received no other perquisites or other personal benefits from the company in 2021.

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GRANTS OF PLAN-BASED AWARDS FOR 2021

The following table reflects the grants of plan-based awards to the NEOs during 2021.

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards(1)			Estimated Future Payouts Under Equity Incentive Plan Awards(2)			All Other Stock Awards: Number of Shares of Stock or Units(3)	Grant Date Fair Value of Stock Awards(4)
		Threshold	Target	Maximum	Threshold	Target	Maximum		
Robert S. McAnnally									
Restricted Unit	2/12/2021							1,444	$ 104,964
Restricted Unit (5)	6/28/2021							2,567	$ 194,964
Performance Unit	2/12/2021				2,889	5,778	11,556		$ 476,743
Performance Unit	6/28/2021				5,135	10,270	20,540		$ 760,904
Short-Term Incentive	1/1/2021	$ -	$ 420,951	$ 789,283					
Pierce H. Norton II									
Restricted Unit	2/12/2021							6,053	$ 439,993
Performance Unit	2/12/2021				12,106	24,212	48,424		$ 1,997,732
Short-Term Incentive	1/1/2021	$ -	$ 390,137	$ 731,507					
Caron A. Lawhorn									
Restricted Unit	2/12/2021							1,376	$ 100,021
Performance Unit	2/12/2021				2,752	5,503	11,006		$ 454,053
Short-Term Incentive	1/1/2021	$ -	$ 282,750	$ 530,156					
Curtis L. Dinan									
Restricted Unit	2/12/2021							1,376	$ 100,021
Restricted Unit (5)	6/28/2021							527	$ 40,026
Performance Unit	2/12/2021				2,752	5,503	11,006		$ 454,053
Performance Unit	6/28/2021				1,054	2,107	4,214		$ 156,108
Short-Term Incentive	1/1/2021	$ -	$ 304,396	$ 570,742					
Joseph L. McCormick									
Restricted Unit	2/12/2021							1,238	$ 89,990
Performance Unit	2/12/2021				2,477	4,953	9,906		$ 408,672
Short-Term Incentive	1/1/2021	$ -	$ 234,000	$ 438,750					
Mark A. Bender									
Restricted Unit	2/12/2021							894	$ 64,985
Performance Unit	2/12/2021				1,789	3,577	7,154		$ 295,138
Short-Term Incentive	1/1/2021	$ -	$ 171,875	$ 322,266					

(1) Reflects amounts that could be earned pursuant to our annual officer STI plan. The plan provides that our NEOs may receive annual STI awards based on the performance of the company measured by financial (EPS) and operational factors (TRIR, PVIR, DART and ERT) and individual performance during the relevant fiscal year. Company targets and individual goals are established annually by the Committee. The Committee establishes annual target awards for each officer expressed as a percentage of their base salaries. The actual amounts earned by the NEOs in 2021 under the plan and paid in 2021 are set forth under the "Non-Equity Incentive Plan Compensation" column in the Summary Compensation Table for 2021 above. For each performance measure of our annual officer STI plan, no incentive amount would be paid for that measure unless the company's actual result exceeds the established threshold levels. If the company's actual results are below the threshold level, the percentage payable for that measure is zero. For the 2021 STI plan, the payout range based on the performance of the company was 50 percent–150 percent of base salary and a personal modifier ranging from 0–125 percent. The threshold amounts reflected in the table apply a personal modifier of 0 percent. The maximum amounts reflected in the table apply a personal modifier of 125 percent to the 150 percent company performance payout. Mr. McAnnally's STI award recognizes the base salary earned and applicable STI targets in his prior role of COO and new role of CEO. Mr. Norton's STI award recognizes the base salary earned up until his retirement date of June 27, 2021. Mr. Dinan's STI award recognizes the base salary earned in his prior role of CCO and his new role of COO.

(2) Reflects the PSUs that could be earned pursuant to awards granted under our ECP that vest three years from the date of grant, at which time the holder is entitled to receive a percentage (0 to 200 percent) of the PSUs granted based on performance criteria. If actual performance is below the threshold level, the percentage of PSUs earned is zero. For this period, the criteria is our TSR over the period of February 15, 2021, to February 17, 2024, compared with the TSR of the peer group. If our actual relative TSR is between the stated performance levels, the percentage of PSUs earned is interpolated between the stated performance levels. One share of our common stock is payable for each performance unit that vests, plus accrued dividends. PSUs are also subject to accelerated vesting upon a CIC.

(3) Reflects RSUs granted under our ECP that vest three years from the date of grant, at which time the grantee is entitled to receive the grant in shares of our common stock, plus accrued dividends.

(4) The aggregate grant date fair value of the RSUs for purposes of ASC Topic 718 was determined based on the closing price of our common stock on the grant date. With respect to the PSUs, the aggregate grant date fair value for purposes of ASC Topic 718 was determined using the probable outcome of the performance conditions as of the grant date based on a valuation model that considers market conditions (such as TSR) and using assumptions developed from historical information of each of the peer companies referenced under "2021 Performance and Compensation Decisions—*Long Term Incentives*" above. This amount is consistent with the estimate of aggregate compensation cost to be recognized over the performance period determined as of the grant date under ASC Topic 718. The value presented is based on 100 percent of the PSUs vesting at the end of the three-year performance period.

(5) In connection with their promotions, Messrs. McAnnally and Dinan received additional grants on June 28, 2021, which had a grant price of $75.95.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END FOR 2021

The following table shows the outstanding equity awards held by the NEOs as of December 31, 2021.

Outstanding Equity Awards at Fiscal Year-End

	Stock Awards					
Name	**Number of Shares or Units of Stock That Have Not Vested(1)(3)**		**Market Value of Shares or Units of Stock That Have Not Vested**	**Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested(2)(3)**		**Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested**
Robert S. McAnnally	13,229	$	1,026,468	4,660	$	361,559
Pierce H. Norton II	-	$	-	20,830	$	1,616,170
Caron A. Lawhorn	3,457	$	268,284	4,660	$	361,559
Curtis L. Dinan	3,993	$	309,870	4,660	$	361,559
Joseph L. McCormick	3,315	$	257,223	4,660	$	361,559
Mark A. Bender	2,362	$	183,235	3,289	$	255,170

(1) Represents RSUs that have not yet vested. RSUs vest three years from the date of grant, at which time the grantee is entitled to receive one share of our common stock for each vested RSU, plus accrued dividends. RSUs accrue dividend equivalents from the date of grant through the vesting date. RSUs are scheduled to vest as set forth in the following table:

Restricted Unit Vesting Schedule

Robert S. McAnnally	1,099	on February 19, 2022
	8,028	on February 19, 2023
	4,102	on February 17, 2024
Pierce H. Norton II	-	on February 19, 2022
	-	on February 19, 2023
	-	on February 17, 2024
Caron A. Lawhorn	1,099	on February 19, 2022
	937	on February 19, 2023
	1,421	on February 17, 2024
Curtis L. Dinan	1,099	on February 19, 2022
	937	on February 19, 2023
	1,957	on February 17, 2024
Joseph L. McCormick	1,099	on February 19, 2022
	937	on February 19, 2023
	1,279	on February 17, 2024
Mark A. Bender	776	on February 19, 2022
	662	on February 19, 2023
	924	on February 17, 2024

(2) Represents PSUs that have not yet vested. PSUs vest three years from the date of grant, at which time the holder is entitled to receive a percentage (0 to 200 percent) of the PSUs granted based on our TSR over the three-year performance period, compared with the TSR of the peer group. One share of our common stock is payable in respect of each PSU granted that becomes vested, plus accrued dividends. PSUs accrue dividend equivalents from the date of grant through the vesting date. The number of PSUs represented and their corresponding market value is based on TSR performance as of December 31, 2021; PSUs vesting in 2022 are estimated at 106% percent of the original grant; PSUs vesting in 2023 are estimated at 0% percent of the original grant; PSUs vesting in 2024 are estimated at 0% percent of the original grant.

The following table reflects the projected vesting level based on our TSR compared with the TSR of the referenced peer group at December 31, 2021:

Performance Unit Vesting Schedule

Robert S. McAnnally	4,660 - -	on February 19, 2022 on February 19, 2023 on February 17, 2024
Pierce H. Norton II	20,830 - -	on February 19, 2022 on February 19, 2023 on February 17, 2024
Caron A. Lawhorn	4,660 - -	on February 19, 2022 on February 19, 2023 on February 17, 2024
Curtis L. Dinan	4,660 - -	on February 19, 2022 on February 19, 2023 on February 17, 2024
Joseph L. McCormick	4,660 - -	on February 19, 2022 on February 19, 2023 on February 17, 2024
Mark A. Bender	3,289 - -	on February 19, 2022 on February 19, 2023 on February 17, 2024

(3) The terms of both our RSUs and our PSUs provide that any such unvested units will become fully vested upon a qualifying termination of employment following a CIC. See "Potential Post-Employment Payments and Payments Upon a Change in Control" on page 59.

OPTION EXERCISES AND STOCK VESTED FOR 2021

The following table sets forth stock awards held by the NEOs that vested during 2021. The company has not awarded any options, therefore no NEO exercised any options during 2021, and no NEO or other employee currently holds any unexercised options.

Option Exercises and Stock Vested

	Stock Awards(1)	
Name	Number of Shares Acquired on Vesting	Value Realized on Vesting(2)
Robert S. McAnnally	7,428	$539,977
Pierce H. Norton II	38,973	$2,851,053
Caron A. Lawhorn	7,428	$539,977
Curtis L. Dinan	7,892	$573,701
Joseph L. McCormick	6,963	$506,174
Mark A. Bender	5,293	$384,736

(1) Certain of the NEOs elected to have vested shares withheld to cover applicable state and federal taxes incurred upon vesting. As a result, the net shares received upon the vesting and the related net value realized are displayed above.

Name	Net Shares Acquired on Vesting	Net Value Realized on Vesting
Robert S. McAnnally	4,076	$296,284
Pierce H. Norton II	21,660	$1,584,548
Caron A. Lawhorn	4,075	$296,212
Curtis L. Dinan	4,333	$314,966
Joseph L. McCormick	3,811	$277,022
Mark A. Bender	2,876	$209,056

(2) The value realized on vesting represents the market value of the shares received based on the closing price of our common stock on the NYSE on the date of vesting.

PENSION BENEFITS FOR 2021

The following table sets forth the estimated present value of accumulated benefits as of December 31, 2021, and payments made during 2021, in respect to each NEO under the referenced retirement plans.

Pension Benefits

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit(1)	Payments During Last Fiscal Year
Robert S. McAnnally	Supplemental Executive Retirement Plan	-(2)	$ -	$ -
	Qualified Pension Plan	-(2)	$ -	$ -
Pierce H. Norton II	Supplemental Executive Retirement Plan	17.00	$7,266,673	$ -
	Qualified Pension Plan	17.00	$1,228,151	$ -
Caron A. Lawhorn	Supplemental Executive Retirement Plan	23.25	$2,390,326	$ -
	Qualified Pension Plan	23.25	$1,770,238	$ -
Curtis L. Dinan	Supplemental Executive Retirement Plan	18.00(3)	$4,138,367	$ -
	Qualified Pension Plan	18.00(3)	$1,069,216	$ -
Joseph L. McCormick	Supplemental Executive Retirement Plan		$ -	$ -
	Qualified Pension Plan	19.00(4)	$1,400,634	$ -
Mark A. Bender	Supplemental Executive Retirement Plan	-(5)	$ -	$ -
	Qualified Pension Plan	-(5)	$ -	$ -

(1) Each executive officer's benefit is determined as of age 62 when an unreduced benefit can be received under the SERP and Qualified Pension Plan. The present value of the unreduced benefit is determined using the assumptions from a measurement date of December 31, 2021. Material assumptions used in the calculation of the present value of accumulated benefits are included in Note 12 to our audited financial statements for the year ended December 31, 2021, included in our Annual Report on Form 10-K filed with the SEC on February 24, 2022.

(2) Mr. McAnnally is not a participant in the SERP or the Qualified Pension Plan.

(3) Mr. Dinan's actual service is 17 years and ten months. There is no resulting benefit augmentation with respect to the additional two months credited to Mr. Dinan's years of service.

(4) Mr. McCormick's actual service is 18 years and ten months. There is no resulting benefit augmentation with respect to the additional two months credited to Mr. McCormick's years of service. Mr. McCormick is not a participant in the SERP.

(5) Mr. Bender is not a participant in the SERP or the Qualified Pension Plan.

Qualified Pension Plan. The Qualified Pension Plan is a defined benefit pension plan qualified under the Internal Revenue Code. At December 31, 2021, the plan covered non-bargaining unit employees hired prior to January 1, 2005, and certain bargaining-unit employees. Also, at December 31, 2021, non-bargaining unit employees hired after December 31, 2004, employees represented by Local No. 304 of the International Brotherhood of Electrical Workers hired on or after July 1, 2010, employees represented by United Steelworkers hired on or after December 15, 2011, and employees who accepted a one-time opportunity to opt out of the Qualified Pension Plan were covered by our Profit Sharing Plan. On December 30, 2021, the Profit Sharing Plan merged with and into the 401(k) Plan.

Benefits under the Qualified Pension Plan generally become vested and non-forfeitable after completion of five years of continuous employment. Under the plan, a vested participant receives a monthly retirement benefit at normal retirement age, unless an early retirement benefit is elected under the plan, in which case the retirement benefit may be actuarially reduced for early commencement. Generally, participants retiring on or after age 62 through normal retirement age receive 100 percent of their accrued monthly benefit which may be reduced depending on the optional form of payment elected at retirement. Benefits are calculated at retirement date based on a participant's credited service (limited to a maximum of 35 years) and final average earnings. The earnings utilized in the retirement plan benefit formula in the Qualified Pension Plan for employees includes the base salary and STI compensation paid to an employee during the period of the employee's final average earnings, less any amounts deferred under the NQDC Plan. The period of final average earnings means the employee's highest earnings during any 60 consecutive months of the last 120 months of employment. For any NEO who retires with vested benefits under the plan, the compensation shown as "Salary" and "Non-Equity Incentive Plan Compensation" in the Summary Compensation Table for 2021 would be considered eligible compensation in determining benefits, except that the plan benefit formula takes into account only fixed percentages of final average earnings. The amount of eligible compensation that may be considered in calculating retirement benefits is also subject to limitations in the Internal Revenue Code and the limitations contained in certain collective bargaining agreements applicable to the plan.

SERP. We maintain a SERP in order to provide supplemental retirement benefits to certain officers. The SERP provides that officers may be selected for participation in a supplemental retirement benefit or an excess retirement benefit, or both. If a participant is eligible for both the supplemental retirement benefit and the excess retirement benefit, the excess retirement benefit and benefits payable under the Qualified Pension Plan are treated as an offset that reduces the supplemental retirement benefit.

Participants in the SERP were selected by our CEO or, in the case of our CEO, by our Board. Our Board may amend or terminate the SERP at any time, provided that accrued benefits to current participants may not be reduced.

No new participants have been added to our SERP since 2005, and the SERP was closed to any additional participants as of January 1, 2014.

Supplemental benefits payable to participating employees in the SERP are based upon a specified percentage (reduced for early retirement and commencement of payment of benefits under the SERP) of the highest 36 consecutive months' compensation of the employee's last 60 months of service. The excess retirement benefit under the SERP pays a benefit equal at least to the benefit that would be payable to the participant under the Qualified Pension Plan if limitations imposed by the Internal Revenue Code were not applicable, less the benefit payable under the Qualified Pension Plan with such limitations. Benefits under the SERP are offset by the payment of benefits under the Qualified Pension Plan that were or would have been paid if the Qualified Pension Plan benefits were commenced at the same time as the SERP benefits. We fund benefits payable under the SERP through a rabbi trust arrangement.

NONQUALIFIED DEFERRED COMPENSATION FOR 2021

The following table sets forth certain information regarding the participation by the NEOs in our NQDC Plan.

Nonqualified Deferred Compensation

Name		Year	Executive Contributions in Last Fiscal Year	Registrant Contributions in Last Fiscal Year(1)	Aggregate Earnings in Last Fiscal Year(2)	Aggregate Withdrawals / Distributions	Aggregate Balance at Fiscal Year End(3)
Robert S. McAnnally		2021	$ 54,494	$ 61,940	$ 6,890	$ -	$ 475,763
		2020	$ 21,064	$ 41,897	$ 1,077	$ -	$ 352,439
		2019	$ 19,000	$ 39,382	$ 5,203	$ -	$ 288,401
Pierce H. Norton II		2021	$ 7,818	$ 7,818	$ 237,326	$ 24,035	$ 2,377,268
		2020	$ 16,000	$ 16,000	$ 317,042	$ -	$ 2,148,341
		2019	$ 96,000	$ 87,558	$ 304,435	$ 15,519	$ 1,799,300
Caron A. Lawhorn		2021	$ 65,250	$ 28,500	$ 85,138	$ -	$ 2,128,043
		2020	$ 62,781	$ 26,613	$ 178,097	$ -	$ 1,949,155
		2019	$ 57,750	$ 24,415	$ 158,736	$ -	$ 1,681,664
Curtis L. Dinan	(6)	2021	$ 73,059	$ 1,318,334	$ 7,004,521	$ 16,020	$ 27,736,936
	(5)	2020	$ 69,100	$ 1,193,894	$ (10,237,296)	$ 12,346	$ 19,357,042
	(4)	2019	$ 71,126	$ 1,063,727	$ 7,051,156	$ -	$ 28,343,690
Joseph L. McCormick		2021	$ 161,000	$ 38,980	$ 421,912	$ -	$ 2,649,836
		2020	$ 118,000	$ 37,538	$ 354,787	$ -	$ 2,027,944
		2019	$ 95,251	$ 35,188	$ 303,244	$ -	$ 1,517,619
Mark A. Bender		2021	$ 15,625	$ 25,555	$ 68,753	$ -	$ 400,147
		2020	$ 15,625	$ 25,801	$ 61,868	$ -	$ 290,214
		2019	$ 12,200	$ 24,037	$ 40,308	$ -	$ 186,920

(1) The "All Other Compensation" column of the Summary Compensation Table at page 50 includes the amounts paid under our NQDC Plan as our excess matching contributions with respect to our 401(k) Plan.

(2) There were no above-market earnings in 2021, 2020, or 2019.

(3) Includes amounts previously reported in the Summary Compensation Table in the previous years when earned, if that officer's compensation was required to be disclosed in a previous year. Amounts reported in such years include previously earned, but deferred, salary and annual incentive awards, company matching contributions, and shares that were deferred upon vesting and the dividend equivalents accumulated on these deferrals.

(4) Includes the value of 25,130 ONEOK shares the receipt of which was deferred by Mr. Dinan upon vesting in January 2010, 27,594 ONEOK shares the receipt of which was deferred by Mr. Dinan upon vesting in January 2011, 74,504 ONEOK shares the receipt of which was deferred upon vesting in January 2012, 56,000 ONEOK shares the receipt of which was deferred upon vesting in January 2013, and 48,738 ONE Gas shares issued upon our separation from ONEOK, in the case of 2010, 2011, 2012 and 2013, under the deferral provisions of ONEOK's Equity Compensation Plan, plus the dividend accumulation on these deferrals for a year-end deferred share balance of 243,227, 255,985 and 269,515 for 2017, 2018, and 2019, respectively, in ONEOK shares and 53,666, 54,992 and 56,239 for 2017, 2018 and 2019, respectively, in ONE Gas shares.

(5) Includes the value of 25,130 ONEOK shares the receipt of which was deferred by Mr. Dinan upon vesting in January 2010, 27,594 ONEOK shares the receipt of which was deferred by Mr. Dinan upon vesting in January 2011, 74,504 ONEOK shares the receipt of which was deferred upon vesting in January 2012, 56,000 ONEOK shares the receipt of which was deferred upon vesting in January 2013, and 48,738 ONE Gas shares issued upon our separation from ONEOK, in the case of 2010, 2011, 2012 and 2013, under the deferral provisions of ONEOK's Equity Compensation Plan, plus the dividend accumulation on these deferrals for a year-end deferred share balance of 255,985, 269,515 and 298,905 for 2018, 2019, and 2020, respectively, in ONEOK shares and 54,992, 56,239 and 57,768 for 2018, 2019 and 2020, respectively, in ONE Gas shares.

(6) Includes the value of 25,130 ONEOK shares the receipt of which was deferred by Mr. Dinan upon vesting in January 2010, 27,594 ONEOK shares the receipt of which was deferred by Mr. Dinan upon vesting in January 2011, 74,504 ONEOK shares the receipt of which was deferred upon vesting in January 2012, 56,000 ONEOK shares the receipt of which was deferred upon vesting in January 2013, and 48,738 ONE Gas shares issued upon our separation from ONEOK, in the case of 2010, 2011, 2012 and 2013, under the deferral provisions of ONEOK's Equity Compensation Plan, plus the dividend accumulation on these deferrals for a year-end deferred share balance of 269,515, 298,905 and 320,717 for 2019, 2020, and 2021, respectively, in ONEOK shares and 56,239, 57,768 and 59,676 for 2019, 2020 and 2021, respectively, in ONE Gas shares.

We maintain a NQDC Plan to provide select employees with the option to defer portions of their compensation and provide nonqualified deferred compensation benefits that are not otherwise available due to limitations on employer and employee contributions to qualified defined contribution plans under the federal tax laws. We match contributions for the benefit of plan participants to replace any company contributions a participant may lose because of limits imposed under the federal tax laws on contributions by a participant in the 401(k) Plan, as well as participants in the Qualified Pension Plan who do not participate in the SERP.

The NQDC Plan also allows for supplemental credit amounts, which are amounts that can be contributed at the discretion of the Committee. Under the NQDC Plan, participants have the option to defer a portion of their salary and/or STI compensation to a short-term deferral account, which pays out a minimum of five years from the date of election to defer compensation into the short-term deferral account, or to a long-term deferral account, which pays out at retirement or termination of the participant's employment. Participants are immediately 100 percent vested. Short-term and Long-term deferral accounts are credited with the actual investment return based on the amount of gains, losses and earnings for each of the investment options selected by the participant. For the year ended December 31, 2021, the investment return for the investment options for short-term and long-term investment accounts were as follows:

Fund Name	Plan Level Returns
American Funds American Mutual R6 (RMFGX)	25.33%
Carillon Scout Mid Cap I (UMBMX)	15.90%
Delaware Small Cap Value Instl (DEVIX)	34.24%
Federated Government Obligation (GOIXX)	0.02%
Fidelity Balanced K (FBAKX)	18.41%
Invesco Government & Agency Portfolio (AGPXX)	0.03%
JPMorgan Large Cap Growth R6 (JLGMX)	18.79%
JPMorgan Small Cap Equity R5 (JSERX)	16.22%
MFS International Diversification R3 (MDIHX)	7.45%
TCW Total Return Bond I (TGLMX)	-1.05%
Vanguard FTSE All-World ex-US Index Fund Admiral Shares (VFWAX)	8.12%
Vanguard Institutional Index I (VINIX)	28.67%
Vanguard PRIMECAP Adm (VPMAX)	21.90%
Vanguard Total Bond Market Index Fund Admiral Shares (VBTLX)	-1.67%
American Funds Target Date 2010 Retirement Fund R6	9.32%
American Funds Target Date 2015 Retirement Fund R6	10.27%
American Funds Target Date 2020 Retirement Fund R6	10.64%
American Funds Target Date 2025 Retirement Fund R6	11.44%
American Funds Target Date 2030 Retirement Fund R6	13.16%
American Funds Target Date 2035 Retirement Fund R6	15.54%

Fund Name	Plan Level Returns
American Funds Target Date 2040 Retirement Fund R6	16.83%
American Funds Target Date 2045 Retirement Fund R6	17.18%
American Funds Target Date 2050 Retirement Fund R6	17.27%
American Funds Target Date 2055 Retirement Fund R6	17.28%
American Funds Target Date 2060 Retirement Fund R6	17.19%
American Funds Target Date 2065 Retirement Fund R6	17.32%

At the distribution date, cash is distributed to participants based on the fair market value of the deemed investment of the participant's accounts at that date. We fund benefits payable under the NQDC Plan through a rabbi trust arrangement.

POTENTIAL POST-EMPLOYMENT PAYMENTS AND PAYMENTS UPON A CHANGE IN CONTROL

Described below are the post-employment compensation and benefits that we provide to our NEOs. The objectives of these compensation and benefits are to:

- assist in recruiting and retaining talented executives in a competitive market;
- provide security for any compensation or benefits that have been earned;
- permit executives to focus on our business;
- eliminate any potential personal bias of an executive against a transaction that is in the best interests of our stakeholders;
- avoid the costs associated with separately negotiating executive severance benefits; and
- provide us with the flexibility needed to react to a continually changing business environment.

We do not enter into individual employment agreements with our executive officers. Instead, in general, the rights of our executives with respect to specific events are covered by our compensation and benefit plans. Under this approach, post-employment compensation and benefits are established separately from the other compensation elements of our executives.

The use of a "plan approach" instead of individual employment agreements serves two objectives. First, the plan approach provides us with more flexibility to change the terms of severance benefits from time to time if necessary. Second, the plan approach is more transparent, both internally and externally. Internal transparency eliminates the need to negotiate separation benefits on a case-by-case basis and assures an executive that his or her severance benefits are comparable with those of his or her peers.

Payments Made Upon Any Termination. Regardless of the manner in which an NEO's employment terminates, he or she is entitled to receive amounts earned during his or her term of employment. These amounts include:

- accrued but unpaid salary;
- amounts contributed under our 401(k) Plan and NQDC Plan; and
- amounts accrued and vested through our Qualified Pension Plan and SERP.

Payments Made Upon Retirement. In the event of the retirement of an NEO, in addition to the items identified above, such NEO will be entitled to:

- receive a prorated share of each outstanding performance unit granted under our ECP upon completion of the performance period;
- receive a prorated portion of each outstanding RSU granted under our ECP;
- receive a prorated portion of the outstanding STI upon completion of the plan year; and
- participate, along with his or her qualifying dependents, in post-retirement health and life benefits.

Payments Made Upon Death or Disability. In the event of the death or disability of an NEO, in addition to the benefits listed under the headings "Payments Made Upon Any Termination" and "Payments Made Upon Retirement" above, the NEO will receive applicable benefits under our disability plan or payments under our life insurance plan.

Payments Made Upon a Termination Without Cause (Other than Following a CIC). In the event of an involuntary termination without cause (other than a qualifying termination following a CIC), an NEO will receive a prorated portion of each outstanding RSU granted under our ECP upon the date of termination. Outstanding PSUs are forfeited.

Payments Made Upon a Qualifying Termination Within Two Years Following a CIC. We believe that the possibility of a CIC creates uncertainty for executive officers because such transactions frequently result in changes in senior management. Our Board has adopted a CIC severance plan (the "Change in Control Plan") that covers all of our executive officers, including the NEOs. Subject to certain exceptions, the Change in Control Plan will provide our officers with severance benefits if they are terminated by us without cause (as defined below) or if they resign for good reason (as defined below), in each case within two years following a CIC of ONE Gas. All CIC benefits are "double trigger," meaning that payments and benefits under the plan are payable only if the officer's employment is terminated by us without "cause" or by the officer for a "good reason" at any time during the two years following a CIC. Severance payments under the plan consist of a cash payment that may be up to three times the participant's base salary and target STI award, plus reimbursement of COBRA healthcare premiums for 18 months. Our Board, upon the recommendation of the Committee, established a severance multiplier of one, two or three times annual salary plus target annual award for all participants in the Change in Control Plan, including three times for the CEO and two times for each of the other NEOs.

The Change in Control Plan does not provide for additional pension benefits upon a CIC. In addition, the Change in Control Plan does not contain an excise tax gross-up for any participant. Rather, severance payments and benefits under the Change in Control Plan will be reduced if, as a result of such reduction, the officer would receive a greater total payment after taking taxes, including excise taxes, into account.

In the event of a qualifying termination following a CIC, an NEO will receive all outstanding RSUs and PSUs granted under our ECP upon the date of termination.

For the purposes of the Change in Control Plan, a "CIC" generally means any of the following events:

- an acquisition of our voting securities by any person that results in the person having beneficial ownership of 20 percent or more of the combined voting power of our outstanding voting securities, other than an acquisition directly from us;
- the current members of our Board, and any new director approved by a vote of at least two-thirds of our Board, cease for any reason to constitute at least a majority of our Board, other than in connection with an actual or threatened proxy contest (collectively, the "Incumbent Board");
- the consummation of a merger, consolidation or reorganization with us or in which we issue securities, unless (a) our shareholders immediately before the transaction, as a result of the transaction, directly or indirectly own at least 50 percent of the combined voting power of the voting securities of the company resulting from the transaction, (b) the members of our Incumbent Board, after the execution of the transaction agreement, constitute at least a majority of the members of the Board of the company resulting from the transaction, or (c) no person other than persons who, immediately before the transaction owned 20 percent or more of our outstanding voting securities, has beneficial ownership of 20 percent or more of the outstanding voting securities of the company resulting from the transaction; or
- our complete liquidation or dissolution or the sale or other disposition of all or substantially all of our assets.

For the purposes of the Change in Control Plan, termination for "cause" means a termination of employment of a participant in the Change in Control Plan by reason of:

- a participant's indictment for or conviction in a court of law of a felony, crime, or offense involving misuse or misappropriation of money or property;
- a participant's violation of any covenant, agreement or obligation not to disclose confidential information regarding the business of the company (or a division or subsidiary) or a participant's violation of any covenant, agreement or obligation not to compete with the company (or a division or subsidiary);
- any act of dishonesty by a participant that adversely affects the business of the company (or a division or subsidiary) or any willful or intentional act of a participant that adversely affects the business, or reflects unfavorably on the reputation, of the company (or a division or subsidiary);
- a participant's material violation of any written policy of the company (or a division or subsidiary); or
- a participant's failure or refusal to perform the specific directives of the Board or its officers, which are consistent with the scope and nature of the participant's duties and responsibilities, to be determined in the Board's sole discretion.

For the purposes of the Change in Control Plan, "good reason" means:

- a participant's demotion or material reduction of the participant's significant authority or responsibility with respect to employment with the company as of the date the CIC occurred;
- a material reduction in the participant's base salary as of the date immediately prior to the CIC;
- a material reduction in STI and/or LTI targets from those applicable to the participant immediately prior to the CIC;
- the relocation to a new principal place of employment of the participant's employment by the company, which is more than 35 miles farther from the participant's principal place of employment prior to such change; and
- the failure of a successor company to explicitly assume the Change in Control Plan.

Potential Post-Employment Payments Tables. The following tables reflect estimates of the incremental amount of compensation due each NEO in the event of such executive's termination of employment by reason of death, disability or retirement, termination of employment without cause, or a qualifying termination within two years following a CIC. The amounts shown assume that such termination was effective as of December 31, 2021, and are estimates of the amounts that would be paid to the executives upon such termination, including, with respect to PSUs, the performance factor calculated as if the performance period ended on December 31, 2021. The amounts reflected in the "Qualifying Termination Following a Change in Control" column of the following tables are amounts that would be paid pursuant to our Change in Control Plan and, with respect to the PSUs, assume achievement of a performance factor at the target of 100 percent.

Robert S. McAnnally	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 3,607,500
Short-Term Incentive	$ 420,951	$ -	$ 420,951
Health and Welfare Benefits	$ -	$ -	$ 26,607
Equity			
Restricted Unit	$ 496,819	$ 496,819	$ 1,026,468
Performance Unit	$ 341,472	$ -	$ 1,905,597
Total	$ 838,291	$ 496,819	$ 2,932,065
Total	$ 1,259,242	$ 496,819	$ 6,987,123

Pierce H. Norton II	Termination Upon Death, Disability or Retirement(1)	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ -
Short-Term Incentive	$ 375,724	$ -	$ -
Health and Welfare Benefits	$ -	$ -	$ -
Equity			
Restricted Unit	$ 890,596	$ -	$ -
Performance Unit	$ 1,960,457	$ -	$ -
Total	$ 2,851,053	$ -	$ -
Total	$ 3,226,777	$ -	$ -

(1) Mr. Norton voluntarily retired from the Company on June 27, 2021, and therefore ceased to be an executive officer as of that date. Accordingly, pursuant to Instruction 4 of Regulation S-K Item 402(j), this table only includes disclosure for the actual triggering event that occurred.

Caron A. Lawhorn	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 1,435,500
Short-Term Incentive	$ 282,750	$ -	$ 282,750
Health and Welfare Benefits	$ -	$ -	$ 34,049
Equity			
Restricted Unit	$ 155,619	$ 155,619	$ 268,284
Performance Unit	$ 341,473	$ -	$ 1,073,135
Total	$ 497,092	$ 155,619	$ 1,341,419

Total	$ 779,842	$ 155,619	$ 3,093,718

Curtis L. Dinan	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 1,650,000
Short-Term Incentive	$ 304,396	$ -	$ 304,396
Health and Welfare Benefits	$ -	$ -	$ 34,049
Equity			
Restricted Unit	$ 163,417	$ 163,417	$ 309,870
Performance Unit	$ 341,473	$ -	$ 1,239,401
Total	$ 504,890	$ 163,417	$ 1,549,271
Total	$ 809,286	$ 163,417	$ 3,537,716

Joseph L. McCormick	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 1,188,000
Short-Term Incentive	$ 234,000	$ -	$ 234,000
Health and Welfare Benefits	$ -	$ -	$ -
Equity			
Restricted Unit	$ 152,547	$ 152,547	$ 257,223
Performance Unit	$ 341,473	$ -	$ 1,029,051
Total	$ 494,020	$ 152,547	$ 1,286,274
Total	$ 728,020	$ 152,547	$ 2,708,274

Mark A. Bender	Termination Upon Death, Disability or Retirement	Termination Without Cause	Qualifying Termination Following a Change in Control
Cash Severance	$ -	$ -	$ 968,750
Short-Term Incentive	$ 171,875	$ -	$ 171,875
Health and Welfare Benefits	$ -	$ -	$ 34,049
Equity			
Restricted Unit	$ 108,159	$ 108,159	$ 183,235
Performance Unit	$ 240,994	$ -	$ 732,851
Total	$ 349,153	$ 108,159	$ 916,086
Total	$ 521,028	$ 108,159	$ 2,090,760

CEO PAY RATIO FOR 2021

In accordance with the requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the SEC adopted Regulation S-K Item 402(u) requiring registrants to disclose (i) the median of the annual total compensation of all employees of the registrant, except the principal executive officer, (ii) the annual total compensation of the principal executive officer of the registrant, and (iii) the ratio of the median of the annual total compensation of all employees of the registrant to the principal executive officer's annual total compensation (the "CEO Pay Ratio").

We used the same median employee as disclosed in our pay ratio disclosure in our 2021 Proxy Statement as there have been no significant changes in the composition of our employee population, employee compensation arrangements or the median employee's position that we reasonably believe would result in a significant change to our pay ratio disclosure. In 2022, we identified the median employee using the total cash compensation for all our employees (whether full-time, part-time, seasonal or temporary) other than the CEO who were employed and received Form W-2 Box 1 earnings as of December 31, 2021. Specifically, we used Form W-2 Box 1 compensation minus any compensation received from the vesting of LTIs (i.e., PSU and RSU vesting) in 2021. We excluded any compensation related to LTIs since PSUs and RSUs are not widely used throughout the company. Less than 5 percent of our employee population receive LTI grants. We did not annualize the compensation for any partial year permanent employees. Since annual short-term incentives are used widely throughout our employee population, we believe total cash compensation which includes short-term incentives is a consistently applied compensation measure that is the most representative measure of compensation for identifying our median employee. No other estimates, assumptions or adjustments were used in identifying our median employee.

After we identified our median employee, we calculated the median employee's annual total compensation in the same manner we calculate the annual total compensation of the NEOs in the Summary Compensation Table which includes base salary plus overtime, if any, short-term incentives, change in pension value and all other compensation. We then calculated the ratio of the CEO's annual total compensation ($2,584,173) to the median employee's annual total compensation ($97,165). The ratio between the annual total compensation of our CEO to the median of the annual total compensation of all of our employees is 27:1. This ratio is a reasonable estimate calculated in a manner consistent with Item 402(u) of Regulation S-K. We believe the methodology, assumptions, and estimates described above to be reasonable given our specific employee population. The SEC rules grant companies flexibility in determining the methodology, assumptions and estimates used to comply with the requirements of this disclosure. As acknowledged by the SEC, this flexibility could reduce the comparability of disclosed pay ratios across companies and our pay ratio may not necessarily be representative or comparable to the ratios disclosed by other companies.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth certain information concerning our common stock that may be issued under our existing equity compensation plans as of December 31, 2021:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities in Column (a)) (c)
Equity compensation plans approved by security holders(1)	401,134(2)	$ -	2,906,459
Equity compensation plans not approved by security holders(3)	73,091	$ 77.59	-
Total	474,225	$ 77.59	2,906,459

(1) Plans approved by shareholders consists of the Amended and Restated Equity Compensation Plan (2018) and Employee Stock Purchase Plan.

(2) Includes outstanding grants of restricted stock unit awards and assumes performance stock unit awards are payable at 100%. The actual payout of the PSUs can range from 0 percent to 200 percent of the units originally awarded depending upon the company's relative three-year TSR. There is no exercise price associated with restrictive stock unit and performance stock unit awards. Column (c) includes 604,750 and 2,301,709 shares available for future issuance under our ESPP and our ECP.

(3) Includes our Deferred Compensation Plan for Non-employee Directors. Compensation deferred into our common stock under our Deferred Compensation Plan for Non-employee Directors is distributed to participants at fair market value on the date of distribution. The price used to calculate the weighted-average exercise price in the table is $77.59, which represents the year-end closing price of our common stock on the NYSE.

PROPOSAL 3 – ADVISORY VOTE ON EXECUTIVE COMPENSATION

INTRODUCTION

The Dodd-Frank Act added provisions to Section 14A of the Exchange Act to provide that a public company's proxy statement in connection with the company's annual meeting of shareholders must, at least once every three years, allow shareholders to cast a non-binding advisory "say-on-pay" vote regarding the compensation of the company's named executive officers as disclosed pursuant to Item 402 of Securities and Exchange Commission Regulation S-K, including the Compensation Discussion and Analysis, compensation tables and narrative discussion. Section 14A of the Exchange Act, as amended by the Dodd-Frank Act, also requires us, not less frequently than once every six years, to provide our shareholders the opportunity to vote, on a non-binding advisory basis, on the frequency with which we will submit to shareholders a "say-on-pay" advisory vote.

At our 2021 annual meeting of shareholders, a substantial majority of our shareholders voted for an annual say-on-pay vote. Based on these results, we have provided our shareholders with an annual, non-binding advisory say-on-pay vote on executive compensation.

OUR EXECUTIVE COMPENSATION PROGRAM

As described in the Compensation Discussion and Analysis section of this proxy statement and the compensation tables and narratives discussion set forth above, our executive compensation program is based on our pay-for-performance philosophy and is designed with the following goals in mind:

- to align the interests of our executive officers with the interests of our stakeholders;
- to attract, retain and motivate executives who are critical to the successful implementation of our strategic plan;
- to pay our executives fairly relative to our industry peers based on their responsibilities, experience and performance; and
- to implement sound governance practices by implementing executive compensation best practices and policies.

Our Executive Compensation Committee regularly reviews the compensation program for our NEOs to assess their effectiveness in delivering these goals.

Examples of how the various elements of our compensation program for our NEOs are linked to company performance and are designed to achieve the goals set forth above include:

- a substantial portion of our NEOs' compensation is "variable" or "at-risk" incentive compensation, meaning that it is tied to our performance relative to various short-term and long-term objectives, which are based on a number of financial and business goals;
- awards to each executive officer are subject to fixed maximums established by our Executive Compensation Committee;
- incentive awards are based on a review of a variety of indicators of performance, thus diversifying the risk associated with any single indicator of performance;
- STI and LTI awards are not tied to formulas that are designed to focus executives on specific short- and intermediate-term outcomes;
- the Executive Compensation Committee approves the final annual incentive plan awards after the review and confirmation of executive and operating and financial performance;
- STI and LTI awards are subject to clawback provisions as described on page 47.
- for executive officers, a significant portion of incentive award value is delivered in the form of our stock-based compensation that vests over multiple years;
- for executive officers, approximately 80 percent of the long-term, stock-based incentive amounts are in the form of PSUs; and
- executive officers are subject to our share ownership guidelines, described on page 46.

For additional information on the compensation program for our NEOs, including specific information about compensation in fiscal year 2021, please read the "Compensation Discussion and Analysis," along with the subsequent tables and narrative descriptions, beginning on page 36.

For the reasons discussed above, the Board recommends that shareholders vote in favor of the following resolution:

"RESOLVED, that the shareholders hereby approve, on an advisory basis, the compensation paid to the NEOs, as disclosed in the company's proxy statement for the 2022 Annual Meeting of Shareholders pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables and narrative discussion."

VOTE REQUIRED AND BOARD RECOMMENDATION

This vote is advisory and will not be binding on the company, our Board or our Executive Compensation Committee. Our Board and our Executive Compensation Committee value the opinions of our shareholders and, to the extent there is any significant vote against the NEO compensation as disclosed in this proxy statement, we will consider our shareholders' concerns, and the Executive Compensation Committee will evaluate whether any actions are necessary to address those concerns.

Approval of this proposal requires the affirmative vote of the holders of a majority of the voting power of the shareholders present online or by proxy and entitled to vote on the proposal at the meeting. Abstentions will have the same effect as votes against this proposal and broker non-votes do not count as present and entitled to vote for purposes of determining the outcome of the vote on this proposal.

RECOMMENDATION OF THE BOARD

Your board unanimously recommends a vote **FOR** the approval of the compensation of our NEOs, as disclosed in this proxy statement pursuant to Item 402 of Regulation S-K, including the compensation discussion and analysis, the compensation tables and the related narrative discussion.

RELATED-PERSON TRANSACTIONS

Our Board recognizes that transactions in which we participate and in which a related person (executive officer, director, director nominee, five percent or greater shareholder and their immediate family members) has a direct or indirect material interest can present potential or actual conflicts of interest and create the appearance that company decisions are based on considerations other than the best interests of the company and its shareholders. Accordingly, as a general matter, it is our preference to avoid related-person transactions. Nevertheless, we recognize that there are situations where related-person transactions may be in, or may be consistent with, the best interests of the company and its shareholders including, but not limited to, situations where we provide products or services to related persons on an arm's length basis and on terms comparable with those provided to unrelated third parties.

In the event we enter into a transaction in which an executive officer (other than an employment relationship), director (other than compensation arrangements for service on our Board provided to each director), director nominee, five percent or greater shareholder, or a member of their immediate family has a direct or indirect material interest, the transaction is presented to our Audit Committee and, if warranted, our Board, for review to determine if the transaction creates a conflict of interest and, if so, is otherwise fair to the company. In determining whether a particular transaction creates a conflict of interest and, if so, that is fair to the company, our Audit Committee and, if warranted, our Board, consider the specific facts and circumstances applicable to each such transaction, including: the parties to the transaction, their relationship to the company and nature of their interest in the transaction; the nature of the transaction; the aggregate value of the transaction; the length of the transaction; whether the transaction occurs in the normal course of our business; the benefits to our company provided by the transaction; if applicable, the availability of other sources of comparable products or services; and, if applicable, whether the terms of the transaction, including price or other consideration, are the same or substantially the same as those available to the company if the transaction were entered into with an unrelated party.

We require each executive officer and director to annually provide us written disclosure of any transaction in which we participate and in which the officer or director or any of his or her immediate family members has a direct or indirect material interest. Our Corporate Governance Committee reviews our disclosure of related-party transactions in connection with its annual review of director independence. These procedures are not in writing but are documented through the meeting agendas and minutes of our Audit and Corporate Governance Committees.

Apart from certain directors and executive officers receiving natural gas service at regulated rates, no related-person transactions exist.

ABOUT THE 2022 ANNUAL MEETING

The following questions and answers are provided for your convenience and briefly address some commonly asked questions about our 2022 Annual Meeting of Shareholders. Please also consult the more detailed information contained elsewhere in this proxy statement and the documents referred to in this proxy statement.

Why did I receive these proxy materials?

We are providing these proxy materials in connection with the solicitation by the Board of proxies to be voted at our 2022 Annual Meeting of Shareholders and at any adjournment or postponement of the meeting. You are invited to attend our virtual Annual Meeting of Shareholders online on May 26, 2022, at 9:00 a.m., Central Daylight Time.

How do I attend the annual meeting?

To register for and virtually attend the live online Annual Meeting, please visit **www.proxydocs.com/ogs**. Please note you will need the control number included on your proxy card, voting instruction form, or Notice of Internet Availability in order to register for and to access the Annual Meeting. Registration to participate is due by Wednesday, May 25, 2022, at 3:00 p.m. Central Daylight Time. Upon completing your registration, you will receive further instructions via email, including a unique link to allow you access to the meeting and to vote and submit questions. Please be sure to follow the instructions found on your proxy card, voting instruction form, or Notice of Internet Availability and subsequent instructions that will be delivered to you via email.

On the day of the annual meeting, May 26, 2022, shareholders may begin to log in to the virtual meeting platform 15 minutes before the meeting starts. The annual meeting will start promptly at 9:00 a.m., Central Daylight Time.

We will have technicians ready to assist you with any technical difficulties you may have accessing the annual meeting. If you encounter any difficulties accessing the virtual meeting platform, including difficulties voting or submitting questions, please call the technical support number included in your instructional email.

If there are any technical issues in convening or hosting the annual meeting, we will promptly issue a news release and post information to our website at www.ONEGas.com under the Investors page including information on when the meeting will be reconvened.

Who may attend and vote at the annual meeting?

All shareholders who held shares of our common stock at the close of business on March 28, 2022, may attend and vote at the meeting.

How do I submit questions at the annual meeting?

It is our desire to conduct a virtual annual meeting that approximates an in-person experience for our shareholders. Shareholders who have logged in to the virtual meeting platform may ask questions at the annual meeting in accordance with the rules of conduct that will be available on the virtual meeting platform.

We will endeavor to answer as many questions submitted by shareholders as time permits. We reserve the right to edit profanity or other inappropriate language and to exclude questions regarding topics that are not pertinent to meeting matters or company business. If we receive substantially similar questions, we may group such questions together and provide a single response to avoid repetition.

What if I have difficulties locating the control number prior to the day of the Annual Meeting?

Prior to the day of the Annual Meeting, if you need assistance with your control number and you hold your shares in your own name, please call toll-free 1-855-217-6403 in the United States. If you hold your shares in a brokerage account or in the name of a bank, trustee or other holder of record, you will need to contact your brokerage firm, bank, trustee or other holder of record for assistance with your control number.

What if I have technical difficulties accessing the online Annual Meeting?

If you encounter difficulties accessing the online Annual Meeting during registration or the Annual Meeting itself, including any difficulties with your control number, please reference a frequently asked questions link that will be posted on the online Annual Meeting site or in your instructional email. A shareholder may also call a technical support number which is provided within the frequently asked questions site.

Will the annual meeting be webcast?

Our annual meeting also will be audio webcast on May 26, 2022. You are invited to visit www.ONEGas.com at 9:00 a.m., Central Daylight Time, on May 26, 2022, to access the webcast of the meeting. Registration for the webcast is required. An archived copy of the webcast will also be available on our website for 30 days following the meeting.

How do I vote?

If you were a shareholder of record at the close of business on the record date of March 28, 2022, you may appoint a proxy through the internet, by telephone or by mail to vote your shares on your behalf. The internet and telephone methods of voting generally are available 24 hours a day and will ensure that your proxy is confirmed and posted immediately. These methods of voting are also available to shareholders who hold their shares in our Direct Stock Purchase and Dividend Reinvestment Plan, our ESP Plan and our 401(k) Plan. In addition, these voting methods are available to ONEOK employees who own our shares in the ONEOK Plan. You may revoke your proxy any time before the annual meeting by following the procedures outlined below under the caption "What can I do if I change my mind after I vote my shares by proxy?" Please help us save time and postage costs by appointing a proxy via the internet or by telephone.

When you appoint a proxy via the internet, by telephone or by mailing a signed proxy card, you are appointing John W. Gibson, Chairman of the Board and Joseph L. McCormick, Senior Vice President, General Counsel and Assistant Secretary, as your representatives at the annual meeting, and they will vote your shares as you have instructed them. If you appoint a proxy via the internet, by telephone or by mailing a signed proxy card but do not provide voting instructions, your shares will be voted *for* the election of each proposed eight director nominees named herein and *for* proposal numbers 2 and 3.

To appoint a proxy to vote your shares on your behalf, please select from the following options:

Via the internet

- Go to the website at **www.proxydocs.com/ogs**, which is available 24 hours a day, 7 days a week, until 11:59 p.m. (Central Daylight Time) on May 25, 2022.
- Enter the control number that appears on your proxy card. This process is designed to verify that you are a shareholder and allows you to vote your shares and confirm that your instructions have been properly recorded.
- Follow the simple instructions.
- **If you appoint a proxy via the internet, you do not have to return your proxy card.**

By telephone

- On a touch-tone telephone, call toll-free **1-866-883-3382**, 24 hours a day, 7 days a week, until 11:59 p.m. (Central Daylight Time) on May 25, 2022.
- Enter the control number that appears on your proxy card. This process is designed to verify that you are a shareholder and allows you to vote your shares and confirm that your instructions have been properly recorded.
- Follow the simple recorded instructions.
- If you appoint a proxy by telephone, you do not have to return your proxy card.

By mail

- Mark your selections on the proxy card.
- Date and sign your name exactly as it appears on your proxy card.
- Mail the proxy card in the enclosed postage-paid envelope.
- If mailed, your completed and signed proxy card must be received prior to the commencement of voting at the annual meeting.

What if my shares are held by my broker, bank or another holder of record?

If your shares are held in a brokerage account, by a bank, trustee or another holder of record, your shares are considered to be held "in street name." If you held shares "in street name" as of the record date of March 28, 2022, this proxy statement and our 2021 annual report to shareholders should have been forwarded to you by your bank, broker or other holder of record, together with a voting instruction card. You have the right to direct your bank, broker or other holder of record how to vote your shares by using the voting instruction card you received from your bank, broker or other holder of record, or by following any instructions provided by your bank, broker or other holder of record for voting via the internet or telephone.

Under the rules of the NYSE, unless you provide your bank, broker or other holder of record with your instructions on how to vote your shares, your bank, broker or other holder of record is prohibited from:

(1) voting your shares in the election of directors; and

(2) voting on the advisory vote to approve executive compensation.

However, your bank, broker or other holder of record can vote on the ratification of the selection of our independent registered public accounting firm.

Consequently, unless you respond to their request for your voting instructions in a timely manner, your shares held by your bank, broker or other holder of record will not be voted on any of these matters (which is referred to as a "broker non-vote"), except the ratification of the selection of our independent registered public accounting firm. Please provide your voting instructions so that your shares may be voted.

What can I do if I change my mind after I vote my shares by proxy?

If you were a shareholder of record at the close of business on the record date, you have the right to revoke your proxy at any time before it is voted at the meeting by:

(1) notifying our corporate secretary in writing;

(2) authorizing a later proxy via the internet or by telephone;

(3) returning a later-dated proxy card; or

(4) voting at the meeting.

If your shares are held by your bank, broker or other holder of record you may revoke any voting instructions you may have previously provided only in accordance with revocation instructions provided by the bank, broker or other holder of record.

Is my vote confidential?

Proxy cards, ballots and voting tabulations that identify individual shareholders are mailed and returned directly to our stock transfer agent who is responsible for tabulating the vote in a manner that protects your voting privacy. It is our policy to protect the confidentiality of shareholder votes throughout the voting process. The vote of any shareholder will not be disclosed to our directors, officers or employees, except:

(1) to meet legal requirements;

(2) to assert or defend claims for or against us; or

(3) in those limited circumstances where:

- (a) a proxy solicitation is contested (which, to our knowledge, is not the case in connection with the 2022 annual meeting),
- (b) a shareholder writes comments on a proxy card, or
- (c) a shareholder authorizes disclosure.

The vote tabulator and the inspector of election has been, and will remain, independent of us. This policy does not prohibit shareholders from disclosing the nature of their votes to our directors, officers or employees, or prevent us from voluntarily communicating with our shareholders, ascertaining which shareholders have voted or making efforts to encourage shareholders to vote.

How is common stock held in our 401(k) Plan and the ONEOK Plan voted?

If you hold shares of our common stock through our 401(k) Plan or the ONEOK Plan, in order for those shares to be voted as you wish, you must instruct the trustee of these plans, Fidelity Management Trust Company, how to vote those shares by providing your instructions via the internet, by telephone or by mail in the manner outlined above. If you fail to provide your instructions, or if you return an instruction card with an unclear voting designation or with no voting designation at all, then the trustee will vote the shares in your account in proportion to the way the other participants in each respective plan vote their shares. These votes receive the same confidentiality as all other shares voted.

To allow sufficient time for voting by the trustee of our 401(k) Plan and the ONEOK Plan, your voting instructions must be received by May 23, 2022.

How will shares for which a proxy is appointed be voted on any other business conducted at the annual meeting that is not described in this proxy statement?

Although we do not know of any business to be considered at the 2022 annual meeting other than the proposals described in this proxy statement, if any other business is properly presented at the annual meeting, your proxy gives authority to John W. Gibson, Chairman of the Board, and Joseph L. McCormick, our Senior Vice President, General Counsel and Assistant Secretary, to vote on these matters at their discretion.

What shares are included on the proxy card(s)?

The shares included on your proxy card(s) represent all of the shares that you owned of record as of the close of business on March 28, 2022, including those shares held in our Direct Stock Purchase and Dividend Reinvestment Plan, our ESP Plan, our 401(k) Plan and the ONEOK Plan. If you do not authorize a proxy via the internet, by telephone or by mail, your shares, except for those shares held in our 401(k) Plan and the ONEOK Plan, will not be voted. Please refer to the discussion above for an explanation of the voting procedures for your shares held by our 401(k) Plan and the ONEOK Plan.

What does it mean if I receive more than one proxy card?

If your shares are registered differently or are in more than one account, you will receive more than one proxy card. Please sign and return all proxy cards, or appoint a proxy via the internet or telephone, to ensure that all your shares are voted. We encourage you to have all accounts registered in the same name and address whenever possible.

Why did we receive just one copy of the proxy statement and annual report when we have more than one stock account in our household?

We have adopted a procedure approved by the SEC called "householding." This procedure permits us to send a single copy of the proxy statement and annual report to a household if the shareholders provide written or implied consent. We previously mailed a notice to eligible registered shareholders stating our intent to utilize this rule unless the shareholder provided an objection. Shareholders continue to receive a separate proxy card for each stock account. Shareholders of record voting by mail can choose this option by marking the appropriate box on the proxy card included with this proxy statement. Shareholders of record voting via telephone or over the internet can choose this option by following instructions provided by telephone or over the internet, as applicable.

Is there a list of shareholders entitled to vote at the annual meeting?

The names of shareholders of record entitled to vote at the annual meeting will be available via the online platform at the annual meeting and for 10 days prior to the meeting for any purpose relevant to the meeting between the hours of 9:00 a.m. and 4:30 p.m. CDT at our principal executive offices at 15 East Fifth Street, Tulsa, Oklahoma, and may be viewed by contacting our corporate secretary.

May I access the notice of annual meeting, proxy statement, 2021 annual report and accompanying documents on the internet?

Important Notice Regarding Internet Availability of Proxy Materials for the Shareholder Meeting to be held on May 26, 2022. This notice of Annual Meeting, proxy statement, form of proxy and our 2021 annual report to shareholders are being distributed and made available on or about April 6, 2022. This proxy statement and our 2021 annual report to shareholders are also available on our website at www.ONEGas.com.

Additionally, in accordance with rules of the SEC, you may access this proxy statement, our 2021 annual report and any other proxy materials we use at **www.proxydocs.com/ogs**.

Instead of receiving future copies of our proxy and annual report materials by mail, shareholders may elect to receive an email that will provide electronic links to these proxy and annual report materials. Opting to receive your proxy materials online will save us the cost of producing and mailing documents to your home or business and will also give you an electronic link to the proxy voting site. You may log on to **www.proxydocs.com/ogs** and follow the prompts to enroll in the electronic proxy delivery service. If you hold your shares in a brokerage account, you may also have the opportunity to receive copies of these documents electronically. Please check the information provided in the proxy materials mailed to you by your broker, bank, or other holder of record of your shares regarding the availability of this service.

What out-of-pocket costs will we incur in soliciting proxies?

Morrow Sodali LLC, 333 Ludlow Street, 5th Floor, South Tower, Stamford, CT 06902, will assist us in the distribution of proxy materials and solicitation of votes for a fee of $10,000, plus out-of-pocket expenses. We also reimburse brokerage firms, banks and other custodians, nominees and fiduciaries for their reasonable expenses for forwarding proxy materials to our shareholders. We will pay all costs of soliciting proxies.

Who is soliciting my proxy?

Our Board is sending you this proxy statement in connection with its solicitation of proxies for use at our 2022 Annual Meeting of Shareholders. Certain of our directors, officers and employees also may solicit proxies on our behalf in person or by mail, telephone, fax or email.

Who will count the vote?

Representatives of our stock transfer agent, Equiniti Trust Company d/b/a EQ Shareowner Services, will tabulate the votes and act as the inspector of the election.

How can I find out the results of the voting at the annual meeting?

Preliminary voting results will be announced at the annual meeting. Voting results will be published in a Current Report on Form 8-K that we will file with the SEC within four business days after the annual meeting.

SHAREHOLDER PROPOSALS

The rules of the SEC provide when a company must include a shareholder's proposal in its proxy statement and identify the proposal in its form of proxy when the company holds an annual or special meeting of shareholders. Under these rules, proposals that shareholders would like to submit for inclusion in our proxy statement for our 2023 Annual Meeting of Shareholders should be received by our corporate secretary at our principal executive offices no later than December 7, 2022. Only those shareholder proposals eligible for inclusion under the rules of the SEC will be included in our proxy statement.

If a shareholder desires to present a proposal, other than the nomination of directors at our 2023 annual meeting, outside the process provided by the rules of the SEC, the shareholder must follow the procedures set forth in our bylaws. Our bylaws generally provide that a shareholder may present a proposal at an annual meeting if (1) the shareholder is a shareholder of record at the time the shareholder gives written notice of the proposal and is entitled to vote at the meeting and (2) the shareholder gives timely written notice of the proposal, including any information regarding the proposal required under our bylaws, to our corporate secretary. To be timely for our 2023 annual meeting, a shareholder's notice must be delivered to, or mailed to and received at, our principal executive offices no later than December 7, 2022.

HOUSEHOLDING

Shareholders with multiple accounts that share the same last name and household mailing address will receive a single copy of shareholder documents (annual report, proxy statement, or other informational statement) unless we are instructed otherwise. Each shareholder, however, will continue to receive a separate proxy card. This practice, known as "householding," is designed to reduce our printing and postage costs.

If you are a registered shareholder and received only one copy of the proxy statement and annual report in your household, we will promptly deliver additional copies, to the extent you request copies, for each member of your household who was a registered shareholder as of the record date by providing written instructions to EQ Shareowner Services, Attn: Householding/ONE Gas, Inc., P.O. Box 64854, St. Paul, Minnesota 55164-0854. You may contact EQ Shareowner Services at 1-855-217-6403 for assistance. You also may contact us in the same manner if you are currently receiving a single copy of the proxy statement and annual report in your household and desire to receive separate copies in the future for each member of your household who is a registered shareholder, or if your household is currently receiving multiple copies of the proxy statement and annual report and you desire to receive a single copy in the future for your entire household. If you are not a registered shareholder and your shares are held by a broker, bank or other holder of record, you will need to contact that entity to revoke your election and receive multiple copies of these documents.

ANNUAL REPORT ON FORM 10-K

Our 2021 annual report to shareholders (which includes our Annual Report on Form 10-K for the year ended December 31, 2021) is available on our website at www.ONEGas.com. We will provide, without charge, on the written request of any person solicited hereby, a copy of our Annual Report on Form 10-K as filed with the SEC for the year ended December 31, 2021. Written requests should be mailed to Brian K. Shore, Corporate Secretary, ONE Gas, Inc., 15 E. Fifth Street, Tulsa, Oklahoma 74103.

OTHER MATTERS

So far as is now known to us, there is no business other than that described above in this proxy statement to be presented to the shareholders for action at the annual meeting. Should other business come before the annual meeting, votes may be cast pursuant to proxies in respect to any such business in the best judgment of the persons acting under the proxies.

Please return your proxy as soon as possible. Unless a quorum consisting of a majority of the outstanding shares entitled to vote is represented at the annual meeting, no business can be transacted. Therefore, please authorize a proxy electronically via the internet, by telephone, or by mail. Please act promptly to ensure that you will be represented at this important meeting.

By order of the Board.

Brian K. Shore
Corporate Secretary

Tulsa, Oklahoma
April 6, 2022

15 East Fifth Street
Tulsa, OK 74103
www.ONEGas.com

ONE Gas

Shareowner Services
P.O. Box 64945
St. Paul, MN 55164-0945

Address Change? Mark box, sign, and indicate changes below: ☐

TO VOTE BY INTERNET OR TELEPHONE, SEE REVERSE SIDE OF THIS PROXY CARD.

Your Board of Directors recommends a vote FOR the election of each of the eight director nominees listed below:

1. Election of directors:

	FOR	AGAINST	ABSTAIN		FOR	AGAINST	ABSTAIN
01 Robert B. Evans	☐	☐	☐	05 Robert S. McAnnally	☐	☐	☐
02 John W. Gibson	☐	☐	☐	06 Pattye L. Moore	☐	☐	☐
03 Tracy E. Hart	☐	☐	☐	07 Eduardo A. Rodriguez	☐	☐	☐
04 Michael G. Hutchinson	☐	☐	☐	08 Douglas H. Yaeger	☐	☐	☐

Please fold here – Do not separate

Your Board of Directors recommends a vote FOR Proposals 2 and 3:

2. Ratification of the selection of PricewaterhouseCoopers LLP as the independent registered public accounting firm of ONE Gas, Inc. for the year ending December 31, 2022. ☐ For ☐ Against ☐ Abstain

3. Advisory vote to approve the Company's executive compensation. ☐ For ☐ Against ☐ Abstain

THIS PROXY WHEN PROPERLY EXECUTED WILL BE VOTED AS DIRECTED OR, IF NO DIRECTION IS GIVEN, WILL BE VOTED AS THE BOARD RECOMMENDS.

Date ______________________________

Signature(s) in Box

Please sign exactly as your name(s) appears on Proxy. If held in joint tenancy, all persons should sign. Trustees, administrators, etc., should include title and authority. Corporations should provide full name of corporation and title of authorized officer signing the Proxy.

ONE Gas, Inc.

ANNUAL MEETING OF SHAREHOLDERS

Thursday, May 26, 2022
9:00 a.m. Central Time

Virtual Meeting Only – No Physical Location

Advance Registration Required by May 25, 2022,
at 3:00 Central Daylight Time at www.proxydocs.com/ogs

ONE Gas 15 East Fifth Street
Tulsa, Oklahoma 74103

proxy

ANNUAL MEETING OF SHAREHOLDERS MAY 26, 2022

THIS PROXY IS SOLICITED ON BEHALF OF THE BOARD OF DIRECTORS

The undersigned hereby appoints John W. Gibson and Joseph L. McCormick, or either of them, with the power of substitution in each, proxies to vote all shares of stock of the undersigned in ONE Gas, Inc. at the Annual Meeting of Shareholders to be held May 26, 2022, and at any and all adjournments or postponements thereof, upon the matter of the election of directors, the proposals referred to in Items 2 and 3 of this Proxy, and any other business that may properly come before the meeting.

Shares will be voted as specified. IF YOU SIGN BUT DO NOT GIVE SPECIFIC INSTRUCTIONS, YOUR SHARES WILL BE VOTED FOR THE ELECTION OF DIRECTORS AS PROPOSED AND FOR PROPOSALS 2 AND 3.

This card also constitutes voting instructions by the undersigned participant to the trustee of the ONE Gas, Inc. 401(k) Plan and the ONEOK, Inc. 401(k) Plan for all shares votable by the undersigned participant and held of record by such trustee, if any. The trustee will vote these shares as directed provided your voting instruction is received by 11:59 p.m. Central Daylight Time on May 23, 2022. If there are any shares for which instructions are not timely received, the trustee will cause all such shares to be voted in the same manner and proportion as the shares of the plan for which timely instructions have been received, unless to do so would be contrary to ERISA. All voting instructions for shares held of record by the plans shall be confidential.

THE BOARD OF DIRECTORS RECOMMENDS A VOTE FOR THE ELECTION OF DIRECTORS AS PROPOSED AND FOR PROPOSALS 2 AND 3.

If you vote by the Internet or Telephone, DO NOT return your proxy card.

Please complete, sign and date the proxy card and return it in the postage-paid envelope.

Vote by Internet, Telephone or Mail
24 Hours a Day, 7 Days a Week

Your phone or Internet vote authorizes the named proxies to vote your shares in the same manner as if you marked, signed and returned your proxy card.

INTERNET/MOBILE
www.proxydocs.com/ogs
Use the Internet to vote your proxy until 11:59 p.m. (CT) on May 25, 2022.

PHONE
1-866-883-3382
Use a touch-tone telephone to vote your proxy until 11:59 p.m. (CT) on May 25, 2022.

MAIL
Mark, sign and date your proxy card and return it in the postage-paid envelope provided.

If you vote your proxy by Internet or by Telephone, you do NOT need to mail back your Proxy Card.

Exhibits JDB-2 through JDB-9 are Confidential
and will be provided pursuant to the terms of the Protective Agreement.

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF JEFF D. BRANZ

BEFORE ME, the undersigned authority, on this day personally appeared Jeff D. Branz who having been placed under oath by me did depose as follows:

1. "My name is Jeff D. Branz. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Director of Compensation and Benefits 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.

Jeff D. Branz

SUBSCRIBED AND SWORN TO BEFORE ME by the said Jeff D. Branz on this 15th day of June 2022.

M. FREEMAN
NOTARY
#21014828
EXP. 11/12/25
PUBLIC
STATE OF OKLAHOMA

M. Freeman
Notary Public in and for the State of Oklahoma

CASE NO. 00009896

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	§ § § § § § § § §	**BEFORE THE** **RAILROAD COMMISSION** **OF TEXAS**

DIRECT TESTIMONY

OF

MARK W. SMITH

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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DIRECT TESTIMONY OF MARK W. SMITH

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark W. Smith. My business address is 15 East Fifth Street in Tulsa, Oklahoma.

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

A. I am Vice President and Treasurer 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 change rates.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a Bachelor of Science in Accounting from Oklahoma State University and a Master's in Business Administration from Phillips University. I am also a CPA. I have testified in cases before the Oklahoma Corporation Commission, the Kansas Corporation Commission, Railroad Commission of Texas ("Commission"), and Federal Energy Regulatory Commission ("FERC"). I previously served on the Southern Gas Association Rate Committee where I taught a portion of its Regulatory 101 course. I have worked for ONE Gas or ONEOK, Inc. for over 35 years in areas that include Rates and Regulatory, Corporate Accounting, Budgeting, Corporate Development and Treasury.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony before this Commission in Gas Utilities Docket ("GUD") Nos. 10506, 10526, 10739, 10766, 10928 and Case No. OS-21-0007061. I have also testified before the Oklahoma Corporation Commission, the Kansas Corporation Commission and FERC.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY AND 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. Confidential Exhibit MWS-1 summarizes the Utility Insurance Company ("UIC") insurance expense charged to TGS and the change in direct insurance cost inclusive of lower deductible limits. Confidential Exhibits MWS-2, MWS-3, MWS-4, and MWS-5 are the policies issued by UIC to TGS. Confidential Exhibit MWS-6 is the analysis of the cost savings from using UIC. Exhibit MWS-7 is a calculation of the Prepaid Pension Asset.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will describe the ONE Gas risk management program and the services provided to TGS by UIC, ONE Gas' captive insurer. I will 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 in Section 104.055(b) of the Gas Utility Regulatory Act. In addition to my testimony addressing UIC, Company witness Stacey L. McTaggart also addresses the affiliate cost recovery standard, and Company witness Stacey R. Borgstadt sponsors the schedule (see Exhibit SRB-2) that identifies the amount of Corporate 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 or captive insurance company is an entity formed by a corporation to provide insurance to its divisions and subsidiaries. Captives are regulated insurance companies that must follow the insurance laws of the state in which they were incorporated and file annually with their respective insurance commissions.

Q. WHY WAS THE UTILITY INSURANCE COMPANY FORMED?

A. UIC was formed as a captive insurance company to provide ONE Gas and its divisions in Kansas, Oklahoma and Texas:

1) consistent and competitive insurance rates over the long-term;
2) continuity of insurance product offerings at a cost that is considerably lower than what ONE Gas could achieve if it sought insurance in the general or retail marketplace;
3) insurance at lower deductible levels than can be purchased in the retail market; and
4) access to the lower priced reinsurance in the wholesale market.

Q. REGARDING ITEM FOUR ABOVE, WHY IS IT IMPORTANT THAT UIC BE ABLE TO PURCHASE REINSURANCE IN THE WHOLESALE MARKET?

A. ONE Gas' experience with the retail market is that it does not often write insurance with low deductibles. In almost all cases in the past, ONE Gas has had to obtain insurance containing a $2 million deductible. There have been several instances where the retail insurance market has sought a $5 million deductible. These high levels of deductibles result in the Company and its customers being exposed to significant financial losses because they must incur large claims prior to deductibles being met. Examples that come into play between $100,000 and $5 million include rising workers compensation expense, auto accidents and the related litigation, property claims related to storm damage with the rising cost of replacement values, and defending the company in liability matters. Additionally, buying in the wholesale market eliminates a premium tax which can be as much as $400,000 for ONE Gas in total.

Q. DOES UIC HAVE THE POTENTIAL TO SMOOTH OUT PREMIUM COSTS OVER THE LONG TERM?

A. Yes, it does. In the general marketplace, rates fluctuate due to overall market conditions and events that are out of ONE Gas' control such as tornadoes, hurricanes, terrorist attacks or other companies inside or outside of our industry suffering significant liability events. In contrast, UIC is able to look at premiums over a longer period and prevent volatility in premiums from happening in the short term.

Q. PLEASE DESCRIBE REINSURANCE AND THE REINSURANCE MARKET.

A. The reinsurance market is a market that sells insurance to insurance companies and not on a retail basis. In effect, it is insurance for retail insurance companies. Because UIC is a regulated insurance company, UIC allows ONE Gas access to reinsurance markets directly versus going through the retail insurance markets where rates include profit, commissions, overhead, taxes and other transactional costs that can significantly increase premiums. By having the option to access the reinsurance markets directly, UIC can obtain lower rates, customize policy language, and secure additional insurance by either lowering the deductibles or raising insurance limits. This ensures competitive and consistent rates for TGS. Reinsurance markets are also much more stable than retail markets and historically have resulted in more favorable rates over the long-term.

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. HOW ARE THE OPERATIONS OF UIC MANAGED?

A. UIC is managed on a day-to-day basis by Aon Risk Solutions, ("Aon"), a third-party captive manager. Aon is one of the largest third-party risk management consulting firms in the world and has a team of individuals who specialize in the management, regulation, and uses for captive insurance companies and their owners. The main differentiator of a captive insurance company and a retail insurance company is that a captive will write only the risks of its parent, namely ONE Gas.

In addition to providing management services for the daily operations of UIC, Aon provides ONE Gas with consultation services regarding insurable risks, coverage and other related services. UIC also uses Spring Consulting as an actuary and consultant in developing rates and actuarial reserves. The direction and philosophy of UIC is determined by UIC's board of directors and the ONE Gas risk management group, which reports to me. Importantly, the Oklahoma Insurance Commission has oversight and governs the rates and capitalization of UIC. UIC's annual filings along with its audited annual financials have been filed with the Oklahoma Insurance Commission and have been accepted.

Q. HAVE THE PREMIUMS FROM UIC BEEN PREVIOUSLY APPROVED BY REGULATORY AUTHORITIES?

A Yes, they have been accepted as appropriate costs in Oklahoma, Kansas, and Texas. With respect to Texas, UIC costs were included in GUD No. 10739, GUD No. 10766 and GUD No. 10928.[1]

Q. DO THE PREMIUMS CHARGED TO TGS INCLUDE INSURANCE COVERAGE FOR CORPORATE ASSETS OF ONE GAS?

A. No, not directly. The corporate area is charged premiums as if it is a division, on its asset and risks. This Corporate insurance expense is allocated through Distrigas to each division, including TGS, as described by Ms. Borgstadt.

Q. WHAT TYPES OF INSURANCE COVERAGE DOES UIC PROVIDE FOR ONE GAS' TGS DIVISION?

A. UIC provides the following insurance coverages for TGS:

1) property, plant, and equipment, including business interruption;
2) general liability and employment practices;
3) workers' compensation and employers' liability;
4) automobile liability;
5) cyber; and
6) medical stop loss.

[1] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order at Findings of Fact ("FoF") 48-51 (Nov. 13, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area*, GUD No. 10766, Final Order at FoF 46-48 (Feb. 5, 2019); and *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS") to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928 consol., Final Order at FoF 59 (Aug. 4, 2020).

Copies of these policies are attached as Confidential Exhibit MWS-2 through Confidential Exhibit MWS-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 $500,000 per occurrence based on the type of policy listed above. 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 is a positive differentiator of ONE Gas that ultimately results in lower costs for TGS and its customers. Lower deductibles also lessen distractions tied to negative financial impacts of unexpected events and allow TGS to focus on infrastructure and reliability and other customer focused priorities. As mentioned earlier in my testimony, 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. Because ONE Gas controls UIC, it is also able to avoid a situation where a retail insurer might act quickly in response to an incident to raise a deductible and premiums.

Q. YOU STATED THAT UIC PROVIDES INSURANCE COVERAGE THAT MAY NOT BE AVAILABLE AT THE UIC DEDUCTIBLE LEVEL AND IS NOT AVAILABLE AT UIC'S PRICING. WHAT DO YOU RELY ON TO SUPPORT THIS STATEMENT?

A. As insurance risks are renewed for an annual term, ONE Gas has attempted to obtain lower deductibles from third-party insurers and has not been able to do so at reasonable rates. During each renewal of our liability insurance (Item 2 above), we ask our broker to request quotes for a $100,000 deductible to make sure the UIC pricing is fair, reasonable and less expensive than what might be available in the retail insurance marketplace. Our liability reinsurance insurance, which exceeds $25 million in limit, is underwritten by an industry mutual, AEGIS. Notably, AEGIS is the liability insurer of choice for most gas and electric utilities in North America. ONE Gas asks AEGIS at each renewal for pricing down to the $100,000 deductible level and AEGIS provides the requested pricing to ONE Gas on an informal basis since AEGIS will not formally offer a renewal at a $100,000 deductible, but did give an indication of price if they were to offer such coverage.

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 and the potential business interruption or net margins of the division;
2) for workers' compensation, the salary, job type being insured and number of employees in a division;
3) for automotive insurance, the number of vehicles that each division is operating; 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 MWS-6, which shows the cost charged to all of the ONE Gas divisions as compared to quotes in the commercial markets. Confidential Exhibit MWS-6 shows that UIC has saved ONE Gas and its customers $7.2 million since UIC was created for liability coverage and $1.6 million for property coverage since UIC was created. ONE Gas was not able to get an insurer to quote auto or workers compensation at this level of deductible.

Q. HOW IS THE COST OF REINSURANCE PASSED THROUGH FROM UIC TO ONE GAS AND ITS DIVISIONS?

A. Any amount of reinsurance that UIC purchases is allocated to the divisions.

Q. HAS UIC PAID OUT CLAIMS?

A. Yes. UIC has paid out two claims on its liability policy that exceeded the premiums paid by ONE Gas. One claim related to Oklahoma Natural Gas and one claim related to TGS. In these cases, UIC, UIC's reinsurer, and ONE Gas shareholders bore the entire cost of the claims above the deductible, while TGS and Oklahoma Natural Gas only paid their premiums and deductible.

Q. DOES THE LONG-TERM FORECAST METHOD OF DETERMINING PREMIUM COSTS BENEFIT TGS AND ITS CUSTOMERS?

A. Yes. Over the long-term, these forecasts provide TGS with more consistency in the premium cost to be incurred. Insurance costs are a necessary part of providing natural gas service. To the extent the costs significantly vary from year to year, based on an annual review of the actual losses incurred, the rates charged to customers would experience more variance in the general market. For example, there were large Texas property losses caused by hurricanes in 2017. Premiums based solely on losses from that year would be markedly higher than premiums based on a longer time horizon. In addition to cost variances, after major catastrophic events, there can be contraction in insurance availability. Through UIC, TGS and its customers are assured of the availability of the same level of insurance coverage at relatively consistent premium costs without being subjected to insurance cycles that may be influenced by events beyond TGS's control. Further, having a relatively stable premium rate allows ONE Gas to plan with greater certainty the investment necessary to ensure a safe and reliable system.

Q. IS THE PRICE CHARGED TO TGS BY UIC HIGHER THAN THE PRICE CHARGED BY UIC TO OTHER DIVISIONS, AFFILIATES OR THIRD PARTIES FOR THE SAME ITEM OR CLASS OF ITEMS?

A. No, it is not. On a risk-adjusted basis, the price charged by UIC to TGS is no higher than what is charged to ONE Gas' other divisions. The same types of underlying costs and methodology are employed in calculating each division's premium.

Q. DOES UIC PROVIDE INSURANCE COVERAGE TO ANY THIRD PARTIES?

A. No, UIC only insures ONE Gas and its divisions, including providing medical stop loss[2] to the ONE Gas employee health benefit plans.

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 and to make sure that expenses are consistent and do not spike or dip from year to year. This is true for both TGS assets that are insured through UIC for which UIC charges TGS a premium and for UIC's coverage of ONE Gas corporate assets. Ms. Borgstadt sponsors the schedule that shows the amount of corporate costs for ONE Gas assets that TGS is seeking to recover through rates. As Confidential Exhibit MWS-6 shows, ONE Gas has saved $7.2 million in liability insurance since the captive was created and $1.6 million in property insurance since the captive was created.

III. PREPAID PENSION

Q. HAS THE INCLUSION OF TGS'S PREPAID PENSION ASSET IN RATE BASE BEEN PREVIOUSLY REVIEWED AND APPROVED?

A. Yes, the Commission approved the rate base treatment of TGS's portion of the ONE Gas prepaid pension asset in the Company's West Texas Service Area case in GUD No. 10506. The Commission determined that the inclusion of the prepaid pension asset in rate base is just and reasonable. The Commission explained that the asset

[2] For insurance purposes, medical stop loss is sometimes considered third-party coverage since participants pay a portion of the premiums.

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.[3] In sum, the prepaid pension asset avoids future additional pension expense, increased variable rate Pension Benefit Guarantee Committee premiums and restrictions placed on the pension plan. The Company also proposed the same treatment of the prepaid pension asset in GUD Nos. 10488, 10526, 10656, 10739, 10766, and 10928 all of which were resolved through settlement agreements that were approved by the Commission.[4]

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 below, ONE Gas and TGS are taking the same approach to these issues as they did in GUD No. 10506 and other prior cases identified above.

[3] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Areas (EPSA), Permian Service Area (PSA) and Dell City Service Area (DCSA)*, GUD No. 10506, Final Order at FoF 61 (Sep. 27, 2016).

[4] With respect to the Commission's Final Orders in GUD Nos. 10488, 10526, 10656, 10739, 10766 and 10928, the parties agreed on "black box" settlement amounts in each of those cases. However, the rate base amount agreed to in each settlement includes the Company's proposed pension plan asset. *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order (May 3, 2016); *Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016); *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018); and GUD No. 10928, Final Order.

Q. WHAT ARE THE TGS AND PROPOSED WEST NORTH SERVICE AREA ("WNSA") 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, 2021, of $24.97 million and an allocated portion of the corporate prepaid asset of $18.37 million. TGS's portion of the total asset is $43.3 million, and the proposed WNSA portion is $19,113,633. These amounts are shown on Exhibit MWS-7.

Q. HOW DOES THIS AMOUNT COMPARE TO THE AMOUNT APPROVED IN GUD NO. 10928, THE CENTRAL GULF RATE CASE?

A. As Exhibit MWS-7 shows, the prepaid asset decreased by $4.3 million from December 31, 2020, to December 31, 2021. Additionally, the expense reduction recognized by customers for pension expense was $332,000. In 2021, TGS customers saved $3.1 million compared with $3.4 million in 2020. The amount has actually decreased approximately $6.9 million from the settled asset amount of $50.2 million in GUD No. 10928, in which no adjustments were proposed by any parties.

Q. WHAT AMOUNT IS THE COMPANY ASKING TO BE INCLUDED IN RATE BASE?

A. The amount for the WNSA is $15.1 million as shown in Exhibit MWS-7. This reflects the prepaid asset of $19.1 million less the associated deferred taxes of $4.0 million for the total of $15.1 million.

IV. EQUITY RETURN AND CAPITAL STRUCTURE

Q. WHAT RETURN ON EQUITY AND CAPITAL STRUCTURE IS TGS PROPOSING IN THIS RATE CASE?

A. TGS is requesting a 10.25% return on equity ("ROE") and a capital structure composed of 40.26% debt and 59.74% equity. The proposed ROE is based on Company witness Bruce Fairchild's analysis and recommendation, and the capital structure is based on the actual capital structure of ONE Gas at December 31, 2021.

Q. DO YOU HAVE THE OPPORTUNITY TO COMMUNICATE WITH THE INVESTMENT COMMUNITY AND CREDIT RATING AGENCIES AS VICE PRESIDENT AND TREASURER FOR ONE GAS?

A. Yes, my duties include communicating with the investment community and credit ratings agencies on a regular basis. I am also involved in preparing communications such as the Company's annual report, proxy, and filings with the Securities and Exchange Commission.

Q. BASED ON YOUR EXPERIENCE, DO YOU HAVE ANY OPINIONS ABOUT THE CURRENT INVESTMENT ENVIRONMENT RELEVANT TO ONE GAS?

A. I do. As Dr. Fairchild's testimony describes, utilities are currently facing challenging investment and credit environments and those environments are expected to get more challenging in the near future. For those reasons, the Commission's decisions on equity return and capital structure are important in this case both for ONE Gas and its customers. In particular, as debt costs increase, it will be important for ONE Gas to maintain its credit quality so that it can continue to borrow at the lowest costs possible.

Q. DO YOU AGREE WITH THE EQUITY RETURN THAT DR. FAIRCHILD IS PROPOSING IN HIS TESTIMONY?

A. Yes, I agree with using a rate towards the higher end of the range based on the changes we are seeing in the market. It is now relatively common knowledge that inflation in the U.S. recently reached a high (8.6%) not seen in the past 40 years. The European Union is also realizing inflation at similar rates. These extremely high inflation rates along with the increases we are seeing in interest rates mark a shift in the market, which will lead to equity returns having to be higher to compete with the debt market. Additionally, as Dr. Fairchild notes, the Federal Reserve has indicated that we can expect to see the Fed Funds Rate rise 25 or 75 basis points at each of its meetings this year. Many economists are predicting a 50-basis point move at some of these meetings, with some being at a more traditional 25-basis point move, and some being as high as 75 basis points as we saw in the Fed's latest move. These increases, the likes of which we have not seen in recent history, will have a major impact on the debt and equity markets going forward. Therefore, it is important to be proactive with respect to return on equity so that ONE Gas' credit metrics are maintained in that more challenging environment.

Q. WHAT SUPPORT DO YOU HAVE FOR YOUR EXPECTATIONS RELATING TO HIGHER FUTURE DEBT COSTS?

A. I have worked with our various banks to get their economist view on rates into the future. Below is a table a table showing how much actual interest rates have already moved.

As of:	2-yr	3-yr	5-yr	7-yr	10-yr	20-yr	30-yr
6/21/2022	**3.20%**	**3.35%**	**3.38%**	**3.39%**	**3.30%**	**3.64%**	**3.39%**
1 Week Ago	**3.43%**	**3.59%**	**3.60%**	**3.58%**	**3.48%**	**3.72%**	**3.43%**
1 Month Ago	**2.58%**	**2.73%**	**2.81%**	**2.82%**	**2.79%**	**3.18%**	**2.99%**
3 Months Ago	**2.13%**	**2.34%**	**2.34%**	**2.36%**	**2.32%**	**2.66%**	**2.53%**

Below is a table a table showing what JP Morgan thinks interest rates will do in the future:

J.P. Morgan interest rate forecasts

	Present	3Q22	4Q22	1Q23	2Q23
Fed funds*	1.60%	2.60%	3.10%	3.35%	3.35%
Overnight SOFR	0.70%	2.20%	2.95%	3.30%	3.30%
3-month LIBOR	2.06%	3.00%	3.45%	3.50%	3.55%
2-year U.S. Treasury	3.16%	3.50%	3.60%	3.50%	3.35%
3-year U.S. Treasury	3.36%	3.60%	3.60%	3.55%	3.50%
5-year U.S. Treasury	3.37%	3.55%	3.60%	3.55%	3.45%
7-year U.S. Treasury	3.38%	3.55%	3.60%	3.55%	3.40%
10-year U.S. Treasury	3.30%	3.45%	3.50%	3.45%	3.35%
30-year U.S. Treasury	3.36%	3.40%	3.45%	3.45%	3.40%

*Represents the upper bound of the fed funds rate

Additionally, many view rates moving back to historic norms, and to understand what historic norms are, I have included the following table that shows that the 10-year treasury rate was 0.92% on December 31, 2020, had risen to 1.51% on December 31, 2021, and then risen even further to 3.31% on June 21, 2022. The table also shows the historical averages for the ten-year treasury over a 5- to 30-year period and since inception. Rates have been significantly higher over the past few years.

Summary of 10-Year Treasury Rates Over Time	
12/31/2020	0.92 %
12/31/2021	1.51 %
Current @ 6/21/2022	3.31% %
5-Year Average	1.91 %
10-Year Average	2.03 %
15-Year Average	2.48 %
20-Year Average	2.95 %
25-Year Average	3.47 %
30-Year Average	3.98 %
Average Since Inception	5.95 %

Q. WHAT IMPACT ARE THESE FACTORS LIKELY TO HAVE ON ONE GAS' COST OF DEBT?

A. As ONE Gas issues new debt and replaces maturing debt it will be forced to issue debt at higher interest rates and this will result in a higher weighted average cost of debt. ONE Gas has several planned and necessary debt issuances in the coming years. As such, it is important for ONE Gas' credit metrics to remain healthy so that debt can be financed at the lowest possible cost.

Q. DO THE CREDIT RATINGS AGENCIES FOLLOW THE REGULATORY OUTCOMES OF ONE GAS' RATE PROCEEDINGS?

A. Yes. Regulatory outcomes are a key driver of credit quality for ONE Gas and the ratings agencies are clear about their importance. For instance, Moody's Investors Services, Inc. in a publication in February 2022, stated:

> ONE Gas' rating could be downgraded if there are adverse regulatory developments or if management policies negatively impact financial performance resulting in weaker financial metrics.

Additionally, Standard & Poor's Financial Services LLC in an April 2022 publication states:

> We view ONE Gas' management of regulatory risk in Oklahoma (42% of rate base), Kansas (29% of rate base), and Texas (29% of rate base) as generally consistent with that of its peers. This largely reflects the company's use of credit-supportive formula rates and constructive cost recovery riders for both pipeline replacement capital spending outside of traditional rate cases and purchased gas, which reduces regulatory lag and supports our view that the company effectively manages regulatory risk.

In short, stability and a credit supportive environment from the regulatory authorities that regulate ONE Gas' divisions are critical to ONE Gas' ability to borrow at the lowest possible rates. Approval of the ROE and capital structure recommended by Dr. Fairchild will make this possible as we enter a more challenging economic environment.

Q. ARE YOU AWARE OF ANY INSTANCES IN WHICH THE CREDIT QUALITY OF ONE GAS HAS BENEFITED CUSTOMERS?

A. Yes. Most recently, following Winter Storm Uri, ONE Gas' ability to access the debt markets at favorable terms resulted in historically low borrowing costs for gas that had to be procured as a result of that storm. Following the storm, ONE Gas was initially able to enter into a credit agreement with Bank of America, that provided $2.5 billion as an unsecured loan - a substantial amount to acquire on an emergency basis for gas costs that would be due in a matter of months. ONE Gas was then subsequently able to refinance those gas costs in two- and three-year notes at rates that were less than 2%. Notably, ONE Gas' outstanding debt increased to $4.1 billion from $1.6 billion due to the Winter Storm Uri gas costs alone. Were it not for ONE Gas' capital structure and financial health going into the storm, financing costs associated with the event most certainly would have been higher.

Q. ARE YOU AWARE OF ANY OTHER FACTS THAT SUPPORT THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. Yes, in the first quarter of 2022, ONE Gas issued an additional $35 million in equity, thereby pushing the equity component of its capital structure to above 61%. As such, the Company's requested equity component of 59.74% is conservative.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Exhibits MWS-1 through MWS-6 are Confidential
and will be provided pursuant to the terms of the Protective Agreement.

TEXAS GAS SERVICE COMPANY
WEST NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	WNSA 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	1,679.953
11	2019	$ 76,979.308	25.40%	$ 19,552.744	$ 33,163.628	$ 52,716.372	7.20%	3,795.579	34,204.485	1,673.884
12	2020	$ 72,824.572	25.63%	$ 18,664.938	$ 28,937.707	$ 47,602.645	7.20%	3,427.390	37,631.875	1,511.510
13	2021	$ 68,548.217	26.81%	$ 18,374.761	$ 24,965.926	$ 43,340.687	7.15%	3,098.859	40,730.734	1,366.625
16								Allocation		
17							TGS Total	to service area	WNSA	
18					Prepaid Pension Asset		$ 43,340.687	44.1009%	$ 19,113.633	
19					Less Deferred Taxes (21%)		(9,101.544)		(4,013.863)	
20					Rate Base		$ 34,239.143		$ 15,099.770	
21										
22										

STATE OF OKLAHOMA §
§
COUNTY OF TULSA §

AFFIDAVIT OF MARK W. SMITH

BEFORE ME, the undersigned authority, on this day personally appeared Mark W. Smith who having been placed under oath by me did depose as follows:

1. "My name is Mark W. Smith. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Vice President and Treasurer 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.

Mark W. Smith
Mark W. Smith

SUBSCRIBED AND SWORN TO BEFORE ME by the said Mark W. Smith on this 16th day of June 2022.

M. FREEMAN NOTARY #21014828 EXP. 11/12/25 PUBLIC STATE OF OKLAHOMA

M Freeman
Notary Public in and for the State of Oklahoma

CASE NO. 00009896

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	**§ § § § § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

JEFFREY J. HUSEN

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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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 E. 5th Street Tulsa, Oklahoma 74103.

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

A. I am Vice-President, Chief Accounting Officer and Controller for ONE Gas, Inc. ("ONE Gas"). I have responsibility for the accounting, tax, financial reporting and budgeting and forecasting functions for ONE Gas. These responsibilities include the selection and application of accounting policies and practices 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 28 years, I have worked in accounting and financial reporting roles. Prior to my current position, I was 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 LLP in Tulsa, Oklahoma. In that role, I audited accounting policies and practices for companies in the utility, transportation and manufacturing industries. I am licensed as a Certified Public Accountant in Oklahoma. I also am certified as a Chartered Global Management Accountant by the American Institute of Certified Public Accountants.

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

A. Yes, it was.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I filed testimony before the Railroad Commission of Texas ("Commission") in Gas Utilities Docket ("GUD") Nos. 10739, 10766, and 10928 and before the Kansas Corporation Commission in 18-KGSG-560-RTS.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes how the Company has complied with Accounting Order GUD No. 10695 concerning Excess Accumulated Deferred Income Tax ("EDIT"). I am also providing testimony on two Private Letter Rulings ("PLR") from the Internal Revenue Service ("IRS"), which impact how the Company should return the EDIT credit to customers, and address the requested modification of the Company's EDIT credit going forward.[1]

[1] Exhibit JJH-1 and Exhibit JJH-2.

Q. HOW DOES YOUR TESTIMONY RELATE TO THE TESTIMONY OF OTHER COMPANY WITNESSES?

A. Company witness Stacey L. McTaggart proposes withdrawal of the Company's EDIT rider and inclusion of the EDIT credit in base rates. Company witness Janet M. Simpson addresses the calculation of Accumulated Deferred Income Taxes ("ADIT") in her testimony.

II. COMPLIANCE WITH ACCOUNTING ORDER IN GUD NO. 10695

Q. WHAT ISSUES DID THE COMMISSION ADDRESS IN GUD NO. 10695?

A. GUD No. 10695 was established by the Commission to address issues relating to the 2017 Tax Cuts and Jobs Act ("TCJA") wherein Congress lowered the corporate tax rate from 35% to 21%. As a result of the accounting order issued by the Commission in the proceeding, utilities were directed to account for certain changes in both tax expense and EDIT.

Q. WHAT DID THE ACCOUNTING ORDER ISSUED BY THE COMMISSION IN GUD NO. 10695 REQUIRE OF TGS WITH RESPECT TO EDIT?

A. The GUD No. 10695 Accounting Order includes two specific requirements related to the treatment of EDIT. These requirements are: (1) gas utilities subject to the Commission's jurisdiction are to accrue on their books, as of January 1, 2018, a regulatory liability to reflect the excess deferred reserve, including any associated gross up in taxes, caused by the reduction in the federal corporate income tax rate (Ordering Paragraph 1(C)) and; (2) the amortization of the entire regulatory liability shall be consistently calculated using a methodology set forth under the Act (Ordering Paragraph 7).[2]

Q. DID THE COMPANY COMPLY WITH THESE REQUIREMENTS?

A. Yes, based on the information available at the time, the Company complied with the requirements of the GUD No. 10695 Accounting Order. The Company has provided the following EDIT credits to customers in the proposed West North Service Area ("WNSA") through the operation of an EDIT credit rider:

Table 1	
Year	**EDIT Credit**
2018	$1,681,286
2019	1,694,650
2020	1,474,120
2021	1,422,666

Each credit was based on an annual amortization using the average rate assumption method ("ARAM") that is required by IRS tax normalization rules for protected EDIT and a 10-year amortization of unprotected EDIT as stated in the tariffs approved by the regulatory authorities in El Paso, the North Texas Service Area ("NTSA"), and the Borger Skellytown Service Area ("BSSA").[3] The EDIT credit is trued-up annually based on the difference between the amount of that year's

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[2] *Regulatory Accounting Related to Federal Income Tax Changes,* GUD No. 10695, Gas Utilities Accounting Order (Feb. 27, 2018). *See* https://portalvhdskzlfb8q9lqr9.blob.core.windows.net/media/44158/gud-10695-accounting-order-01-01-18.pdf.

[3] City of El Paso, Resolution (Feb. 6, 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 at Findings of Fact ("FoF") 45 (Nov. 13, 2018); City of Aledo, Ordinance 2018-103 (Nov. 15, 2018), City of Breckenridge, Ordinance 18-18 (Nov. 6, 2018), City of Bryson, Ordinance 0-2018-02 (Nov. 12, 2018), City of Graford, Ordinance 2018-6 (Nov. 13, 2018), City of Graham, Ordinance 1076 (Nov. 1, 2018), City of Hudson, Ordinance 2018-21 (Dec. 13, 2018), City of Jacksboro, Ordinance O-21-18 (Oct. 22, 2018), City of Millsap, Ordinance 18-04-01 (Dec. 4, 2018), City of Mineral Wells, Ordinance 2018-21 (Nov. 6, 2018), City of Weatherford, Ordinance 945-2018-60 (Dec. 11, 2018), City of Willow Park, Ordinance 783-18 (Nov. 13, 2018), City of Borger, Resolution R-024-18 (Dec. 18, 2018); *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Borger-Skellytown Service Area,* GUD No. 10766, Final Order at FoF 43 (Feb. 5, 2019).

EDIT credit and the amount actually credited to customers. However, a recent IRS PLR issued on August 14, 2020 has identified an issue, described further below, relating to how the Company has treated the Cost of Removal ("COR") portion of its depreciation expense in the Company's ARAM amortization calculations that must be corrected.

Q. CAN THE COMPANY CONTINUE RETURNING EDIT TO CUSTOMERS IN THE SAME MANNER DESCRIBED ABOVE?

A. No, based on a different and second IRS PLR addressing a different normalization issue described below, it is my recommendation the EDIT Rider be withdrawn and EDIT be included in base rates.

Q. WILL THE REMEDIATION OF THE PLR ISSUES IDENTIFIED ABOVE AFFECT THE TOTAL AMOUNT OF EDIT TO BE CREDITED TO CUSTOMERS IN THE PROPOSED WNSA?

A. Absolutely not. Customers will still receive approximately $21 million in total EDIT credits that were quantified following the TCJA and included within all ONE Gas EDIT Rider filings since their implementation.

III. PRIVATE LETTER RULINGS

Q. PLEASE DESCRIBE THE IRS PLR INCLUDED AS EXHIBIT JJH-1.

A. The Company has been made aware of a potential IRS normalization issue through the issuance of a PLR to another utility, attached to my testimony as Exhibit JJH-1. The normalization issue is related to TGS's current treatment of the COR portion of its depreciation expense, which creates a deferred tax asset and, pursuant to the new PLR, is not "protected" under IRS normalization rules in the ARAM amortization calculation.

Q. PLEASE EXPLAIN THIS ISSUE RELATED TO COR.

A. Per the PLR, the COR portion of depreciation is not "protected" under IRS normalization rules. TGS previously treated the COR portion of depreciation as "protected" and, as such, did not separate COR from depreciation in its regulatory depreciation calculations. Importantly, TGS's prior treatment of COR benefited ratepayers because the COR portion was actually an asset and would have reduced the amount of unprotected EDIT returned to ratepayers through the Rider. Additionally, at the time of the TCJA, TGS did not estimate a COR component of its accumulated depreciation for purposes of determining the "protected" balance of book versus tax depreciation timing differences. Rather, the timing difference that creates a deferred tax and associated EDIT asset related to COR was netted against the protected portion of its EDIT and amortized using the ARAM calculation consistent with protected timing differences of book versus tax depreciation. This was consistent with how TGS treated all protected EDIT. Now, to avoid a normalization violation under the new PLR, the COR portion of book versus tax depreciation timing differences needs to be separated from both the original EDIT liability and from the depreciation expense used in the ARAM calculation and included as an "unprotected" EDIT asset and amortized as such. Otherwise, the remaining protected EDIT may be returned too quickly under the ARAM calculation.

Q. WHAT IS TGS'S REQUEST TO ADDRESS THE IRS NORMALIZATION ISSUE RELATED TO COR?

A. TGS has estimated the amount of COR that was included as protected since December 31, 2017 at the time of the TCJA that should now be considered unprotected. TGS requests that this amount be accounted for as a separate asset from the existing unprotected EDIT liability that is being amortized over 10 years and requests that it be amortized utilizing the same amortization period as the ARAM calculation consistent with depreciation-related timing differences that remain in the protected portion of EDIT.

Q. WHY IS IT IMPORTANT TO SEPARATELY ACCOUNT FOR THE COR PORTION OF UNPROTECTED EDIT AND UTILIZE A DIFFERENT AMORTIZATION?

A. COR in depreciation rates is deducted for tax purposes when the expenses are incurred with the disposal of an asset. As a result, the book depreciation expense being incurred prior to the tax deduction results in a deferred tax asset. When tax rates changed in the TCJA, this deferred tax asset is remeasured based on the new tax rate and the adjustment creates an EDIT asset, meaning it is an amount that will be "collected" from customers. Unprotected EDIT can be credited to ratepayers over any period authorized by the regulatory authority. If the COR were to be included with the 10-year amortization of unprotected EDIT, the EDIT credit to customers would be significantly reduced in the short term. By continuing to utilize the ARAM period for COR, TGS will be able to continue to provide EDIT credits consistent with prior years.

Q. DOES THIS CHANGE IN TREATMENT AFFECT THE TOTAL AMOUNT OF EDIT TO BE CREDITED TO CUSTOMERS IN THE PROPOSED WNSA?

A. No, as mentioned previously, customers will still receive approximately $21 million of total EDIT credits that were quantified following the TCJA and included within all EDIT Rider filings since that date.

Q. IS THIS CHANGE RETROACTIVE?

A. No, it is not. The separation of COR into an unprotected asset only affects the amortization of EDIT on a going forward basis.

Q. PLEASE DESCRIBE THE IRS PLR CONTAINED IN EXHIBIT JJH-2.

A. Since the TCJA, TGS has paid estimated EDIT credits to customers based on tax years that are not consistent with the test year utilized to establish base rates. For example, in the West Texas Service Area, the 2016 Rate Case was based on a test year ending September 30, 2015 with 3-month post-test year updates through December 31, 2015, while the EDIT credit issued in 2022 was an estimated credit for the 2021 tax year ended December 31, 2021. Therefore, base rates were based on December 31, 2015, and EDIT was based on December 31, 2021. The inconsistency between base rates test year and EDIT credit tax year has existed for every year's EDIT credit. The same inconsistency has existed in the NTSA and the BSSA for the same reasons. Per the PLR, attached as Exhibit JJH-2, it is a violation of normalization rules for EDIT and base rates to be based on different time periods and for EDIT from future time periods to be returned in advance of the time period being used for ADIT.

Q. HOW DOES TGS PLAN TO ADDRESS THIS POTENTIAL NORMALIZATION ISSUE?

A. In Revenue Procedure 2020-39, the IRS has provided a safe-harbor for inadvertent normalization violations by indicating that corrective actions which convert a non-compliant crediting method to a compliant crediting method that are taken at the earliest available opportunity will not be considered a normalization violation. TGS believes the earliest available opportunity to take a corrective action as provided for in Revenue Procedure 2020-39 is this statement of intent filing. The only way to adequately address the disconnect between the basis for EDIT credits and base rates is to withdraw the separate EDIT Rider and include protected EDIT as part of base rates.

Q. AGAIN, WILL CUSTOMERS RECEIVE ANY MORE OR LESS TOTAL EDIT CREDITS?

A. No, as mentioned previously, customers in the proposed WNSA will receive credit for the same total amount of approximately $21 million through EDIT credits that now will reduce the tax expense component of our cost of service.

Q. ARE TGS'S REQUESTED MODIFICATIONS BEING MADE IN A WAY THAT CAUSES THE LEAST IMPACT ON EDIT CREDITS IN THIS STATEMENT OF INTENT WHILE ENSURING MINIMAL RISK OF A NORMALIZATION VIOLATION?

A. Yes. In particular, the request to separately account for the COR asset and amortize over the ARAM period as opposed to the 10 years applied to the current unprotected

EDIT liability will ensure that the amounts of the credit are consistent with previous credits.

Q. DOES TGS BELIEVE THERE ARE SERIOUS CONSEQUENCES IF THE IRS DETERMINES THAT A NORMALIZATION VIOLATION HAS OCCURRED IF THE REQUESTED MODIFICATIONS ARE NOT APPROVED?

A. Yes, it does.

Q. WHAT IS THE POTENTIAL IMPACT OF A NORMALIZATION VIOLATION FROM THE IRS?

A. If TGS were to be found in violation of the IRS normalization rules, it could lose the ability to take accelerated depreciation credits on its annual tax returns going forward. These tax credits result in tens of millions of dollars annually in non-investor supplied capital that serves as an offset to rate base when calculating customer rates. In addition, TGS would have to pay the IRS any amounts refunded in advance of when they should have been under the normalization rules.

IV. EDIT BALANCE AND ANNUAL AMORTIZATION

Q. WHAT IS THE EDIT BALANCE FOR THE PROPOSED WNSA?

A. As contained in Exhibit JJH-3, the balance of EDIT for the proposed WNSA at December 31, 2021 is $14,871,247.

Q. HOW IS THE EDIT BALANCE AT DECEMBER 31, 2021 CALCULATED?

A. The initial EDIT balance, shown on page 10 of Exhibit JJH-3, of the proposed WNSA was calculated by taking the difference between the ADIT balance on the day before the tax rate change and the ADIT balance calculated using the newly enacted corporate tax rate resulting from the 2017 TCJA. The December 31, 2021

EDIT balance for the proposed WNSA is calculated by taking the initial EDIT balance and subtracting the annual amortization for the years 2018, 2019, 2020 and 2021, also shown on page 10 of Exhibit JJH-3, resulting in a December 31, 2021 balance of $14,871,247.

Q. WHAT IS THE AMOUNT OF THE ANNUAL AMORTIZATION OF THE EDIT?

A. As shown in Exhibit JJH-3, the annual amortization of EDIT for the proposed WNSA is $1,422,666.

Q. HOW WAS THE ANNUAL AMORTIZATION AMOUNT OF THE EDIT BALANCE CALCULATED?

A. Exhibit JJH-3 contains the calculation of the EDIT amortization amount for the proposed WNSA using the ARAM methodology for the protected portions of EDIT, the same ARAM amortization percentage for the non-protected COR EDIT balance resulting from the PLR issue previously discussed, and the ten-year amortization period for non-protected EDIT.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Internal Revenue Service

Number: **202033002**
Release Date: 8/14/2020

Index Number: 168.24-01

In Re:

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-122510-19

Date:
March 26, 2020

LEGEND:

Taxpayer =

Parent =

State A =

Commission A =

Commission B =

Date 1 =

Date 2 =

Date 3 =

Date 4 =

Date 5 =

Month 1 =

Month 2 =

Year 1 =

Year 2 =

Year 3 =

Year 4 =

Year 5 =

Year 6 =

Dear :

This letter responds to a request for a private letter ruling dated September 26, 2019, and submitted on behalf of Taxpayer regarding the application of the depreciation normalization rules under § 168(i)(9) of the Internal Revenue Code and § 1.167(l)-1 of the Income Tax Regulations (together, the "Normalization Rules") to certain State A state regulatory procedures which are described in this letter. The relevant facts as represented in your submission are set forth below.

FACTS

Taxpayer is an investor-owned regulated utility incorporated under the laws of State A. Taxpayer is an accrual basis taxpayer and reports on a calendar year basis.

Taxpayer is wholly owned by Parent. Parent is a State A corporation. Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent.

Taxpayer is a regulated utility engaged principally in the purchase, transmission, distribution, and sale of electric energy and the purchase, distribution, and sale of natural gas in State A. Taxpayer is subject to regulation as to rates and conditions of service by Commission A as well as Commission B. Both these regulators establish Taxpayer's rates based on its costs, including a provision for a return on the capital employed by Taxpayer in its regulated businesses.

Taxpayer has claimed accelerated depreciation on all of its public utility property (both electric and gas) to the full extent those deductions have been available. Taxpayer has normalized the federal income taxes deferred as a result of its claiming these deductions in accordance with the Normalization Rules. As a consequence, Taxpayer has a substantial balance of accumulated deferred federal income taxes (ADFIT) that is attributable to accelerated depreciation reflected on its regulated books of account for each of its divisions. In accordance with State A ratemaking practice, Taxpayer has reduced its rate base by its ADFIT balance.

Commission B has established a system to track accounts for both jurisdictional electric and gas companies. These accounts prescribe the accounting rules which are used by most large investor-owned electric and gas companies and are employed by Taxpayer's electric and gas divisions. The applicable regulations contain several definitions relevant to Taxpayer's inquiry including definitions for cost of removal (COR), salvage value, net salvage value, service value, and depreciation.

In general, based on these definitions, for purposes of regulatory reporting, the net positive value or net cost of disposing of an asset at the end of its life is incorporated into the annual depreciation charge. COR is, therefore, most often (but not always) a component of establishing the applicable depreciation rate. In Taxpayer's case, due to the amount of COR it anticipates, in almost all instances its assets have negative net salvage values so that its book depreciation rate is higher than it would be were salvage value not considered. In effect, the annual depreciation charge creates a reserve for COR over the operating life of the asset. Since book depreciation expense is included in Taxpayer's cost of service used for establishing its rates, customers pay for the COR as book depreciation is factored into their rates. This COR reserve is reflected as an addition to Taxpayer's accumulated depreciation account. When the COR is actually incurred, the amount expended is debited to that same account, thereby reducing the balance.

For tax purposes, COR is deductible only when actually incurred. Taxpayer, therefore, reports its customer collections that fund the COR reserve as taxable income over the operating life of an asset, claiming an offsetting tax deduction only at the end of the life of that asset. Taxpayer has normalized COR since the Year 1 tax year. All references below to COR-related deferred tax accounting relate only to COR associated with assets placed in service after Year 2. Since COR is normalized in setting rates, customers are provided a tax benefit commensurate with their funding of COR. In other words, they are provided the COR tax benefit as they fund the COR reserve – prior to the time Taxpayer actually claims that benefit on its tax return.

The tax effect of the COR funding as described creates a deferred tax asset ("DTA"). This represents the future benefit to be derived from the eventual COR tax deduction. The COR-related DTA is included in Taxpayer's overall plant-related ADFIT account that reduces Taxpayer's ADFIT balance.

COR can (and does) impact ADFIT balances in an additional way. The COR included in depreciation expense (that is, the accrual) is an estimate prepared for an entire class of assets contained in a Commission B account. It is likely that any COR estimate will be too high or too low with respect to any individual asset with the ultimate answer remaining unknown until all vintages of each asset class are retired and removed. Any running variance from the estimate is recorded on Taxpayer's balance sheet. Where the accrual exceeds the actual COR, it creates a net credit to the accumulated depreciation account. Where the actual COR exceeds the accrual, it creates a net debit to that account. This treatment means that Taxpayer will recover under-accruals from customers and refund over-accruals to customers through future rate adjustments. These future rate adjustments will give rise to future increases or decreases in taxable income. Under applicable accounting principles, Taxpayer must record the deferred tax consequences of these future events. An over-accrual produces a DTA (the tax benefit of a future deduction due to the refund of the excess collection) while an under-accrual produces a deferred tax liability "DTL" (the tax cost of future taxable income due to the collection of the shortfall).

For the electric distribution division, the COR book/regulatory accrual has always been included in the development of the book depreciation rate. Thus, instead of waiting for the Taxpayer to incur the tax benefit of COR, its' Customers are provided the COR tax benefit as they fund the COR reserve – prior to the time Taxpayer actually claims that benefit on its tax return. This produces a DTA as described. In addition, as of Date 1, Taxpayer has, in total, incurred more COR than it has recovered from customers and, thus, is under-accrued for COR. This has produced a DTL, also as described. Both the DTA and DTL are included within Taxpayer's overall plant-related ADFIT Account.

Prior to Month 1 Year 3, the gas distribution division accrued and collected COR as a component of the book depreciation rate. However, pursuant to order of Commission A, that collection practice was modified in Year 3. Beginning in Month 1 Year 3, the gas-only COR regulatory accrual was removed from the book depreciation rate. Rather, Taxpayer was allowed to record and recover annually (through a fixed dollar depreciation charge incremental to the normal depreciation computed via application of the depreciation rate) an amount representing an estimate of the annual COR that would be incurred in that year. At the time of this modification, the cumulative COR accrued exceeded COR actually incurred (that is, Taxpayer was over-accrued). At that time, Taxpayer had recorded a net DTA (to reflect the tax benefit of the future reduction in rates associated with refunding the excess to customers).

Since converting to this methodology in Year 3, COR actually incurred has significantly exceeded COR accrued and recovered, resulting in a DTL (the tax cost of recovering the under-accrual in the future). As of Date 1, the two components (pre-Month 1 Year 3 and post-Month 2 Year 3) combined represented a net DTL.

Effective Date 2, pursuant to an Order issued by Commission A, gas COR regulatory recovery has reverted back to a component of the book depreciation rate. The fixed dollar accrual which began in Year 3 has been eliminated.

Since Year 4, Taxpayer's tax fixed asset system has separately identified the portion of Taxpayer's book depreciation expense that relates to COR since that date. As a consequence, the system distinguishes between COR book/tax differences and depreciation method/life differences even though they are both derived from Taxpayer's book depreciation. Though the system has the capability of tracking the reversals of these differences separately, in order to set it up to do this, a significant amount of work and data manipulation would be required. It is not currently configured in a manner that would allow this.

In years prior to Year 5, Taxpayer paid income tax at a 35% rate on the recovery of the COR portion of book depreciation (and provided its customers a tax benefit at that tax rate). However, as a result of the tax rate reduction enacted as part of the Tax Cuts and Jobs Act ("TCJA"), Taxpayer will only receive a 21% benefit when the COR deduction is claimed or when any over-accrual is refunded and will pay only a 21% tax on the recovery of any COR under-accrual. In other words, in the case of COR, the tax rate reduction enacted as part of the TCJA has produced both a deferred tax shortfall as well as an excess tax reserve. Because Taxpayer will not recover the 14% "excess" tax it paid on its recovery of the COR component of book depreciation from the government when it claims its COR deduction, it must recover it from its customers. Conversely, because Taxpayer will not pay the 14% "excess" deferred tax it accrued on its obligation to refund over-accrued COR, it must restore the amount to its customers (that is, it also has COR-related excess deferred taxes).

Taxpayer's Changes in Accounting Method for Mixed Service Costs and Repairs

Prior to Taxpayer's Year 6 tax year, in capitalizing its indirect overhead costs – including its mixed service costs – Taxpayer followed the same methodology for both book and tax purposes. Effective for its Year 6 tax year, Taxpayer filed with the Internal Revenue Service an Application for Change in Accounting Method (Form 3115) in which it requested permission to depart from its book method for tax purposes. The result of the change was to recharacterize a substantial quantity of mixed service costs that Taxpayer had previously capitalized into depreciable assets as deductible costs (including additions to cost of goods sold). This resulted in Taxpayer claiming a negative adjustment under § 481(a) (that is, a deduction) to remove from the tax basis of its existing assets all such recharacterized costs to the extent Taxpayer had not previously depreciated them ("Section 481 Adjustment").

Also, prior to Taxpayer's Year 6 tax year, in identifying deductible repairs, Taxpayer followed the same methodology for both book and tax purposes. Effective for its Year 6 tax year, Taxpayer filed an Application for Change in Accounting Method (Form 3115) in which it requested permission to depart from its book method for tax purposes. In general, under its new tax method, Taxpayer elected to use larger units of property than used for book purposes. The result of the change was to characterize many projects that were capitalized for book purposes as deductible repairs for tax purposes. This resulted in Taxpayer claiming a negative § 481 Adjustment to remove from the tax basis of its existing assets all such recharacterized costs to the extent Taxpayer had not previously depreciated them.

Adjustments (additions) were made to Taxpayer's ADFIT accounts, which already reflected the deferred tax consequences of having claimed accelerated depreciation on both types of costs after they were capitalized for tax purposes for the additional deferred taxes produced by the § 481 Adjustments.

Taxpayer's Recent Commission A Proceedings

On Date 3, Taxpayer filed with Commission A to adjust both its electric and its gas rates. The parties to the proceeding reached an agreement and, on or about Date 4, Taxpayer submitted a stipulation to Commission A for its approval. Commission A approved the stipulation on Date 5.

The stipulation provides that:

> 1) Taxpayer will seek a private letter ruling to determine if excess deferred taxes associated with excess tax over book depreciation that is subsequently reversed by accounting method changes relating to repair deductions and the capitalization of mixed service costs are protected by the normalization rules and subject to reversal under the ARAM; and that
>
> 2) Taxpayer will seek a private letter ruling from the IRS to determine whether post-Year 1 cost of removal is protected by the normalization rules and, if so, whether it is to be treated as a separate temporary difference or part of the overall depreciation temporary difference for purposes of ARAM amortization.

RULINGS REQUESTED

Taxpayer requests the following guidance:

1) Under the circumstances described above, is Taxpayer's electric distribution COR-related net DTL "protected" by the Normalization Rules?

2) If Taxpayer's electric distribution COR-related deferred tax is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?

3) Under the circumstances described above, is Taxpayer's gas distribution COR-related net DTA accumulated through the depreciation rate prior to Month 1 of Year 3 "protected" by the Normalization Rules?

4) If Taxpayer's gas distribution COR-related deferred tax accumulated through the depreciation rate prior to Month 1 of Year 3 is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?

5) Under the circumstances described above, is Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 "protected" by the Normalization Rules?

6) If Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?

7) If Taxpayer's COR-related deferred tax shortfall is "protected," do the Normalization Rules permit Taxpayer to collect a shortfall any more rapidly than using the ARAM?

8) Do Taxpayer's depreciation-related ADFIT balances created pursuant to the Normalization Rules that are attributable to costs that were capitalized into the basis of depreciable assets prior to Taxpayer changing its method of accounting for those costs remain subject to the Normalization Rules after the change in method of accounting pursuant to which such costs were reclassified as current deductions?

LAW AND ANALYSIS

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A)(i) requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 481(a) requires those adjustments necessary to prevent amounts from being duplicated or omitted to be taken into account when a taxpayer's taxable income is computed under a method of accounting different from the method used to compute taxable income for the preceding taxable year. *See also* § 2.05(1) of Rev. Proc. 97-27, 97-27, 1997-1 C.B. 680 (the operative method change revenue procedure at the time Taxpayer filed its Form 3115, *Application for Change in Accounting Method*).

An adjustment under § 481(a) can include amounts attributable to taxable years that are closed by the period of limitation on assessment under § 6501(a). *Suzy's Zoo v. Commissioner*, 114 T.C. 1, 13 (2000), *aff'd*, 273 F.3d 875, 884 (9th Cir. 2001); *Superior Coach of Florida, Inc. v. Commissioner*, 80 T.C. 895, 912 (1983), *Weiss v. Commissioner*, 395 F.2d 500 (10th Cir. 1968), *Spang Industries, Inc. v. United States*, 6 Cl. Ct. 38, 46 (1984), *rev'd on other grounds* 791 F.2d 906 (Fed. Cir. 1986). *See also Mulholland v. United States*, 28 Fed. Cl. 320, 334 (1993) (concluding that a court has the authority to review the taxpayer's threshold selection of a method of accounting *de novo*, and must determine, *ab initio*, whether the taxpayer's reported income is clearly reflected).

Sections 481(c) and 1.481-4 provide that the adjustment required by § 481(a) may be taken into accounting in determining taxable income in the manner, and subject to the conditions, agreed to by the Service and a taxpayer. Section 1.446-1(e)(3)(i) authorizes the Service to prescribe administrative procedures setting forth the limitations, terms, and conditions deemed necessary to permit a taxpayer to obtain consent to change a method of accounting in accordance with § 446(e). *See also* § 5.02 of Rev. Proc. 97-27.

When there is a change in method of accounting to which § 481(a) is applied, § 2.05(1) of Rev. Proc. 97-27 provides that income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed, and income for the year of change and the following taxable years must be determined under the new method of accounting as if the new method had always been used.

Because of their similarity, we address requests 1, 3, and 5 together. For all of the COR-related amounts at issue in these requests, the amounts are not protected by the Normalization Rules. Generally, § 168(i)(9)(A) does not refer to COR. Moreover, there is no reference to an acceleration of taxes but only to a deferral. While COR may be a component of the calculation of the amount treated as book depreciation, it is a deduction under § 162 and has nothing to do with actual accelerated tax depreciation. While depreciation method and life differences are created and reversed solely through depreciation, such is not the case with COR. While the COR timing differences may often originate as a component of book depreciation, it reverses through the incurred COR expenditure.

Taxpayer's ruling request 8 pertains to the depreciation-related ADIT existing prior to the year of change (Year 6) for public utility property in service as of the end of the taxable year immediately preceding the year of change. Beginning with the year of change, the Year 6 Consent Agreement granted Taxpayer permission to change its (1) method of accounting for mixed service costs to recharacterize a substantial quantity of mixed service costs that Taxpayer had previously capitalized into depreciable assets as deductible costs (including additions to cost of goods sold) and (2) to depart from its book method for tax purposes electing to use for tax purposes larger units of property than used for book purposes which resulted in characterizing many projects that were capitalized for book purposes as deductible repairs for tax purposes.

When there is a change in method of accounting to which § 481(a) is applied, income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed by Taxpayer, and income for the year of change and the following taxable years must be determined under Taxpayer's new method of accounting as if the new method had always been used. *See* § 481(a); § 1.481-1(a)(1); and § 2.05(1) of Rev. Proc. 97-27. In other words: (1) Taxpayer's new method of accounting is implemented beginning in the year of change; (2) Taxpayer's old method of accounting used in the taxable years preceding the year of change is not disturbed; and (3) Taxpayer takes into account a § 481(a) adjustment in computing taxable income to offset any consequent omissions or duplications.

Accordingly, for public utility property in service as of the end of the taxable year immediately preceding the year of change (Year 6), the depreciation-related ADIT existing prior to the year of change for the changes in methods of accounting subject to the Year 6 Consent Agreement does not remain subject to the normalization method of accounting within the meaning of § 168(i)(9) after implementation of the new tax methods of accounting in the year of change and subsequent taxable years.

Based on the foregoing, we conclude that:

1) Under the circumstances described above, Taxpayer's electric distribution COR-related net DTL is not "protected" by the Normalization Rules.

3) Under the circumstances described above, Taxpayer's gas distribution COR-related net DTA accumulated through the depreciation rate prior to Month 1 of Year 3 is not "protected" by the Normalization Rules.

5) Under the circumstances described above, Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 is not "protected" by the Normalization Rules.

Because these amounts in requests 1, 3, and 5 are not protected by the Normalization Rules, requests 2, 4, 6, and 7 are moot.

8) Taxpayer's depreciation related ADFIT balances created pursuant to the Normalization Rules that are attributable to costs that were capitalized into the basis of depreciable assets prior to Taxpayer changing its method of accounting for those costs do not remain subject to the Normalization Rules after the change in method of accounting pursuant to which such costs were reclassified as current deductions.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

This ruling is based upon information and representations submitted by Taxpayer and accompanied by penalty of perjury statements executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representatives.

Sincerely,

Patrick S. Kirwan
Chief, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)

cc:

Internal Revenue Service

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Department of the Treasury
Washington, DC 20224

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Refer Reply To:
CC:PSI:B6
PLR-101961-21
Date:
July 26, 2021

Legend

Taxpayer =
Corporation =
State A =
State B =
Commission A =
Commission B =
Order =
Date 1 =
Date 2 =
Date 3 =
Date 4 =
Date 5 =
Date 6 =
Date 7 =
Date 8 =
Year 1 =
Year 2 =
Year 3 =

Dear :

This letter responds to a request for a private letter ruling dated January 7, 2021, submitted by Taxpayer. Taxpayer requests rulings with respect to the application of § 168(i)(9) of the Internal Revenue Code, former § 167(l), and section 13001(d) of the Tax Cuts and Jobs Act, Pub. L. 115-97(the "TCJA") (together, the Normalization Rules), regarding the proper accounting and ratemaking treatment of excess deferred income taxes ("EDIT"). The relevant facts as represented in Taxpayer's submission are set forth below.

FACTS

Taxpayer is an electric and natural gas utility headquartered in State A.

Taxpayer is a wholly owned member of Corporation and Subsidiaries consolidated group. Corporation is an energy services holding company incorporated in State B. Taxpayer is included in the consolidated federal income tax return of Corporation. Taxpayer employs a calendar year reporting period and uses an accrual method of accounting. Corporation elected to be treated as a corporation for federal tax purposes. Corporation and Subsidiaries are not presently under audit by the Internal Revenue Service.

Taxpayer is engaged in the production, transmission, and distribution of electricity and the distribution of natural gas in State A. It is subject to the regulatory authority of Commission A and Commission B as to the terms and conditions of service and the rates it is permitted to charge for its service. Its rates are established or approved based on its costs of service, including a return on its capital investment (rate base).

Taxpayer's rates are established by Commission A on a "cost of service, rate-of-return" basis. Thus, Taxpayer is permitted an opportunity to recover its prudently incurred costs and earn an appropriate return on its rate base, which reflects its net invested capital. The convention employed in State A with respect to rate base is that a utility's accumulated deferred income tax balance ("ADIT") offsets gross rate base (rate base computed before reduction by ADIT). Included in Taxpayer's ADIT balance are a significant amount of deferred taxes attributable to accelerated depreciation claimed with respect to public utility property. Thus, Taxpayer's ADIT is, to a substantial extent, subject to the normalization rules contained in § 168(i)(9) and former § 167(l). Commission A uses an historical test period consisting of a 12-month period for purposes of determining Taxpayer's costs and rate base. Results of this test period are adjusted by "pro forma adjustments" to remove materially distortive items and to give effect to known and measurable changes that are not offset by other factors.

As part of this process of setting rates, Taxpayer computes its depreciation expense and its income tax expense, including both current and deferred components of income tax expense, for inclusion in its cost of service. Taxpayer also reduces its gross rate base by its ADIT balance to determine the rate base on which it is permitted to earn a return. Taxpayer's accounting treatment for depreciation expense, income tax expense, ADIT, and rate base has been consistent with the Normalization Rules.

On December 22, 2017, the TCJA was signed into law. Among other changes, the TCJA reduced the federal corporate income tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017, Taxpayer's calendar Year 1 tax year.

As a result of the tax reduction, the deferred taxes Taxpayer had accumulated at a 35 percent rate were reduced to those that would have been accumulated at a 21 percent rate had the 21 percent rate been in effect for all prior years. Because Taxpayer had a net deferred tax liability ("DTL") on December 31, 2017, the tax rate reduction resulted in EDIT, because Taxpayer now expects to pay income taxes to the Department of the Treasury at the reduced 21 percent rate, as the timing differences that gave rise to its DTL reverse. In general, Taxpayer had collected the EDIT from customers through its traditional ratemaking methodology and not on a precise dollar-for-dollar basis. The 14-percentage point reduction in the tax rate is available to reduce the tax expense that Taxpayer included in setting customer rates. It is the timing of this reduction of the EDIT that is the issue of this ruling request.

Taxpayer maintains records that include the vintage records necessary to apply the average rate assumption method ("ARAM"). The total balance of Taxpayer's EDIT is unknown. The annual amount of EDIT reversal under ARAM will vary each year, and this variance is unknown at this time. In general, this variability is caused by future events, including the time at which a vintage begins to reverse or when a vintage fully reverses. Taxpayer provides deferred taxes on plant-related timing differences whether or not those timing differences are protected by the Normalization Rules or unprotected by the Normalization Rules. Taxpayer and Commission A intend to apply ARAM to all plant-related timing differences. There is no dispute over this intent to apply ARAM. Throughout Taxpayer's general rate case ("GRC"), these balances are commonly referred to as "protected plus" or "PP" to acknowledge the fact that ARAM is being applied not only to all protected EDIT, but also unproteced plant-related EDIT.

Taxpayer has been accounting for EDIT balances in ratemaking on a consistent method since the Tax Reform Act of 1986, Pub. L. No: 99-514 ("TRA 1986"). That method has been as follows:

> Taxpayer closes its books on a monthly basis. Each resulting monthly income statement and balance sheet contains its share of book depreciation, rate base, income tax expense, and ADIT (including EDIT). Taxpayer includes the ARAM reversal of EDIT in its monthly calculation of tax expense. Its EDIT balance is included in its ADIT to ensure that rate base is reduced by the proper amount of deferred taxes. This treatment ensures that book depreciation, income tax expense, ADIT, and rate base are computed consistently.
>
> Taxpayer's rates are set periodically in a GRC using an historical test period. In a GRC, the accounting activity recorded in each month during the historical test year is the basis for setting customer rates, plus or minus any pro-forma adjustments. Once customer rates are established, they remain constant until the next GRC. At that next GRC, customer rates will be reset based on a new, different historical test year – different income and expenses (including income tax expense and book depreciation expense), different rate base, and different

ADIT. The assumption underlying the use of an historical test year is that the costs and benefits in the historical period, plus or minus any pro-forma adjustments, will be representative of future periods during which customers will pay the rates. The process is intended to ensure that customer rates will be fair, just, reasonable, and sufficient. This is so even though the actual income and incurred costs, including EDIT reversals, for the period for which the rates are set will be different than those used to set the rates during the GRC.

In its Year 2 GRC, Taxpayer used calendar year Year 1 as the historical test year. This was its first GRC following the TCJA. In its monthly accounting activity throughout Year 1, Taxpayer recorded its EDIT reversal using ARAM. Those accounting entries had the effect of reducing Taxpayer's deferred tax expense and reduced Taxpayer's EDIT balance. No other entries were made with respect to EDIT. These entries were identical to those Taxpayer made since the tax rate reduction provided by the TRA 1986 to account for the EDIT created by the TRA 1986 tax rate reduction and used to set rates since that time.

In filing its Year 2 GRC, Taxpayper included the EDIT reversals that it recorded in calendar year Year 1, consistent with the use of Year 1 as the historical test period. In addition, its ADIT balance, including the EDIT, reflected these reversals. The accounting that occurred in calendar year Year 1 formed the basis for the amounts that Taxpayer proposed in setting rates for Year 2. In other words, the Year 1 book accounting provides the basis for ratemaking in the Year 2 GRC, which was originally intended to be effective for new rates beginning in mid-Year 3.

In response to Taxpayer's Year 2 GRC filing, Commission A issued Order on Date 1. Commission A did not follow Taxpayer's requested historical treatment. Instead, Commission A ordered the approach that raises the normalization issues that are the subject of this request.

Order requires Taxpayer to separately track EDIT on a tariff rate schedule independent of its rates set in its general rate order. In one requirement, Commission A requires the schedule to be updated annually for the reversal of the EDIT for the current year as if rates were set each year. Furthermore, in another requirement, Commission A requires Taxpayer to true-up for the difference between the EDIT amounts set in the schedule and the actual amount passed back due to volumetric variances. Commission A has ordered that the schedule must produce an annual adjustment to Taxpayer's rates for ARAM amortization of EDIT without any corresponding adjustment to Taxpayer's rates for annual changes in depreciation expense, income tax expense, rate base, or ADIT (including EDIT).

Order includes Taxpayer's depreciation expense, tax expense, ADIT (including EDIT), and rate base for the test year in the computation of the primary cost of service and base rate. Order then requries an adjustment to cost of service by removing the test year ARAM amortization of EDIT and substituting for that amount, as a reduction in cost of service, the estimated EDIT amortization for the year following the test year plus the next year which includes part of the rate year (in total, a 24-month period). No other similar adjustments are made for depreciation expense, income tax expense, ADIT (including EDIT), or rate base, which were, instead, based on the historical test period (again, not including pro forma adjustments which are not a topic of this PLR).

Order was applied to Taxpayer as follows: The test year was calendar year Year 1. The original rate year was to be Date 2 through Date 3, but the start of that rate period was initially delayed due to Coronavirus to an effective date of Date 4. After some further delays, the rates became effective Date 5, for gas operations and Date 6, for electric operations. Taxpayer's originally proposed ARAM EDIT amortization was based on the test year (calendar year Year 1). The Order adjustment was based on an estimate of ARAM EDIT amortization for the two-year period Date 7 through Date 8, the total two-year amount to be passed back in one year.

Taxpayer has proposed corrective action if the Service concludes that the EDIT treatment in Order is not consistent with a normalization method of accounting. If that determination is made, Taxpayer will need to reestablish a normalization method of accounting. In that event, Commission A has agreed to immediately open a proceeding upon Taxpayer's receipt of a PLR from the Service and revisit its order to comply with the Normalization Rules. This agreement was a condition of Taxpayer dismissing its judicial appeal of Order.

Taxpayer has taken additional action to ensure a quick and complete correction if Order is found inconsistent with the Normalization Rules. Taxpayer filed an accounting petition with Commission A on Date 5 in which it requested that Commission A allow Taxpayer to track the difference between Taxpayer's approach and the approach required in Order. The difference between the two approaches will be recorded to Taxpayer's balance sheet as a monthly entry. Two accounts will be used – a tracking account and a contra account (collectively, the "PLR Tracker Accounts"). The two accounts will net to zero and thereby have no impact on Taxpayer's financial results, as doing otherwise would not be in compliance with Commission A's order. However, the accounts will provide contemporaneous documentation of the variance between the two approaches.

For gas customers, rates consistent with Order went into effect on Date 5. For electric customers, new rates went into effect on Date 6. For both gas and electric customers, the accounting petition will provide Commission A with the ability to correct any normalization infraction that the IRS identifies in its ruling.

Taxpayer anticipates that any correction will involve two elements. The first element is a new tariff rate that will comply with the Service's ruling, which will be a new base tariff. That rate would continue in effect until Taxpayer's next rate-setting event, which is expected to be a GRC. The second element is a temporary tariff rate to bring the EDIT balance back into alignment with a normalization method of accounting. This second component would have the effect of reversing the amounts that were tracked in the PLR Tracker Accounts. The recovery of these balances would likely occur over a relatively short period.

RULINGS REQUESTED

Taxpayer requests rulings whether the accounting for EDIT as required by Order of Commission A is consistent with the Normalization Rules of § 168(i)(9), former § 167(l), and section 13004(d) of the TCJA. Specifically:

(1) Whether the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA permit Taxpayer to adjust its EDIT ARAM amortization based on the test year to the EDIT ARAM amortization based on one or more subsequent years without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(2) Whether the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA permit Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(3) Whether the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA permit Taxpayer to provide a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(4) Additionally, Taxpayer asks that if we determine that any of the requirements described of Order are not consistent with the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA, Taxpayer requests that we provide in the ruling that Taxpayer will not be considered to be in violation of the normalization rules if it follows the corrective actions described in its letter.

LAW AND ANALYSIS

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a “normalization method of accounting.” A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A) requires that a taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of § 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under § 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under § 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base (hereinafter referred to as the "Consistency Rule").

Taxpayer's requests relate primarily to Taxpayer's compliance with the Consistency Rule. Taxpayer asks whether the Normalization Rules permit Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense. More specifically, Taxpayer also asks whether the Normalization Rules permit Taxpayer to adjust its EDIT ARAM amortization based on the test year to the EDIT ARAM amortization based on one or more subsequent years without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense. Lastly, Taxpayer asks whether the Normalization Rules permit Taxpayer to provide a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

Therefore, the threshold question is whether the Consistency Rule applies to EDIT being accounted for under ARAM. Because these amounts were originally deferred pursuant to a normalization method of accounting, these amounts remain subject to the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA. Thus, if the EDIT being accounted for under ARAM is subject to Normalization Rules, the Consistency Rule must apply to the EDIT.

As described in § 168(i)(9)(B)(ii), the use of a procedure or adjustment that uses an estimate or projection of any of (1) the taxpayer's tax expense, (2) depreciation expense, or (3) reserve for deferred taxes under § 168(i)(9)(A)(ii), does not comply with the Consistency Rule unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base. Therefore, generally, the Normalization Rules do not permit Taxpayer to adjust its EDIT ARAM amortization without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense**.** More specifically, in regard to request (1), the Normalization Rules do not allow Taxpayers to make an adjustment to cost of service by removing the test year ARAM amortization of EDIT and substituting for that amount, as a reduction in cost of service, the estimated EDIT amortization for the year following the test year plus the next year which includes part of the rate year (in total, a 24-month period) while also making no similar adjustments for depreciation, expense, income tax expense, ADIT (including EDIT), or rate base, which were based on the historical test period. In regard to request (2), the Normalization Rules do not allow Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

Additionally, in response to request (3), providing a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense likewise is not in compliance with the Consistency Rule. The true-up mechanism adjusts for volume differences only with respect to one item, EDIT amortization. This results in the use of estimated volumes in setting rates for all items other than EDIT reversal which uses actual volumes. This treatment is an inconsistent use of estimates or projects not allowed by section 168(i)(9)(B).

The Normalization Rules were enacted in response to Congressional concerns over the growing number of public utility commissions that were mandating investor-owned regulated utilities to not retain these tax benefits from accelerated depreciation, but, instead, to immediately flow-through all of these tax incentives to ratepayers in the form of lower income tax expense in regulated cost of service rates. Congress' response was to enact legislation that would preclude regulated investor-owned utilities from utilizing accelerated depreciation methods of tax purposes if the related tax benefits were immediately flowed-through to ratepayers in rates or were flowed-through to ratepayers faster than permitted under the Normalization Rules.

The underlying concept and purpose of the Normalization Rules is to prevent the flow-through of these accelerated depreciation-related tax benefits to ratepayers in regulated rates any faster than permitted by the Normalization Rules. Thus, the flow-through of these tax benefits to ratepayers faster than permitted by the Normalization Rules would result in a normalization violation that would preclude the taxpayer from using any of the accelerated tax depreciation methods on public utility property and, instead, require the taxpayer to use the same depreciation method and period as those used to compute depreciation expense in its cost of service for ratemaking purposes. Conversely, a taxpayer that flows through these tax benefits to ratepayers slower than permitted by the Normalization Rules, or that never flows through any of the tax benefits from accelerated depreciation to ratepayers, would not be in violation of those rules.

By removing EDIT amortization for the test year and including the estimated EDIT amortization for the two following years, the EDIT amortization on the cost of service is higher than allowed under the ARAM limitation for the test year. This acceleration of the EDIT amortization occurs under the Order without any reduction to the EDIT balance which is taken into account in determining rate base. This provides customers not only with a lower cost of service through the acceleration of EDIT amortization but also a rate base which is artificially low because the EDIT credit balance included in rate base has not been reduced by the EDIT reversal that has been accelerated. This incorrectly provides customers with the double benefit of lower cost of service and lower rate base for the same EDIT.

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting. However, in the legislative history to the enactment of the normalization requirements of the Investment Tax Credit (ITC), Congress stated that it hopes that sanctions will not have to be imposed and that disallowance of the tax benefit (there, the ITC) should be imposed only after a regulatory body has required or insisted upon such treatment by a utility. See Senate Report No. 92-437, 92nd Cong., 1st Sess. 40-41 (1971), 1972-2 C.B. 559, 581. See also, Rev. Proc. 2017-47, 2017-38 I.R.B. 233, September 18, 2017.

Commission A has, at all times, required that utilities under its jurisdiction use normalization methods of accounting. Further, Commission A has agreed to immediately open a proceeding upon receipt of Taxpayer's receipt of a PLR from the Service and revisit its order to comply with the Normalization Rules if the Service concludes that Order results in a rate calculation that is not consistent with the Normalization rules.

Taxpayer also intended at all times to comply with the Normalization Rules. Taxpayer has initiated the measures necessary to conform to the Normalization Rules. As noted, Taxpayer filed an accounting petition with Commission A in which it requested that Commission A allow Taxpayer to track the difference between Taxpayer's approach and the approach required in Order. The difference between the two approaches will be recorded to Taxpayer's balance sheet as a monthly entry identified as "the PLR Tracker Accounts." For both gas and electric customers, the accounting petition provides

Commission A with the ability to correct any normalization infraction that the IRS identifies in this ruling.

Taxpayer's failure to comply with the Normalization Rules was inadvertent. Because the Commission, as well as Taxpayer, at all times sought to comply, and because corrective actions will be taken at the earliest available opportunity, it is not appropriate to conclude that the failure to follow the Consistency Rule for the EDIT that is a part of ADIT and calculated according to ARAM constituted a normalization violation and apply the sanction of denial of accelerated depreciation to Taxpayer.

CONCLUSION

Accordingly, we rule as follows:

(1) The Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA do not permit Taxpayer to adjust its EDIT ARAM amortization based on the text year to the EDIT ARAM amortization based on one or more subsequent years without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense;

(2) The Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA do not permit Taxpayer to adjust its EDIT ARAM amortization annually without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

(3) The Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA do not permit Taxpayer to provide a true-up to EDIT ARAM amortization in the year following the rate year based on volume variances between the test year and the rate year without making similar adjustments to rate base, ADIT, book depreciation expense, and tax expense.

(4) While we have determined that the described requirements of Order are not consistent with the Normalization Rules of § 168(i)(9), former § 167(l), and section 13001(d) of the TCJA, Taxpayer will not be considered to be in violation of the normalization rules if it follows the corrective actions described in its letter.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent.

This ruling is based upon information and representations submitted by Taxpayer and accompanied by penalty of perjury statements executed by an appropriate party.

While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the LB&I Policy Office.

Sincerely,

Patrick S. Kirwan
Chief, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)

cc:

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2021
ARAM Estimate for amounts attributed to the Borger Skellytown Service Area

Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Non-protected (ARAM)	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount
	(a) = (b)+(c)+(d)	(b)	(c)	(d)	(a1)	(a2)
Borger - Skellytown Service Area Plant Assets Depreciation	(1,051,947)	$ (1,051,947)			$ (1,051,947)	
Borger - Skellytown Service Area Repairs	(366,112)			(366,112)	$ (366,112)	
Borger - Skellytown Cost of Removal Asset	407,385		407,385		$ 407,385	
Borger - Skellytown Service Area Other Nonprotected plant	(46,224)			(46,224)	$ (46,224)	
Borger-Skellytown Other Rate Base Items	(98,429)			(98,429)	(98,429)	
TGS Division Plant Assets Depreciation	(4,907)	(4,907)			(4,907)	
ONEGas Plant Assets Depreciation	(28,823)	(28,823)		-		(28,823)
Borger-Skellytown NOL	611,019	$ 611,019			$ 611,019	
Total ADIT - Accumulated Deferred Income Taxes	**(578,038)**	**(474,658)**	**407,385**	**(510,765)**	**(549,215)**	**(28,823)**

Percent Protected	82%

BSSA

	TGS Amortization	ONE Gas Amortization	TGS NOL	Total Amortization	EOY Regulatory Liability Balance
Year 1 - 2018 Actuals	$ 49,784	$ 3,231	$ (4,048)	$ 48,967	$ (529,071)
Year 2 - 2019 Actuals	$ 55,364	$ 3,078	$ (13,787)	$ 44,655	$ (484,416)
Year 3 - 2020 Actuals	$ 50,710	$ 2,137	$ (6,757)	$ 46,090	$ (438,326)
Year 4 - 2021 Est	$ 62,537	$ 2,204	$ (6,334)	$ 58,408	$ (379,918)
Year 5 - 2022 Est	$ 49,857	$ 2,181	$ (9,190)	$ 42,847	$ (337,071)
Year 6 - 2023 Est	$ 52,646	$ 2,161	$ (23,178)	$ 31,629	$ (305,441)
Year 7 - 2024 Est	$ 50,093	$ 2,727	$ (30,082)	$ 22,738	$ (282,703)
Year 8 - 2025 Est	$ 56,059	$ 2,727	$ (15,847)	$ 42,939	$ (239,764)
Year 9 - 2026 Est	$ 60,255	$ 2,727	$ (13,236)	$ 49,746	$ (190,018)

Accumulated Deferred Income Taxes for:	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization
Borger - Skellytown Service Area Plant Assets Depreciation	$ 4,815	$ 17,412	$ 7,648	$ 20,761	$ 9,452	$ 19,442	$ 23,626	$ 20,207	$ 22,572
Borger - Skellytown Service Area Repairs	41,233	$ 41,233	$ 41,233	$ 41,233	$ 41,233	$ 41,233	$ 41,233	$ 41,233	$ 41,233
Borger - Skellytown Cost of Removal Asset	(2,699)	$ (9,192)	$ (4,505)	$ (4,223)	$ (6,128)	$ (15,453)	$ (20,057)	$ (10,565)	$ (8,825)
Borger - Skellytown Service Area Other Nonprotected plant	(4,622)	$ (4,622)	$ (4,622)	$ (4,622)	$ (4,622)	$ (4,622)	$ (4,622)	$ (4,622)	$ (4,622)
Borger-Skellytown Other Rate Base Items	$ 9,843	$ 9,843	$ 9,843	$ 9,843	$ 9,843	$ 9,843	$ 9,843	$ 9,843	$ 9,843
TGS Division Plant Assets Depreciation	$ 1,214	$ 691	$ 1,113	$ (454)	$ 79	$ 2,204	$ 71	$ (36)	$ 53
ONEGas Plant Assets Depreciation	$ 3,231	$ 3,078	$ 2,137	$ 2,204	$ 2,181	$ 2,161	$ 2,727	$ 2,727	$ 2,727
Borger-Skellytown NOL	$ (4,048)	$ (13,787)	$ (6,757)	$ (6,334)	$ (9,190)	$ (23,178)	$ (30,082)	$ (15,847)	$ (13,236)
Total ADIT - Accumulated Deferred Income Taxes	**48,967**	**44,655**	**46,090**	**58,408**	**42,847**	**31,629**	**22,738**	**42,939**	**49,746**

	Amortization Period		ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	**Unprotected 10 Year**	**Protected (ARAM)**	**Protected**	**Unprotected**	**Total**	**Regulatory Liability net refund**
Year 1 - 2018 Actuals	0.66%	10.00%	11.21%	6,029	43,755	49,784	49,784
Year 2 - 2019 Actual	2.26%	10.00%	10.68%	18,103	37,261	55,364	55,364
Year 3 - 2020 Actual	1.11%	10.00%	7.41%	8,761	41,949	50,710	50,710
Year 4 - 2021 Est	1.04%	10.00%	7.65%	20,306	42,231	62,537	62,537
Year 5 - 2022 Est	1.50%	10.00%	7.57%	9,531	40,326	49,857	49,857
Year 6 - 2023 Est	3.79%	10.00%	7.50%	21,645	31,000	52,646	52,646
Year 7 - 2024 Est	4.92%	10.00%	9.46%	23,696	26,397	50,093	50,093
Year 8 - 2025 Est	2.59%	10.00%	9.43%	20,170	35,888	56,059	56,059
Year 9 - 2026 Est	2.17%	10.00%	9.35%	22,625	37,629	60,255	60,255

	Amortization Period		Amortization		Financial Impact	
NOL	**Protected (ARAM)**	**Unprotected 10 Year**	**Protected**	**Unprotected**	**Total**	**Regulatory Liability net refund**
Year 1 - 2018 Actuals	0.66%	10.00%	(4,048)	-	(4,048)	(4,048)
Year 2 - 2019 Actual	2.26%	10.00%	(13,787)	-	(13,787)	(13,787)
Year 3 - 2020 Actual	1.11%	10.00%	(6,757)	-	(6,757)	(6,757)
Year 4 - 2021 Est	1.04%	10.00%	(6,334)	-	(6,334)	(6,334)
Year 5 - 2022 Est	1.50%	10.00%	(9,190)	-	(9,190)	(9,190)
Year 6 - 2023 Est	3.79%	10.00%	(23,178)	-	(23,178)	(23,178)
Year 7 - 2024 Est	4.92%	10.00%	(30,082)	-	(30,082)	(30,082)
Year 8 - 2025 Est	2.59%	10.00%	(15,847)	-	(15,847)	(15,847)
Year 9 - 2026 Est	2.17%	10.00%	(13,236)	-	(13,236)	(13,236)

	ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	**Protected**	**Unprotected**	**Total**	**Regulatory Liability net refund**
Year 1 - 2018 Actuals	11.21%	3,231	-	3,231	3,231
Year 2 - 2019 Actual	10.68%	3,078	-	3,078	3,078
Year 3 - 2020 Actual	7.41%	2,137	-	2,137	2,137
Year 4 - 2021 Est	7.65%	2,204	-	2,204	2,204
Year 5 - 2022 Est	7.57%	2,181	-	2,181	2,181
Year 6 - 2023 Est	7.50%	2,161	-	2,161	2,161
Year 7 - 2024 Est	9.46%	2,727	-	2,727	2,727
Year 8 - 2025 Est	9.43%	2,727	-	2,727	2,727
Year 8 - 2025 Est	9.35%	2,727	-	2,727	2,727

ARAM Estimate for amounts attributed to the North Texas Service Area

Accumulated Deferred Income Taxes for:	**Excess ADIT**	**Protected**	**Non-protected (ARAM)**	**Unprotected**	**TGS Amortizaton Amount**	**ONE Gas Amortization Amount**
	(a) = (b)+(c)+(d)	**(b)**	**(c)**	**(d)**	**(a1)**	**(a2)**
North Texas Direct Plant Assets Depreciation	(5,633,448)	$ (5,633,448)			$ (5,633,448)	
North Texas Tax Repairs	(2,294,592)			(2,294,592)	$ (2,294,592)	
North Texas Cost of Removal Asset	1,848,049		1,848,049		$ 1,848,049	
North Texas Other Nonprotected Plant Related	(106,579)			(106,579)	$ (106,579)	
North Texas Other Rate Base Items	(163,965)			(163,965)	(163,965)	
TGS Division Plant Assets Depreciation	(14,123)	(14,123)			(14,123)	
ONEGas Plant Assets Depreciation	(82,957)	(82,957)				(82,957)
North Texas NOL	2,743,600	$ 2,743,600		$ -	$ 2,743,600	$ -
Excess ADIT - Accumulated Deferred Income Taxes	**(3,704,015)**	**(2,986,928)**	**1,848,049**	**(2,565,136)**	**(3,621,058)**	**(82,957)**

Percent Protected	81%

NTX

	TGS Amortization	ONE Gas Amortization	TGS NOL	Total Amortization	EOY Regulatory Liability Balance
Year 1 - 2018 Actuals	$ 270,297	$ 9,301	$ (19,890)	$ 259,708	$ (3,444,307)
Year 2 - 2019 Actuals	$ 271,965	$ 8,863	$ (24,798)	$ 256,031	$ (3,188,276)
Year 3 - 2020 Actuals	$ 264,682	$ 6,149	$ (28,435)	$ 242,397	$ (2,945,880)
Year 4 - 2021 Est	$ 263,928	$ 6,345	$ (25,413)	$ 244,859	$ (2,701,020)
Year 5 - 2022 Est	$ 263,281	$ 6,277	$ (39,753)	$ 229,804	$ (2,471,216)
Year 6 - 2023 Est	$ 277,419	$ 6,221	$ (45,088)	$ 238,552	$ (2,232,665)
Year 7 - 2024 Est	$ 279,480	$ 7,849	$ (57,887)	$ 229,442	$ (2,003,223)
Year 8 - 2025 Est	$ 286,462	$ 7,823	$ (69,506)	$ 224,779	$ (1,778,444)
Year 9 - 2026 Est	$ 278,157	$ 7,823	$ (69,506)	$ 216,474	$ (1,561,970)

Accumulated Deferred Income Taxes for:	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization
North Texas Direct Plant Assets Depreciation	$ 31,139	$ 37,618	$ 31,570	$ 33,292	$ 40,771	$ 52,385	$ 69,207	$ 84,324	$ 66,314
North Texas Tax Repairs	222,007	$ 222,007	$ 222,007	$ 222,007	$ 222,007	$ 222,007	$ 222,007	$ 222,007	$ 222,007
North Texas Cost of Removal Asset	(13,398)	$ (16,703)	$ (19,153)	$ (17,118)	$ (26,777)	$ (30,370)	$ (38,992)	$ (46,819)	$ (37,371)
North Texas Other Nonprotected Plant Related	10,658	$ 10,658	$ 10,658	$ 10,658	$ 10,658	$ 10,658	$ 10,658	$ 10,658	$ 10,658
North Texas Other Rate Base Items	$ 16,396	$ 16,396	$ 16,396	$ 16,396	$ 16,396	$ 16,396	$ 16,396	$ 16,396	$ 16,396
TGS Division Plant Assets Depreciation	$ 3,494	$ 1,989	$ 3,203	$ (1,308)	$ 226	$ 6,343	$ 203	$ (105)	$ 153
ONEGas Plant Assets Depreciation	$ 9,301	$ 8,863	$ 6,149	$ 6,345	$ 6,277	$ 6,221	$ 7,849	$ 7,823	$ 7,823
North Texas NOL	$ (19,890)	$ (24,798)	$ (28,435)	$ (25,413)	$ (39,753)	$ (45,088)	$ (57,887)	$ (69,506)	$ (69,506)
Total ADIT - Accumulated Deferred Income Taxes	**259,708**	**256,031**	**242,397**	**244,859**	**229,804**	**238,552**	**229,442**	**224,779**	**216,474**

	Amortization Period		ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	Unprotected 10 Year	Protected (ARAM)	Protected	Unprotected	Total	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.72%	10.00%	11.21%	34,633	235,664	270,297	270,297
Year 2 - 2019 Actual	0.90%	10.00%	10.68%	39,607	232,358	271,965	271,965
Year 3 - 2020 Actual	1.04%	10.00%	7.41%	34,774	229,908	264,682	264,682
Year 4 - 2021 Est	0.93%	10.00%	7.65%	31,984	231,944	263,928	263,928
Year 5 - 2022 Est	1.45%	10.00%	7.57%	40,997	222,284	263,281	263,281
Year 6 - 2023 Est	1.64%	10.00%	7.50%	58,727	218,691	277,419	277,419
Year 7 - 2024 Est	2.11%	10.00%	9.46%	69,411	210,070	279,480	279,480
Year 8 - 2025 Est	2.53%	10.00%	9.43%	84,219	202,243	286,462	286,462
Year 9 - 2026 Est	2.02%	10.00%	9.35%	66,466	211,691	278,157	278,157

	Amortization Period		Amortization		Financial Impact	
NOL	Protected (ARAM)	Unprotected 10 Year	Protected	Unprotected	Total including Gross Up	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.72%	10.00%	(19,890)	-	(19,890)	(19,890)
Year 2 - 2019 Actual	0.90%	10.00%	(24,798)	-	(24,798)	(24,798)
Year 3 - 2020 Actual	1.04%	10.00%	(28,435)	-	(28,435)	(28,435)
Year 4 - 2021 Est	0.93%	10.00%	(25,413)	-	(25,413)	(25,413)
Year 5 - 2022 Est	1.45%	10.00%	(39,753)	-	(39,753)	(39,753)
Year 6 - 2023 Est	1.64%	10.00%	(45,088)	-	(45,088)	(45,088)
Year 7 - 2024 Est	2.11%	10.00%	(57,887)	-	(57,887)	(57,887)
Year 8 - 2025 Est	2.53%	10.00%	(69,506)	-	(69,506)	(69,506)
Year 9 - 2026 Est	2.02%	10.00%	(69,506)	-	(69,506)	(69,506)

	ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	Protected	Unprotected	Total including Gross Up	Regulatory Liability net refund
Year 1 - 2018 Actuals	11.21%	9,301	-	9,301	9,301
Year 2 - 2019 Actual	10.68%	8,863	-	8,863	8,863
Year 3 - 2020 Actual	7.41%	6,149	-	6,149	6,149
Year 4 - 2021 Est	7.65%	6,345	-	6,345	6,345
Year 5 - 2022 Est	7.57%	6,277	-	6,277	6,277
Year 6 - 2023 Est	7.50%	6,221	-	6,221	6,221
Year 7 - 2024 Est	9.46%	7,849	-	7,849	7,849
Year 8 - 2025 Est	9.43%	7,823	-	7,823	7,823
Year 9 - 2026 Est	9.35%	7,823	-	7,823	7,823

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2021
ARAM Estimate for amounts attributed to the West Texas Service Area

Accumulated Deferred Income Taxes for:	**Excess ADIT**	**Protected**	**Non-protected (ARAM)**	**Unprotected**	**TGS Amortization Amount**	**ONE Gas Amortization Amount**
	(a) = (b)+(c)+(d)	**(b)**	**(c)**	**(d)**	**(a1)**	**(a2)**
West Texas Direct Plant Assets Depreciation	(38,828,435)	$ (38,828,435)			$ (38,828,435)	
West Texas Repairs	(8,676,591)			(8,676,591)	$ (8,676,591)	
West Texas Cost of Removal Asset	12,447,499		12,447,499		$ 12,447,499	
West Texas Other Nonprotected plant	(1,641,568)			(1,641,568)	$ (1,641,568)	
West Texas Other Rate Base Items	(2,624,110)			(2,624,110)	(2,624,110)	
TGS Division Plant Assets Depreciation	(229,619)	(229,619)			(229,619)	
ONEGas Plant Assets Depreciation	(1,365,165)	(1,365,165)				(1,365,165)
West Texas NOL	24,056,073	$ 24,056,073		$ -	$ 24,056,073	
ADIT - Accumulated Deferred Income Taxes	**(16,861,916)**	**(16,367,146)**	**12,447,499**	**(12,942,269)**	**(15,496,751)**	**(1,365,165)**

Percent Protected	97%

WTX

	TGS Amortization	ONE Gas Amortization	TGS NOL	Total Amortization	EOY Regulatory Liability Balance
Year 1 - 2018 Actuals	$ 1,365,169	$ 153,053	$ (145,610)	$ 1,372,612	$ (15,489,304)
Year 2 - 2019 Actuals	$ 1,372,196	$ 145,859	$ (124,090)	$ 1,393,964	$ (14,095,340)
Year 3 - 2020 Actuals	$ 1,318,541	$ 106,210	$ (239,118)	$ 1,185,633	$ (12,909,707)
Year 4 - 2021 Est	$ 1,220,250	$ 144,298	$ (245,150)	$ 1,119,399	$ (11,790,309)
Year 5 - 2022 Est	$ 1,310,721	$ 166,414	$ (402,056)	$ 1,075,079	$ (10,715,230)
Year 6 - 2023 Est	$ 1,493,014	$ 108,667	$ (327,748)	$ 1,273,934	$ (9,441,296)
Year 7 - 2024 Est	$ 1,486,473	$ 135,288	$ (463,850)	$ 1,157,911	$ (8,283,385)
Year 8 - 2025 Est	$ 1,487,797	$ 134,469	$ (455,540)	$ 1,166,726	$ (7,116,660)
Year 9 - 2026 Est	$ 1,482,638	$ 134,469	$ (441,342)	$ 1,175,765	$ (5,940,895)

Accumulated Deferred Income Taxes for:	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization
West Texas Direct Plant Assets Depreciation	$ 185,484	$ 163,105	$ 191,965	$ 170,141	$ 316,864	$ 361,260	$ 524,959	$ 526,987	$ 510,303
West Texas Repairs	771,654	$ 771,654	$ 771,654	$ 771,654	$ 771,654	$ 771,654	$ 771,654	$ 771,654	$ 771,654
West Texas Cost of Removal Asset	(75,344)	$ (64,209)	$ (123,728)	$ (126,849)	$ (208,038)	$ (169,589)	$ (240,013)	$ (235,713)	$ (228,366)
West Texas Other Nonprotected plant	164,157	$ 164,157	$ 164,157	$ 164,157	$ 164,157	$ 164,157	$ 164,157	$ 164,157	$ 164,157
West Texas Other Rate Base Items	$ 262,411	$ 262,411	$ 262,411	$ 262,411	$ 262,411	$ 262,411	$ 262,411	$ 262,411	$ 262,411
TGS Division Plant Assets Depreciation	$ 56,808	$ 75,078	$ 52,083	$ (21,263)	$ 3,674	$ 103,122	$ 3,307	$ (1,699)	$ 2,480
ONEGas Plant Assets Depreciation	$ 153,053	$ 145,859	$ 106,210	$ 144,298	$ 166,414	$ 108,667	$ 135,288	$ 134,469	$ 134,469
West Texas NOL	$ (145,610)	$ (124,090)	$ (239,118)	$ (245,150)	$ (402,056)	$ (327,748)	$ (463,850)	$ (455,540)	$ (441,342)
ADIT - Accumulated Deferred Income Taxes	**1,372,612**	**1,393,964**	**1,185,633**	**1,119,399**	**1,075,079**	**1,273,934**	**1,157,911**	**1,166,726**	**1,175,765**

	Amortization Period		ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	Unprotected 10 Year	Protected (ARAM)	Protected	Unprotected	Total	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.61%	10.00%	11.21%	242,292	1,122,877	1,365,169	1,365,169
Year 2 - 2019 Actual	0.52%	10.00%	10.68%	238,183	1,134,012	1,372,196	1,372,196
Year 3 - 2020 Actual	0.99%	10.00%	7.78%	244,048	1,074,493	1,318,541	1,318,541
Year 4 - 2021 Est	1.02%	10.00%	10.57%	148,878	1,071,372	1,220,250	1,220,250
Year 5 - 2022 Est	1.67%	10.00%	12.19%	320,538	990,183	1,310,721	1,310,721
Year 6 - 2023 Est	1.36%	10.00%	7.96%	464,382	1,028,633	1,493,014	1,493,014
Year 7 - 2024 Est	1.93%	10.00%	9.91%	528,265	958,208	1,486,473	1,486,473
Year 8 - 2025 Est	1.89%	10.00%	9.85%	525,288	962,508	1,487,797	1,487,797
Year 9 - 2026 Est	1.83%	10.00%	9.70%	512,783	969,855	1,482,638	1,482,638

	Amortization Period		ONE Gas Amortization Period	Amortization		Financial Impact	
NOL	Protected (ARAM)	Unprotected 10 Year	Protected (ARAM)	Protected	Unprotected	Total including Gross Up	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.00%	10.00%	0.00%	(145,610)	-	(145,610)	(145,610)
Year 2 - 2019 Actual	0.00%	10.00%	0.00%	(124,090)	-	(124,090)	(124,090)
Year 3 - 2020 Actual	0.00%	10.00%	0.00%	(239,118)	-	(239,118)	(239,118)
Year 4 - 2021 Est	0.00%	10.00%	0.00%	(245,150)	-	(245,150)	(245,150)
Year 5 - 2022 Est	2.95%	10.00%	0.00%	(402,056)	-	(402,056)	(402,056)
Year 6 - 2023 Est	6.08%	10.00%	0.00%	(327,748)	-	(327,748)	(327,748)
Year 7 - 2024 Est	6.54%	10.00%	0.00%	(463,850)	-	(463,850)	(463,850)
Year 8 - 2025 Est	10.15%	10.00%	0.00%	(455,540)	-	(455,540)	(455,540)
Year 9 - 2026 Est	1.17%	10.00%	0.00%	(441,342)	-	(441,342)	(441,342)

	ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	Protected	Unprotected	Total including Gross Up	Regulatory Liability net refund
Year 1 - 2018 Actuals	11.21%	153,053	-	153,053	153,053
Year 2 - 2019 Actual	10.68%	145,859	-	145,859	145,859
Year 3 - 2020 Actual	7.78%	106,210	-	106,210	106,210
Year 4 - 2021 Est	10.57%	144,298	-	144,298	144,298
Year 5 - 2022 Est	12.19%	166,414	-	166,414	166,414
Year 6 - 2023 Est	7.96%	108,667	-	108,667	108,667
Year 7 - 2024 Est	9.91%	135,288	-	135,288	135,288
Year 8 - 2025 Est	9.85%	134,469	-	134,469	134,469
Year 9 - 2026 Est	9.70%	134,469	-	134,469	134,469

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
TWELVE MONTHS ENDED DECEMBER 31, 2021
ARAM Estimate for amounts attributed to the West-North Service Area

Accumulated Deferred Income Taxes for:	Excess ADIT	Protected	Non-protected (ARAM)	Unprotected	TGS Amortization Amount	ONE Gas Amortization Amount
	(a) = (b)+(c)+(d)	(b)	(c)	(d)	(a1)	(a2)
West-North Direct Plant Assets Depreciation	(45,513,830)	$ (45,513,830)	$ -	$ -	$ (45,513,830)	$ -
West-North Repairs	(11,337,295)	0	0	(11,337,295)	$ (11,337,295)	0
West-North Cost of Removal Asset	14,702,934	0	14,702,934	-	$ 14,702,934	0
West-North Other Nonprotected plant	(1,794,371)	0	0	(1,794,371)	$ (1,794,371)	0
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	27,410,692	$ 27,410,692	$ -	$ -	$ 27,410,692	$ -
ADIT - Accumulated Deferred Income Taxes	**(21,143,969)**	**(19,828,732)**	**14,702,934**	**(16,018,171)**	**(19,667,024)**	**(1,476,945)**

Percent Protected	94%

WNSA

	TGS Amortization	ONE Gas Amortization	TGS NOL	Total Amortization	EOY Regulatory Liability Balance
Year 1 - 2018 Actuals	$ 1,685,249	$ 165,585	$ (169,548)	$ 1,681,286	$ (19,462,683)
Year 2 - 2019 Actuals	$ 1,699,525	$ 157,800	$ (162,675)	$ 1,694,650	$ (17,768,033)
Year 3 - 2020 Actuals	$ 1,633,933	$ 114,496	$ (274,309)	$ 1,474,120	$ (16,293,913)
Year 4 - 2021 Est	$ 1,546,715	$ 152,847	$ (276,896)	$ 1,422,666	$ (14,871,247)
Year 5 - 2022 Est	$ 1,623,859	$ 174,871	$ (451,000)	$ 1,347,730	$ (13,523,517)
Year 6 - 2023 Est	$ 1,823,079	$ 117,049	$ (396,013)	$ 1,544,115	$ (11,979,402)
Year 7 - 2024 Est	$ 1,816,047	$ 145,864	$ (551,820)	$ 1,410,090	$ (10,569,312)
Year 8 - 2025 Est	$ 1,830,318	$ 145,019	$ (540,893)	$ 1,434,444	$ (9,134,867)
Year 9 - 2026 Est	$ 1,821,050	$ 145,019	$ (524,084)	$ 1,441,985	$ (7,692,883)

Accumulated Deferred Income Taxes for:	2018 Amortization	2019 Amortization	2020 Amortization	2021 Amortization	2022 Amortization	2023 Amortization	2024 Amortization	2025 Amortization	2026 Amortization
West-North Direct Plant Assets Depreciation	$ 221,438	$ 218,135	$ 231,184	$ 224,193	$ 367,087	$ 433,086	$ 617,792	$ 631,518	$ 599,189
West-North Repairs	1,034,894	$ 1,034,894	$ 1,034,894	$ 1,034,894	$ 1,034,894	$ 1,034,894	$ 1,034,894	$ 1,034,894	$ 1,034,894
West-North Cost of Removal Asset	(91,441)	$ (90,105)	$ (147,386)	$ (148,190)	$ (240,943)	$ (215,413)	$ (299,062)	$ (293,097)	$ (274,562)
West-North Other Nonprotected plant	170,192	$ 170,192	$ 170,192	$ 170,192	$ 170,192	$ 170,192	$ 170,192	$ 170,192	$ 170,192
West-North Other Rate Base Items	$ 288,650	$ 288,650	$ 288,650	$ 288,650	$ 288,650	$ 288,650	$ 288,650	$ 288,650	$ 288,650
TGS Division Plant Assets Depreciation	$ 61,516	$ 77,758	$ 56,399	$ (23,025)	$ 3,978	$ 111,668	$ 3,581	$ (1,840)	$ 2,685
ONEGas Plant Assets Depreciation	$ 165,585	$ 157,800	$ 114,496	$ 152,847	$ 174,871	$ 117,049	$ 145,864	$ 145,019	$ 145,019
West-North NOL	$ (169,548)	$ (162,675)	$ (274,309)	$ (276,896)	$ (451,000)	$ (396,013)	$ (551,820)	$ (540,893)	$ (524,084)
ADIT - Accumulated Deferred Income Taxes	**1,681,286**	**1,694,650**	**1,474,120**	**1,422,666**	**1,347,730**	**1,544,115**	**1,410,090**	**1,434,444**	**1,441,985**

	Amortization Period		ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	Unprotected 10 Year	Protected (ARAM)	Protected	Unprotected	Total	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.61%	10.00%	11.21%	282,954	1,402,296	1,685,249	1,685,249
Year 2 - 2019 Actual	0.52%	10.00%	10.68%	295,893	1,403,632	1,699,525	1,699,525
Year 3 - 2020 Actual	0.99%	10.00%	7.78%	287,583	1,346,350	1,633,933	1,633,933
Year 4 - 2021 Est	1.02%	10.00%	10.57%	201,168	1,345,547	1,546,715	1,546,715
Year 5 - 2022 Est	1.67%	10.00%	12.19%	371,065	1,252,794	1,623,859	1,623,859
Year 6 - 2023 Est	1.36%	10.00%	7.96%	544,755	1,278,324	1,823,079	1,823,079
Year 7 - 2024 Est	1.93%	10.00%	9.91%	621,372	1,194,675	1,816,047	1,816,047
Year 8 - 2025 Est	1.89%	10.00%	9.85%	629,678	1,200,640	1,830,318	1,830,318
Year 9 - 2026 Est	1.83%	10.00%	9.70%	601,875	1,219,175	1,821,050	1,821,050

	Amortization Period		ONE Gas Amortization Period	Amortization		Financial Impact	
NOL	Protected (ARAM)	Unprotected 10 Year	Protected (ARAM)	Protected	Unprotected	Total including Gross Up	Regulatory Liability net refund
Year 1 - 2018 Actuals	0.00%	10.00%	0.00%	(169,548)	-	(169,548)	(169,548)
Year 2 - 2019 Actual	0.00%	10.00%	0.00%	(162,675)	-	(162,675)	(162,675)
Year 3 - 2020 Actual	0.00%	10.00%	0.00%	(274,309)	-	(274,309)	(274,309)
Year 4 - 2021 Est	0.00%	10.00%	0.00%	(276,896)	-	(276,896)	(276,896)
Year 5 - 2022 Est	2.95%	10.00%	0.00%	(451,000)	-	(451,000)	(451,000)
Year 6 - 2023 Est	6.08%	10.00%	0.00%	(396,013)	-	(396,013)	(396,013)
Year 7 - 2024 Est	6.54%	10.00%	0.00%	(551,820)	-	(551,820)	(551,820)
Year 8 - 2025 Est	10.15%	10.00%	0.00%	(540,893)	-	(540,893)	(540,893)
Year 9 - 2026 Est	1.17%	10.00%	0.00%	(524,084)	-	(524,084)	(524,084)

	ONE Gas Amortization Period	Amortization		Financial Impact	
	Protected (ARAM)	Protected	Unprotected	Total including Gross Up	Regulatory Liability net refund
Year 1 - 2018 Actuals	11.21%	165,585	-	165,585	165,585
Year 2 - 2019 Actual	10.68%	157,800	-	157,800	157,800
Year 3 - 2020 Actual	7.78%	114,496	-	114,496	114,496
Year 4 - 2021 Est	10.57%	152,847	-	152,847	152,847
Year 5 - 2022 Est	12.19%	174,871	-	174,871	174,871
Year 6 - 2023 Est	7.96%	117,049	-	117,049	117,049
Year 7 - 2024 Est	9.91%	145,864	-	145,864	145,864
Year 8 - 2025 Est	9.85%	145,019	-	145,019	145,019
Year 9 - 2026 Est	9.70%	145,019	-	145,019	145,019

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE
TWELVE MONTHS ENDED DECEMBER 31, 2021
2021 EDIT Amortization attributed to the West-North Service Area

	January	February	March	April	May	June	July	August	September	October	November	December	Total
BSSA	(12,020)	(9,491)	(4,749)	(3,732)	(2,348)	(1,180)	(2,693)	(2,342)	(1,419)	(3,960)	(7,476)	(6,997)	(58,408)
NTX	(50,392)	(39,790)	(19,907)	(15,647)	(9,843)	(4,946)	(11,288)	(9,819)	(5,950)	(16,601)	(31,342)	(29,334)	(244,859)
WTSA	(230,372)	(181,902)	(91,007)	(71,530)	(45,000)	(22,612)	(51,604)	(44,888)	(27,201)	(75,895)	(143,283)	(134,104)	(1,119,399)
WNSA	(292,785)	(231,183)	(115,663)	(90,908)	(57,191)	(28,738)	(65,585)	(57,049)	(34,571)	(96,457)	(182,101)	(170,435)	(1,422,666)

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, Chief Accounting Officer and Controller 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 16th day of June 2022.

M. FREEMAN NOTARY #21014828 EXP. 11/12/25 PUBLIC STATE OF OKLAHOMA

M Freeman
Notary Public in and for the State of Oklahoma

CASE NO. 00009896

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	§ § § § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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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 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. PLEASE DESCRIBE YOUR CURRENT POSITION.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. In 2013, I joined Sussex Economic Advisors, LLC ("Sussex"). Sussex was acquired by ScottMadden in 2016.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL EXPERIENCE.

A. I hold a Bachelor's degree from St. Anselm College, a Master's degree in Economics from The Pennsylvania State University, and a Master's degree in Business Administration from Babson College.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE RAILROAD COMMISSION OF TEXAS ("COMMISSION")?

A. Yes. I previously sponsored testimony before this Commission as well as 21 other state regulatory commissions. Exhibit TSL-1 contains a list of regulatory proceedings in which I have sponsored testimony.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREPARED EXHIBITS SUPPORTING YOUR TESTIMONY?

A. Yes. My testimony is supported by the exhibits in the List of Exhibits. The exhibits were prepared by me or under my direction.

II. <u>PURPOSE AND OVERVIEW OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I was retained by Texas Gas Service ("TGS" or the "Company") to develop a lead-lag study that determines the cash working capital ("CWC") requirement for the Company's proposed West North Texas Service Area ("WNSA"), which is a combination of the existing Borger Skellytown Service Area ("BSSA"), North Texas Service Area ("NTSA") and West Texas Service Area ("WTSA"). In addition to the schedules that reflect the Company's requested consolidation of the proposed WNSA, the Company is also providing stand-alone schedules for the BSSA, NTSA and WTSA should the Company's request for consolidation not be approved. The lead-lag study summary and supporting calculations for the proposed WNSA are included, respectively, in Exhibits TSL-2 and TSL-3.

Q. PLEASE DEFINE THE TERM "CASH WORKING CAPITAL."

A. The term "cash working capital" 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 RATE PROCEEDING CONSISTENT WITH THE COMMISSION'S 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 Gas Utilities Docket ("GUD") No. 10506,[1] except as noted below.

Q. ARE THE RESULTS OF THE LEAD-LAG STUDY IN THIS PROCEEDING AN ACCURATE ASSESSMENT OF THE COMPANY'S CWC REQUIREMENT?

A. Yes, this lead-lag study is based on the Company's current billing, collection, and payment practices, and thus provides an accurate assessment of the Company's CWC requirements.

III. LEAD-LAG STUDY APPROACH

Q. WHAT ARE THE RESULTS OF THE LEAD-LAG STUDY CONDUCTED FOR TGS?

A. The Company's lead-lag study is summarized in Exhibit TSL-2 and shows a CWC requirement of negative $3.5 million for the test year January 1, 2021 through December 31, 2021.

[1] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA),* GUD No. 10506, consol., Final Order at Finding of Fact ("FoF") 58 (Sept. 27, 2016).

Q. WAS THE LEAD-LAG STUDY BASED ON ONE OR MORE OF THE COMPANY'S SERVICE AREAS?

A. Yes, the lead-lag study was based on data for all of TGS's service areas in Texas, including the proposed WNSA. The data includes customer billing and revenue data to determine the revenue lag, and payment and financial data to determine the expense leads - as well as various other supporting documents.

The approach of developing a lead-lag study to be applicable to all of TGS's service areas in Texas is consistent with the intent of the Commission's Final Order in GUD No. 10285, which states, "TGS shall include a lead-lag study to establish cash working capital with its next filed Statement of Intent proceeding involving one or more of its El Paso, Rio Grande Valley or Austin Service Areas. The resulting lead-lag study shall be designed to be applicable to all TGS Service Areas." [2]

Q. DOES THE COMPANY INTEND TO USE THIS LEAD-LAG STUDY IN FUTURE RATE CASE PROCEEDINGS FOR THE COMPANY'S OTHER SERVICE AREAS IN TEXAS?

A. Yes, the Company intends to use this lead-lag study in future rate case proceedings for the Company's other service areas in Texas in determining the CWC requirement. This approach is consistent with the Company's approach in the most recent rate case proceedings for: Gulf Coast Service Area (GUD No. 10488);[3]

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[2] *Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10285, Final Order at FoF 28 (Nov. 26, 2013).
[3] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order (May 3, 2016).

West Texas Service Area (GUD No. 10506);[4] Central Texas Service Area (GUD No. 10526);[5] Rio Grande Valley Service Area (GUD No. 10656);[6] North Texas Service Area (GUD No. 10739);[7] Borger-Skellytown Service Area (GUD No. 10766);[8] and Central Texas Service Area and Gulf Coast Service Area (GUD No. 10928).[9]

Q. WHY DOES THE COMPANY INTEND TO USE THIS LEAD-LAG STUDY IN FUTURE RATE CASE PROCEEDINGS FOR THE COMPANY'S OTHER SERVICE AREAS IN TEXAS?

A. The Company intends to use this lead-lag study in future rate proceedings for four reasons: (1) the Company was previously directed by the Commission to develop a lead-lag study designed to be applicable to all TGS service areas in Texas; (2) the study is based on data for all of TGS's service areas in Texas; (3) the study is an accurate representation of the Company's CWC requirement over the next several years, provided there are no significant changes in the Company's billing, collection, and/or payment procedures that have a significant impact on the overall

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[4] GUD No. 10506, Final Order.

[5] *Statement of Intent of Texas Gas Service Company (TGS), Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016).

[6] *Statement of Intent of Texas Gas Service Company, Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018).

[7] *Statement of Intent of Texas Gas Service Company, Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area*, GUD No. 10739, Final Order (Nov. 13, 2018).

[8] *Statement of Intent of Texas Gas Service Company, Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of Borger-Skellytown Service Area*, GUD No. 10766, Final Order (Feb. 5, 2019).

[9] *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and the Gulf Coast Service Area*, GUD No. 10928 consol., Final Order (Aug. 4, 2020).

results; and (4) the study helps to minimize rate case expenses by developing a single lead-lag study for application to all of the Texas service areas rate case proceedings.

Q. WHAT WAS THE APPROACH USED TO DEVELOP THE LEAD-LAG STUDY?

A. The lead-lag study consists of two elements: revenue lag and expense leads. The revenue lag measures from the time service is provided to customers until the time customer payments are received by the Company. Expense leads measure from the time the Company receives goods and services used to provide service to the time the Company pays for those goods and services. The expense leads are measured in days, converted to dollar-days, and summarized for each cost element in the lead-lag study. The difference between the revenue lag and expense lead determines if there is a net revenue lag (revenue lag days are more than the expense lead days) or a net expense lead (revenue lag days are less than the expense lead days) for each cost element in the lead-lag study. The net lead-lag days are applied to adjusted test year expenses since they reflect the Company's ongoing expenses and thus best represent the Company's ongoing CWC requirements.

Q. WHAT WAS THE DATA USED TO DEVELOP THE LEAD-LAG STUDY?

A. The lead-lag study was based on the Company's customer and financial data from January 1, 2021 through December 31, 2021. The data included customer billing and collection data, and payment and expense financial data.

A. Revenue Lag

Q. WHAT ARE THE COMPONENTS OF THE REVENUE LAG?

A. Revenue lag measures the number of days from the time service is provided to customers to the time payment is received from customers. The revenue lag consists of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Q. WHAT IS THE SERVICE LAG?

A. The service lag measures the average number of days in the service period; i.e., the number of days from the start of the billing month to the end of the billing month. Meters are read at the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that natural gas is delivered evenly over the service period.

Q. WHAT IS THE BILLING LAG?

A. The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers. The billing lag includes time for review and validation of billed usage and dollars.

Q. HOW WAS THE BILLING LAG MEASURED?

A. The billing lag was based on a random sample of customer bills for each of the six customer classifications (residential, commercial, industrial, public authority, transportation, and irrigation), as shown on Exhibit TSL-3.

Q. WHAT IS THE COLLECTION LAG?

A. The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received.

Q. HOW WAS THE COLLECTION LAG MEASURED?

A. The collection lag was based on the same sample of customer bills used to determine the billing lag.

Q. HOW WAS THE REVENUE LAG DETERMINED?

A. The revenue lag is 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 THE DEVELOPMENT OF O&M EXPENSE LEADS.

A. O&M expense leads were measured separately for the following groups: (1) purchased gas expenses; (2) regular payroll expenses; (3) short-term incentive compensation expenses; and (4) third-party O&M expenses.

Q. HOW WERE LEAD DAYS FOR PURCHASED GAS EXPENSES DETERMINED?

A. Lead days for purchased gas expenses were based on the number of days from the midpoint of the service period (i.e., when gas was received and delivered to customers) to the payment date. The payment date occurs in the month after the gas was received and delivered to customers.

Q. HOW WERE LEAD DAYS FOR REGULAR PAYROLL EXPENSES DETERMINED?

A. Lead days for regular payroll expenses were based on the Company's salary and wages payment process, which pays employees on a bi-weekly or semi-monthly basis. Lead days for regular payroll expenses were based on the number of days from the midpoint of the pay period to the payment date.

Q. DID THE STUDY ADJUST FOR VACATION PAY?

A. Yes. The lead-lag study adjusts for vacation pay, reflecting that vacation pay is generally earned before it is taken. The adjustment is based on the regular payroll lead days and the midpoint of the year.

Q. HOW WERE LEAD DAYS FOR THE ANNUAL PERFORMANCE BONUS DETERMINED?

A. Lead days for the Company's annual performance bonus were based on the number of days from the midpoint of the performance period (i.e., twelve-months ending December 2020) to the payment date. The annual performance bonus is paid annually in March for the performance period that reflects the preceding calendar year.

Q. HOW WERE LEAD DAYS FOR THIRD-PARTY O&M EXPENSES DETERMINED?

A. Lead days for third-party O&M expenses were based on a random sample of invoices paid during the test year. The sample was used to determine the number of days from the time services were provided to the payment date.

Lead days from the service period to the invoice date were based on a stratified sample of invoices paid by the Company over the period January 1, 2021 through December 31, 2021. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The study relies on a sample of invoices to measure the lead days because the service periods were not readily available electronically and required detailed inspection of individual invoices.

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company over the period January 1, 2021 through December 31, 2021. Lead days were measured for each invoice as the number of days from the invoice date to the payment date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The approach is a change from the approach used in the Company's most recent lead-lag study in GUD No. 10928.[10] The prior approach relied on the sample of invoices to calculate the lead days from invoice date to payment date while the current approach relies on the 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,

[10] GUD No. 10928, Final Order.

and December 15. If the scheduled payment date falls on a Saturday, Sunday, or legal holiday, the payment is due on the next regular business day.

3. Taxes Other than Income Taxes

Q. WHAT TAXES ARE INCLUDED IN THE TAXES OTHER THAN INCOME TAXES?

A. Taxes other than income taxes consists of: (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, and return (including return on equity and interest on long-term debt).

IV. CONCLUSION

Q. WHAT WERE THE RESULTS OF THE LEAD-LAG STUDY?

A. The Company's lead-lag study is summarized in Exhibit TSL-2 and shows a CWC requirement of negative $3.5 million for the test year January 1, 2021 through December 31, 2021.

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.

scottmadden
MANAGEMENT CONSULTANTS

Summary

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 22 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. 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

- “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).

scottmadden
MANAGEMENT CONSULTANTS

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	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			
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)	5/21	Docket No. A 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	Docket No. A.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.
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.
Illinois Commerce Commission			
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.
Maine Public Utilities Commission			
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.

Sponsor	Date	Docket No.	Subject
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			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
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.
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			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's 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 cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.

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Sponsor	Date	Docket No.	Subject
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the 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 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 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 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 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	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

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Sponsor	Date	Docket No.	Subject
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.
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the 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.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas

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Sponsor	Date	Docket No.	Subject
			adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
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	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.

Sponsor	Date	Docket No.	Subject
Virginia State Corporation Commission			
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.

Texas Gas Service, A Division of One Gas, Inc.
West-North Service Area
Summary of Lead-Lag Study
Cash Working Capital Requirement

Line	Description	Test Year Amount	Average Daily Amount	Revenue Lag	Ref. (*)	Expense Lag	Ref. (*)	Net (Lead)/Lag Days	Working Capital Requirement
1	Operations and Maintenance Expenses								
2	Purchased Gas Costs	$ 82,080,953	$ 224,879	45.47	A	(40.63)	B	4.84	$ 1,089,068
3	Labor - Regular Payroll Expense	21,878,096	59,940	45.47	A	(27.70)	C	17.78	1,065,451
4	Labor - Annual Performance Bonus Expense	4,838,841	13,257	45.47	A	(242.92)	C	(197.44)	(2,617,544)
5	Non-Labor - Other O&M Expense	23,520,358	64,439	45.47	A	(39.20)	C	6.28	404,370
6	Total O&M Expenses	$ 132,318,249	$ 362,516						$ (58,655)
7	Federal Income Taxes								
8	Current Income Taxes	$ 9,629,801	$ 26,383	45.47	A	(37.00)	D	8.47	$ 223,517
9	Deferred Income Taxes		-	0.00		0.00		0.00	-
10	Total Federal Income Taxes	$ 9,629,801	$ 26,383						$ 223,517
11	Taxes Other Than Income Taxes								
12	FICA	$ 1,591,995	$ 4,362	45.47	A	(12.61)	E	32.87	$ 143,350
13	Federal Unemployment	13,283	36	45.47	A	(30.01)	E	15.46	563
14	State Unemployment	49,874	137	45.47	A	(113.17)	E	(67.70)	(9,250)
15	State Gross Receipts	3,406,328	9,332	45.47	A	(77.00)	E	(31.53)	(294,265)
16	Local Franchise Tax	8,377,329	22,952	45.47	A	(93.29)	E	(47.82)	(1,097,545)
17	State Franchise Tax	1,745,805	4,783	45.47	A	47.71	E	93.18	445,684
18	Ad Valorem	7,183,100	19,680	45.47	A	(196.17)	E	(150.70)	(2,965,686)
19	Sales Tax	3,060,478	8,385	45.47	A	(35.88)	E	9.59	80,434
20	RRC Gas Utility Tax	18,022	49	45.47	A	(86.81)	E	(41.34)	(2,041)
21	Taxes Other Than Income Taxes	$ 25,446,214	$ 69,716						$ (3,698,756)
22	Interest on Customer Deposits	$ 4,703	$ 13	45.47	A	(168.77)	F	(123.30)	$ (1,589)
23	Depreciation Expense	$ 24,213,706	$ 66,339	0.00		0.00		0.00	$ -
24	Return	$ 45,791,339	$ 125,456	0.00		0.00		0.00	$ -
25	Total	$ 237,404,013	$ 650,422						$ (3,535,483)

(*) 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

		Service Lag	Billing Lag	Collection Lag				
Line	Description	Service Period	Meter Read to Mail	Mail to Clear	Total Revenue Lag	Reference	Revenue	Dollar Days
1	Residential	15.21	6.25	26.55	48.01	WP A-1	$ 301,450,044	$ 14,472,448,316
2	Commercial	15.21	5.80	17.06	38.07	WP A-2	91,471,811	3,482,134,928
3	Industrial	15.21	6.00	18.88	40.09	WP A-3	2,851,444	114,317,331
4	Public Authority	15.21	6.93	21.47	43.61	WP A-4	19,754,626	861,431,056
5	Transportation	15.21	10.06	18.75	44.02	WP A-5	15,911,445	700,487,356
6	Irrigation	15.21	5.78	18.78	39.76	WP A-6	2,170,342	86,298,593
7	Composite Revenue Collection Days	15.21	6.32	23.94	45.47		$ 433,609,712	$ 19,717,117,581

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Purchased Gas

Line	Month	From	To	Expense	Total Days	Midpoint	Days Paid from End-of-Month	(Lead)/Lag Days	Dollar Days	Composite (Lead)/Lag Days
1	January-2021	01/01/21	01/31/21	$ 21,833,528	31.00	(15.50)	(25.55)	(41.05)	$ (896,192,218)	
2	February-2021	02/01/21	02/28/21	21,755,449	28.00	(14.00)	(25.15)	(39.15)	(851,768,097)	
3	March-2021	03/01/21	03/31/21	12,872,918	31.00	(15.50)	(25.66)	(41.16)	(529,876,292)	
4	April-2021	04/01/21	04/30/21	10,057,845	30.00	(15.00)	(24.91)	(39.91)	(401,448,820)	
5	May-2021	05/01/21	05/31/21	11,032,898	31.00	(15.50)	(24.61)	(40.11)	(442,538,966)	
6	June-2021	06/01/21	06/30/21	9,454,273	30.00	(15.00)	(25.76)	(40.76)	(385,331,884)	
7	July-2021	07/01/21	07/31/21	11,216,497	31.00	(15.50)	(24.79)	(40.29)	(451,888,156)	
8	August-2021	08/01/21	08/31/21	11,791,698	31.00	(15.50)	(24.10)	(39.60)	(466,924,747)	
9	September-2021	09/01/21	09/30/21	13,824,591	30.00	(15.00)	(22.70)	(37.70)	(521,129,751)	
10	October-2021	10/01/21	10/31/21	17,236,961	31.00	(15.50)	(27.17)	(42.67)	(735,451,851)	
11	November-2021	11/01/21	11/30/21	20,973,830	30.00	(15.00)	(27.53)	(42.53)	(892,035,434)	
12	December-2021	12/01/21	12/31/21	29,037,542	31.00	(15.50)	(25.45)	(40.95)	(1,189,155,086)	
13			Total	$ 191,088,028					$ (7,763,741,302)	(40.63)

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
O&M Expenses

Line	Description	(Lead)/Lag Days	Reference
1	Regular Payroll Expenses	(27.70)	WP C-1
2	Annual Performance Bonus Expense	(242.92)	WP C-1
3	Labor-Related - Subtotal		
4	Other O&M Expenses	(39.20)	WP C-5

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Federal Income Tax

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
1	First Quarter	1/1/2021	12/31/2021	(182.50)	4/15/2021	25.00%	260.00	19.38
2	Second Quarter	1/1/2021	12/31/2021	(182.50)	6/15/2021	25.00%	199.00	4.13
3	Third Quarter	1/1/2021	12/31/2021	(182.50)	9/15/2021	25.00%	107.00	(18.88)
4	Fourth Quarter	1/1/2021	12/31/2021	(182.50)	12/15/2021	25.00%	16.00	(41.63)
5	Federal Income Tax (Lead)/Lag Days							(37.00)

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Taxes Other Than Income Tax

Line	Description	(Lead)/Lag Days	Reference
1	FICA	(12.61)	WP E-1
2	Federal Unemployment	(30.01)	WP E-2
3	State Unemployment	(113.17)	WP E-3
4	State Gross Receipts	(77.00)	WP E-4
5	Local Franchise Tax	(93.29)	WP E-5
6	State Franchise Tax	47.71	WP E-6
7	Ad Valorem	(196.17)	WP E-7
8	Sales Tax	(35.88)	WP E-8
9	RRC Gas Utility Tax	(86.81)	WP E-9

Texas Gas Service, A Division of One Gas, Inc.
Summary of Lead-Lag Study
Interest on Customer Deposits

Line	Description	Test Year Interest Expense	Average Monthly Interest	Accrued Interest Balance	Composite (Lead)/Lag Days
1	12/1/2020			$ 53,906	
2	1/1/2021		$ 9,132	63,038	
3	2/1/2021		9,132	72,169	
4	3/1/2021		8,248	80,417	
5	4/1/2021		9,132	89,549	
6	5/1/2021		8,837	98,386	
7	6/1/2021		9,132	-	
8	7/1/2021		8,837	8,837	
9	8/1/2021		9,132	17,969	
10	9/1/2021		9,132	27,100	
11	10/1/2021		8,837	35,937	
12	11/1/2021		9,132	45,069	
13	12/1/2021		8,837	53,906	
14	Average			$ 49,714	
15	Interest Expense	$ 107,518			
16	Daily Interest Expense	$ 295			
17	Composite (Lead)/Lag Days				(168.77)

STATE OF VERMONT §
§
COUNTY OF CHITTENDEN §

AFFIDAVIT OF TIMOTHY S. LYONS

BEFORE ME, the undersigned authority, on this day personally appeared Timothy S. Lyons who having been placed under oath by me did depose as follows:

1. "My name is Timothy S. Lyons. I am over the age of eighteen (18) and fully competent to make this affidavit. I am a Partner with ScottMadden, Inc. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Timothy S. Lyons

Timothy S. Lyons

SUBSCRIBED AND SWORN TO BEFORE ME by the said Timothy S. Lyons on this 17th day of June 2022.

QUILLYN PETERSON
Notary Public, State of Vermont
Commission No. 157.0014160
My Commission Expires 01/31/2023

Notary Public in and for the State of ~~Oklahoma~~ Vermont

CASE NO. 00009896

STATEMENT OF INTENT OF TEXAS	**§**	
GAS SERVICE COMPANY, A	**§**	
DIVISION OF ONE GAS, INC., TO	**§**	**BEFORE THE**
CHANGE GAS UTILITY RATES	**§**	
WITHIN THE UNINCORPORATED	**§**	**RAILROAD COMMISSION**
AREAS OF THE WEST TEXAS	**§**	
SERVICE AREA, THE NORTH TEXAS	**§**	**OF TEXAS**
SERVICE AREA, AND THE BORGER	**§**	
SKELLYTOWN SERVICE AREA	**§**	

DIRECT TESTIMONY

OF

JANET M. SIMPSON

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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EXHIBIT JMS-3	West Texas Service Area (WTSA) ADIT Calculation
EXHIBIT JMS-4	North Texas Service Area (NTSA) ADIT Calculation
EXHIBIT JMS-5	Borger Skellytown Service Area (BSSA) ADIT Calculation
EXHIBIT JMS-6	City of El Paso Ordinance 15316

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 13215 Bee Cave Pkwy., Galleria Oaks Building B, Suite B-250, Bee Cave, TX 78738.

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 and a Certified Forensic 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 rates in the Company's newly proposed West North Service Area ("WNSA"). The WNSA combines the Company's existing West Texas Service Area ("WTSA"), North Texas Service Area ("NTSA") and Borger Skellytown Service Area ("BSSA"). Total WNSA ADIT is negative $50,432,866.[1] This ADIT balance is reflected as a reduction to rate base on the WNSA Rate Case Schedules, Schedule B, line 8 and is itemized on Schedule B-9. On a stand-alone basis, the WTSA ADIT is negative $38,896,854,

[1] Due to rounding, Schedule B shows $(50,432,867).

the NTSA ADIT is negative $9,958,249[2] and the BSSA ADIT is negative $1,577,763. ADIT is also reflected on Schedule B, line 14 and itemized on Schedule B-9 of the WTSA, NTSA, and BSSA Rate Case Schedules.

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

[2] Due to rounding, Schedule B shows as $(9,958,249).

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 WNSA ADIT BALANCE

Q. WHAT ARE THE COMPONENTS OF THE WNSA ADIT AMOUNT OF ($(50,432,866) REFERENCED PREVIOUSLY?

A. The WNSA ADIT balance consists of the following five major components:

WNSA Direct Plant-Related	$(82,382,966)
WNSA Other Direct Rate Base Items	(4,965,068)
TGS Division Plant-Related	(704,098)
ONE Gas Plant-Related	(2,462,154)
WNSA NOL	40,081,420
Total WNSA ADIT	**$(50,432,866)**

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 WNSA DIRECT PLANT ASSETS.

A. The first component of total WNSA ADIT is ADIT associated with the plant-related timing differences for plant that is physically located in the WNSA (i.e., "direct plant"). I computed ADIT applicable to the WNSA plant items as of December 31, 2021 by comparing per Book net plant for those locations as of December 31, 2021 to per Tax net plant for those locations as of December 31, 2021. 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 WNSA to comply with the requirements of City of El Paso Ordinance 15316, a copy of which is provided as Exhibit JMS-6. 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 WTSA rate case (Gas Utilities Docket ("GUD") No. 10506).

The total difference between the adjusted net book and net tax plant amounts, multiplied by the current income tax rate of 21%, represents the WNSA direct plant-related ADIT as of December 31, 2021. Total WNSA plant-related ADIT as of December 31, 2021 equals $(82,382,966).[3]

Q. PLEASE EXPLAIN THE SECOND COMPONENT OF WNSA 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

[3] Due to rounding, Schedule B shows $(82,382,967).

- 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 WNSA Other Direct Rate Base-related ADIT as of December 31, 2021, which is equal to $(4,965,068).

Q. PLEASE DESCRIBE THE NEXT TWO COMPONENTS OF THE ADIT CALCULATION.

A. The next two components of the WNSA ADIT calculation are for (1) ADIT related to an allocated portion of TGS Division plant, and (2) an allocated portion of ONE Gas corporate plant as of test-year end. These amounts were computed by comparing net book plant and net tax plant balances for TGS Division and ONE Gas corporate plant as of December 31, 2021. The ONE Gas temporary differences were multiplied by the allocation factors that have been applied to the related plant amounts by Company witness Stacey Borgstadt to determine the portion of those differences applicable to TGS. Both the TGS Division plant temporary differences and the TGS portion of allocated corporate plant temporary differences were multiplied by the federal tax rate of 21%, and then allocated to the WNSA. To allocate the appropriate portions to the WNSA, both the TGS Division and the allocated ONE Gas corporate ADIT amounts were multiplied by the WNSA test-year-end customer allocation factor, consistent with the methodology used by Ms. Borgstadt to allocate shared service and corporate expenses and plant and accumulated depreciation balances. The result is $(704,098) of TGS Division plant

ADIT and $(2,462,154) of ONE Gas corporate plant ADIT applicable to the WNSA.

Q. WHAT IS THE FINAL COMPONENT OF WNSA ADIT?

A. The final component is ADIT relating to the WNSA's portion of the TGS NOL.

Q. WHY IS THE TAX NOL ADIT INCLUDED IN THE ADIT CALCULATION?

A. As explained previously, a reduction to rate base for ADIT is only necessary or appropriate to the extent it represents cost-free capital. As of December 31, 2021, the Company had a cumulative Tax NOL and, as a result, has been unable to take full advantage of the temporary differences that gave rise to the entire ADIT credit balance discussed above. To the extent the Company does not have sufficient taxable income for tax purposes to realize the full benefit of the cost-free capital arising from the temporary differences between financial statement and tax return income, no reduction to rate base is warranted. As a result, when computing ADIT for rate base, the ADIT balance must be reduced to remove the portion of that balance that has yet to provide actual cost-free capital to the Company. Reduction of the ADIT credit balance has the effect of increasing rate base.

Q. WHAT IS THE TOTAL ESTIMATED TGS NOL ADIT APPLICABLE TO THE WNSA AS OF DECEMBER 31, 2021, AND HOW IS IT COMPUTED?

A. The total estimated NOL ADIT applicable to the WNSA on a stand-alone basis as of December 31, 2021 is $40,081,420. The calculation of this amount starts with cumulative 2003 through December 31, 2021 total TGS taxable income per Book of $694,905,290. Using the cost center component of the Company's account structure, I segregated and grouped this amount into each of the Company's direct jurisdictional cost center groups, each allocable regional cost center group, and the TGS allocable division office cost center group. The TGS allocable division office cost center group includes the TGS portion of allocated corporate costs. I then made several ratemaking adjustments and tax adjustments to determine the WNSA NOL. First, an adjustment was made to align the purchased gas cost expense reflected in the proposed WNSA and other TGS jurisdiction cost centers to equal the jurisdictional purchased gas revenue. Next, I removed amounts that are not applicable for ratemaking purposes such as legislative, charitable, merchandising, and other non-utility expenses and revenues as well as unbilled revenue transactions that are not included in the development of the revenue requirement. Then, various adjustments were made to compute taxable income appropriate for use in calculating the regulatory tax NOL amount. First, to calculate the per Tax deduction applicable for meals, I removed from per Book expense 50% of the cumulative meals cost, consistent with the IRS treatment of that item as a permanent difference 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. The final step was to apply the WNSA customer-based allocation factors to the resulting allocable TGS division net loss and the allocable regional net loss amounts as shown on Exhibit JMS-2. The allocated amounts applicable to the WNSA were then added to the WNSA direct net loss amounts to determine the total WNSA tax NOL.

Q. WHAT IS THE RESULTING WNSA NOL ADIT AMOUNT?

A. The result is a cumulative WNSA Tax NOL of $190,863,907 as of December 31, 2021. Multiplying this amount by the income tax rate of 21% yields the WNSA NOL ADIT of $40,081,420, which is the final component of the WNSA 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 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.[4] In addition, inclusion of ADIT on the NOL in this case is consistent with the Company's methodology on this issue in GUD Nos. 10488, 10506, 10526, 10656, 10739, 10766, and 10928. GUD Nos. 10488, 10526, 10656, 10739, 10766, and 10928 were resolved through unanimous settlement agreements the Commission approved on May 3, 2017, November 15, 2017, March 20, 2018, November 13, 2018, February 5, 2019, and August 4, 2020, respectively.[5] GUD No. 10506 was a litigated case in which the Commission approved the Company's request to include ADIT on the NOL. The Final Order in GUD No. 10506 was issued on September 27, 2017.[6]

[4] *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 and consol. dockets, Proposal for Decision at 92 (Nov. 13, 2012).
[5] 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 Central Texas Service Area and Gulf Coast Service Area,* GUD No. 10928 consol., the parties agreed to settle all issues except for consolidation, which was litigated and the Commission approved.
[6] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA)*, GUD No. 10506, Final Order and Attached Schedules – Decision Summary with Schedules, Schedule B-9 (page 33 of 267) corresponds to Schedule B-9 in the Company's GUD No. 10506 initial filing as well as the table in the GUD No. 10506 Direct Testimony of Janet Simpson, page 9.

IV. CALCULATION OF WTSA, NTSA, AND BSSA ADIT

Q. DID YOU FOLLOW THE SAME APPROACH WHEN SEPARATELY CALCULATING THE ADIT AMOUNTS FOR THE WTSA, NTSA AND BSSA?

A. Yes, the same methodology was used for the WTSA, NTSA and BSSA calculations as was used for the combined WNSA calculation except that direct service area amounts specifically applicable to the WTSA, NTSA and BSSA were used rather than total WNSA amounts, and the WTSA, NTSA and BSSA allocation factors applicable to TGS Division and ONE Gas plant as well as to TGS shared services were used.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS PERTAINING TO THE WTSA ADIT.

A. The amount of ADIT applicable to the WTSA that should be deducted from rate base if it is necessary to develop a WTSA stand-alone revenue requirement is $(38,896,854) and consists of the following components:

WTSA Direct Plant-Related	$(69,181,517)
WTSA Other Direct Rate Base Items	(4,543,921)
TGS Division Plant-Related	(653,487)
ONEGAS Plant-Related	(2,285,173)
WTSA NOL	37,767,244
Total WTSA ADIT	**$(38,896,854)**

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS PERTAINING TO THE NTSA ADIT.

A. The amount of ADIT applicable to the NTSA that should be deducted from rate base if it is necessary to develop a NTSA stand-alone revenue requirement is $(9,958,249) and consists of the following components:

NTSA Direct Plant-Related	$(11,413,209)
NTSA Other Direct Rate Base Items	(321,511)
TGS Division Plant-Related	(37,690)
ONEGAS Plant-Related	(131,798)
NTSA NOL	1,945,959
Total NTSA ADIT	**$(9,958,249)**

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS PERTAINING TO THE BSSA ADIT.

A. The amount of ADIT applicable to the BSSA that should be deducted from rate base if it is necessary to develop a BSSA stand-alone revenue requirement is $(1,577,763) and consists of the following components:

BSSA Direct Plant-Related	$(1,788,240)
BSSA Other Direct Rate Base Items	(99,636)
TGS Division Plant-Related	(12,921)
ONEGAS Plant-Related	(45,183)
BSSA NOL	368,217
Total BSSA ADIT	$(1,577,763)

Q. DOES THE SUM OF YOUR RECOMMENDED WTSA, NTSA, AND BSSA ADIT AMOUNTS EQUAL YOUR RECOMMENDED WNSA ADIT?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

JANET M. SIMPSON

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PROFILE

Janet Simpson is the owner of Utility Regulatory Consulting, LLC ("URC"), a consulting firm providing accounting and regulatory services to the utility industry. Prior to establishing URC in 2020, she serviced 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 both 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 a variety of financial, regulatory, and technical areas, including evaluating financial transactions, developing accounting entries and procedures, implementing financial processes, analyzing financial data, and creating complex spreadsheet models. As a specialist in utility regulatory accounting and 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

- Newfield Network Ontological Coaching
- Internal Family Systems – Level 1 and Level 2
- BBA in Accounting, University of Texas at Austin
- Certified Public Accountant, Texas

PROFESSIONAL ASSOCIATIONS

- International Coaching Federation (ICF)
- American Institute of Certified Public Accountants
- Texas Society of Certified Public Accountants

SELECTED ENGAGEMENTS

- *Liberty Utilities (New England Natural Gas Company)* – CY2021 Gas System Enhancement Plan Reconciliation Filing, DPU 22-GREC-04 (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)
- *IFS Institute* – Program Assistant, IFS Level 1 Training
- *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)
- *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 service by SiEnergy in Central and South Texas - GUD 10679 (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)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2017 plan year), 16-GSEP-04 (2016)
- *Liberty Utilities (New England Natural Gas Company)* – CY2015 Gas System Enhancement Plan Reconciliation Filing, DPU 16-GREC-04 (2016)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2016)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates within the Unincorporated Areas of the Central Texas and South Texas Service Areas – ADIT issues – GUD 10526 (2016)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates within the Unincorporated Areas of the El Paso Service Area, Permian Service Area, and Dell City Service Area – ADIT issues – GUD 10506 (2016)
- *Texas Gas Service* – Statement of Intent of Texas Gas Service Company to Increase Gas Utility Rates within the Unincorporated Areas of the Galveston Service Area and the South Jefferson County Service Area – ADIT issues – GUD 10488 (2015)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2016 plan year), 15-GSEP-04 (2015)
- *Liberty Utilities (New England Natural Gas Company)* – Massachusetts Rate Case, DPU 15-75 Petition for Approval of a General Increase in Rates (2015)
- *Texas Gas Service* – El Paso Annual Rate Review – ADIT issues (2015)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2015)
- *Texas Gas Service* – Various Service Areas – Calculation of service-area-specific Net Operating Loss ADIT for annual Cost of Service Adjustment filings (2015)
- *Liberty Utilities (New England Natural Gas Company)* – CY2014 Targeted Infrastructure Recovery Factor Compliance Filing, DPU 15-54 (2015)
- *Liberty Utilities (New England Natural Gas Company)* – Compliance with an Act Relative to Natural Gas Leaks, 2014 Acts, Chapter 149, Section 2, (2015 plan year), DPU 14-133 (2014)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2014)
- *Texas Gas Service* – El Paso Annual Rate Review – ADIT issues (2014)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2014)
- *Texas Gas Service* – Various Service Areas – Development of approach and calculation of service-area-specific Net Operating Loss ADIT for annual Cost of Service Adjustment filings (2014)
- *Liberty Utilities (New England Natural Gas Company)* – CY2013 Targeted Infrastructure Recovery Factor Compliance Filing, DPU 14-82 (2014)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2013)
- *Texas Gas Service* – Rio Grande Valley Service Area – Statement of Intent to Change Rates (2013)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2013)
- *New England Gas Company*-CY2012 Targeted Infrastructure Recovery Factor Filing, DPU 13-77 (2013)
- *New England Gas Company*-Joint Petition for Approval of the Sale of New England Gas Company, DPU 13-07 (2013)
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas pursuant to Rate Schedule 16, Rider COSA – Cost of Service Adjustment (2012)
- *New England Gas Company*-Petition of New England Gas Company for the Establishment of a Regulatory Asset, DPU 12-68 (2012)
- *New England Gas Company*-CY2011 Targeted Infrastructure Recovery Factor Filing, DPU 12-37 (2012)

- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2012)
- *Nebraska Public Service Commission* – Gas Cost Adjustment Audit of Northwestern Energy, January 2009-April 2012; Application NG-0071 (2012)
- *New England Gas Company*-CY2010 Targeted Infrastructure Recovery Factor Compliance Filing, DPU 11-42 (2011)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2011)
- *Nebraska Public Service Commission* – Gas Cost Adjustment Audit of Black Hills Energy, January 2008-December 2010; Application NG-0066 (2011)
- *New England Gas Company* – Massachusetts Rate Case, DPU 10-114 Petition for Approval of a General Increase in Rates (2010)
- *Texas Gas Service* – Rio Grande Valley Service Area – Cost of Service Adjustment (2010)
- *Texas Gas Service* –El Paso Service Area - Statement of Intent to Change Rates (2009)
- *New England Gas Company* – DPU 09-131 Petition of New England Gas Company for approval of an Earnings Sharing Rate Adjustment (2009)
- *New England Gas Company* – DPU 09-83 Petition of New England Gas Company for approval by the Department of Public Utilities of its 2009 Pension Expense Factor filing (2009)
- *New England Gas Company* – DPU 08-66 Petition of New England Gas Company for approval by the Department of Public Utilities of its 2008 Pension Expense Factor filing (2008)
- *New England Gas Company* – DPU 08-64 Petition of New England Gas Company for approval of an earnings sharing rate adjustment (2008)
- *New England Gas Company* – Massachusetts Rate Case, DPU 08-35 Petition for Approval of a General Increase in Rates (2008)
- *Texas Gas Service* – Rio Grande Valley Service Area - Statement of Intent to Change Rates (2008)
- *Texas Gas Service* – Permian and Central Texas Regions - Expert services regarding revenue deficiency tax items (2008)
- *CoServ Gas, Ltd.* – G.U.D. 9670 - Petition for de Novo Review of the Reduction of the Gas Utility Rates of Atmos Energy Corp., Mid-Tex Division, by the Cities of Addison, Benbrook, Blue Ridge, et. al., and Statement of Intent Filed by Atmos Energy Corp., Mid-Tex Division to Change Rates in the Company's Statewide Gas Utility System – Analytical services to support rebuttal testimony of June M. Dively regarding proposed change in rates (2006)
- *Texas Gas Service* - Statement of Intent to Increase Rates in its Rio Grande Valley Region – Expert services regarding development of various cost-of-service components (2006)
- *CoServ Gas, Ltd.* - Statement of Intent to Increase Rates in the Environs – (2006)
- *Crosstex Energy Services, Ltd.* – Compliance reporting support for Commissions in the States of Texas, Louisiana, Mississippi and Alabama (2006, 2007, 2008)
- *Crosstex Energy Services, Ltd.* – Development of processes to support regulatory requirements in connection with conversion to PeopleSoft Accounting Systems (2006)
- *CoServ Gas, Ltd.* – Functional process analysis and support pertaining to various regulatory accounting, plant, and work order system requirements for company conversion to Oracle Accounting Systems (2005).
- *Texas State Natural Gas* - Statement of Intent to Increase Rates in Eagle Pass, Texas (2005)
- *Texas State Natural Gas* - Gas distribution system acquisition due diligence review (2005)
- *Texas General Land Office* - TXU Rate Case G.U.D. 9500 (2004)
- *CoServ Gas, Ltd.* - Statement of Intent to Change Rates in 25 cities in North Texas (2004)
- *Texas Gas Service* - Statement of Intent to Change Rates - South Jefferson County, TX (2003)
- *Southern Union Gas* - Statement of Intent to Change Rates - El Paso and Andrews, TX (1999)
- *Missouri Gas Energy* - Case No. GR-98-140 General rate increase (1998)
- *Missouri Gas Energy* - Case No. GR-96-285 General rate increase (1996)
- *Southern Union Company* – Functional Requirements Project Leader - development of processes to support accounting and regulatory requirements in connection with conversion to Infinium Software Accounting Systems from separate accounting systems of Rio Grande Valley Gas Company, Missouri Gas Energy, and Southern Union Gas (1994-1996)
- *Missouri Gas Energy* - Gas system acquisition by due diligence review and accounting integration (1994)
- *Rio Grande Valley* - Gas system acquisition by due diligence review and accounting integration (1993)
- *City of Nixon Gas System* - Gas system acquisition by due diligence review and accounting integration (1992)
- *Andrews Gas Company* - Gas system acquisition by due diligence review and accounting integration (1991)
- *South Texas Utilities* - Gas system acquisition by due diligence review and accounting integration (1991)

- *Gulf States Utilities Co*– PUCT Docket No. 6525 Application for Authority to Change Rates (1986)
- *San Patricio Electric Coop*– PUCT Docket No. 6620 Petition for Authority to Change Rates (1986)
- *Fayette Electric Coop* – PUCT Docket No. 6907 Petition for Authority to Change Rates (1986)
- *El Paso Electric Company* – PUCT Docket No. 6350 Application for a General Rate Case (1985)
- *Southwest Rural Electric Association* – PUCT Docket No. 6143 Application for Tariff Revisions (1985)
- *West Texas Utilities Co*– PUCT Docket No. 5764 Application for Authority to Change Rates (1984)
- *Texas-New Mexico Power Company* – PUCT Docket No. 5568 Application for Authority to Change Rates (1984)
- *San Bernard Electric Cooperative, Inc.* – PUCT Docket No. 5467 Appl. for Authority to Change Rates (1984),
- *South Texas Electric Cooperative, Inc* – PUCT Docket No. 5440 Appl. for Tariff Revisions to Reduce Fuel Factor (1984)

SUMMARY ADIT ALLOCATIONS TO THE WEST-NORTH SERVICE AREA
Year Ended 12/31/2021

Accumulated Deferred Income Taxes for:	ADIT at 21%
West-North Repair Adjustments	(26,939,517)
All Other West-North Plant-Related	(55,443,450)
Subtotal West-North Direct Plant Assets Depreciation	(82,382,966)
West-North Other Rate Base Items	(4,965,068)
TGS Division Plant Assets Depreciation	(704,098)
ONEGas Plant Assets Depreciation	(2,462,154)
West-North NOL	40,081,420
Total ADIT - Accumulated Deferred Income Taxes	(50,432,866)

Accumulated Deferred Income Tax - West-North Service Area Plant Related Items

As of December 31, 2021 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%
Borger	14,906,407	(3,956,977)	10,949,430	8,047,607	(5,316,035)	2,731,573	8,217,857	(1,725,750)
Skellytown	363,739	(159,015)	204,724	103,748	(101,884)	1,864	202,859	(42,600)
Breckenridge	14,238,986	(679,853)	13,559,133	6,099,074	(2,836,176)	3,262,899	10,296,234	(2,162,209)
Graham	8,636,124	(1,290,349)	7,345,775	3,258,232	(1,729,654)	1,528,578	5,817,198	(1,221,611)
Jacksboro	5,619,510	(585,899)	5,033,612	2,145,769	(1,282,785)	862,984	4,170,628	(875,832)
Mineral Wells	22,971,827	(2,263,639)	20,708,188	12,475,205	(5,766,617)	6,708,589	13,999,599	(2,939,916)
Possum Kingdom	1,810,727	194,179	2,004,907	1,230,089	(175,157)	1,054,932	949,974	(199,495)
Weatherford	36,091,349	(4,372,930)	31,718,419	23,576,362	(10,652,763)	12,923,599	18,794,820	(3,946,912)
North Texas General Plant	446,807	(186,764)	260,044	383,350	(198,069)	185,281	74,763	(15,700)
Andrews	10,366,627	(967,774)	9,398,853	5,285,020	(1,668,648)	3,616,373	5,782,480	(1,214,321)
Crane	3,820,710	(885,610)	2,935,100	1,810,917	(904,799)	906,118	2,028,982	(426,086)
Dell City	2,552,456	(1,331,428)	1,221,028	1,664,609	(1,167,654)	496,955	724,073	(152,055)
El Paso	579,505,638	(99,389,696)	480,115,942	373,939,004	(190,469,853)	183,469,151	296,646,791	(62,295,826)
Fort Bliss	7,615,062	464,782	8,079,844	6,659,990	(4,659,064)	2,000,926	6,078,918	(1,276,573)
McCamey	2,921,562	(886,820)	2,034,742	1,328,238	(706,552)	621,686	1,413,056	(296,742)
Pecos/Monahans	25,476,819	(5,388,859)	20,087,960	15,437,706	(8,547,273)	6,890,434	13,197,526	(2,771,480)
West-North Service Area	737,344,349	(121,686,651)	615,657,698	463,444,923	(236,182,983)	227,261,939	388,395,759	(81,563,109)
Adjustments per Rate Case Schedules								
Borger-Skellytown Area	135,606.61	77,461.43	213,068	42,038	76,318	118,357	94,711	(19,889)
North Texas Area	415,677	103,821	519,498	184,655	89,443	274,099	245,399	(51,534)
West Texas Area	(4,131,978)	4,546,109	414,131	(4,213,446.45)	4,344,798.60	131,352	282,779	(59,384)
Subtotal Adjustments	(3,580,695)	4,727,391	1,146,697	(3,986,753)	4,510,560	523,808	622,889	(130,807)
City of El Paso VTGS 2003 Adjustment								
Remove El Paso VTGS Vintage Tax Info per Tax Reports				(76,933,255)	72,797,403	(4,135,852)	4,135,852	(868,529)
Replace with El Paso Method VTGS Vintage Tax Info				130,999,120	(130,144,460)	854,660	(854,660)	179,479
Subtotal - City of El paso VTGS 2003 Adjustment				54,065,864	(57,347,057)	(3,281,192)	3,281,192	(689,050)
Adjusted West-North Service Area	733,763,655	(116,959,260)	616,804,395	513,524,034	(289,019,479)	224,504,555	392,299,840	(82,382,966)
			-			-		0
TGS Division (Allocated to West-North Service Area)	4,653,657	(1,070,073)	3,583,584	1,532,852	(1,302,115)	230,737	3,352,847	(704,098)
ONEGas (Allocated to West-North Service Area)	28,856,481	(12,649,016)	16,207,465	22,314,438	(17,831,517)	4,482,921	11,724,543	(2,462,154)

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	896,913		896,913	(188,352)
Prepaid Pension (funding in excess of FAS87 expense)	19,113,633		19,113,633	(4,013,863)
Section 8.209 Deferral	1,843,921	-	1,843,921	(387,223)
Other Regulatory Assets	1,788,715		1,788,715	(375,630)
Total Other Rate Base Items	23,643,182	-	23,643,182	(4,965,068)

Check to Rate Case Schedules

	Direct	TGS Division	Corporate	Total
Plant in Service				
Per Above	733,763,654.90	4,653,657	28,856,481	767,273,792.52
Per Rate Case Schedules				
Plant in Service	668,181,051.51	4,590,058.94	28,351,537.49	701,122,647.94
CCNC	65,582,603.38	63,597.92	504,943.21	66,151,144.51
	733,763,654.89	4,653,656.86	28,856,480.70	767,273,792.45
	(0)	(0)	(0)	(0)
Reserves				
Per Above	(116,959,259.73)	(1,070,072.76)	(12,649,016.03)	(130,678,348.52)
Per Rate Case Schedules	(116,959,260.00)	(1,070,072.76)	(12,649,016.04)	(130,678,348.80)
	0	0	0	0

SUMMARY ADIT ALLOCATIONS TO THE West Texas SERVICE AREA
Year Ended 12/31/2021

Accumulated Deferred Income Taxes for:	ADIT at 21%
West Texas Repair Adjustments	(21,850,445)
All Other West Texas Plant-Related	(47,331,072)
Subtotal West Texas Direct Plant Assets Depreciation	(69,181,517)
West Texas Other Rate Base Items	(4,543,921)
TGS Division Plant Assets Depreciation	(653,487)
ONEGas Plant Assets Depreciation	(2,285,173)
West Texas NOL	37,767,244
Total ADIT - Accumulated Deferred Income Taxes	(38,896,854)

Accumulated Deferred Income Tax - West Texas Service Area Plant Related Items

As of December 31, 2021 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%
Andrews	10,366,627	(967,774)	9,398,853	5,285,020	(1,668,648)	3,616,373	5,782,480	(1,214,321)
Crane	3,820,710	(885,610)	2,935,100	1,810,917	(904,799)	906,118	2,028,982	(426,086)
Dell City	2,552,456	(1,331,428)	1,221,028	1,664,609	(1,167,654)	496,955	724,073	(152,055)
El Paso	579,505,638	(99,389,696)	480,115,942	373,939,004	(190,469,853)	183,469,151	296,646,791	(62,295,826)
Fort Bliss	7,615,062	464,782	8,079,844	6,659,990	(4,659,064)	2,000,926	6,078,918	(1,276,573)
McCamey	2,921,562	(886,820)	2,034,742	1,328,238	(706,552)	621,686	1,413,056	(296,742)
Pecos/Monahans	25,476,819	(5,388,859)	20,087,960	15,437,706	(8,547,273)	6,890,434	13,197,526	(2,771,480)
West Texas Service Area	632,258,873	(108,385,405)	523,873,468	406,125,485	(208,123,843)	198,001,642	325,871,826	(68,433,083)
Adjustments per Rate Schedules								
Miscodes and Miscellaneous Adjustments	227,782	(7,792)	219,991	146,314	(14,962)	131,352	88,639	(18,614)
Retiring Assets	(4,359,760)	4,359,760	-	(4,359,760)	4,359,760	-	-	-
Reserve Rebalancing and Add'l Fort Bliss Depr Adj		194,140	194,140			-	194,140	(40,769)
			-			-	-	-
Subtotal Adjustments	(4,131,978)	4,546,109	414,131	(4,213,446)	4,344,799	131,352	282,779	(59,384)
City of El Paso VTGS 2003 Adjustment								
Remove El Paso VTGS Vintage Tax Info per Tax Reports				(76,933,255)	72,797,403	(4,135,852)	4,135,852	(868,529)
Replace with El Paso Method VTGS Vintage Tax Info				130,999,120	(130,144,460)	854,660	(854,660)	179,479
Subtotal - City of El paso VTGS 2003 Adjustment				54,065,864	(57,347,057)	(3,281,192)	3,281,192	(689,050)
Adjusted West Texas Service Area	628,126,895	(103,839,296)	524,287,599	455,977,903	(261,126,101)	194,851,802	329,435,797	(69,181,517)
			-			-		0
TGS Division (Allocated to West Texas Service Area)	4,319,149	(993,155)	3,325,994	1,422,670	(1,208,518)	214,152	3,111,842	(653,487)
ONEGas (Allocated to West Texas Service Area)	26,782,259	(11,739,797)	15,042,462	20,710,463	(16,549,777)	4,160,686	10,881,776	(2,285,173)

Accumulated Deferred Income Tax Analysis For West 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	896,913		896,913	(188,352)
Prepaid Pension (funding in excess of FAS87 expense)	17,739,733		17,739,733	(3,725,344)
Section 8.209 Deferral	1,377,375	-	1,377,375	(289,249)
Other Regulatory Assets	1,623,697		1,623,697	(340,976)
Total Other Rate Base Items	21,637,718	-	21,637,718	(4,543,921)

Check to Rate Case Schedules

	Direct	TGS Division	Corporate	Total
Plant in Service				
Per Above	628,126,894.88	4,319,149	26,782,259	659,228,303.06
Per Rate Case Schedules				
Plant in Service	578,982,828.73	4,260,122.65	26,313,611.42	609,556,562.80
CCNC	49,144,066.14	59,026.46	468,647.58	49,671,740.18
	628,126,894.87	4,319,149.11	26,782,259.00	659,228,302.98
	(0)	(0)	(0)	(0)
Reserves				
Per Above	(103,839,296.24)	(993,155.27)	(11,739,796.93)	(116,572,248.43)
Per Rate Case Schedules	(103,839,296.24)	(993,155.27)	(11,739,796.93)	(116,572,248.44)
	-	0	0	0

SUMMARY ADIT ALLOCATIONS TO North Texas SERVICE AREA
Year Ended 12/31/2021

Accumulated Deferred Income Taxes for:	ADIT at 21%
North Texas Service Area Direct Plant Repairs	(4,620,719)
North Texas Direct Plant Assets Depreciation	(6,792,491)
Subtotal North Texas Direct Plant Assets Depreciation	(11,413,209)
North Texas Other Rate Base Items	(321,511)
TGS Division Plant Assets Depreciation	(37,690)
ONEGas Plant Assets Depreciation	(131,798)
North Texas NOL	1,945,959
ADIT - Accumulated Deferred Income Taxes	(9,958,249)

Accumulated Deferred Income Tax - North Texas Service Area Plant Related Items

As of December 31, 2021 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%
Breckenridge	14,238,986	(679,853)	13,559,133	6,099,074	(2,836,176)	3,262,899	10,296,234	(2,162,209)
Graham	8,636,124	(1,290,349)	7,345,775	3,258,232	(1,729,654)	1,528,578	5,817,198	(1,221,611)
Jacksboro	5,619,510	(585,899)	5,033,612	2,145,769	(1,282,785)	862,984	4,170,628	(875,832)
Mineral Wells	22,971,827	(2,263,639)	20,708,188	12,475,205	(5,766,617)	6,708,589	13,999,599	(2,939,916)
Possum Kingdom	1,810,727	194,179	2,004,907	1,230,089	(175,157)	1,054,932	949,974	(199,495)
Weatherford	36,091,349	(4,372,930)	31,718,419	23,576,362	(10,652,763)	12,923,599	18,794,820	(3,946,912)
North Texas General Plant	446,807	(186,764)	260,044	383,350	(198,069)	185,281	74,763	(15,700)
North Texas Service Area	89,815,331	(9,185,254)	80,630,077	49,168,082	(22,641,221)	26,526,861	54,103,216	(11,361,675)
Adjustments per Rate Case Schedules								
Miscodes and Miscellaneous Adjustments	510,472.06	(2,171.20)	508,300.86	279,450.42	(5,351.91)	274,098.52	234,202.34	(49,182.49)
Retiring Assets	(94,795.26)	94,795.26	-	(94,795.26)	94,795.26	-	-	-
Reserve Rebalancing		11,197.00	11,197.00				11,197.00	(2,351.37)
			-					-
Subtotal Adjustments	415,677	103,821	519,498	184,655	89,443	274,099	245,399	(51,534)
Adjusted North Texas Service Area	90,231,008	(9,081,433)	81,149,575	49,352,737	(22,551,778)	26,800,959	54,348,615	(11,413,209)
			-			-		0
TGS Division (Allocated to North Texas SA)	249,108	(57,280)	191,828	82,053	(69,702)	12,351	179,476	(37,690)
ONEGas (Allocated to North Texas SA)	1,544,674	(677,096)	867,578	1,194,481	(954,513)	239,969	627,609	(131,798)

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)
Section 8.209 Deferral	377,873	-	377,873	(79,353)
Prepaid Pension	1,023,144	-	1,023,144	(214,860)
Other Regulatory Assets	129,990		129,990	(27,298)
Total Other Rate Base Items	1,531,007	-	1,531,007	(321,511)

	Direct	Division	One Gas	Total
Checks to COSA Schedules				
Gross Plant - Direct				
Per Above	90,231,008	249,108	1,544,674	92,024,789
Per Schedules				
Acct 1010	74,356,485	245,704	1,517,644	76,119,833
Acct 1060	15,874,522	3,404	27,029	15,904,956
	90,231,008	249,108	1,544,674	92,024,789
Difference	-	0	(0)	(0)
Reserves				
Per Above	(9,081,433)	(57,280)	(677,096)	(9,815,809)
Per Schedules	(9,081,433)	(57,280)	(677,096)	(9,815,810)
Difference	0	(0)	(0)	0
Net Plant (Direct & Allocated)				
Per Above	81,149,575	191,828	867,578	82,208,980
Per Schedules	81,149,574	191,828	867,578	82,208,980
Difference	0	(0)	(0)	0

	A	B	C	D	E	F	G	H	I
1									
2	**SUMMARY ADIT ALLOCATIONS TO THE BORGER SKELLYTOWN SERVICE AREA**								
3	**Year Ended 12/31/2021**								
4									
5									
6									
7	**Accumulated Deferred Income Taxes for:**	**ADIT at 21%**							
8	**Borger-Skellytown Repair Adjustments**	(468,353)							
9	**All Other Borger-Skellytown Plant-Related**	(1,319,887)							
10	**Subtotal Borger-Skellytown Direct Plant Assets Depreciation**	(1,788,240)							
11	**Borger-Skellytown Other Rate Base Items**	(99,636)							
12	**TGS Division Plant Assets Depreciation**	(12,921)							
13	**ONEGas Plant Assets Depreciation**	(45,183)							
14	**Borger-Skellytown NOL**	368,217							
15									
16	**Total ADIT - Accumulated Deferred Income Taxes**	(1,577,763)							
17									
18									
19									
20	**Accumulated Deferred Income Tax - Borger-Skellytown Service Area Plant Related Items**								
21									
22		**Gross**		**Net**	**Gross**		**Net**	**Difference**	**ADIT**
23	**As of December 31, 2021**	**Book**	**Book**	**Book**	**Tax**	**Tax**	**Tax**	**in Net**	**Asset/(Liability)**
24	**Town**	**Basis**	**Reserve**	**Basis**	**Basis**	**Reserve**	**Basis**	**Plant Basis**	**at 21%**
25									
26	Borger	14,906,407	(3,956,977)	10,949,430	8,047,607	(5,316,035)	2,731,573	8,217,857	(1,725,750)
27	Skellytown	363,739	(159,015)	204,724	103,748	(101,884)	1,864	202,859	(42,600)
28				-			-	-	-
29	Borger-Skellytown Service Area	15,270,146	(4,115,992)	11,154,154	8,151,356	(5,417,919)	2,733,437	8,420,717	(1,768,351)
30									
31	Adjustments per Rate Case Schedules							-	-
32	Miscodes and Miscellaneous Adjustments	200,708.27	8,521.40	209,229.67	107,140.07	11,216.80	118,356.87	90,872.80	(19,083.29)
33	Retiring Assets	(65,101.66)	65,101.66	-	(65,101.66)	65,101.66	-	-	-
34	Reserve Rebalancing		3,838	3,838			-	3,838	(806)
35				-			-	-	-
36	Subtotal Adjustments	135,607	77,461	213,068	42,038	76,318	118,357	94,711	(19,889)
37									
38	Adjusted Borger-Skellytown Service Area	15,405,752	(4,038,530)	11,367,222	8,193,394	(5,341,600)	2,851,794	8,515,428	(1,788,240)
39				-			-		(0)
40									
41	TGS Division (Allocated to Borger-Skellytown Service Area)	85,400	(19,637)	65,763	28,130	(23,895)	4,234	61,528	(12,921)
42									
43	ONEGas (Allocated to Borger-Skellytown Service Area)	529,548	(232,123)	297,425	409,494	(327,228)	82,267	215,158	(45,183)
44									
45									
46	**Accumulated Deferred Income Tax Analysis For Borger-Skellytown Service Area Other Rate Base Items**								
47									
48		**Balance Sheet Impact per Book**	**Balance Sheet Impact per Tax**	**Difference**	**ADIT Asset/(Liability)**				
49									
50	Prepaid Pension (funding in excess of FAS87 expense)	350,756		350,756	(73,659)				
51									
52	Section 8.209 Deferral	88,673	-	88,673	(18,621)				
53									
54	Other Regulatory Assets	35,028		35,028	(7,356)				
55									
56	Total Other Rate Base Items	474,457	-	474,457	(99,636)				
57	Thanks								
58									
59									
60									
61	Check to Rate Case Schedules								
62		Direct	TGS Division	Corporate	Total				
63	Plant in Service								
64	Per Above	15,405,752.48	85,400	529,548	16,020,700.35				
65	Per Rate Case Schedules								
66	Plant in Service	14,841,737.48	84,232.63	520,281.88	15,446,251.99				
67	CCNC	564,015.00	1,167.09	9,266.26	574,448.35				
68		15,405,752.48	85,399.72	529,548.14	16,020,700.34				
69		-	(0)	(0)	(0)				
70	Reserves								
71	Per Above	(4,038,530.47)	(19,637.01)	(232,123.35)	(4,290,290.83)				
72	Per Rate Case Schedules	(4,038,530.47)	(19,637.01)	(232,123.35)	(4,290,290.83)				
73		-	(0)	(0)	(0)				
74									
75									
76									

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 C. Caballero~~
Mayor ~~PRO-TEM~~
LARRY M. MEDINA

ATTEST:

for Richarda Duffy Momsen 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

STATE OF TEXAS §
§
COUNTY OF TRAVIS §

AFFIDAVIT OF JANET SIMPSON

BEFORE ME, the undersigned authority, on this day personally appeared Janet Simpson who having been placed under oath by me did depose as follows:

1. "My name is Janet Simpson. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as Managing Member of Utility Regulatory Consulting, LLC. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in this document is true and correct to the best of my knowledge."

Further affiant sayeth not.

DocuSigned by:
Janet Simpson
4AD8D9974657486...

Janet Simpson

SUBSCRIBED AND SWORN TO BEFORE ME by the said Janet Simpson on this 17th day of June 2022.

DocuSigned by:
Christine Marie Bell
1C45AAFD08DC44A...

Notary Public in and for the State of Texas

NOTARY PUBLIC STATE OF TEXAS
CHRISTINE MARIE BELL
Notary ID 130547096
My Commission Expires 2/19/2024

CASE NO. 00009896

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	**§ § § § § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

DR. RONALD E. WHITE

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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DIRECT TESTIMONY OF DR. RONALD E. WHITE

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I serve as President of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND.

A. I was awarded a B.S. degree in Engineering Operations and M.S. and Ph.D. degrees in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation, valuation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the Midwest Finance Association, and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Prior to joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over 30 jurisdictions, including Texas. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. Appendix A contains a more detailed description of my professional qualifications.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by Texas Gas Service Company (TGS), a division of ONE Gas, Inc., to conduct a 2022 depreciation rate study for: a) plant located in a proposed West–North Service Area (WNSA), which consolidates the West Texas Service Area (WTSA), the North Texas Service Area (NTSA) and the Borger/Skellytown Service Area (BSSA); and b) for common facilities shared among all TGS Service Areas (the TGS Division). Additionally, at the request of TGS, the Fort Bliss Service Area (FBSA) was removed from the WTSA before combining WTSA, NTSA and BSSA into the WNSA. FBSA was therefore included in the 2022 study as a stand–alone service area.

Accompanying my testimony is Exhibit REW–1, titled "2022 Depreciation Rate Study." This document, prepared by me or under my direction and supervision, is the 2022 study for a combined West–North Service Area, the Fort Bliss Service Area and the TGS Division. The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates.

II. DEVELOPMENT OF DEPRECIATION RATES

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential (or future economic benefit) of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other noncash expenses) or cash inflows attributable to the use of that asset alone. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life become more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent 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 comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon authorized levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.[1]

Q. PLEASE DESCRIBE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step 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 the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about 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. 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 is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is most often obtained 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

[1]I do not discuss nor have I considered whether other regulatory or public policy goals should influence or be reflected in developing depreciation rates. Such considerations remain the prerogative of the regulatory agency responsible for prescribing appropriate depreciation rates.

time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the estimated projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current recorded reserve balance with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

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 (or computed) and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments requiring an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute or rebalance recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and net salvage rates. A redistribution of recorded reserves will initialize a reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon 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.

III. 2022 TGS DEPRECIATION STUDY

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY TGS FOR THE PROPOSED WNSA.

A. Current depreciation rates for WTSA were developed in a 2015 study and approved in GUD 10506 (Order Dated September 27, 2016). Current rates for NTSA were developed in a 2018 study and approved by the Commission pursuant to a Settlement Agreement in GUD 10739 (Order dated November 13, 2018).

Current rates for BSSA were developed in a 2018 update of a 2015 study approved by the Commission in GUD 10766 (Order dated February 5, 2019).

Current depreciation rates for TGSD were developed in a 2019 Central-Gulf Service Area (CGSA) study based on December 31, 2018 plant and depreciation reserves. Rates developed for TGSD were approved by the Commission pursuant to a Settlement Agreement in GUD 10928 (Order dated August 4, 2020).

Q. DID TGS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2022 DEPRECIATION STUDY?

A. Yes. The database used in the 2022 study was assembled by appending 2019–2021 plant and reserve activity to the statewide data base used in conducting a 2019 study for the Central-Gulf Service Area (CGSA). 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 at December 31, 2021 were derived by Foster Associates in a forward–flow calculation in which accounting activity was appended to the database used in conducting the 2019 CGSA study. The accuracy and completeness of the assembled data base was validated by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each rate category to the official plant records of the Company over the period 2019-2021. Derived age distributions on December 31, 2021 were also reconciled to the continuing property records of TGS. Annual plant activity prior to 2019 was reconciled in the 2019 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, all 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. The observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using the projection life derived from the polynomial hazard function) to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

Plant accounting and depreciation reserve records are maintained by TGS for its existing five service areas and the TGS Division that supports all service areas.[2] Projection lives and projection curves were estimated in the TGS study from the combined database of the existing five service areas. Average service lives and remaining service lives were distinguished among service areas in the development of vintage–group depreciation rates.

Q. WHY WERE PARAMETERS FOR THE PROPOSED WNSA ESTIMATED FROM A COMBINED DATABASE OF TGS SERVICE AREAS RATHER THAN FROM SERVICE–AREA SPECIFIC DATABASES?

A. Service areas were combined to maximize sample sizes for estimating projection lives, projection curves and future net salvage rates and, as a cost saving measure, to reduce the number of independent statistical studies conducted for TGS. Total plant included in the 2022 study on December 31, 2021 for TGS (excluding the

[2] Existing service areas include: Central-Gulf Texas; Rio Grande Valley; North Texas; Borger/Skellytown; and West Texas.

TGS Division) was $1,787.2 million. The amount of investment in each of the existing five service areas ranges between $15.0 million for Borger/Skellytown and $859.1 million for the existing Central–Gulf Service Area. NTSA represents $88.6 million or 5.0 percent of TGS total plant investments and WTSA represents $624.5 million or 34.9 percent of TGS total plant investments.

Plant investments located in the five service areas are designed, constructed and maintained under uniform policies and practices. Retirement units are standardized for all TGS service areas as are design standards, maintenance practices and material types. Recommended projection lives, projection curves and future net salvage rates derived from a combined database were reviewed by TGS operations personnel and found to be reasonable for all Service Areas.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR TGS PLANT AND EQUIPMENT?

A. Yes. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2022 study to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from TGS personnel were blended with judgment and historical net salvage indications in developing estimates of the future. Future net salvage rates were estimated from the combined database of the five service areas.

Average net salvage rates for all depreciable plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates were distinguished among service areas in the development of vintage–group depreciation rates.

Q. WERE OTHER FACTORS CONSIDERED IN RECOMMENDING FUTURE NET SALVAGE RATES FOR TGS?

A. Yes. 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. The increase in 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. First In, First Out (FIFO) pricing of retirements used by TGS also exacerbates high measurements of realized net salvage rates.

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 incurred 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.

Another 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 variability and upward trend observed in net savage rates. Based on these concerns, an internal investigation was conducted of the allocation of project costs between cost of removal and replacement plant additions. Revised allocation factors were then developed in which 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 implied from an assumed continued application of the recently applied standards were projected using a per–unit formulation of future net salvage rates.[3] Trend indications derived from this analysis were comparable to those observed in the banding analyses.

It is the opinion of Foster Associates that it is premature to adjust currently approved net salvage rates for mains and services to rates indicated in the banding and per–unit analyses. The magnitude and trend of future net salvage rates will remain unstable until the new standards have been applied for a number of years.

Based on a consideration of the above factors, Foster Associates is recommending tempered increases in future net salvage rates in the direction of the trends observed in both the banding and per–unit analyses. It is likely, however, that costs of removal will continue to escalate beyond the net salvage rates recommended in the current study. Future net salvage rates of –40 percent are recommended for transmission and distribution mains. A rate of –60 percent is recommended for distribution services.

[3] A per–unit formulation of future net salvage rates is described by the following four steps:

Step 1. Average net salvage per–unit recorded over a few recent activity years to obtain a normalized per–unit ratio applicable to future vintage–year retirements.

Step 2. Divide the average ratio derived in Step 1 by vintaged per-unit additions.

Step 3. Multiply forecasted retirements by ratios derived in Step 2 and a selected age–adjusted inflation rate to obtain forecasted future net salvage for each future activity year.

Step 4. Sum the forecasted future net salvage derived in Step 3 and divide by total plant in service to obtain estimate of future net salvage rate.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Statement C of Exhibit REW–1 provides a comparison of recorded, computed and redistributed reserves on December 31, 2021. The recorded reserve for WNSA was $119,402,307 or 16.6 percent of the depreciable plant investment. The corresponding computed reserve is $155,740,282 or 21.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $36,337,975 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in the 2022 study.

Recorded reserves for the FBSA on December 31, 2021 were $1,140,637 or 15.0 percent of the depreciable plant investment. The corresponding computed reserve is $1,465,276 or 19.36 percent of the depreciable plant investment.

Recorded reserves for the TGS Division on December 31, 2021 were set equal to computed reserves of $2,569,342 or 24.9 percent of the amortizable plant investment. The equivalency between recorded and computed reserves was achieved by transferring recorded reserves in proportion to customer counts, from Account 390.10 (Structures and Improvements) from each service area in which investments were recorded in Account 390.10.

Q. DID FOSTER ASSOCIATES REBALANCE DEPRECIATION RESERVES IN THE 2019 STUDY?

A. Yes. A rebalancing of recorded reserves is consistent with the objectives of depreciation accounting and Commission precedent.[4] 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

[4] See, for example, GUD Nos. 10488, 10526 and 10928.

be realigned to eliminate reserve imbalances created by the implementation of amortization accounting.

Recorded reserves were rebalanced by multiplying the calculated reserve for each primary account by the ratio of total recorded reserves to total calculated reserves. The sum of redistributed reserves is, therefore, equal to total recorded reserves before redistribution. Reserves for amortizable categories were adjusted by replacing recorded reserves with current measured theoretical reserves and distributing any reserve imbalances to depreciable categories.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM USED TO DEVELOP CURRENT DEPRECIATION RATES FOR TGS.

A. With the exception of selected asset categories for which amortization accounting has been approved, TGS is currently using a depreciation system composed of the straight–line method, vintage group procedure and, remaining–life technique for all depreciable rate categories included in the 2022 study. Amortization accounting is used for general plant categories and cathodic protections anodes 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.

The formulation of an account accrual rate using the vintage–group procedure is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, 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 both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

Q. WAS THE DEPRECIATION SYSTEM IN THE 2022 STUDY CHANGED FROM THE SYSTEM CURRENTLY APPROVED FOR TGS?

A. No. The system used for all service areas was retained in the 2022 study. 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.

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR TGS IN THE 2022 STUDY.

A. Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation rates recommended for the proposed WNSA.

	Accrual Rates			2022 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	2.06%	2.60%	0.54%	$ 988,059	$ 1,250,892	$ 262,833
Distribution	2.34%	2.97%	0.63%	14,360,786	18,216,069	3,855,283
General Plant	6.72%	6.16%	-0.56%	3,949,797	3,621,510	(328,287)
Total	2.68%	3.20%	0.52%	$ 19,298,643	$23,088,471	$3,789,828

Table 1. West-North Texas Service Area

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.20 percent. Depreciation expense is currently accrued at rates that composite to 2.68 percent. The recommended change in the composite depreciation rate is an increase of 0.52 percentage points. A continued application of current rates would provide annualized depreciation expense of $19,298,643 compared with an annualized expense of $23,088,471 using the rates developed in the 2022 study. The change in depreciation expense for 2022 is an increase of $3,789,828.

Table 2 below provides a summary of the changes in annual rates and accruals recommended for the FBSA.

	Accrual Rates			2022 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	2.07%	2.41%	0.34%	$ 155,835	$ 181,669	$ 25,833
General Plant	6.58%	6.67%	0.09%	3,989	4,039	50
Total	2.10%	2.44%	0.34%	$ 159,824	$ 185,707	$ 25,883

Table 2. Fort Bliss Service Area

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.44 percent. Depreciation expense is currently accrued at rates that composite to 2.10 percent. The recommended change in the composite depreciation rate is an increase of 0.34 percentage points. A continued application of current rates would provide annualized depreciation expense of $159,824 compared with an annualized expense of $185,707 using the rates developed in the 2022 study. The change in depreciation expense for 2022 is an increase of $25,883.

Table 3 below provides a summary of the changes in annual rates and accruals resulting recommended for the TGS Division.

	Accrual Rates			2022 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	6.20%	5.83%	-0.37%	$ 640,836	$ 603,047	(37,788)
Total	6.20%	5.83%	-0.37%	$ 640,836	$ 603,047	$ (37,788)

Table 3. TGS Division

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 5.83 percent. Depreciation expense is currently accrued at rates that composite to 6.20 percent. A continued application of current rates would provide annualized depreciation expense of $640,836 compared with an annualized expense of $603,047 using the rates developed in the 2022 study. The change in depreciation expense for 2022 is a reduction of $37,788.

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–01933A–12–0126, Tucson Electric Power Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01933A–15–0322, Tucson Electric Power Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01933A–19–0028, Tucson Electric Power Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–15–0142, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Application No. A.16–09–001 Southern California Edison; testimony regarding estimation of service lives and net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1115, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1137, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1162, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. *99*-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 16-KGSG-491-RTS, Kansas Gas Service, a Division of ONE Gas, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 18-WSEE-328-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9424, Delmarva Power and Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9481, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 15–155, Massachusetts Electric Company/Nantucket Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–18150, DTE Electric Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Montana Public Service Commission, Docket No. D2018.2.12, NorthWestern Energy –Montana; testimony supporting proposed depreciation rates

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR87060552, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR21030679, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR19030420, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony supporting depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR15111304, New Jersey Natural Gas Company; testimony supporting depreciation rates.

New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 202100063, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Oklahoma Corporation Commission, Cause No. PUD 201500213, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

South Dakota Public Utilities Commission, Docket No. EL14–106, NorthWestern Energy; testimony supporting revised depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10488, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10506, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10656, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10526, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10928, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Engagements

Arbitrator in a Technical Dispute relating to classification of Capital Budget expenditures.

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, et. al. File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University: (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee).

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

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SPEAKER

Depreciation Training Seminar, Kansas Gas Service, October 2018.

Depreciation Workshop, Oklahoma Corporation Commission, Public Utility Division, March 2015.

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Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

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Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

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Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

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Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

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Why Economic Depreciation? American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

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Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

April 2022

2022 Depreciation Rate Study

Texas Gas Service
A Division of ONE Gas

– West–North Texas
– Fort Bliss
– TGS Division

foster associates

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INTRODUCTION

This report presents findings and recommendations developed in a 2022 depreciation study conducted for gas plant owned and operated by Texas Gas Service (TGS), a division of ONE Gas, Inc., and located in the West–North Texas Service Area (WNSA). The study also includes TGS Division (TGSD), supporting common facilities shared among all TGS Service Areas.

Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned businesses including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

At the request of TGS, the WNSA was created in the 2022 study by combining the West Texas Service Area (WTSA), the North Texas Service Area (NTSA) and the Borger/Skellytown Service Area (BSSA). Service areas combined into the WNSA are shown in Figure 1 below.

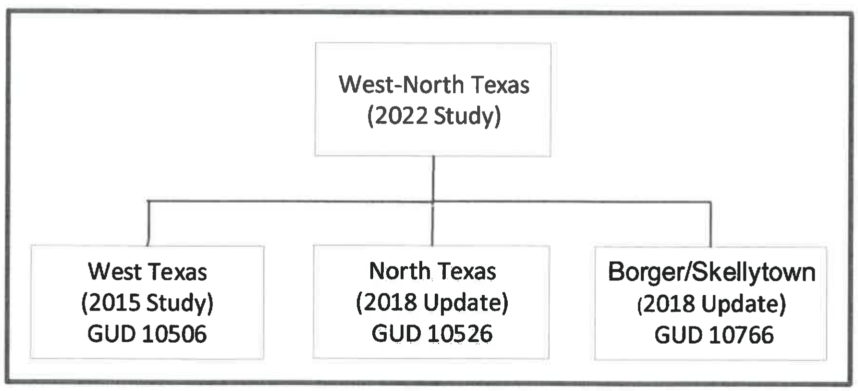


Figure 1. West-North Texas Consolidated Service Areas

Recommended parameters (*i.e.*, projection curves, projection lives and future net salvage rates) estimated for the WNSA were derived from a 2022 combined analysis of all (*i.e.*, statewide) TGS Service Areas. Proposed depreciation rates for the WNSA were derived from a weighted average of accrual rates developed separately for WTSA, NTSA and BSSA. Rates for each of the three Service Areas were derived from age distributions of surviving plant, recorded depreciation reserves and average net salvage rates specific to each Service Area.

TGS also requested removal of the Fort Bliss Service Area (FBSA) from the WTSA before combining WTSA, NTSA and BSSA into the WNSA. FBSA was therefore included in the 2022 study as a stand–alone service area, becoming one of four remaining service areas as illustrated in Figure 2 below.

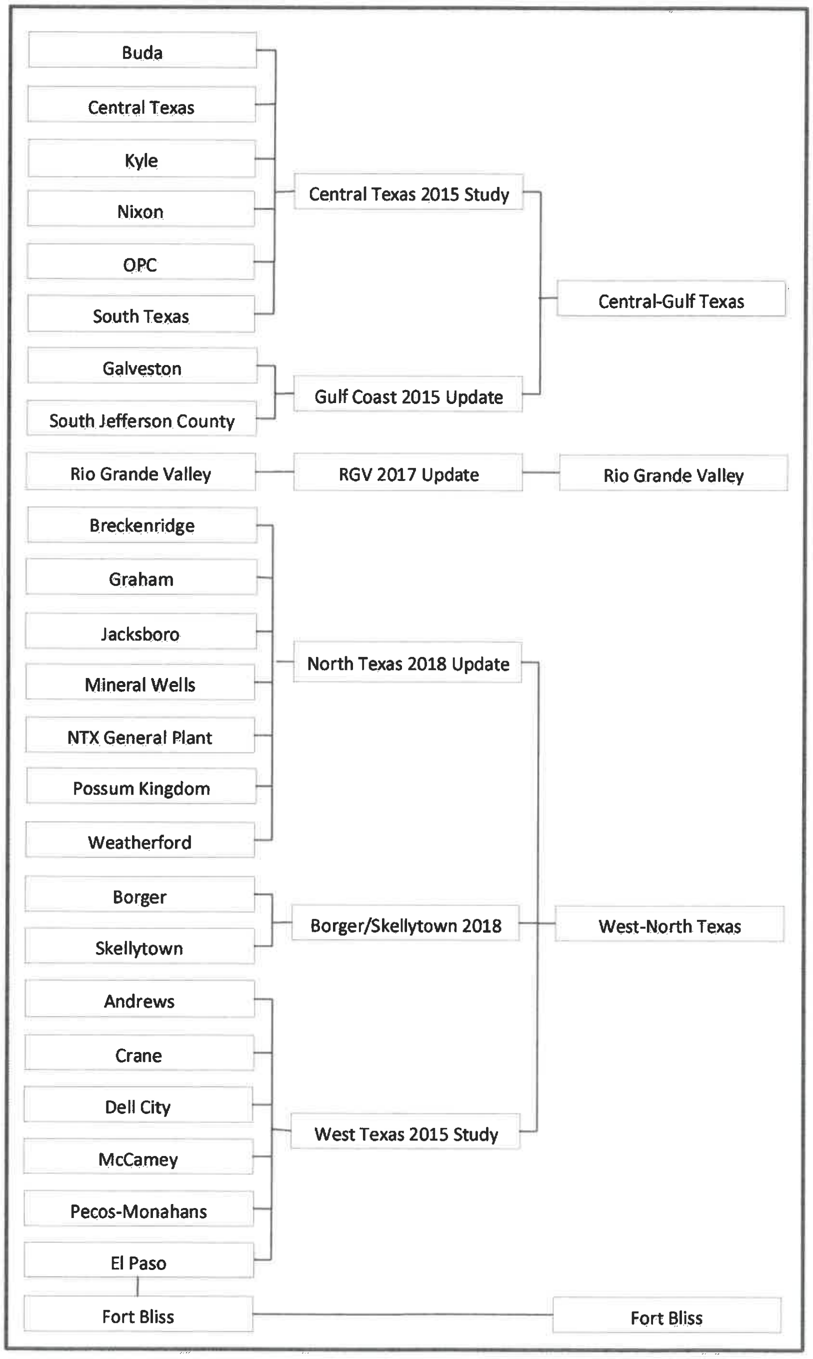


Figure 2. Texas Gas Service Areas

Current depreciation rates for WTSA were developed in a 2015 study and approved in GUD 10506 (Order Dated September 27, 2016). Current rates for NTSA were developed in a 2018 study and approved by the Commission pursuant to a Settlement Agreement in GUD 10739 (Order dated November 13, 2018). Current rates for BSSA were developed in a 2018 update of a 2015 study approved by the Commission in GUD 10766 (Order dated February 5, 2019).

Current depreciation rates for TGSD were developed in a 2019 Central-Gulf Service Area (CGSA) study based on December 31, 2018 plant and depreciation reserves. Rates developed for TGSD were approved by the Commission pursuant to a Settlement Agreement in GUD 10928 (Order dated August 4, 2020).

The principal findings and recommendations of the 2022 WNSA study are summarized in Section IV (Statements) of this report. Section IV includes statements for the NTSA, WTSA, FBSA, BSSA and TGS Division.

Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides 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 including projection life, projection curve and future net salvage rates. Statement F also contains current and proposed statistics including average service lives, average remaining lives, and average net salvage rates.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to Company official records;
- Discussions with TGS 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 rate categories in NTSA, WTSA, FBSA, BSSA 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 currently approved amortization categories.

PROPOSED DEPRECIATION RATES

Table 1 below contains a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation rates recommended for WNSA.

	Accrual Rates			2022 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	2.06%	2.60%	0.54%	$ 988,059	$ 1,250,892	$ 262,833
Distribution	2.34%	2.97%	0.63%	14,360,786	18,216,069	3,855,283
General Plant	6.72%	6.16%	-0.56%	3,949,797	3,621,510	(328,287)
Total	2.68%	3.20%	0.52%	$19,298,643	$23,088,471	$3,789,828

Table 1. West-North Texas Service Area

Primary account depreciation rates equivalent to a composite rate of 3.20 percent are recommended for WNSA. Depreciation expense is currently accrued at rates that composite to 2.68 percent. The recommended change in the composite depreciation rate is an increase of 0.52 percentage points.

A continued application of current rates would produce annualized depreciation expense of $19,298,643 compared with an annualized expense of $23,088,471 using the rates recommended in this study. The resulting 2022 expense increase is $3,789,828. The computed change in annualized accruals includes an increase of $1,112,086 attributable to an amortization of a $36,337,975 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2022 study. Of the 21 plant accounts included in the WNSA, rate reductions are recommended for 4 accounts, rate increases for 16 accounts and no rate change for 1 account.

Table 2 below contains a summary of annual rates and accruals for FBSA.

	Accrual Rates			2022 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	2.07%	2.41%	0.34%	$ 155,835	$ 181,669	$ 25,833
General Plant	6.58%	6.67%	0.09%	3,989	4,039	50
Total	2.10%	2.44%	0.34%	$ 159,824	$ 185,707	$ 25,883

Table 2. Fort Bliss Service Area

Primary account depreciation rates equivalent to a composite rate of 2.44 percent are recommended for the FBSA. Depreciation expense is currently accrued at rates that composite to 2.10 percent. The recommended change in the composite depreciation rate is an increase of 0.34 percentage points.

A continued application of current rates would produce annualized depreciation expense of $159,824 compared with an annualized expense of $185,707 using the rates developed in this study. The resulting 2022 expense increase is $25,883. The computed change in annualized accruals includes an increase of $6,150 attributable to an amortization of a $324,639 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2022 study. Of the 9 plant accounts included in the FBSA, a rate reduction is recommended for 1 account and rate increases for 8 accounts.

Table 3 below provides a summary of annual rates and accruals for the TGS Division.

	Accrual Rates			2022 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
General Plant	6.20%	5.83%	-0.37%	$ 640,836	$ 603,047	(37,788)
Total	6.20%	5.83%	-0.37%	$ 640,836	$ 603,047	$ (37,788)

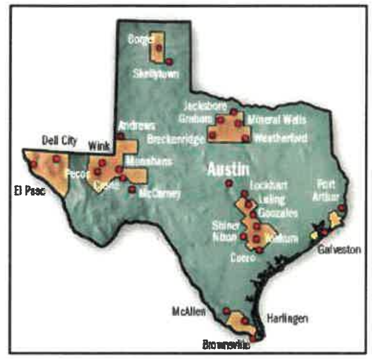
Table 3. TGS Division

Primary account depreciation rates equivalent to a composite rate of 5.83 percent are recommended for the Division. Depreciation expense is currently accrued at rates that composite to 6.20 percent.

A continued application of current rates would produce annualized depreciation expense of $640,836 compared with an annualized expense of $603,047 using the rates developed in this study. The resulting 2022 expense reduction is $37,788. Of the 5 plant accounts included in the TGS Division, a rate reduction is recommended for 1 account and no rate changes for 4 accounts. Computed and redistributed reserves are equal for all plant accounts.

COMPANY PROFILE

GENERAL



Texas Gas Service is a division of Tulsa–based ONE Gas, Inc. (NYSE: OGS), one of the largest publicly traded, 100 percent–regulated natural gas utilities in the United States. ONE Gas provides natural gas distribution services to more than 2 million customers in Oklahoma, Kansas and Texas. Headquartered in Tulsa, Oklahoma, its companies include the largest natural gas distributor in Oklahoma and Kansas, and the third largest in Texas, in terms of customers.

ONE Gas is a successor to the company founded in 1906 as Oklahoma Natural Gas Company, and became ONEOK, Inc. (NYSE: OKE) in 1980. ONEOK separated its natural gas distribution business in 2014 to create ONE Gas, Inc.

Texas Gas Service was founded in Wink, Texas in 1929 as Southern Union Gas. The Company grew to become the third largest natural gas distribution company in Texas. In January 2003, ONEOK purchased these Texas assets and named the distribution company Texas Gas Service Company.

GAS UTILITY OPERATIONS

By December 31, 2021, Texas Gas Service owned and operated approximately 10,720 miles of distribution mains and 309 miles of transmission mains. The distribution system consists of 5,343 miles of cathodically protected pipe, 463 miles of unprotected steel pipe, 24 miles of cast/wrought iron and 4,890 miles of plastic mains. All transmission mains are cathodically protected.

At the end of 2021, Texas Gas Service maintained 697,577 service lines consisting of 48,299 unprotected lines, 227,764 cathodically protected lines, 145 copper lines and 384,158 plastic lines.

The Company owns and operates 152 city gate stations serving wholesale and retail customers. A total of 20 service centers are located in Central–Gulf Texas, West–North Texas, Rio Grande Valley and Fort Bliss.

The majority of natural gas supply is provided under contracts from a number of suppliers awarded through a competitive bid process. The remainder of natural gas supply is purchased from a combination of direct wellhead production, natural gas processing plants, natural gas marketers and production companies.

CUSTOMER BASE

Texas Gas Service provides natural gas service to over 690,267 customers including residential, commercial, industrial, and transportation in more than 100 communities.

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by TGS for WNSA, Fort Bliss and the TGS Division.

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 2022 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 2022 study was assembled by appending 2019–2021 plant and reserve activity to the statewide data base used in conducting a 2019 study for the Central-Gulf Service Area (CGSA). 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 at December 31, 2021 were derived by Foster Associates in a forward–flow calculation in which accounting activity was appended to the database used in conducting the 2019 CGSA study. The accuracy and completeness of the assembled data base was validated by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each rate category to the official plant records of the Company over the period 2019-2021. Derived age distributions on December 31, 2021 were also reconciled to the continuing property records of TGS. Annual plant activity prior to 2019 was reconciled in the 2019 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 2022 study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2022 study are the Iowa–type curves mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second– and third–degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. Observed proportions surviving were then fitted by a weighted least–squares procedure to the Iowa–curve family (using the projection life derived from the polynomial hazard function) to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

The set of computer programs used in the TGS study provides multiple rolling–band and shrinking–band analyses of an account. Observation bands are defined for a "retirement era" that restricts the analysis to retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output and algorithms for calculating depreciation rates and accruals.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are viewed as “interim” retirements that will be replaced in order to maintain the integrity of the system. Plant facilities may also be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts were treated as full mortality categories in the TGS study.

Plant accounting and depreciation reserve records are currently maintained by TGS for five (5) 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 five 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: Central-Gulf Texas; Rio Grande Valley; North Texas; Borger/Skellytown; and West Texas.

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. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

As noted above, depreciation reserve records are maintained by TGS for five service areas. Future net salvage rates were estimated in the TGS study from the combined database of the five service areas. 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 2022 study to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as the weighting of future net salvage estimates changes from the installation of subsequent plant additions. 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. First In, First Out (FIFO) pricing of retirements used by TGS also exacerbates high measurements of realized net salvage rates.

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 incurred 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 implied from an assumed continued application of the recently applied standards were projected using a per–unit formulation of future net salvage rates. Trend indications derived from this analysis were comparable to those observed in the banding analyses.

It is the opinion of Foster Associates that it is premature to adjust currently approved net salvage rates for mains and services to rates indicated in the banding and per–unit analyses. The magnitude and trend of future net salvage rates will remain unstable until the new standards have been applied for a number of years.

Based on a consideration of the above factors, Foster Associates is recommending tempered increases in future net salvage rates in the direction of the trends observed in both the banding and per–unit analyses. It is likely, however, that costs of removal will continue to escalate beyond the net salvage rates recommended in the current study. Future net salvage rates of –40 percent are recommended for transmission and distribution mains. A rate of –60 percent is recommended for distribution services.

Depreciation Reserve Analysis

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measurement of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor or projection curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of multiple vintages. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or 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. When depreciation rates are derived from settlements or other Commission directives, some accounts may appear over–depreciated and other accounts may appear under–depreciated relative to calculated or theoretical reserves. Differences between theoretical and recorded reserves also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of conducting 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-life and net salvage parameters.

A redistribution of recorded reserves is considered appropriate for TGS at this time. Offsetting reserve imbalances attributable to both the passage of time and recommended parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

Recorded reserves were rebalanced by multiplying the calculated reserve for each primary account within a function by the ratio of the total recorded reserves to the calculated reserve. The sum of the redistributed reserves is, therefore, equal to the total recorded depreciation reserve before the redistribution. Reserves for general amortizable categories were adjusted by replacing recorded reserves with current theoretical reserves and distributing reserve imbalances to depreciable categories.

Statement C provides a comparison of recorded, computed and redistributed reserves on December 31, 2021. The recorded reserve for WNSA was $119,402,307 or 16.6 percent of the depreciable plant investment. The corresponding computed reserve is $155,740,282 or 21.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $36,337,975 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Recorded reserves for the FBSA on December 31, 2021 were $1,140,637 or 15.0 percent of the depreciable plant investment. The corresponding computed reserve is $1,465,267 or 19.36 percent of the depreciable plant investment.

Recorded reserves for the TGS Division on December 31, 2021 were set equal to computed reserves of $2,569,342 or 24.9 percent of the amortizable plant investment. The equivalency between recorded and computed reserves was achieved by transferring recorded reserves in proportion to customer counts, from Account 390.10 (Structures and Improvements) from each service area in which investments were recorded in Account 390.10, Reserve amounts totaling $474,312 transferred from each service area are shown in Figure 3 below.

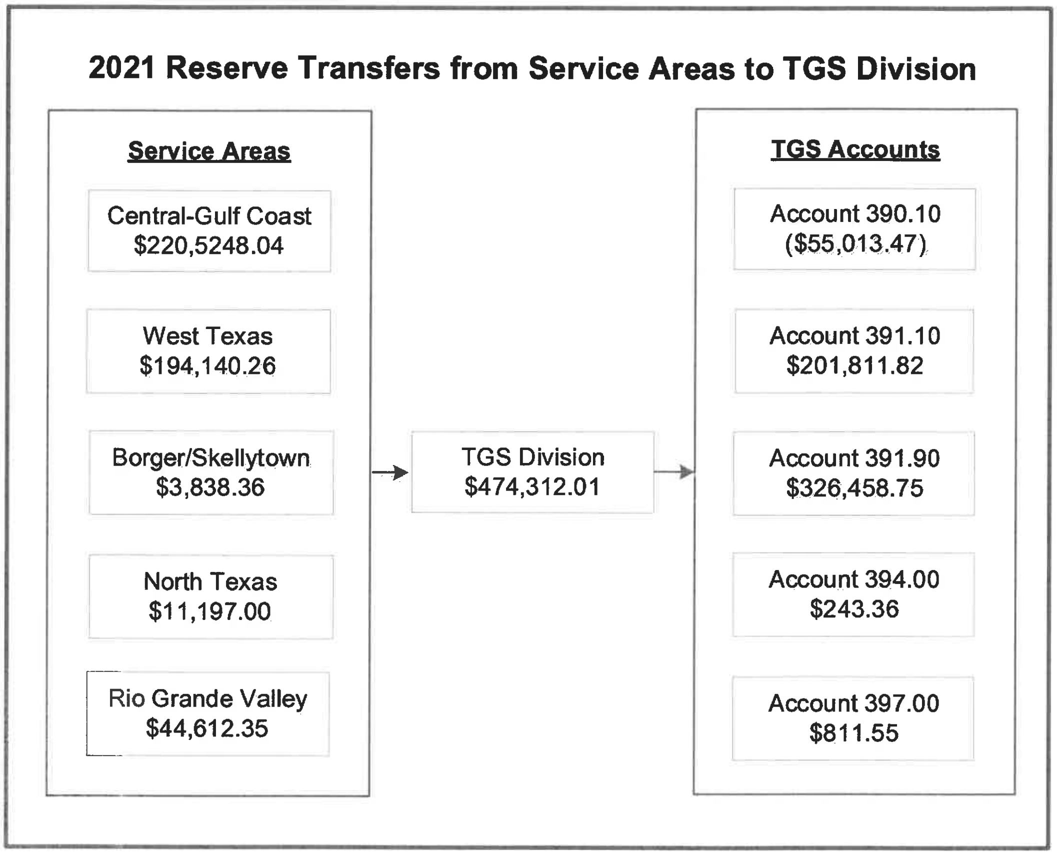


Figure 3. Reserve Transfers to TGS Division

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2022 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.

As noted earlier, plant accounting and depreciation reserve records are maintained by TGS for five (5) 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 five service areas. Average service lives and remaining service lives were distinguished among service areas in the development of generation arrangements unique to each service area. 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 unique to each service area.

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 ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting included in this study is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for the selected plant categories relieves TGS of the burden of maintaining detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

The treatment of amortization accounts in the current study was designed to report annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Proposed accrual rates shown in Statement A, however, are the reciprocal of amortization periods to be applied to after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period. This reporting is consistent with rates prescribed by the Commission for amortization accounts in prior proceedings.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and proposed service life and net salvage parameters recommended for TGS plant and equipment categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2022 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2021.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of plant investments (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by TGS for the mix of investments recorded on December 31, 2021. Similarly, proposed depreciation accruals shown on Statements B are the product of plant investments and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

Statements A through F

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2021)			Proposed (at 12/31/2021)		
	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
WEST-NORTH TEXAS						
TRANSMISSION PLANT						
367.00 Mains	1.96%		1.96%	1.73%	0.81%	2.54%
369.00 Meas. and Reg. Station Equipment	3.53%		3.53%	2.72%	0.76%	3.49%
Total Transmission Plant	2.06%		2.06%	1.80%	0.80%	2.60%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	2.31%		2.31%	3.18%	0.32%	3.49%
376.00 Mains	1.94%		1.94%	1.57%	0.73%	2.30%
376.90 Mains - Cathodic Protection	4.16%		4.16%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	2.25%		2.25%	1.73%	0.51%	2.24%
379.00 Meas. and Reg. Station Equip. - City Gate	1.71%		1.71%	1.60%	0.43%	2.04%
380.00 Services	2.26%		2.26%	1.91%	1.31%	3.22%
381.00 Meters	3.79%		3.79%	3.46%	0.61%	4.07%
383.00 House Regulators	2.51%		2.51%	2.97%	0.57%	3.54%
385.00 Industrial Meas. and Reg. Station Equip.	2.14%		2.14%	1.81%	0.57%	2.38%
386.00 Other Property on Customers' Premises	4.86%		4.86%	14.31%	-0.07%	14.25%
Total Distribution Plant	2.34%		2.34%	2.12%	0.85%	2.97%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.65%		2.65%	2.73%	0.26%	2.99%
392.00 Transportation Equipment	9.66%		9.66%	8.57%	-0.80%	7.78%
396.00 Power Operated Equipment	7.04%		7.04%	6.23%	-0.33%	5.90%
Total Depreciable	6.66%		6.66%	6.05%	-0.34%	5.72%
Amortizable						
391.10 Office Furniture and Fixtures	6.41%		6.41%	← 15 Year Amortization →		6.67%
391.90 Computers and Electronic Equipment	8.26%		8.26%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment	6.55%		6.55%	← 15 Year Amortization →		6.67%
394.00 Tools, Shop and Garage Equipment	6.39%		6.39%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.65%		6.65%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	6.76%		6.76%	6.41%		6.41%
Total General Plant	6.72%		6.72%	6.28%	-0.12%	6.16%
TOTAL WEST-NORTH TEXAS	2.68%		2.68%	2.44%	0.77%	3.20%

TEXAS GAS SERVICE
Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual			Proposed 2022 Annualized Accrual			
		Investment	Net Salvage	Total	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								
367.00 Mains	$ 44,997,886	$ 879,848	$ -	$ 879,848	$ 780,530	$ 363,450	$ 1,143,980	$ 264,132
369.00 Meas. and Reg. Station Equipment	3,066,096	108,211		108,211	83,522	23,390	106,912	(1,299)
Total Transmission Plant	$ 48,063,982	$ 988,059	$ -	$ 988,059	$ 864,052	$ 386,840	$ 1,250,892	$ 262,833
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 305,151	$ 7,059	$ -	$ 7,059	$ 9,694	$ 970	$ 10,663	$ 3,604
376.00 Mains	283,923,020	5,509,111		5,509,111	4,468,450	2,074,378	6,542,827	1,033,716
376.90 Mains - Cathodic Protection	26,337,052	1,095,137		1,095,137	1,653,227		1,653,227	558,090
378.00 Meas. and Reg. Station Equip. - General	15,066,670	338,359		338,359	260,007	76,927	336,934	(1,425)
379.00 Meas. and Reg. Station Equip. - City Gate	7,418,677	126,977		126,977	119,054	32,103	151,158	24,181
380.00 Services	188,991,476	4,277,018		4,277,018	3,614,877	2,472,893	6,087,770	1,810,752
381.00 Meters	58,743,502	2,226,823		2,226,823	2,033,039	360,305	2,393,344	166,521
383.00 House Regulators	15,305,163	383,453		383,453	455,200	87,278	542,478	159,025
385.00 Industrial Meas. and Reg. Station Equip.	17,060,815	365,863		365,863	309,568	97,179	406,747	40,884
386.00 Other Property on Customers' Premises	638,228	30,986		30,986	91,358	(437)	90,921	59,935
Total Distribution Plant	$ 613,789,754	$ 14,360,786	$ -	$ 14,360,786	$ 13,014,473	$ 5,201,595	$ 18,216,069	$ 3,855,283
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 8,167,758	$ 216,569	$ -	$ 216,569	$ 222,799	$ 21,508	$ 244,307	$ 27,738
392.00 Transportation Equipment	10,613,217	1,025,367		1,025,367	909,878	(84,629)	825,249	(200,118)
396.00 Power Operated Equipment	2,380,590	167,499		167,499	148,276	(7,892)	140,384	(27,115)
Total Depreciable	$ 21,161,565	$ 1,409,435	$ -	$ 1,409,435	$ 1,280,954	$ (71,013)	$ 1,209,941	$ (199,494)
Amortizable								
391.10 Office Furniture and Fixtures	$ 1,379,239	$ 88,375	$ -	$ 88,375	$ 80,212	$ -	$ 80,212	$ (8,163)
391.90 Computers and Electronic Equipment	3,756,154	310,398		310,398	189,010		189,010	(121,388)
393.00 Stores Equipment	30,808	2,018		2,018	2,034		2,034	16
394.00 Tools, Shop and Garage Equipment	6,839,251	437,192		437,192	437,675		437,675	483
397.00 Communication Equipment	25,593,465	1,702,380		1,702,380	1,702,639		1,702,639	259
398.00 Miscellaneous Equipment								
Total Amortizable	$ 37,598,917	$ 2,540,362	$ -	$ 2,540,362	$ 2,411,570	$ -	$ 2,411,570	$ (128,793)
Total General Plant	$ 58,760,482	$ 3,949,797	$ -	$ 3,949,797	$ 3,692,524	$ (71,013)	$ 3,621,510	$ (328,287)
TOTAL WEST-NORTH TEXAS	$ 720,614,218	$ 19,298,643	$ -	$ 19,298,643	$ 17,571,049	$ 5,517,422	$ 23,088,471	$ 3,789,828

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
WEST-NORTH TEXAS							
TRANSMISSION PLANT							
367.00 Mains	$ 44,997,886	$ 2,633,201	5.85%	$ 4,278,965	9.51%	$ 2,808,359	6.24%
369.00 Meas. and Reg. Station Equipment	3,066,096	607,496	19.81%	696,629	22.72%	432,338	14.10%
Total Transmission Plant	$ 48,063,982	$ 3,240,697	6.74%	$ 4,975,594	10.35%	$ 3,240,697	6.74%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 305,151	$ 154,915	50.77%	$ 169,024	55.39%	$ 121,446	39.80%
376.00 Mains	283,923,020	49,393,559	17.40%	47,301,523	16.66%	33,601,976	11.83%
376.90 Mains - Cathodic Protection	26,337,052	1,835,399	6.97%	11,678,177	44.34%	11,678,177	44.34%
378.00 Meas. and Reg. Station Equip. - General	15,066,670	2,275,373	15.10%	1,459,946	9.69%	1,049,417	6.97%
379.00 Meas. and Reg. Station Equip. - City Gate	7,418,677	1,788,289	24.11%	1,286,900	17.35%	929,006	12.52%
380.00 Services	188,991,476	21,324,762	11.28%	35,351,172	18.71%	26,092,832	13.81%
381.00 Meters	58,743,502	15,243,134	25.95%	22,508,059	38.32%	16,840,097	28.67%
383.00 House Regulators	15,305,163	4,043,955	26.42%	6,826,833	44.60%	5,122,629	33.47%
385.00 Industrial Meas. and Reg. Station Equip.	17,060,815	4,117,551	24.13%	3,974,192	23.29%	2,975,439	17.44%
386.00 Other Property on Customers' Premises	638,228	266,308	41.73%	583,866	91.48%	441,041	69.10%
Total Distribution Plant	$ 613,789,754	$ 100,443,244	16.36%	$ 131,139,692	21.37%	$ 98,852,060	16.11%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 8,167,758	$ 811,818	9.94%	$ 2,686,863	32.90%	$ 1,625,367	19.90%
392.00 Transportation Equipment	10,613,217	5,977,955	56.33%	3,258,025	30.70%	2,266,294	21.35%
396.00 Power Operated Equipment	2,380,590	1,452,034	60.99%	841,120	35.33%	578,902	24.32%
Total Depreciable	$ 21,161,565	$ 8,241,807	38.95%	$ 6,786,008	32.07%	$ 4,470,562	21.13%
Amortizable							
391.10 Office Furniture and Fixtures	$ 1,379,239	$ 415,679	30.14%	$ 794,128	57.58%	$ 794,128	57.58%
391.90 Computers and Electronic Equipment	3,756,154	2,177,642	57.98%	2,906,965	77.39%	2,906,965	77.39%
393.00 Stores Equipment	30,808	10,482	34.02%	22,985	74.61%	22,985	74.61%
394.00 Tools, Shop and Garage Equipment	6,839,251	1,309,047	19.14%	2,781,990	40.68%	2,781,990	40.68%
397.00 Communication Equipment	25,593,465	5,160,307	20.16%	6,332,920	24.74%	6,332,920	24.74%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 37,598,917	$ 9,073,157	24.13%	$ 12,838,988	34.15%	$ 12,838,988	34.15%
Total General Plant	$ 58,760,482	$ 17,314,964	29.47%	$ 19,624,996	33.40%	$ 17,309,550	29.46%
TOTAL WEST-NORTH TEXAS	$ 720,614,218	$ 120,998,905	16.79%	$ 155,740,282	21.61%	$ 119,402,307	16.57%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
WEST-NORTH TEXAS							
TRANSMISSION PLANT							
367.00 Mains	$ 44,997,886	$ 3,830,794	8.51%	$ (1,022,435)	-2.27%	$ 2,808,359	6.24%
369.00 Meas. and Reg. Station Equipment	3,066,096	413,120	13.47%	19,218	0.63%	432,338	14.10%
Total Transmission Plant	$ 48,063,982	$ 4,243,914	8.83%	$ (1,003,217)	-2.09%	$ 3,240,697	6.74%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 305,151	$ 110,396	36.18%	$ 11,051	3.62%	$ 121,446	39.80%
376.00 Mains	283,923,020	34,288,572	12.08%	(686,596)	-0.24%	33,601,976	11.83%
376.90 Mains - Cathodic Protection	26,337,052	11,678,177	44.34%			11,678,177	44.34%
378.00 Meas. and Reg. Station Equip. - General	15,066,670	1,370,759	9.10%	(321,343)	-2.13%	1,049,417	6.97%
379.00 Meas. and Reg. Station Equip. - City Gate	7,418,677	853,428	11.50%	75,578	1.02%	929,006	12.52%
380.00 Services	188,991,476	25,005,950	13.23%	1,086,882	0.58%	26,092,832	13.81%
381.00 Meters	58,743,502	15,629,955	26.61%	1,210,142	2.06%	16,840,097	28.67%
383.00 House Regulators	15,305,163	4,808,443	31.42%	314,186	2.05%	5,122,629	33.47%
385.00 Industrial Meas. and Reg. Station Equip.	17,060,815	2,397,309	14.05%	578,130	3.39%	2,975,439	17.44%
386.00 Other Property on Customers' Premises	638,228	440,082	68.95%	959	0.15%	441,041	69.10%
Total Distribution Plant	$ 613,789,754	$ 96,583,071	15.74%	$ 2,268,989	0.37%	$ 98,852,060	16.11%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 8,167,758	$ 1,464,530	17.93%	$ 160,837	1.97%	$ 1,625,367	19.90%
392.00 Transportation Equipment	10,613,217	2,586,177	24.37%	(319,883)	-3.01%	2,266,294	21.35%
396.00 Power Operated Equipment	2,380,590	601,446	25.26%	(22,545)	-0.95%	578,902	24.32%
Total Depreciable	$ 21,161,565	$ 4,652,153	21.98%	$ (181,591)	-0.86%	$ 4,470,562	21.13%
Amortizable							
391.10 Office Furniture and Fixtures	$ 1,379,239	$ 794,128	57.58%	$ -		$ 794,128	57.58%
391.90 Computers and Electronic Equipment	3,756,154	2,906,965	77.39%			2,906,965	77.39%
393.00 Stores Equipment	30,808	22,985	74.61%			22,985	74.61%
394.00 Tools, Shop and Garage Equipment	6,839,251	2,781,990	40.68%			2,781,990	40.68%
397.00 Communication Equipment	25,593,465	6,332,920	24.74%			6,332,920	24.74%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 37,598,917	$ 12,838,988	34.15%	$ -		$ 12,838,988	34.15%
Total General Plant	$ 58,760,482	$ 17,491,141	29.77%	$ (181,591)	-0.31%	$ 17,309,550	29.46%
TOTAL WEST-NORTH TEXAS	$ 720,614,218	$ 118,318,126	16.42%	$ 1,084,181	0.15%	$ 119,402,307	16.57%

TEXAS GAS SERVICE
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									
367.00 Mains	$ 45,522,622	$524,736	$ 44,997,886	-881.0%	-40.0%	$ (4,623,072)	$ (17,999,154)	($22,622,226)	-49.7%
369.00 Meas. and Reg. Station Equipment	3,138,289	72,193	3,066,096	-251.4%	-25.0%	(181,493)	(766,524)	(948,017)	-30.2%
Total Transmission Plant	$ 48,660,911	$ 596,929	$ 48,063,982	-804.9%	-39.0%	$ (4,804,565)	$ (18,765,678)	$ (23,570,243)	-48.4%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 307,713	$ 2,562	$ 305,151		-10.0%	$ -	$ (30,515)	$ (30,515)	-9.9%
376.00 Mains	300,102,403	16,179,383	283,923,020	-199.0%	-40.0%	(32,198,721)	(113,569,208)	(145,767,929)	-48.6%
376.90 Mains - Cathodic Protection	33,820,966	7,483,914	26,337,052						
378.00 Meas. and Reg. Station Equip. - General	15,990,071	923,401	15,066,670	-145.2%	-25.0%	(1,340,510)	(3,766,668)	(5,107,177)	-31.9%
379.00 Meas. and Reg. Station Equip. - City Gate	7,636,897	218,220	7,418,677	-125.4%	-25.0%	(273,617)	(1,854,669)	(2,128,286)	-27.9%
380.00 Services	196,922,730	7,931,254	188,991,476	-369.9%	-60.0%	(29,334,577)	(113,394,886)	(142,729,463)	-72.5%
381.00 Meters	64,897,481	6,153,979	58,743,502	-56.7%	-15.0%	(3,487,404)	(8,811,525)	(12,298,929)	-19.0%
383.00 House Regulators	16,090,104	784,941	15,305,163	-136.8%	-15.0%	(1,073,704)	(2,295,774)	(3,369,478)	-20.9%
385.00 Industrial Meas. and Reg. Station Equip.	18,406,051	1,345,236	17,060,815	-48.6%	-30.0%	(653,623)	(5,118,245)	(5,771,868)	-31.4%
386.00 Other Property on Customers' Premises	718,421	80,193	638,228	19.8%		15,878		15,878	2.2%
Total Distribution Plant	$ 654,892,837	$ 41,103,083	$ 613,789,754	-166.3%	-40.5%	$ (68,346,277)	$ (248,841,490)	$ (317,187,767)	-48.4%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 8,728,215	$ 560,457	$ 8,167,758	-6.5%	-10.0%	$ (36,368)	$ (816,776)	$ (853,143)	-9.8%
392.00 Transportation Equipment	14,459,515	3,846,298	10,613,217	2.9%	10.0%	111,252	1,061,322	1,172,574	8.1%
396.00 Power Operated Equipment	3,374,914	994,324	2,380,590	8.5%	5.0%	84,998	119,030	204,027	6.0%
Total Depreciable	$ 26,562,644	$ 5,401,079	$ 21,161,565	3.0%	1.7%	$ 159,882	$ 363,575	$ 523,458	2.0%
Amortizable									
391.10 Office Furniture and Fixtures	$ 3,532,401	$2,153,162	$ 1,379,239			$ -	$ -		
391.90 Computers and Electronic Equipment	4,646,217	890,063	3,756,154						
393.00 Stores Equipment	149,172	118,364	30,808						
394.00 Tools, Shop and Garage Equipment	10,712,537	3,873,286	6,839,251						
397.00 Communication Equipment	27,771,828	2,178,363	25,593,465						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 46,812,155	$ 9,213,238	$ 37,598,917			$ -	$ -		
Total General Plant	$ 73,374,799	$ 14,614,317	$ 58,760,482	1.1%	0.6%	$ 159,882	$ 363,575	$ 523,458	0.7%
TOTAL WEST-NORTH TEXAS	$ 776,928,547	$ 56,314,329	$ 720,614,218	-129.6%	-37.1%	$ (72,990,960)	$ (267,243,593)	$ (340,234,553)	-43.8%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2021) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
WEST-NORTH TEXAS												
TRANSMISSION PLANT												
367.00 Mains							60.00	L1	60.45	52.68	-49.7	-40.0
369.00 Meas. and Reg. Station Equipment							40.00	L1	40.50	31.81	-30.2	-25.0
Total Transmission Plant									3.74	50.76	-48.4	-39.0
DISTRIBUTION PLANT												
375.10 Structures and Improvements							40.00	R4	41.44	20.57	-9.9	-10.0
376.00 Mains							67.00	R2	67.10	55.71	-48.6	-40.0
376.90 Mains - Cathodic Protection							15.00	SQ	15.00	8.84		
378.00 Meas. and Reg. Station Equip. - General							60.00	R1	60.35	52.72	-31.9	-25.0
379.00 Meas. and Reg. Station Equip. - City Gate							65.00	R1.5	65.72	55.23	-27.9	-25.0
380.00 Services							55.00	R2	55.33	45.35	-72.5	-60.0
381.00 Meters							30.00	R2.5	32.89	21.20	-19.0	-15.0
383.00 House Regulators							35.00	R3	39.58	23.03	-20.9	-15
385.00 Industrial Meas. and Reg. Station Equip.							58.00	R1.5	58.24	47.29	-31.4	-30.0
386.00 Other Property on Customers' Premises							20.00	S3	25.03	2.18	2.2	
Total Distribution Plant									50.05	39.66	-48.4	-40.5
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements							43.00	R3	42.95	30.17	-9.8	-10.0
392.00 Transportation Equipment							13.00	L1	13.62	8.79	8.1	10.0
396.00 Power Operated Equipment							18.00	L1.5	18.61	11.86	6.0	5.0
Total Depreciable									19.28	12.85	2.0	1.7
Amortizable												
391.10 Office Furniture and Fixtures							15.00	SQ	15.00	6.50		
391.90 Computers and Electronic Equipment							7.00	SQ	7.00	4.44		
393.00 Stores Equipment							15.00	SQ	15.00	3.81		
394.00 Tools, Shop and Garage Equipment							15.00	SQ	15.00	9.09		
397.00 Communication Equipment							15.00	SQ	15.00	11.29		
398.00 Miscellaneous Equipment												
Total Amortizable									13.46	9.45		
Total General Plant									15.10	10.41	0.7	0.6
TOTAL WEST-NORTH TEXAS									39.80	33.49	-43.8	-37.1

Statements A through F

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2021)			Proposed (at 12/31/2021)		
	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
NORTH TEXAS						
TRANSMISSION PLANT						
367.00 Mains	2.34%		2.34%	1.85%	0.75%	2.60%
369.00 Meas. and Reg. Station Equipment	3.99%		3.99%	2.86%	0.71%	3.57%
Total Transmission Plant	2.84%		2.84%	2.16%	0.74%	2.89%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	4.38%		4.38%	4.97%	0.49%	5.46%
376.00 Mains	2.03%		2.03%	1.63%	0.69%	2.32%
376.90 Mains - Cathodic Protection	6.67%		6.67%	← 15 Year Amortization →		6.57%
378.00 Meas. and Reg. Station Equip. - General	2.33%		2.33%	1.74%	0.45%	2.19%
379.00 Meas. and Reg. Station Equip. - City Gate	1.90%		1.90%	1.62%	0.42%	2.04%
380.00 Services	2.77%		2.77%	2.03%	1.33%	3.36%
381.00 Meters	5.11%		5.11%	4.10%	0.62%	4.72%
383.00 House Regulators	3.44%		3.44%	3.33%	0.48%	3.81%
385.00 Industrial Meas. and Reg. Station Equip.	2.35%		2.35%	1.86%	0.57%	2.43%
386.00 Other Property on Customers' Premises	18.62%		18.62%	35.48%		35.48%
Total Distribution Plant	2.48%		2.48%	2.00%	0.77%	2.77%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	3.07%		3.07%	2.07%	0.20%	2.27%
392.00 Transportation Equipment	10.38%		10.38%	6.17%	-0.63%	5.54%
396.00 Power Operated Equipment	9.79%		9.79%	4.50%	-0.16%	4.34%
Total Depreciable	8.37%		8.37%	4.87%	-0.35%	4.52%
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	7.00%		7.00%	6.88%		6.88%
Total General Plant	7.75%		7.75%	5.77%	-0.19%	5.58%
TOTAL NORTH TEXAS	2.89%		2.89%	2.29%	0.70%	2.99%

TEXAS GAS SERVICE
Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual Investment	Current 2022 Annualized Accrual Net Salvage	Current 2022 Annualized Accrual Total	Proposed 2022 Annualized Accrual Investment	Proposed 2022 Annualized Accrual Net Salvage	Proposed 2022 Annualized Accrual Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
NORTH TEXAS								
TRANSMISSION PLANT								
367.00 Mains	$ 1,722,259	$ 40,301	$ -	$ 40,301	$ 31,862	$ 12,917	$ 44,779	$ 4,478
369.00 Meas. and Reg. Station Equipment	750,393	29,941		29,941	21,461	5,328	26,789	(3,152)
Total Transmission Plant	$ 2,472,652	$ 70,242	$ -	$ 70,242	$ 53,323	$ 18,245	$ 71,568	$ 1,326
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 28,085	$ 1,230	$ -	$ 1,230	$ 1,396	$ 138	$ 1,533	$ 303
376.00 Mains	50,884,921	1,032,964		1,032,964	829,424	351,106	1,180,530	147,566
376.90 Mains - Cathodic Protection	2,833,700	189,008		189,008	186,196		186,196	(2,812)
378.00 Meas. and Reg. Station Equip. - General	3,526,251	82,162		82,162	61,357	15,868	77,225	(4,937)
379.00 Meas. and Reg. Station Equip. - City Gate	1,564,987	29,735		29,735	25,353	6,573	31,926	2,191
380.00 Services	16,031,590	444,075		444,075	325,441	213,220	538,661	94,586
381.00 Meters	2,707,045	138,330		138,330	110,989	16,784	127,773	(10,557)
383.00 House Regulators	752,409	25,883		25,883	25,055	3,612	28,667	2,784
385.00 Industrial Meas. and Reg. Station Equip.	1,030,085	24,207		24,207	19,160	5,871	25,031	824
386.00 Other Property on Customers' Premises	9,515	1,772		1,772	3,376		3,376	1,604
Total Distribution Plant	$ 79,368,588	$ 1,969,365	$ -	$ 1,969,365	$ 1,587,746	$ 613,172	$ 2,200,918	$ 231,553
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 986,951	$ 30,299	$ -	$ 30,299	$ 20,430	$ 1,974	$ 22,404	$ (7,896)
392.00 Transportation Equipment	2,263,461	234,947		234,947	139,656	(14,260)	125,396	(109,552)
396.00 Power Operated Equipment	479,691	46,962		46,962	21,586	(768)	20,819	(26,143)
Total Depreciable	$ 3,730,103	$ 312,208	$ -	$ 312,208	$ 181,672	$ (13,053)	$ 168,618	$ (143,590)
Amortizable								
391.10 Office Furniture and Fixtures	$ 32,029	$ 2,136	$ -	$ 2,136	$ 2,112		$ 2,112	$ (24)
391.90 Computers and Electronic Equipment	131,695	18,819		18,819	18,814		18,814	(6)
393.00 Stores Equipment	4,161	278		278	257		257	(20)
394.00 Tools, Shop and Garage Equipment	1,118,844	74,627		74,627	71,345		71,345	(3,282)
397.00 Communication Equipment	1,765,211	117,740		117,740	117,366		117,366	(374)
398.00 Miscellaneous Equipment								
Total Amortizable	$ 3,051,940	$ 213,600	$ -	$ 213,600	$ 209,894		$ 209,894	$ (3,705)
Total General Plant	$ 6,782,043	$ 525,808	$ -	$ 525,808	$ 391,566	$ (13,053)	$ 378,512	$ (147,296)
TOTAL NORTH TEXAS	$ 88,623,283	$ 2,565,414	$ -	$ 2,565,414	$ 2,032,635	$ 618,363	$ 2,650,998	$ 85,584

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
NORTH TEXAS							
TRANSMISSION PLANT							
367.00 Mains	$ 1,722,259	$ 133,389	7.74%	$ 414,507	24.07%	$ 214,585	12.46%
369.00 Meas. and Reg. Station Equipment	750,393	200,012	26.65%	229,513	30.59%	118,816	15.83%
Total Transmission Plant	$ 2,472,652	$ 333,401	13.48%	$ 644,020	26.05%	$ 333,401	13.48%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 28,085	$ 14,335	51.04%	$ 19,466	69.31%	$ 7,867	28.01%
376.00 Mains	50,884,921	2,552,026	5.02%	6,553,687	12.88%	2,648,555	5.20%
376.90 Mains - Cathodic Protection	2,833,700	1,167,648	41.21%	1,666,924	58.82%	1,666,924	58.82%
378.00 Meas. and Reg. Station Equip. - General	3,526,251	120,540	3.42%	169,754	4.81%	68,603	1.95%
379.00 Meas. and Reg. Station Equip. - City Gate	1,564,987	60,450	3.86%	137,047	8.76%	55,385	3.54%
380.00 Services	16,031,590	1,093,791	6.82%	2,200,279	13.72%	889,203	5.55%
381.00 Meters	2,707,045	595,818	22.01%	773,195	28.56%	312,473	11.54%
383.00 House Regulators	752,409	69,177	9.19%	183,243	24.35%	74,054	9.84%
385.00 Industrial Meas. and Reg. Station Equip.	1,030,085	95,985	9.32%	130,189	12.64%	52,614	5.11%
386.00 Other Property on Customers' Premises	9,515	9,515	100.00%	8,926	93.81%	3,607	37.91%
Total Distribution Plant	$ 79,368,588	$ 5,779,286	7.28%	$ 11,842,710	14.92%	$ 5,779,286	7.28%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 986,951	$ 166,135	16.83%	$ 389,449	39.46%	$ 459,722	46.58%
392.00 Transportation Equipment	2,263,461	1,328,052	58.67%	837,442	37.00%	988,553	43.67%
396.00 Power Operated Equipment	479,691	255,446	53.25%	212,594	44.32%	250,955	52.32%
Total Depreciable	$ 3,730,103	$ 1,749,633	46.91%	$ 1,439,485	38.59%	$ 1,699,230	45.55%
Amortizable							
391.10 Office Furniture and Fixtures	$ 32,029	$ 9,363	29.23%	$ 10,364	32.36%	$ 10,364	32.36%
391.90 Computers and Electronic Equipment	131,695	33,442	25.39%	41,334	31.39%	41,334	31.39%
393.00 Stores Equipment	4,161	3,119	74.95%	3,312	79.60%	3,312	79.60%
394.00 Tools, Shop and Garage Equipment	1,118,844	432,859	38.69%	470,797	42.08%	470,797	42.08%
397.00 Communication Equipment	1,765,211	791,432	44.83%	794,810	45.03%	794,810	45.03%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 3,051,940	$ 1,270,214	41.62%	$ 1,320,617	43.27%	$ 1,320,617	43.27%
Total General Plant	$ 6,782,043	$ 3,019,847	44.53%	$ 2,760,102	40.70%	$ 3,019,847	44.53%
TOTAL NORTH TEXAS	$ 88,623,283	$ 9,132,534	10.30%	$ 15,246,832	17.20%	$ 9,132,534	10.30%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
NORTH TEXAS							
TRANSMISSION PLANT							
367.00 Mains	$ 1,722,259	$ 165,208	9.59%	$ 49,377	2.87%	$ 214,585	12.46%
369.00 Meas. and Reg. Station Equipment	750,393	95,053	12.67%	23,763	3.17%	118,816	15.83%
Total Transmission Plant	$ 2,472,652	$ 260,261	10.53%	$ 73,140	2.96%	$ 333,401	13.48%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 28,085	$ 7,152	25.46%	$ 715	2.55%	$ 7,867	28.01%
376.00 Mains	50,884,921	2,671,440	5.25%	(22,884)	-0.04%	2,648,555	5.20%
376.90 Mains - Cathodic Protection	2,833,700	1,666,924	58.82%			1,666,924	58.82%
378.00 Meas. and Reg. Station Equip. - General	3,526,251	86,996	2.47%	(18,393)	-0.52%	68,603	1.95%
379.00 Meas. and Reg. Station Equip. - City Gate	1,564,987	53,570	3.42%	1,815	0.12%	55,385	3.54%
380.00 Services	16,031,590	1,022,919	6.38%	(133,716)	-0.83%	889,203	5.55%
381.00 Meters	2,707,045	275,275	10.17%	37,198	1.37%	312,473	11.54%
383.00 House Regulators	752,409	61,868	8.22%	12,187	1.62%	74,054	9.84%
385.00 Industrial Meas. and Reg. Station Equip.	1,030,085	46,446	4.51%	6,167	0.60%	52,614	5.11%
386.00 Other Property on Customers' Premises	9,515	3,607	37.91%			3,607	37.91%
Total Distribution Plant	$ 79,368,588	$ 5,896,197	7.43%	$ (116,912)	-0.15%	$ 5,779,286	7.28%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 986,951	$ 415,203	42.07%	$ 44,520	4.51%	$ 459,722	46.58%
392.00 Transportation Equipment	2,263,461	1,096,641	48.45%	(108,089)	-4.78%	988,553	43.67%
396.00 Power Operated Equipment	479,691	267,310	55.73%	(16,355)	-3.41%	250,955	52.32%
Total Depreciable	$ 3,730,103	$ 1,779,154	47.70%	$ (79,924)	-2.14%	$ 1,699,230	45.55%
Amortizable							
391.10 Office Furniture and Fixtures	$ 32,029	$ 10,364	32.36%			$ 10,364	32.36%
391.90 Computers and Electronic Equipment	131,695	41,334	31.39%			41,334	31.39%
393.00 Stores Equipment	4,161	3,312	79.60%			3,312	79.60%
394.00 Tools, Shop and Garage Equipment	1,118,844	470,797	42.08%			470,797	42.08%
397.00 Communication Equipment	1,765,211	794,810	45.03%			794,810	45.03%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 3,051,940	$ 1,320,617	43.27%			$ 1,320,617	43.27%
Total General Plant	$ 6,782,043	$ 3,099,771	45.71%	$ (79,924)	-1.18%	$ 3,019,847	44.53%
TOTAL NORTH TEXAS	$ 88,623,283	$ 9,256,230	10.44%	$ (123,696)	-0.14%	$ 9,132,534	10.30%

TEXAS GAS SERVICE
Average Net Salvage

Statement E

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
NORTH TEXAS									
TRANSMISSION PLANT									
367.00 Mains	$ 1,851,359	$ 129,100	$ 1,722,259	-73.6%	-40.0%	$ (95,018)	$ (688,904)	$ (783,921)	-42.3%
369.00 Meas. and Reg. Station Equipment	750,393		750,393		-25.0%		(187,598)	(187,598)	-25.0%
Total Transmission Plant	$ 2,601,752	$ 129,100	$ 2,472,652	-73.6%	-35.4%	$ (95,018)	$ (876,502)	$ (971,519)	-37.3%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 28,085	$ -	$ 28,085		-10.0%		$ (2,809)	$ (2,809)	-10.0%
376.00 Mains	55,566,086	4,681,165	50,884,921	-111.9%	-40.0%	(5,238,224)	(20,353,968)	(25,592,192)	-46.1%
376.90 Mains - Cathodic Protection	3,679,877	846,177	2,833,700						
378.00 Meas. and Reg. Station Equip. - General	3,912,810	386,559	3,526,251	-55.5%	-25.0%	(214,540)	(881,563)	(1,096,103)	-28.0%
379.00 Meas. and Reg. Station Equip. - City Gate	1,597,760	32,773	1,564,987	-124.4%	-25.0%	(40,770)	(391,247)	(432,016)	-27.0%
380.00 Services	17,862,806	1,831,216	16,031,590	-193.4%	-60.0%	(3,541,572)	(9,618,954)	(13,160,526)	-73.7%
381.00 Meters	4,283,336	1,576,291	2,707,045	-16.4%	-15.0%	(258,512)	(406,057)	(664,568)	-15.5%
383.00 House Regulators	1,008,087	255,678	752,409	-10.4%	-15.0%	(26,591)	(112,861)	(139,452)	-13.8%
385.00 Industrial Meas. and Reg. Station Equip.	1,119,120	89,035	1,030,085	-56.6%	-30.0%	(50,394)	(309,026)	(359,419)	-32.1%
386.00 Other Property on Customers' Premises	9,515		9,515						
Total Distribution Plant	$ 89,067,482	$ 9,698,894	$ 79,368,588	-96.6%	-40.4%	$ (9,370,601)	$ (32,076,484)	$ (41,447,085)	-46.5%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 991,238	$ 4,287	$ 986,951	83.9%	-10.0%	$ 3,597	$ (98,695)	$ (95,098)	-9.6%
392.00 Transportation Equipment	2,897,459	633,998	2,263,461	10.5%	10.0%	66,570	226,346	292,916	10.1%
396.00 Power Operated Equipment	993,914	514,223	479,691	3.0%	5.0%	15,427	23,985	39,411	4.0%
Total Depreciable	$ 4,882,611	$ 1,152,508	$ 3,730,103	7.4%	4.1%	$ 85,593	$ 151,636	$ 237,229	4.9%
Amortizable									
391.10 Office Furniture and Fixtures	$ 384,459	$ 352,430	$ 32,029						
391.90 Computers and Electronic Equipment	458,947	327,252	131,695						
393.00 Stores Equipment	6,221	2,060	4,161						
394.00 Tools, Shop and Garage Equipment	1,824,964	706,120	1,118,844						
397.00 Communication Equipment	1,845,419	80,208	1,765,211						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 4,520,010	$ 1,468,070	$ 3,051,940						
Total General Plant	$ 9,402,621	$ 2,620,578	$ 6,782,043	3.3%	2.2%	$ 85,593	$ 151,636	$ 237,229	2.5%
TOTAL NORTH TEXAS	$ 101,071,855	$ 12,448,572	$ 88,623,283	-75.4%	-37.0%	$ (9,380,026)	$ (32,801,350)	$ (42,181,376)	-41.7%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters P-Life/ AYFR	Current Curve Shape	Current VG ASL	Current Rem. Life	Current Avg. Sal.	Current Fut. Sal.	Proposed (at December 31, 2021) P-Life/ AYFR	Proposed Curve Shape	Proposed VG ASL	Proposed Rem. Life	Proposed Avg. Sal.	Proposed Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
NORTH TEXAS												
TRANSMISSION PLANT												
367.00 Mains	60.00	R1	60.24	52.03	-34.2	-30.0	60.00	L1	60.12	48.98	-42.3	-40.0
369.00 Meas. and Reg. Station Equipment	32.00	L1.5	32.23	23.16	-10.0	-10.0	40.00	L1	40.46	30.56	-25.0	-25.0
Total Transmission Plant									52.39	41.74	-37.3	-35.4
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	40.16	18.15	-5.0	-5.0	40.00	R4	40.58	15.01	-10.0	-10.0
376.00 Mains	65.00	R1.5	64.94	57.34	-26.9	-20.0	67.00	R2	66.74	58.07	-46.1	-40.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	9.79			15.00	SQ	15.00	6.18		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	54.80	51.15	-24.6	-20.0	60.00	R1	59.79	56.14	-28.0	-25.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.36	54.90	-11.3	-10.0	65.00	R1.5	65.17	59.65	-27.0	-25.0
380.00 Services	55.00	R2	54.77	46.67	-48.0	-30.0	55.00	R2	54.66	46.03	-73.7	-60.0
381.00 Meters	25.00	R2.5	24.65	19.68	-7.9	-10.0	30.00	R2.5	29.29	21.92	-15.5	-15.0
383.00 House Regulators	35.00	R3	34.88	27.43	-6.2	-5.0	35.00	R3	34.65	27.60	-13.8	-15.0
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	54.95	50.08	-24.7	-20.0	58.00	R1.5	57.81	51.36	-32.1	-30.0
386.00 Other Property on Customers' Premises	20.00	S3	22.64	3.54			20.00	S3	28.28	1.75		
Total Distribution Plant									54.34	46.03	-46.5	-40.4
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.79	28.12	-4.5	-5.0	43.00	R3	43.38	27.92	-9.6	-10.0
392.00 Transportation Equipment	10.00	L0	11.26	7.33	5.2	5.0	13.00	L1	14.18	8.36	10.1	10.0
396.00 Power Operated Equipment	13.00	L2	13.57	6.63	5.9	10.0	18.00	L1.5	18.62	9.83	4.0	5.0
Total Depreciable									17.92	10.68	4.9	4.1
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	7.44			15.00	SQ	15.00	10.15		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	2.13			7.00	SQ	7.00	4.80		
393.00 Stores Equipment	15.00	SQ	15.00	7.06			15.00	SQ	15.00	3.06		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	8.12			15.00	SQ	15.00	8.69		
397.00 Communication Equipment	15.00	SQ	15.00	11.86			15.00	SQ	15.00	8.25		
398.00 Miscellaneous Equipment												
Total Amortizable									14.30	8.11		
Total General Plant							0.07		16.09	9.38	2.5	2.2
TOTAL NORTH TEXAS									45.93	37.92	-41.7	-37.0

Statements A through F

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2021)			Proposed (at 12/31/2021)		
	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
BORGER/SKELLYTOWN						
TRANSMISSION PLANT						
367.00 Mains						
369.00 Meas. and Reg. Station Equipment						
Total Transmission Plant						
DISTRIBUTION PLANT						
375.10 Structures and Improvements	4.41%		4.41%	3.17%	0.31%	3.48%
376.00 Mains	1.95%		1.95%	1.62%	0.72%	2.34%
376.90 Mains - Cathodic Protection	6.67%		6.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	2.22%		2.22%	1.94%	0.38%	2.32%
379.00 Meas. and Reg. Station Equip. - City Gate	1.71%		1.71%	1.63%	0.28%	1.91%
380.00 Services	3.07%		3.07%	2.00%	1.65%	3.65%
381.00 Meters	4.44%		4.44%	3.43%	0.74%	4.17%
383.00 House Regulators	2.70%		2.70%	2.81%	0.40%	3.21%
385.00 Industrial Meas. and Reg. Station Equip.	2.25%		2.25%	1.96%	0.53%	2.49%
386.00 Other Property on Customers' Premises	9.66%		9.66%	18.63%		18.63%
Total Distribution Plant	3.05%		3.05%	2.52%	0.85%	3.38%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.63%		2.63%	2.26%	0.20%	2.46%
392.00 Transportation Equipment	9.12%		9.12%	6.21%	-0.59%	5.62%
396.00 Power Operated Equipment	7.22%		7.22%	5.09%	-0.21%	4.88%
Total Depreciable	5.61%		5.61%	4.08%	-0.15%	3.93%
Amortizable						
391.10 Office Furniture and Fixtures	6.67%		6.67%	← 15 Year Amortization →		6.67%
391.90 Computers and Electronic Equipment	14.29%		14.29%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment						
394.00 Tools, Shop and Garage Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	7.27%		7.27%	6.74%		6.74%
Total General Plant	6.22%		6.22%	5.06%	-0.09%	4.97%
TOTAL BORGER/SKELLYTOWN	3.52%		3.52%	2.90%	0.71%	3.61%

TEXAS GAS SERVICE
Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual Investment	Net Salvage	Total	Proposed 2022 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
BORGER/SKELLYTOWN								
TRANSMISSION PLANT								
367.00 Mains	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
369.00 Meas. and Reg. Station Equipment								
Total Transmission Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 7,451	$ 329	$ -	$ 329	$ 236	$ 23	$ 259	$ (69)
376.00 Mains	6,051,657	118,007		118,007	98,037	43,572	141,609	23,601
376.90 Mains - Cathodic Protection	1,451,863	96,839		96,839	96,791		96,791	(48)
378.00 Meas. and Reg. Station Equip. - General	70,347	1,562		1,562	1,365	267	1,632	70
379.00 Meas. and Reg. Station Equip. - City Gate	141,089	2,413		2,413	2,300	395	2,695	282
380.00 Services	3,198,277	98,187		98,187	63,966	52,772	116,737	18,550
381.00 Meters	1,306,961	58,029		58,029	44,829	9,672	54,500	(3,529)
383.00 House Regulators	411,103	11,100		11,100	11,552	1,644	13,196	2,097
385.00 Industrial Meas. and Reg. Station Equip.	168,231	3,785		3,785	3,297	892	4,189	404
386.00 Other Property on Customers' Premises	4,576	442		442	853		853	410
Total Distribution Plant	$ 12,811,555	$ 390,693	$ -	$ 390,693	$ 323,225	$ 109,237	$ 432,461	$ 41,768
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 715,753	$ 18,824	$ -	$ 18,824	$ 16,176	$ 1,432	$ 17,608	$ (1,217)
392.00 Transportation Equipment	532,904	48,601		48,601	33,093	(3,144)	29,949	(18,652)
396.00 Power Operated Equipment	160,515	11,589		11,589	8,170	(337)	7,833	(3,756)
Total Depreciable	$ 1,409,172	$ 79,014	$ -	$ 79,014	$ 57,440	$ (2,050)	$ 55,390	$ (23,624)
Amortizable								
391.10 Office Furniture and Fixtures	$ 6,363	$ 424	$ -	$ 424	$ 424		$ 424	$ (0)
391.90 Computers and Electronic Equipment	65,394	9,345		9,345	9,342		9,342	(3)
393.00 Stores Equipment								
394.00 Tools, Shop and Garage Equipment	446,420	29,776		29,776	27,212		27,212	(2,564)
397.00 Communication Equipment	308,743	20,593		20,593	18,792		18,792	(1,802)
398.00 Miscellaneous Equipment								
Total Amortizable	$ 826,920	$ 60,139	$ -	$ 60,139	$ 55,770		$ 55,770	$ (4,368)
Total General Plant	$ 2,236,092	$ 139,153	$ -	$ 139,153	$ 113,210	$ (2,050)	$ 111,160	$ (27,993)
TOTAL BORGER/SKELLYTOWN	$ 15,047,647	$ 529,846	$ -	$ 529,846	$ 436,434	$ 107,187	$ 543,621	$ 13,776

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
BORGER/SKELLYTOWN							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 7,451	$ 6,595	88.51%	$ 7,486	100.47%	$ 5,451	73.16%
376.00 Mains	6,051,657	2,026,704	33.49%	1,792,259	29.62%	1,305,115	21.57%
376.90 Mains - Cathodic Protection	1,451,863	59,185	4.08%	717,731	49.44%	$ 717,731	49.44%
378.00 Meas. and Reg. Station Equip. - General	70,347	30,725	43.68%	34,226	48.65%	24,923	35.43%
379.00 Meas. and Reg. Station Equip. - City Gate	141,089	31,084	22.03%	45,895	32.53%	33,421	23.69%
380.00 Services	3,198,277	393,049	12.29%	816,456	25.53%	594,540	18.59%
381.00 Meters	1,306,961	404,060	30.92%	436,189	33.37%	317,631	24.30%
383.00 House Regulators	411,103	209,655	51.00%	234,992	57.16%	171,120	41.62%
385.00 Industrial Meas. and Reg. Station Equip.	168,231	68,723	40.85%	84,166	50.03%	61,289	36.43%
386.00 Other Property on Customers' Premises	4,576	4,576	99.99%	4,305	94.08%	3,135	68.51%
Total Distribution Plant	$ 12,811,555	$ 3,234,356	25.25%	$ 4,173,705	32.58%	$ 3,234,356	25.25%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 715,753	$ 75,922	10.61%	$ 118,152	16.51%	$ 136,796	19.11%
392.00 Transportation Equipment	532,904	302,355	56.74%	196,828	36.93%	227,887	42.76%
396.00 Power Operated Equipment	160,515	71,819	44.74%	45,522	28.36%	52,705	32.84%
Total Depreciable	$ 1,409,172	$ 450,095	31.94%	$ 360,502	25.58%	$ 417,388	29.62%
Amortizable							
391.10 Office Furniture and Fixtures	$ 6,363	$ 2,098	32.97%	$ 2,757	43.33%	$ 2,757	43.33%
391.90 Computers and Electronic Equipment	65,394	20,004	30.59%	16,274	24.89%	16,274	24.89%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	446,420	180,308	40.39%	197,415	44.22%	197,415	44.22%
397.00 Communication Equipment	308,743	165,076	53.47%	183,747	59.51%	183,747	59.51%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 826,920	$ 367,486	44.44%	$ 400,193	48.40%	$ 400,193	48.40%
Total General Plant	$ 2,236,092	$ 817,581	36.56%	$ 760,695	34.02%	$ 817,581	36.56%
TOTAL BORGER/SKELLYTOWN	$ 15,047,647	$ 4,051,937	26.93%	$ 4,934,400	32.79%	$ 4,051,937	26.93%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
BORGER/SKELLYTOWN							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 7,451	$ 4,946	66.38%	$ 506	6.79%	$ 5,451	73.16%
376.00 Mains	6,051,657	1,093,172	18.06%	211,943	3.50%	1,305,115	21.57%
376.90 Mains - Cathodic Protection	1,451,863	717,731	49.44%			717,731	49.44%
378.00 Meas. and Reg. Station Equip. - General	70,347	17,511	24.89%	7,412	10.54%	24,923	35.43%
379.00 Meas. and Reg. Station Equip. - City Gate	141,089	19,256	13.65%	14,164	10.04%	33,421	23.69%
380.00 Services	3,198,277	722,912	22.60%	(128,373)	-4.01%	594,540	18.59%
381.00 Meters	1,306,961	332,719	25.46%	(15,088)	-1.15%	317,631	24.30%
383.00 House Regulators	411,103	146,271	35.58%	24,849	6.04%	171,120	41.62%
385.00 Industrial Meas. and Reg. Station Equip.	168,231	44,506	26.46%	16,784	9.98%	61,289	36.43%
386.00 Other Property on Customers' Premises	4,576	3,135	68.51%			3,135	68.51%
Total Distribution Plant	$ 12,811,555	$ 3,102,158	24.21%	$ 132,197	1.03%	$ 3,234,356	25.25%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 715,753	$ 115,937	16.20%	$ 20,860	2.91%	$ 136,796	19.11%
392.00 Transportation Equipment	532,904	254,817	47.82%	(26,930)	-5.05%	227,887	42.76%
396.00 Power Operated Equipment	160,515	56,433	35.16%	(3,728)	-2.32%	52,705	32.84%
Total Depreciable	$ 1,409,172	$ 427,187	30.31%	$ (9,798)	-0.70%	$ 417,388	29.62%
Amortizable							
391.10 Office Furniture and Fixtures	$ 6,363	$ 2,757	43.33%			$ 2,757	43.33%
391.90 Computers and Electronic Equipment	65,394	16,274	24.89%			16,274	24.89%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	446,420	197,415	44.22%			197,415	44.22%
397.00 Communication Equipment	308,743	183,747	59.51%			183,747	59.51%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 826,920	$ 400,193	48.40%			$ 400,193	48.40%
Total General Plant	$ 2,236,092	$ 827,380	37.00%	$ (9,798)	-0.44%	$ 817,581	36.56%
TOTAL BORGER/SKELLYTOWN	$ 15,047,647	$ 3,929,538	26.11%	$ 122,399	0.81%	$ 4,051,937	26.93%

TEXAS GAS SERVICE
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
BORGER/SKELLYTOWN									
TRANSMISSION PLANT									
367.00 Mains	$ -		$ -			$ -	$ -		
369.00 Meas. and Reg. Station Equipment									
Total Transmission Plant	$ -	$ -	$ -			$ -	$ -	$ -	
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 9,647	$ 2,196	$ 7,451		-10.0%		$ (745)	$ (745)	-7.7%
376.00 Mains	7,275,944	1,224,287	6,051,657	-80.7%	-40.0%	(988,000)	(2,420,663)	(3,408,662)	-46.8%
376.90 Mains - Cathodic Protection	2,224,600	772,737	1,451,863						
378.00 Meas. and Reg. Station Equip. - General	110,564	40,217	70,347	-0.3%	-25.0%	(121)	(17,587)	(17,707)	-16.0%
379.00 Meas. and Reg. Station Equip. - City Gate	276,987	135,898	141,089	-2.2%	-25.0%	(2,990)	(35,272)	(38,262)	-13.8%
380.00 Services	3,365,460	167,183	3,198,277	-764.7%	-60.0%	(1,278,448)	(1,918,966)	(3,197,415)	-95.0%
381.00 Meters	1,673,490	366,529	1,306,961	-62.9%	-15.0%	(230,547)	(196,044)	(426,591)	-25.5%
383.00 House Regulators	469,568	58,465	411,103	-0.1%	-15.0%	(58)	(61,665)	(61,724)	-13.1%
385.00 Industrial Meas. and Reg. Station Equip.	204,854	36,623	168,231	-5.4%	-30.0%	(1,978)	(50,469)	(52,447)	-25.6%
386.00 Other Property on Customers' Premises	4,576		4,576						
Total Distribution Plant	$ 15,615,690	$ 2,804,135	$ 12,811,555	-89.2%	-36.7%	$ (2,502,141)	$ (4,701,412)	$ (7,203,553)	-46.1%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 822,884	$ 107,131	$ 715,753		-10.0%	$ -	$ (71,575)	$ (71,575)	-8.7%
392.00 Transportation Equipment	553,607	20,703	532,904		10.0%		53,290	53,290	9.6%
396.00 Power Operated Equipment	185,903	25,388	160,515		5.0%		8,026	8,026	4.3%
Total Depreciable	$ 1,562,394	$ 153,222	$ 1,409,172		-0.7%	$ -	$ (10,259)	$ (10,259)	-0.7%
Amortizable									
391.10 Office Furniture and Fixtures	$82,621	$76,258	$6,363						
391.90 Computers and Electronic Equipment	218,027	152,633	65,394						
393.00 Stores Equipment									
394.00 Tools, Shop and Garage Equipment	622,204	175,784	446,420						
397.00 Communication Equipment	354,826	46,083	308,743						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 1,277,678	$ 450,758	$ 826,920						
Total General Plant	$ 2,840,072	$ 603,980	$ 2,236,092		-0.5%	$ -	$ (10,259)	$ (10,259)	-0.4%
TOTAL BORGER/SKELLYTOWN	$ 18,455,762	$ 3,408,115	$ 15,047,647	-73.4%	-31.3%	$ (2,502,141)	$ (4,711,671)	$ (7,213,812)	-39.1%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

	Current Parameters						Proposed Parameters (at December 31, 2021)					
Account Description	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
BORGER/SKELLYTOWN												
TRANSMISSION PLANT												
367.00 Mains												
369.00 Meas. and Reg. Station Equipment												
Total Transmission Plant												-39.2
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	52.56	6.15	-3.9	-5.0	40.00	R4	119.70	10.59	-7.7	-10.0
376.00 Mains	65.00	R1.5	68.39	51.57	-28.2	-20.0	67.00	R2	67.20	50.53	-46.8	-40.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	10.80			15.00	SQ	15.00	7.58		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	54.99	38.69	-12.8	-20.0	60.00	R1	58.77	38.68	-16.0	-25.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.47	49.55	-5.3	-10.0	65.00	R1.5	65.20	52.98	-13.8	-25.0
380.00 Services	55.00	R2	56.12	39.62	-70.3	-30.0	55.00	R2	56.25	38.79	-95.0	-60.0
381.00 Meters	25.00	R2.5	28.18	19.93	-19.1	-10.0	30.00	R2.5	33.41	21.73	-25.5	-15.0
383.00 House Regulators	35.00	R3	45.72	25.10	-10.3	-5.0	35.00	R3	44.76	22.89	-13.1	-15.0
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	56.50	38.41	-17.4	-20.0	58.00	R1.5	59.07	37.61	-25.6	-30.0
386.00 Other Property on Customers' Premises	20.00	S3	24.98	2.56			20.00	S3	28.57	1.69		
Total Distribution Plant									42.93	29.55	-46.1	-40.7
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.07	37.39	-4.2	-5.0	43.00	R3	43.03	37.01	-8.7	-10.0
392.00 Transportation Equipment	10.00	L0	11.28	7.49	4.8	5.0	13.00	L1	14.31	8.40	9.6	10.0
396.00 Power Operated Equipment	13.00	L2	13.25	10.28	8.2	10.0	18.00	L1.5	18.31	12.75	4.3	5.0
Total Depreciable									22.50	16.61	-0.7	-0.7
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	12.50			15.00	SQ	15.00	8.50		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	1.67			7.00	SQ	7.00	5.26		
393.00 Stores Equipment	15.00	SQ	15.00	1.00								
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	8.69			15.00	SQ	15.00	8.96		
397.00 Communication Equipment	15.00	SQ	15.00	10.07			15.00	SQ	15.00	6.07		
398.00 Miscellaneous Equipment												
Total Amortizable									13.76	7.39		
Total General Plant									18.22	12.09	-0.4	-0.5
TOTAL BORGER/SKELLYTOWN									35.73	24.46	-39.1	-31.3

Statements A through F

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2021) Investgment	Salvage	Total	Proposed (at 12/31/2021) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
WEST TEXAS						
TRANSMISSION PLANT						
367.00 Mains	1.94%		1.94%	1.73%	0.81%	2.54%
369.00 Meas. and Reg. Station Equipment	3.38%		3.38%	2.68%	0.78%	3.46%
Total Transmission Plant	2.01%		2.01%	1.78%	0.81%	2.59%
DISTRIBUTION PLANT						
375.10 Structures and Improvements	2.04%		2.04%	2.99%	0.30%	3.29%
376.00 Mains	1.92%		1.92%	1.56%	0.74%	2.30%
376.90 Mains - Cathodic Protection	3.67%		3.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	2.22%		2.22%	1.72%	0.53%	2.25%
379.00 Meas. and Reg. Station Equip. - City Gate	1.66%		1.66%	1.60%	0.44%	2.04%
380.00 Services	2.20%		2.20%	1.90%	1.30%	3.20%
381.00 Meters	3.71%		3.71%	3.43%	0.61%	4.04%
383.00 House Regulators	2.45%		2.45%	2.96%	0.58%	3.54%
385.00 Industrial Meas. and Reg. Station Equip.	2.13%		2.13%	1.81%	0.57%	2.38%
386.00 Other Property on Customers' Premises	4.61%		4.61%	13.96%	-0.07%	13.89%
Total Distribution Plant	2.30%		2.30%	2.13%	0.86%	2.99%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.59%		2.59%	2.88%	0.28%	3.16%
392.00 Transportation Equipment	9.49%		9.49%	9.43%	-0.86%	8.57%
396.00 Power Operated Equipment	6.26%		6.26%	6.81%	-0.39%	6.42%
Total Depreciable	6.35%		6.35%	6.50%	-0.35%	6.15%
Amortizable						
391.10 Office Furniture and Fixtures	6.40%		6.40%	← 15 Year Amortization →		6.67%
391.90 Computers and Electronic Equipment	7.93%		7.93%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment	6.53%		6.53%	← 15 Year Amortization →		6.67%
394.00 Tools, Shop and Garage Equipment	6.31%		6.31%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.65%		6.65%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	6.72%		6.72%	6.36%		6.36%
Total General Plant	6.60%		6.60%	6.41%	-0.11%	6.30%
TOTAL WEST TEXAS	2.63%		2.63%	2.45%	0.78%	3.22%

TEXAS GAS SERVICE Statement B

Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual			Proposed 2022 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
WEST TEXAS								
TRANSMISSION PLANT								
367.00 Mains	$ 43,275,627	$ 839,547	$ -	$ 839,547	$ 748,668	$ 350,533	$ 1,099,201	$ 259,654
369.00 Meas. and Reg. Station Equipment	2,315,703	78,271		78,271	62,061	18,062	80,123	1,853
Total Transmission Plant	$ 45,591,330	$ 917,818	$ -	$ 917,818	$ 810,729	$ 368,595	$ 1,179,324	$ 261,506
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ 269,615	$ 5,500	$ -	$ 5,500	$ 8,061	$ 809	$ 8,870	$ 3,370
376.00 Mains	226,986,442	4,358,140		4,358,140	3,540,988	1,679,700	5,220,688	862,548
376.90 Mains - Cathodic Protection	22,051,489	809,290		809,290	$ 1,370,240		1,370,240	560,950
378.00 Meas. and Reg. Station Equip. - General	11,470,072	254,636		254,636	197,285	60,791	258,077	3,441
379.00 Meas. and Reg. Station Equip. - City Gate	5,712,601	94,829		94,829	91,402	25,135	116,537	21,708
380.00 Services	169,761,609	3,734,755		3,734,755	3,225,471	2,206,901	5,432,371	1,697,616
381.00 Meters	54,729,496	2,030,464		2,030,464	1,877,222	333,850	2,211,072	180,607
383.00 House Regulators	14,141,651	346,470		346,470	418,593	82,022	500,614	154,144
385.00 Industrial Meas. and Reg. Station Equip.	15,862,499	337,871		337,871	287,111	90,416	377,527	39,656
386.00 Other Property on Customers' Premises	624,137	28,773		28,773	87,130	(437)	86,693	57,920
Total Distribution Plant	$ 521,609,611	$ 12,000,728	$ -	$ 12,000,728	$ 11,103,502	$ 4,479,187	$ 15,582,690	$ 3,581,961
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 6,465,054	$ 167,445	$ -	$ 167,445	$ 186,194	$ 18,102	$ 204,296	$ 36,851
392.00 Transportation Equipment	7,816,852	741,819		741,819	737,129	(67,225)	669,904	(71,915)
396.00 Power Operated Equipment	1,740,384	108,948		108,948	118,520	(6,787)	111,733	2,785
Total Depreciable	$ 16,022,290	$ 1,018,212	$ -	$ 1,018,212	$ 1,041,843	$ (55,910)	$ 985,933	$ (32,280)
Amortizable								
391.10 Office Furniture and Fixtures	$ 1,340,847	$ 85,814	$ -	$ 85,814	$ 77,676		$ 77,676	$ (8,139)
391.90 Computers and Electronic Equipment	3,559,065	282,234		282,234	160,855		160,855	(121,379)
393.00 Stores Equipment	26,647	1,740		1,740	1,776		1,776	36
394.00 Tools, Shop and Garage Equipment	5,273,987	332,789		332,789	339,117		339,117	6,329
397.00 Communication Equipment	23,519,511	1,564,047		1,564,047	1,566,481		1,566,481	2,434
398.00 Miscellaneous Equipment								
Total Amortizable	$ 33,720,057	$ 2,266,624	$ -	$ 2,266,624	$ 2,145,905		$ 2,145,905	$ (120,719)
Total General Plant	$ 49,742,347	$ 3,284,836	$ -	$ 3,284,836	$ 3,187,748	$ (55,910)	$ 3,131,838	$ (152,999)
TOTAL WEST TEXAS	$ 616,943,288	$ 16,203,383	$ -	$ 16,203,383	$ 15,101,980	$ 4,791,872	$ 19,893,852	$ 3,690,469

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
WEST TEXAS							
TRANSMISSION PLANT							
367.00 Mains	$ 43,275,627	$ 2,499,812	5.78%	$ 3,864,458	8.93%	$ 2,593,774	5.99%
369.00 Meas. and Reg. Station Equipment	2,315,703	407,484	17.60%	467,116	20.17%	313,522	13.54%
Total Transmission Plant	$ 45,591,330	$ 2,907,296	6.38%	$ 4,331,574	9.50%	$ 2,907,296	6.38%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 269,615	$ 133,984	49.69%	$ 142,072	52.69%	$ 108,128	40.10%
376.00 Mains	226,986,442	44,814,829	19.74%	38,955,577	17.16%	29,648,306	13.06%
376.90 Mains - Cathodic Protection	22,051,489	608,565	2.76%	9,293,522	42.14%	9,293,522	42.14%
378.00 Meas. and Reg. Station Equip. - General	11,470,072	2,124,108	18.52%	1,255,966	10.95%	955,890	8.33%
379.00 Meas. and Reg. Station Equip. - City Gate	5,712,601	1,696,754	29.70%	1,103,958	19.32%	840,200	14.71%
380.00 Services	169,761,609	19,837,922	11.69%	32,334,437	19.05%	24,609,089	14.50%
381.00 Meters	54,729,496	14,243,256	26.02%	21,298,675	38.92%	16,209,993	29.62%
383.00 House Regulators	14,141,651	3,765,123	26.62%	6,408,598	45.32%	4,877,455	34.49%
385.00 Industrial Meas. and Reg. Station Equip.	15,862,499	3,952,842	24.92%	3,759,837	23.70%	2,861,536	18.04%
386.00 Other Property on Customers' Premises	624,137	252,217	40.41%	570,635	91.43%	434,299	69.58%
Total Distribution Plant	$ 521,609,611	$ 91,429,602	17.53%	$ 115,123,277	22.07%	$ 89,838,418	17.22%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 6,465,054	$ 569,761	8.81%	$ 2,179,262	33.71%	$ 1,028,849	15.91%
392.00 Transportation Equipment	7,816,852	4,347,549	55.62%	2,223,755	28.45%	1,049,854	13.43%
396.00 Power Operated Equipment	1,740,384	1,124,769	64.63%	583,004	33.50%	275,241	15.81%
Total Depreciable	$ 16,022,290	$ 6,042,079	37.71%	$ 4,986,021	31.12%	$ 2,353,944	14.69%
Amortizable							
391.10 Office Furniture and Fixtures	$ 1,340,847	$ 404,219	30.15%	$ 781,007	58.25%	$ 781,007	58.25%
391.90 Computers and Electronic Equipment	3,559,065	2,124,195	59.68%	2,849,357	80.06%	2,849,357	80.06%
393.00 Stores Equipment	26,647	7,363	27.63%	19,673	73.83%	19,673	73.83%
394.00 Tools, Shop and Garage Equipment	5,273,987	695,880	13.19%	2,113,778	40.08%	2,113,778	40.08%
397.00 Communication Equipment	23,519,511	4,203,799	17.87%	5,354,363	22.77%	5,354,363	22.77%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 33,720,057	$ 7,435,457	22.05%	$ 11,118,178	32.97%	$ 11,118,178	32.97%
Total General Plant	$ 49,742,347	$ 13,477,536	27.09%	$ 16,104,199	32.38%	$ 13,472,122	27.08%
TOTAL WEST TEXAS	$ 616,943,288	$ 107,814,434	17.48%	$ 135,559,050	21.97%	$ 106,217,837	17.22%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
WEST TEXAS							
TRANSMISSION PLANT							
367.00 Mains	$ 43,275,627	$ 3,665,585	8.47%	$ (1,071,811)	-2.48%	$ 2,593,774	5.99%
369.00 Meas. and Reg. Station Equipment	2,315,703	318,067	13.74%	(4,545)	-0.20%	313,522	13.54%
Total Transmission Plant	$ 45,591,330	$ 3,983,652	8.74%	$ (1,076,356)	-2.36%	$ 2,907,296	6.38%
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ 269,615	$ 98,298	36.46%	$ 9,830	3.65%	$ 108,128	40.10%
376.00 Mains	226,986,442	30,523,960	13.45%	(875,654)	-0.39%	29,648,306	13.06%
376.90 Mains - Cathodic Protection	22,051,489	9,293,522	42.14%			9,293,522	42.14%
378.00 Meas. and Reg. Station Equip. - General	11,470,072	1,266,252	11.04%	(310,362)	-2.71%	955,890	8.33%
379.00 Meas. and Reg. Station Equip. - City Gate	5,712,601	780,601	13.66%	59,599	1.04%	840,200	14.71%
380.00 Services	169,761,609	23,260,119	13.70%	1,348,970	0.79%	24,609,089	14.50%
381.00 Meters	54,729,496	15,021,961	27.45%	1,188,032	2.17%	16,209,993	29.62%
383.00 House Regulators	14,141,651	4,600,305	32.53%	277,150	1.96%	4,877,455	34.49%
385.00 Industrial Meas. and Reg. Station Equip.	15,862,499	2,306,357	14.54%	555,179	3.50%	2,861,536	18.04%
386.00 Other Property on Customers' Premises	624,137	433,340	69.43%	959	0.15%	434,299	69.58%
Total Distribution Plant	$ 521,609,611	$ 87,584,715	16.79%	$ 2,253,703	0.43%	$ 89,838,418	17.22%
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 6,465,054	$ 933,391	14.44%	$ 95,458	1.48%	$ 1,028,849	15.91%
392.00 Transportation Equipment	7,816,852	1,234,718	15.80%	(184,864)	-2.36%	1,049,854	13.43%
396.00 Power Operated Equipment	1,740,384	277,704	15.96%	(2,462)	-0.14%	275,241	15.81%
Total Depreciable	$ 16,022,290	$ 2,445,813	15.27%	$ (91,868)	-0.57%	$ 2,353,944	14.69%
Amortizable							
391.10 Office Furniture and Fixtures	$ 1,340,847	$ 781,007	58.25%			$ 781,007	58.25%
391.90 Computers and Electronic Equipment	3,559,065	2,849,357	80.06%			2,849,357	80.06%
393.00 Stores Equipment	26,647	19,673	73.83%			19,673	73.83%
394.00 Tools, Shop and Garage Equipment	5,273,987	2,113,778	40.08%			2,113,778	40.08%
397.00 Communication Equipment	23,519,511	5,354,363	22.77%			5,354,363	22.77%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 33,720,057	$ 11,118,178	32.97%			$ 11,118,178	32.97%
Total General Plant	$ 49,742,347	$ 13,563,991	27.27%	$ (91,868)	-0.18%	$ 13,472,122	27.08%
TOTAL WEST TEXAS	$ 616,943,288	$ 105,132,359	17.04%	$ 1,085,478	0.18%	$ 106,217,837	17.22%

TEXAS GAS SERVICE
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 TEXAS									
TRANSMISSION PLANT									
367.00 Mains	$ 43,671,263	$395,636	$ 43,275,627	-1144.5%	-40.0%	$ (4,528,054)	$ (17,310,251)	($21,838,305)	-50.0%
369.00 Meas. and Reg. Station Equipment	2,387,896	72,193	2,315,703	-251.4%	-25.0%	(181,493)	(578,926)	(760,419)	-31.8%
Total Transmission Plant	$ 46,059,159	$ 467,829	$ 45,591,330	-1006.7%	-39.2%	$ (4,709,547)	$ (17,889,177)	$ (22,598,724)	-49.1%
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ 269,981	$ 366	$ 269,615		-10.0%		$ (26,962)	$ (26,962)	-10.0%
376.00 Mains	237,260,373	10,273,931	226,986,442	-252.8%	-40.0%	(25,972,498)	(90,794,577)	(116,767,074)	-49.2%
376.90 Mains - Cathodic Protection	27,916,489	5,865,000	22,051,489						
378.00 Meas. and Reg. Station Equip. - General	11,966,697	496,625	11,470,072	-226.7%	-25.0%	(1,125,849)	(2,867,518)	(3,993,367)	-33.4%
379.00 Meas. and Reg. Station Equip. - City Gate	5,762,150	49,549	5,712,601	-463.9%	-25.0%	(229,858)	(1,428,150)	(1,658,008)	-28.8%
380.00 Services	175,694,464	5,932,855	169,761,609	-413.2%	-60.0%	(24,514,557)	(101,856,965)	(126,371,522)	-71.9%
381.00 Meters	58,940,655	4,211,159	54,729,496	-71.2%	-15.0%	(2,998,345)	(8,209,424)	(11,207,770)	-19.0%
383.00 House Regulators	14,612,449	470,798	14,141,651	-222.4%	-15.0%	(1,047,055)	(2,121,248)	(3,168,302)	-21.7%
385.00 Industrial Meas. and Reg. Station Equip.	17,082,077	1,219,578	15,862,499	-49.3%	-30.0%	(601,252)	(4,758,750)	(5,360,002)	-31.4%
386.00 Other Property on Customers' Premises	704,330	80,193	624,137	19.8%		15,878		15,878	2.3%
Total Distribution Plant	$ 550,209,665	$ 28,600,054	$ 521,609,611	-197.5%	-40.7%	$ (56,473,535)	$ (212,063,594)	$ (268,537,129)	-48.8%
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 6,914,093	$ 449,039	$ 6,465,054	-8.9%	-10.0%	$ (39,964)	$ (646,505)	$ (686,470)	-9.9%
392.00 Transportation Equipment	11,008,449	3,191,597	7,816,852	1.4%	10.0%	44,682	781,685	826,368	7.5%
396.00 Power Operated Equipment	2,195,097	454,713	1,740,384	15.3%	5.0%	69,571	87,019	156,590	7.1%
Total Depreciable	$ 20,117,639	$ 4,095,349	$ 16,022,290	1.8%	1.4%	$ 74,289	$ 222,199	$ 296,488	1.5%
Amortizable									
391.10 Office Furniture and Fixtures	$3,065,321	$1,724,474	$1,340,847						
391.90 Computers and Electronic Equipment	3,969,243	410,178	3,559,065						
393.00 Stores Equipment	142,951	116,304	26,647						
394.00 Tools, Shop and Garage Equipment	8,265,369	2,991,382	5,273,987						
397.00 Communication Equipment	25,571,583	2,052,072	23,519,511						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 41,014,467	$ 7,294,410	$ 33,720,057						
Total General Plant	$ 61,132,106	$ 11,389,759	$ 49,742,347	0.7%	0.4%	$ 74,289	$ 222,199	$ 296,488	0.5%
TOTAL WEST TEXAS	$ 657,400,930	$ 40,457,642	$ 616,943,288	-151.0%	-37.2%	$ (61,108,793)	$ (229,730,571)	$ (290,839,364)	-44.2%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

	Current Parameters						Proposed Parameters (at December 31, 2021)					
Account Description	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
WEST TEXAS												
TRANSMISSION PLANT												
367.00 Mains	66.00	S0.5	56.10			-10.0	60.00	L1	60.46	52.83	-50.0	-40.0
369.00 Meas. and Reg. Station Equipment	15.00	SQ	32.81	27.64	-14.5	-10.0	40.00	L1	40.51	32.22	-31.8	-25.0
Total Transmission Plant									58.98	51.31	-49.1	-39.2
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	40.39	21.12	-5.0	-5.0	40.00	R4	40.79	21.25	-10.0	-10.0
376.00 Mains	65.00	R1.5	65.53	53.96	-26.5	-20.0	67.00	R2	67.18	55.31	-49.2	-40.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	10.05			15.00	SQ	15.00	9.27		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	56.00	47.71	-25.1	-20.0	60.00	R1	60.53	51.75	-33.4	-25.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	66.08	50.57	-12.1	-10.0	65.00	R1.5	65.89	54.06	-28.8	-25.0
380.00 Services	59.00	S0.5	47.27	-34.80		-30.0	55.00	R2	55.38	45.41	-71.9	-60.0
381.00 Meters	25.00	R2.5	29.60	17.32	-11.6	-10.0	30.00	R2.5	33.08	21.15	-19.0	-15.0
383.00 House Regulators	35.00	R3	41.79	24.28	-4.9	-5.0	35.00	R3	39.75	22.76	-21.7	-15.0
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	55.75	44.19	-19.7	-20.0	58.00	R1.5	58.26	47.13	-31.4	-30.0
386.00 Other Property on Customers' Premises	20.00	S3	20.88	4.23	2.3		20.00	S3	24.96	2.19	2.3	
Total Distribution Plant									49.66	39.06	-48.8	-40.7
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.39	29.94	-534.0	-5.0	43.00	R3	42.87	29.76	-9.9	-10.0
392.00 Transportation Equipment	10.00	LO	10.33	7.81	0.3	5.0	13.00	L1	13.42	8.93	7.5	10.0
396.00 Power Operated Equipment	13.00	L2	14.02	6.92	9.2	10.0	18.00	L1.5	18.64	12.34	7.1	5.0
Total Depreciable									19.38	13.12	1.5	1.4
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	8.12			15.00	SQ	15.00	6.40		
391.90 Computers and Electronic Equipment	10.00	SQ	10.00	6.82			7.00	SQ	7.00	4.41		
393.00 Stores Equipment	15.00	SQ	15.00	7.11			15.00	SQ	15.00	3.93		
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	9.46			15.00	SQ	15.00	9.18		
397.00 Communication Equipment	15.00	SQ	15.00	11.16			15.00	SQ	15.00	11.59		
398.00 Miscellaneous Equipment	15.00	SQ	15.00	6.20								
Total Amortizable									13.39	9.61		
Total General Plant									14.87	10.48	0.5	0.4
TOTAL WEST TEXAS									42.19	33.17	-44.2	-37.2

Statements A through F

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2021)			Proposed (at 12/31/2021)		
	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
FORT BLISS						
TRANSMISSION PLANT						
367.00 Mains						
369.00 Meas. and Reg. Station Equipment						
Total Transmission Plant						
DISTRIBUTION PLANT						
375.10 Structures and Improvements						
376.00 Mains	1.92%		1.92%	1.55%	0.64%	2.19%
376.90 Mains - Cathodic Protection	3.67%		3.67%	← 15 Year Amortization →		6.67%
378.00 Meas. and Reg. Station Equip. - General	2.22%		2.22%	1.69%	0.42%	2.11%
379.00 Meas. and Reg. Station Equip. - City Gate						
380.00 Services	2.20%		2.20%	1.89%	1.17%	3.06%
381.00 Meters	3.71%		3.71%	3.74%	0.56%	4.30%
383.00 House Regulators	2.45%		2.45%	3.01%	0.46%	3.47%
385.00 Industrial Meas. and Reg. Station Equip.	2.13%		2.13%	1.78%	0.54%	2.32%
386.00 Other Property on Customers' Premises						
Total Distribution Plant	2.07%		2.07%	1.75%	0.66%	2.41%
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.59%		2.59%			
392.00 Transportation Equipment	9.49%		9.49%			
396.00 Power Operated Equipment	6.26%		6.26%			
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	6.31%		6.31%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.65%		6.65%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	6.58%		6.58%	6.67%		6.67%
Total General Plant	6.58%		6.58%	6.67%		6.67%
TOTAL FORT BLISS	2.10%		2.10%	1.79%	0.66%	2.44%

TEXAS GAS SERVICE
Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual Investment	Net Salvage	Total	Proposed 2022 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
FORT BLISS								
TRANSMISSION PLANT								
367.00 Mains	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
369.00 Meas. and Reg. Station Equipment								
Total Transmission Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376.00 Mains	5,252,028	100,839		100,839	81,406	33,613	115,019	14,180
376.90 Mains - Cathodic Protection	164,588	6,040		6,040	8,069		8,069	2,029
378.00 Meas. and Reg. Station Equip. - General	632,107	14,033		14,033	10,683	2,655	13,337	(695)
379.00 Meas. and Reg. Station Equip. - City Gate								
380.00 Services	916,397	20,161		20,161	17,320	10,722	28,042	7,881
381.00 Meters	147,452	5,470		5,470	5,515	826	6,340	870
383.00 House Regulators	92,302	2,261		2,261	2,778	425	3,203	941
385.00 Industrial Meas. and Reg. Station Equip.	330,071	7,031		7,031	5,875	1,782	7,658	627
386.00 Other Property on Customers' Premises								
Total Distribution Plant	$ 7,534,945	$ 155,835	$ -	$ 155,835	$ 131,646	$ 50,022	$ 181,669	$ 25,833
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	738		738	779		779	42
397.00 Communication Equipment	48,893	3,251		3,251	3,260		3,260	8
398.00 Miscellaneous Equipment								
Total Amortizable	$ 60,583	$ 3,989	$ -	$ 3,989	$ 4,039		$ 4,039	$ 50
Total General Plant	$ 60,583	$ 3,989	$ -	$ 3,989	$ 4,039	$ -	$ 4,039	$ 50
TOTAL FORT BLISS	$ 7,595,528	$ 159,824	$ -	$ 159,824	$ 135,685	$ 50,022	$ 185,707	$ 25,883

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
FORT BLISS							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains	5,252,028	(630,323)	-12.00%	974,284	18.55%	741,508	14.12%
376.90 Mains - Cathodic Protection	164,588	26,346	16.01%	86,816	52.75%	86,816	52.75%
378.00 Meas. and Reg. Station Equip. - General	632,107	49,979	7.91%	45,179	7.15%	34,385	5.44%
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services	916,397	6,341	0.69%	207,927	22.69%	158,249	17.27%
381.00 Meters	147,452	61,756	41.88%	62,511	42.39%	47,576	32.27%
383.00 House Regulators	92,302	15,564	16.86%	20,351	22.05%	15,489	16.78%
385.00 Industrial Meas. and Reg. Station Equip.	330,071	105	0.03%	48,523	14.70%	36,930	11.19%
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ 7,534,945	$ (470,232)	-6.24%	$ 1,445,591	19.19%	$ 1,120,952	14.88%
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	953	8.15%	1,169	10.00%	1,169	10.00%
397.00 Communication Equipment	48,893	13,319	27.24%	18,516	37.87%	18,516	37.87%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 60,583	$ 14,272	23.56%	$ 19,685	32.49%	$ 19,685	32.49%
Total General Plant	$ 60,583	$ 14,272	23.56%	$ 19,685	32.49%	$ 19,685	32.49%
TOTAL FORT BLISS	$ 7,595,528	$ (455,960)	-6.00%	$ 1,465,276	19.29%	$ 1,140,637	15.02%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
FORT BLISS							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains	5,252,028	580,893	11.06%	160,615	3.06%	741,508	14.12%
376.90 Mains - Cathodic Protection	164,588	86,816	52.75%			86,816	52.75%
378.00 Meas. and Reg. Station Equip. - General	632,107	27,870	4.41%	6,514	1.03%	34,385	5.44%
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services	916,397	107,388	11.72%	50,861	5.55%	158,249	17.27%
381.00 Meters	147,452	41,370	28.06%	6,206	4.21%	47,576	32.27%
383.00 House Regulators	92,302	13,468	14.59%	2,020	2.19%	15,489	16.78%
385.00 Industrial Meas. and Reg. Station Equip.	330,071	29,770	9.02%	7,160	2.17%	36,930	11.19%
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ 7,534,945	$ 887,577	11.78%	$ 233,376	3.10%	$ 1,120,952	14.88%
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	1,169	10.00%			1,169	10.00%
397.00 Communication Equipment	48,893	18,516	37.87%			18,516	37.87%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 60,583	$ 19,685	32.49%			$ 19,685	32.49%
Total General Plant	$ 60,583	$ 19,685	32.49%	$ -		$ 19,685	32.49%
TOTAL FORT BLISS	$ 7,595,528	$ 907,262	11.94%	$ 233,376	3.07%	$ 1,140,637	15.02%

TEXAS GAS SERVICE
Average Net Salvage

Statement E

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
FORT BLISS									
TRANSMISSION PLANT									
367.00 Mains	$ -		$ -			$ -	$ -		
369.00 Meas. and Reg. Station Equipment									
Total Transmission Plant	$ -	$ -	$ -			$ -	$ -	$ -	
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ -	$ -	$ -				$ -	$ -	
376.00 Mains	5,586,623	334,595	5,252,028	-75.6%	-40.0%	(252,954)	(2,100,811)	(2,353,765)	-42.1%
376.90 Mains - Cathodic Protection	164,588		164,588						
378.00 Meas. and Reg. Station Equip. - General	636,500	4,393	632,107	-42.1%	-25.0%	(1,849)	(158,027)	(159,876)	-25.1%
379.00 Meas. and Reg. Station Equip. - City Gate									
380.00 Services	951,458	35,061	916,397	-122.6%	-60.0%	(42,985)	(549,838)	(592,823)	-62.3%
381.00 Meters	147,452		147,452		-15.0%		(22,118)	(22,118)	-15.0%
383.00 House Regulators	92,302		92,302		-15.0%		(13,845)	(13,845)	-15.0%
385.00 Industrial Meas. and Reg. Station Equip.	330,498	427	330,071	-612.5%	-30.0%	(2,615)	(99,021)	(101,637)	-30.8%
386.00 Other Property on Customers' Premises									
Total Distribution Plant	$ 7,909,421	$ 374,476	$ 7,534,945	-80.2%	-39.1%	$ (300,403)	$ (2,943,661)	$ (3,244,064)	-41.0%
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		11,690						
397.00 Communication Equipment	48,893		48,893						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 60,583	$ -	$ 60,583						
Total General Plant	$ 60,583	$ -	$ 60,583			$ -	$ -	$ -	
TOTAL FORT BLISS	$ 7,970,004	$ 374,476	$ 7,595,528	-80.2%	-38.8%	$ (300,403)	$ (2,943,661)	$ (3,244,064)	-40.7%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2021) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
FORT BLISS												
TRANSMISSION PLANT												
367.00 Mains	66.00	S0.5	56.10			-10.0						
369.00 Meas. and Reg. Station Equipment	15.00	SQ	32.81	27.64	-14.5	-10.0						
Total Transmission Plant												-39.2
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	40.39	21.12	-5.0	-5.0						
376.00 Mains	65.00	R1.5	65.53	53.96	-26.5	-20.0	67.00	R2	67.16	57.40	-42.1	-40.0
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	10.05			15.00	SQ	15.00	9.64		
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	56.00	47.71	-25.1	-20.0	60.00	R1	60.07	56.59	-25.1	-25.0
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	66.08	50.57	-12.1	-10.0						
380.00 Services	59.00	S0.5	47.27	-34.80		-30.0	55.00	R2	55.14	46.65	-62.3	-60.0
381.00 Meters	25.00	R2.5	29.60	17.32	-11.6	-10.0	30.00	R2.5	30.49	19.25	-15.0	-15.0
383.00 House Regulators	35.00	R3	41.79	24.28	-4.9	-5.0	35.00	R3	35.05	28.33	-15.0	-15.0
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	55.75	44.19	-19.7	-20.0	58.00	R1.5	58.14	51.25	-30.8	-30.0
386.00 Other Property on Customers' Premises	20.00	S3	20.88	4.23	2.3							
Total Distribution Plant									58.20	49.62	-41.0	-40.7
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.39	29.94	-534.0	-5.0						
392.00 Transportation Equipment	10.00	LO	10.33	7.81	0.3	5.0						
396.00 Power Operated Equipment	13.00	L2	14.02	6.92	9.2	10.0						
Total Depreciable												
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	8.12								
391.90 Computers and Electronic Equipment	10.00	SQ	10.00	6.82								
393.00 Stores Equipment	15.00	SQ	15.00	7.11								
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	9.46			15.00	SQ	15.00	13.50		
397.00 Communication Equipment	15.00	SQ	15.00	11.16			15.00	SQ	15.00	9.32		
398.00 Miscellaneous Equipment	15.00	SQ	15.00	6.20								
Total Amortizable									15.00	10.13		
Total General Plant									15.00	10.13		
TOTAL FORT BLISS									56.89	48.43	-40.7	-38.8

Statements A through F

TEXAS GAS SERVICE
Component Accrual Rates
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2021)			Proposed (at 12/31/2021)		
	Investgment	Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
TGS DIVISION						
TRANSMISSION PLANT						
367.00 Mains						
369.00 Meas. and Reg. Station Equipment						
Total Transmission Plant						
DISTRIBUTION PLANT						
375.10 Structures and Improvements						
376.00 Mains						
376.90 Mains - Cathodic Protection						
378.00 Meas. and Reg. Station Equip. - General						
379.00 Meas. and Reg. Station Equip. - City Gate						
380.00 Services						
381.00 Meters						
383.00 House Regulators						
385.00 Industrial Meas. and Reg. Station Equip.						
386.00 Other Property on Customers' Premises						
Total Distribution Plant						
GENERAL PLANT						
Depreciable						
390.10 Structures and Improvements	2.59%		2.59%	2.33%	0.23%	2.56%
392.00 Transportation Equipment						
396.00 Power Operated Equipment						
Total Depreciable	2.59%		2.59%	2.33%	0.23%	2.56%
Amortizable						
391.10 Office Furniture and Fixtures	6.67%		6.67%	← 15 Year Amortization →		6.67%
391.90 Computers and Electronic Equipment	14.29%		14.29%	← 7 Year Amortization →		14.29%
393.00 Stores Equipment						
394.00 Tools, Shop and Garage Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
397.00 Communication Equipment	6.67%		6.67%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment						
Total Amortizable	8.97%		8.97%	8.34%		8.34%
Total General Plant	6.20%		6.20%	5.73%	0.10%	5.83%
TOTAL TGS DIVISION	6.20%		6.20%	5.73%	0.10%	5.83%

TEXAS GAS SERVICE
Component Accruals
Current: BG/VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/21 Investment	Current 2022 Annualized Accrual			Proposed 2022 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
TGS DIVISION								
TRANSMISSION PLANT								
367.00 Mains	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
369.00 Meas. and Reg. Station Equipment								
Total Transmission Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DISTRIBUTION PLANT								
375.10 Structures and Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376.00 Mains								
376.90 Mains - Cathodic Protection								
378.00 Meas. and Reg. Station Equip. - General								
379.00 Meas. and Reg. Station Equip. - City Gate								
380.00 Services								
381.00 Meters								
383.00 House Regulators								
385.00 Industrial Meas. and Reg. Station Equip.								
386.00 Other Property on Customers' Premises								
Total Distribution Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GENERAL PLANT								
Depreciable								
390.10 Structures and Improvements	$ 4,486,255	$ 116,194	$ -	$ 116,194	$ 104,530	$ 10,318	$ 114,848	$ (1,346)
392.00 Transportation Equipment								
396.00 Power Operated Equipment								
Total Depreciable	$ 4,486,255	$ 116,194	$ -	$ 116,194	$ 104,530	$ 10,318	$ 114,848	$ (1,346)
Amortizable								
391.10 Office Furniture and Fixtures	$ 2,691,240	$ 179,506	$ -	$ 179,506	$ 174,476		$ 174,476	$ (5,030)
391.90 Computers and Electronic Equipment	1,762,953	251,926		251,926	221,901		221,901	(30,025)
393.00 Stores Equipment								
394.00 Tools, Shop and Garage Equipment	154,325	10,293		10,293	10,288		10,288	(5)
397.00 Communication Equipment	1,243,127	82,917		82,917	81,535		81,535	(1,382)
398.00 Miscellaneous Equipment								
Total Amortizable	$ 5,851,645	$ 524,642	$ -	$ 524,642	$ 488,199		$ 488,199	$ (36,442)
Total General Plant	$ 10,337,900	$ 640,836	$ -	$ 640,836	$ 592,729	$ 10,318	$ 603,047	$ (37,788)
TOTAL TGS DIVISION	$ 10,337,900	$ 640,836	$ -	$ 640,836	$ 592,729	$ 10,318	$ 603,047	$ (37,788)

TEXAS GAS SERVICE
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2021

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TGS DIVISION							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains							
376.90 Mains - Cathodic Protection							
378.00 Meas. and Reg. Station Equip. - General							
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services							
381.00 Meters							
383.00 House Regulators							
385.00 Industrial Meas. and Reg. Station Equip.							
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ -	$ -		$ -		$ -	
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,486,255	$ 785,250	17.50%	$ 255,925	5.70%	$ 255,925	5.70%
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ 4,486,255	$ 785,250	17.50%	$ 255,925	5.70%	$ 255,925	5.70%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,691,240	$ 321,887	11.96%	$ 523,699	19.46%	$ 523,699	19.46%
391.90 Computers and Electronic Equipment	1,762,953	657,393	37.29%	983,852	55.81%	983,852	55.81%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	154,325	9,375	6.07%	9,618	6.23%	9,618	6.23%
397.00 Communication Equipment	1,243,127	795,436	63.99%	796,248	64.05%	796,248	64.05%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 5,851,645	$ 1,784,092	30.49%	$ 2,313,417	39.53%	$ 2,313,417	39.53%
Total General Plant	$ 10,337,900	$ 2,569,342	24.85%	$ 2,569,342	24.85%	$ 2,569,342	24.85%
TOTAL TGS DIVISION	$ 10,337,900	$ 2,569,342	24.85%	$ 2,569,342	24.85%	$ 2,569,342	24.85%

TEXAS GAS SERVICE
Depreciation Reserve Components
Redistributed Reserve
December 31, 2021

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
TGS DIVISION							
TRANSMISSION PLANT							
367.00 Mains	$ -	$ -		$ -		$ -	
369.00 Meas. and Reg. Station Equipment							
Total Transmission Plant	$ -	$ -		$ -		$ -	
DISTRIBUTION PLANT							
375.10 Structures and Improvements	$ -	$ -		$ -		$ -	
376.00 Mains							
376.90 Mains - Cathodic Protection							
378.00 Meas. and Reg. Station Equip. - General							
379.00 Meas. and Reg. Station Equip. - City Gate							
380.00 Services							
381.00 Meters							
383.00 House Regulators							
385.00 Industrial Meas. and Reg. Station Equip.							
386.00 Other Property on Customers' Premises							
Total Distribution Plant	$ -	$ -		$ -		$ -	
GENERAL PLANT							
Depreciable							
390.10 Structures and Improvements	$ 4,486,255	$ 232,659	5.19%	$ 23,266	0.52%	$ 255,925	5.70%
392.00 Transportation Equipment							
396.00 Power Operated Equipment							
Total Depreciable	$ 4,486,255	$ 232,659	5.19%	$ 23,266	0.52%	$ 255,925	5.70%
Amortizable							
391.10 Office Furniture and Fixtures	$ 2,691,240	$ 523,699	19.46%			$ 523,699	19.46%
391.90 Computers and Electronic Equipment	1,762,953	983,852	55.81%			983,852	55.81%
393.00 Stores Equipment							
394.00 Tools, Shop and Garage Equipment	154,325	9,618	6.23%			9,618	6.23%
397.00 Communication Equipment	1,243,127	796,248	64.05%			796,248	64.05%
398.00 Miscellaneous Equipment							
Total Amortizable	$ 5,851,645	$ 2,313,417	39.53%			$ 2,313,417	39.53%
Total General Plant	$ 10,337,900	$ 2,546,076	24.63%	$ 23,266	0.23%	$ 2,569,342	24.85%
TOTAL TGS DIVISION	$ 10,337,900	$ 2,546,076	24.63%	$ 23,266	0.23%	$ 2,569,342	24.85%

TEXAS GAS SERVICE
Average Net Salvage

Statement E

Account Description	Plant Investment			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									
TRANSMISSION PLANT									
367.00 Mains	$ -		$ -			$ -	$ -		
369.00 Meas. and Reg. Station Equipment									
Total Transmission Plant	$ -	$ -	$ -			$ -	$ -	$ -	
DISTRIBUTION PLANT									
375.10 Structures and Improvements	$ -	$ -	$ -				$ -	$ -	
376.00 Mains									
376.90 Mains - Cathodic Protection									
378.00 Meas. and Reg. Station Equip. - General									
379.00 Meas. and Reg. Station Equip. - City Gate									
380.00 Services									
381.00 Meters									
383.00 House Regulators									
385.00 Industrial Meas. and Reg. Station Equip.									
386.00 Other Property on Customers' Premises									
Total Distribution Plant	$ -	$ -	$ -			$ -	$ -	$ -	
GENERAL PLANT									
Depreciable									
390.10 Structures and Improvements	$ 4,505,569	$ 19,314	$ 4,486,255		-10.0%	$ -	$ (448,626)	$ (448,626)	-10.0%
392.00 Transportation Equipment									
396.00 Power Operated Equipment									
Total Depreciable	$ 4,505,569	$ 19,314	$ 4,486,255		-10.0%	$ -	$ (448,626)	$ (448,626)	-10.0%
Amortizable									
391.10 Office Furniture and Fixtures	$3,457,063	$765,823	$2,691,240						
391.90 Computers and Electronic Equipment	13,682,175	11,919,222	1,762,953						
393.00 Stores Equipment									
394.00 Tools, Shop and Garage Equipment	273,032	118,707	154,325						
397.00 Communication Equipment	1,554,769	311,642	1,243,127						
398.00 Miscellaneous Equipment									
Total Amortizable	$ 18,967,039	$ 13,115,394	$ 5,851,645						
Total General Plant	$ 23,472,608	$ 13,134,708	$ 10,337,900		-4.3%	$ -	$ (448,626)	$ (448,626)	-1.9%
TOTAL TGS DIVISION	$ 23,472,608	$ 13,134,708	$ 10,337,900		-4.3%	$ -	$ (448,626)	$ (448,626)	-1.9%

TEXAS GAS SERVICE
Current and Proposed Parameters
Vintage Group Procedure

Statement F

Account Description	Current Parameters						Proposed Parameters (at December 31, 2021)					
	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
TGS DIVISION												
TRANSMISSION PLANT												
367.00 Mains												
369.00 Meas. and Reg. Station Equipment												
Total Transmission Plant												-39.2
DISTRIBUTION PLANT												
375.10 Structures and Improvements	40.00	R4	52.56	6.15	-3.9	-5.0						
376.00 Mains	65.00	R1.5	68.39	51.57	-28.2	-20.0						
376.90 Mains - Cathodic Protection	15.00	SQ	15.00	10.80								
378.00 Meas. and Reg. Station Equip. - General	55.00	R0.5	54.99	38.69	-12.8	-20.0						
379.00 Meas. and Reg. Station Equip. - City Gate	65.00	R1.5	65.47	49.55	-5.3	-10.0						
380.00 Services	55.00	R2	56.12	39.62	-70.3	-30.0						
381.00 Meters	25.00	R2.5	28.18	19.93	-19.1	-10.0						
383.00 House Regulators	35.00	R3	45.72	25.10	-10.3	-5.0						
385.00 Industrial Meas. and Reg. Station Equip.	55.00	R1	56.50	38.41	-17.4	-20.0						
386.00 Other Property on Customers' Premises	20.00	S3	24.98	2.56								
Total Distribution Plant												-40.7
GENERAL PLANT												
Depreciable												
390.10 Structures and Improvements	40.00	R1.5	40.07	37.39	-4.2	-5.0	43.00	R3	43.00	40.77	-10.0	-10.0
392.00 Transportation Equipment	10.00	L0	11.28	7.49	4.8	5.0						
396.00 Power Operated Equipment	13.00	L2	13.25	10.28	8.2	10.0						
Total Depreciable									43.00	40.77	-10.0	-10.0
Amortizable												
391.10 Office Furniture and Fixtures	15.00	SQ	15.00	12.50			15.00	SQ	15.00	12.08		
391.90 Computers and Electronic Equipment	7.00	SQ	7.00	1.67			7.00	SQ	7.00	3.09		
393.00 Stores Equipment	15.00	SQ	15.00	1.00								
394.00 Tools, Shop and Garage Equipment	15.00	SQ	15.00	8.69			15.00	SQ	15.00	14.07		
397.00 Communication Equipment	15.00	SQ	15.00	10.07			15.00	SQ	15.00	5.39		
398.00 Miscellaneous Equipment												
Total Amortizable									11.16	6.74		
Total General Plant									16.44	12.39	-1.9	-4.3
TOTAL TGS DIVISION									16.44	12.39	-1.9	-4.3

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 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
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 4. 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 data base 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 projection 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 Texas Service Area
Distribution Plant
Account: 376.00 Mains

Dispersion: 67 - R2
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2021 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2021	0.5	12,907,000	67.00	66.55	0.9932	1.0000	12,819,769	192,641
2020	1.5	25,653,468	67.00	65.64	0.9797	1.0000	25,133,721	382,878
2019	2.5	10,025,165	67.00	64.74	0.9663	1.0000	9,687,037	149,619
2018	3.5	11,626,435	67.01	63.85	0.9529	1.0000	11,078,336	173,507
2017	4.5	10,560,980	67.00	62.96	0.9396	1.0000	9,923,406	157,620
2016	5.5	10,267,327	67.02	62.07	0.9261	1.0000	9,508,541	153,191
2015	6.5	9,491,565	67.03	61.19	0.9128	1.0000	8,663,747	141,596
2014	7.5	13,039,113	67.04	60.31	0.8996	1.0000	11,730,152	194,507
2013	8.5	10,447,124	67.06	59.43	0.8863	1.0000	9,259,242	155,796
2012	9.5	11,979,780	67.06	58.56	0.8733	1.0000	10,461,766	178,647
2011	10.5	7,365,957	67.08	57.69	0.8600	1.0000	6,334,925	109,801
2010	11.5	5,704,838	67.06	56.83	0.8475	1.0000	4,834,968	85,073
2009	12.5	3,244,343	67.12	55.98	0.8340	1.0000	2,705,801	48,339
2008	13.5	9,774,295	67.14	55.12	0.8210	1.0000	8,024,810	145,581
2007	14.5	4,975,616	67.11	54.27	0.8088	1.0000	4,024,256	74,146
2006	15.5	3,800,287	66.57	53.43	0.8026	1.0000	3,050,170	57,086
2005	16.5	3,911,999	67.20	52.59	0.7826	1.0000	3,061,664	58,214
2004	17.5	3,941,799	66.74	51.76	0.7755	1.0000	3,057,047	59,062
2003	18.5	4,065,155	66.51	50.93	0.7658	1.0000	3,113,045	61,122
2002	19.5	1,222,186	66.63	50.11	0.7521	1.0000	919,147	18,343
2001	20.5	2,498,744	67.42	49.29	0.7311	1.0000	1,826,872	37,063
2000	21.5	2,756,335	67.36	48.48	0.7197	1.0000	1,983,677	40,920
1999	22.5	3,148,084	67.47	47.67	0.7066	1.0000	2,224,310	46,661
1998	23.5	2,358,903	67.53	46.87	0.6941	1.0000	1,637,244	34,934
1997	24.5	3,504,888	67.58	46.07	0.6817	1.0000	2,389,340	51,862
1996	25.5	102,346	63.59	45.28	0.7120	1.0000	72,874	1,609
1995	26.5	286,784	65.40	44.50	0.6803	1.0000	195,113	4,385
1994	27.5	824,772	66.04	43.72	0.6620	1.0000	545,996	12,490
1993	28.5	1,392,712	67.61	42.94	0.6352	1.0000	884,602	20,600
1992	29.5	1,337,644	67.83	42.17	0.6217	1.0000	831,676	19,720
1991	30.5	2,620,037	67.73	41.41	0.6114	1.0000	1,601,907	38,682
1990	31.5	2,207,254	65.45	40.66	0.6212	1.0000	1,371,140	33,725
1989	32.5	1,609,913	64.93	39.91	0.6146	1.0000	989,490	24,795
1988	33.5	1,244,267	64.93	39.16	0.6032	1.0000	750,510	19,164
1987	34.5	1,638,938	63.62	38.43	0.6040	1.0000	989,883	25,760
1986	35.5	1,482,558	64.27	37.70	0.5865	1.0000	869,577	23,068
1985	36.5	985,225	64.55	36.97	0.5728	1.0000	564,344	15,264

TEXAS GAS SERVICE COMPANY
West Texas Service Area
Distribution Plant
Account: 376.00 Mains

Dispersion: 67 - R2
Procedure: Vintage Group

Generation Arrangement

Vintage	Age (December 31, 2021)	Surviving Plant (December 31, 2021)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1984	37.5	1,473,098	65.51	36.25	0.5534	1.0000	815,214	22,486
1983	38.5	1,008,821	64.51	35.54	0.5510	1.0000	555,816	15,637
1982	39.5	1,668,718	66.32	34.84	0.5253	1.0000	876,578	25,160
1981	40.5	1,486,989	67.21	34.14	0.5080	1.0000	755,389	22,124
1980	41.5	1,359,278	67.72	33.45	0.4940	1.0000	671,448	20,071
1979	42.5	2,212,211	68.54	32.77	0.4782	1.0000	1,057,797	32,278
1978	43.5	1,206,154	68.36	32.10	0.4695	1.0000	566,316	17,645
1977	44.5	772,538	67.87	31.43	0.4630	1.0000	357,718	11,382
1976	45.5	652,187	66.98	30.77	0.4594	1.0000	299,599	9,738
1975	46.5	940,038	69.47	30.11	0.4335	1.0000	407,467	13,531
1974	47.5	869,017	69.53	29.47	0.4238	1.0000	368,319	12,499
1973	48.5	918,967	69.99	28.83	0.4119	1.0000	378,535	13,129
1972	49.5	615,698	69.91	28.20	0.4034	1.0000	248,352	8,806
1971	50.5	600,428	70.08	27.58	0.3936	1.0000	236,310	8,568
1970	51.5	483,176	70.22	26.97	0.3840	1.0000	185,558	6,881
1969	52.5	373,816	70.52	26.36	0.3738	1.0000	139,730	5,301
1968	53.5	368,876	70.39	25.76	0.3660	1.0000	135,014	5,241
1967	54.5	444,412	70.56	25.17	0.3568	1.0000	158,549	6,298
1966	55.5	402,801	70.45	24.59	0.3491	1.0000	140,609	5,718
1965	56.5	133,911	68.77	24.02	0.3493	1.0000	46,774	1,947
1964	57.5	152,249	69.36	23.46	0.3382	1.0000	51,483	2,195
1963	58.5	266,915	72.19	22.90	0.3172	1.0000	84,673	3,697
1962	59.5	628,199	73.01	22.35	0.3062	1.0000	192,340	8,604
1961	60.5	392,044	74.03	21.82	0.2947	1.0000	115,535	5,296
1960	61.5	426,382	73.88	21.29	0.2881	1.0000	122,862	5,771
1959	62.5	478,800	74.02	20.77	0.2806	1.0000	134,340	6,469
1958	63.5	521,219	75.15	20.26	0.2695	1.0000	140,491	6,936
1957	64.5	503,700	75.06	19.75	0.2632	1.0000	132,568	6,711
1956	65.5	372,785	75.85	19.26	0.2539	1.0000	94,661	4,915
1955	66.5	406,369	75.32	18.78	0.2493	1.0000	101,310	5,396
1954	67.5	212,528	76.81	18.30	0.2383	1.0000	50,636	2,767
1953	68.5	126,244	76.32	17.83	0.2337	1.0000	29,501	1,654
1952	69.5	34,666	73.96	17.38	0.2350	1.0000	8,145	469
1951	70.5	30,880	73.21	16.93	0.2312	1.0000	7,140	422
1950	71.5	61,378	74.61	16.49	0.2210	1.0000	13,562	823
1949	72.5	59,216	74.50	16.06	0.2155	1.0000	12,763	795
1948	73.5	37,323	73.61	15.63	0.2124	1.0000	7,927	507

TEXAS GAS SERVICE COMPANY
West Texas Service Area
Distribution Plant
Account: 376.00 Mains

Dispersion: 67 - R2
Procedure: Vintage Group

Generation Arrangement

Vintage	Age (December 31, 2021)	Surviving Plant (December 31, 2021)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1947	74.5	25,005	70.86	15.22	0.2148	1.0000	5,370	353
1946	75.5	71,381	76.62	14.81	0.1933	1.0000	13,800	932
1945	76.5	5,836	74.90	14.41	0.1924	1.0000	1,123	78
1944	77.5	24	63.78	14.02	0.2199	1.0000	5	
1942	79.5	5,468	76.48	13.27	0.1735	1.0000	948	71
1941	80.5	190	66.43	12.90	0.1942	1.0000	37	3
1940	81.5	1,214	72.15	12.54	0.1738	1.0000	211	17
1939	82.5	464	69.85	12.19	0.1745	1.0000	81	7
1938	83.5	27	71.84	11.84	0.1648	1.0000	5	
1931	90.5	2,964	83.07	9.57	0.1152	1.0000	341	36
1930	91.5	84	83.47	9.26	0.1110	1.0000	9	1
1929	92.5	156,000	90.09	8.96	0.0995	1.0000	15,516	1,732
1928	93.5	751	81.69	8.66	0.1060	1.0000	80	9
1924	97.5	1	82.55	7.48	0.0906	1.0000		
1923	98.5	842	86.77	7.19	0.0828	1.0000	70	10
1922	99.5	1,938	90.62	6.89	0.0761	1.0000	147	21
1921	100.5	611	90.54	6.61	0.0730	1.0000	45	7
1919	102.5	19	83.25	6.03	0.0724	1.0000	1	
1917	104.5	3,094	104.63	5.45	0.0521	1.0000	161	30
1914	107.5	4,190	99.83	4.58	0.0459	1.0000	192	42
1913	108.5	34	87.90	4.30	0.0489	1.0000	2	
1912	109.5	433	99.51	4.01	0.0403	1.0000	17	4
1900	121.5	2	116.34	0.93	0.0080	1.0000		
Total	14.1	$226,986,442	67.18	55.31	0.8232	1.0000	$186,859,296	$3,378,687

TEXAS GAS SERVICE COMPANY
West Texas Service Area
Distribution Plant
Account: 376.00 Mains

Age Distribution

Vintage	Age as of 12/31/2021	Derived Additions	1999 Opening Balance	Experience to 12/31/2021 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2021	0.5	12,907,033		12,907,000	1.0000	0.5000
2020	1.5	25,653,504		25,653,468	1.0000	1.5000
2019	2.5	10,025,165		10,025,165	1.0000	2.5000
2018	3.5	11,629,646		11,626,435	0.9997	3.4993
2017	4.5	10,605,889		10,560,980	0.9958	4.4877
2016	5.5	10,267,345		10,267,327	1.0000	5.5000
2015	6.5	9,492,371		9,491,565	0.9999	6.4999
2014	7.5	13,059,836		13,039,113	0.9984	7.4922
2013	8.5	10,450,176		10,447,124	0.9997	8.4983
2012	9.5	12,037,373		11,979,780	0.9952	9.4845
2011	10.5	7,392,103		7,365,957	0.9965	10.4929
2010	11.5	5,759,699		5,704,838	0.9905	11.4456
2009	12.5	3,270,782		3,244,343	0.9919	12.4816
2008	13.5	9,867,770		9,774,295	0.9905	13.4795
2007	14.5	5,117,094		4,975,616	0.9724	14.4174
2006	15.5	4,176,825		3,800,287	0.9099	14.8528
2005	16.5	3,939,255		3,911,999	0.9931	16.4478
2004	17.5	4,230,473		3,941,799	0.9318	16.9507
2003	18.5	4,435,741		4,065,155	0.9165	17.6802
2002	19.5	1,308,224		1,222,186	0.9342	18.7569
2001	20.5	2,498,744		2,498,744	1.0000	20.5000
2000	21.5	2,779,352		2,756,335	0.9917	21.3917
1999	22.5	3,160,336		3,148,084	0.9961	22.4461
1998	23.5		2,382,291	2,358,903	0.9902	23.4464
1997	24.5		3,526,480	3,504,888	0.9939	24.4408
1996	25.5		139,396	102,346	0.7342	21.3859
1995	26.5		335,901	286,784	0.8538	24.1242
1994	27.5		1,302,153	824,772	0.6334	25.6843
1993	28.5		1,437,553	1,392,712	0.9688	28.1771
1992	29.5		1,360,234	1,337,644	0.9834	29.3158
1991	30.5		2,723,940	2,620,037	0.9619	30.1289
1990	31.5		2,569,289	2,207,254	0.8591	28.7491
1989	32.5		1,942,929	1,609,913	0.8286	29.1304
1988	33.5		1,498,498	1,244,267	0.8303	30.0240
1987	34.5		2,734,476	1,638,938	0.5994	29.6065
1986	35.5		1,883,277	1,482,558	0.7872	31.1340
1985	36.5		1,243,106	985,225	0.7926	32.2871
1984	37.5		1,844,677	1,473,098	0.7986	34.1230

TEXAS GAS SERVICE COMPANY
West Texas Service Area
Distribution Plant
Account: 376.00 Mains

Age Distribution

Vintage	Age as of 12/31/2021	Derived Additions	1999 Opening Balance	Experience to 12/31/2021 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1983	38.5		1,484,560	1,008,821	0.6795	33.9871
1982	39.5		2,019,655	1,668,718	0.8262	36.6525
1981	40.5		1,753,731	1,486,989	0.8479	38.3886
1980	41.5		1,582,624	1,359,278	0.8589	39.7399
1979	42.5		2,427,484	2,212,211	0.9113	41.3854
1978	43.5		1,354,557	1,206,154	0.8904	42.0317
1977	44.5		926,965	772,538	0.8334	42.3623
1976	45.5		864,511	652,187	0.7544	42.2722
1975	46.5		1,083,712	940,038	0.8674	45.5695
1974	47.5		988,311	869,017	0.8793	46.4123
1973	48.5		1,041,495	918,967	0.8824	47.6564
1972	49.5		733,660	615,698	0.8392	48.3475
1971	50.5		695,110	600,428	0.8638	49.2684
1970	51.5		578,673	483,176	0.8350	50.1573
1969	52.5		434,995	373,816	0.8594	51.1991
1968	53.5		457,592	368,876	0.8061	51.7929
1967	54.5		542,731	444,412	0.8188	52.6830
1966	55.5		516,248	402,801	0.7802	53.2757
1965	56.5		184,773	133,911	0.7247	52.2881
1964	57.5		220,943	152,249	0.6891	53.5647
1963	58.5		309,285	266,915	0.8630	57.0579
1962	59.5		691,356	628,199	0.9086	58.5326
1961	60.5		405,445	392,044	0.9669	60.1930
1960	61.5		448,322	426,382	0.9511	60.6675
1959	62.5		512,881	478,800	0.9335	61.4213
1958	63.5		534,214	521,219	0.9757	63.1542
1957	64.5		568,496	503,700	0.8860	63.6454
1956	65.5		382,869	372,785	0.9737	65.0089
1955	66.5		479,957	406,369	0.8467	65.0285
1954	67.5		220,294	212,528	0.9647	67.0662
1953	68.5		200,785	126,244	0.6288	67.0956
1952	69.5		156,899	34,666	0.2209	65.2436
1951	70.5		87,781	30,880	0.3518	64.9864
1950	71.5		178,210	61,378	0.3444	66.8727
1949	72.5		173,657	59,216	0.3410	67.2152
1948	73.5		106,392	37,323	0.3508	66.7734
1947	74.5		63,989	25,005	0.3908	64.4574
1946	75.5		129,563	71,381	0.5509	70.6225

TEXAS GAS SERVICE COMPANY
West Texas Service Area
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Age Distribution

Vintage	Age as of 12/31/2021	Derived Additions	1999 Opening Balance	Experience to 12/31/2021 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1945	76.5		22,341	5,836	0.2612	69.3080
1944	77.5		10,530	24	0.0023	58.5679
1942	79.5		30,695	5,468	0.1781	71.9759
1941	80.5		23,033	190	0.0083	62.2569
1940	81.5		7,040	1,214	0.1725	68.2895
1939	82.5		14,270	464	0.0325	66.2921
1938	83.5		2,971	27	0.0092	68.5621
1937	84.5		3,061		0.0000	70.8975
1936	85.5		58,343		0.0000	79.0174
1935	86.5		12,341		0.0000	73.8567
1934	87.5		319		0.0000	67.0000
1933	88.5		8,272		0.0000	77.6122
1932	89.5		4,514		0.0000	76.9635
1931	90.5		134,432	2,964	0.0220	81.3792
1930	91.5		30,725	84	0.0027	81.9405
1929	92.5		261,329	156,000	0.5970	88.7253
1928	93.5		9,087	751	0.0827	80.4731
1927	94.5		1,894		0.0000	81.6820
1926	95.5		4,246		0.0000	83.4959
1924	97.5		1,769	1	0.0006	81.8122
1923	98.5		6,473	842	0.1300	86.1201
1922	99.5		5,437	1,938	0.3564	90.0605
1921	100.5		11,456	611	0.0534	90.0599
1920	101.5		994		0.0000	79.0000
1919	102.5		215	19	0.0881	82.8949
1918	103.5		475		0.0000	81.0000
1917	104.5		3,248	3,094	0.9527	104.3818
1916	105.5		10,678		0.0000	91.1372
1915	106.5		839		0.0000	84.0002
1914	107.5		6,417	4,190	0.6530	99.6936
1913	108.5		427	34	0.0798	87.7956
1912	109.5		6,834	433	0.0633	99.4234
1911	110.5		4,100		0.0000	88.0000
1910	111.5		5,449		0.0000	92.2409
1909	112.5		10		0.0000	90.0000
1908	113.5		327		0.0000	91.0000
1907	114.5		1,037		0.0000	108.9089
1906	115.5		4,371		0.0000	101.9933

TEXAS GAS SERVICE COMPANY
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Age Distribution

				Experience to 12/31/2021		
Vintage	Age as of 12/31/2021	Derived Additions	1999 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1905	116.5		17,387		0.0000	95.2237
1900	121.5		1,323	2	0.0016	116.3389
Total	14.1	$184,064,736	$53,195,636	$226,986,442	0.9567	

TEXAS GAS SERVICE COMPANY
West Texas Service Area
Distribution Plant
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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	55,887,322	3,305,039	141,680		59,050,681
2000	59,050,681	5,088,541	293,660		63,845,562
2001	63,845,562	2,729,023	2,941,706		63,632,879
2002	63,632,879	1,071,677	137,130		64,567,427
2003	64,567,427	3,078,308	564		67,645,171
2004	67,645,171	8,454,748	106,551		75,993,368
2005	75,993,368	5,060,054	147,150		80,906,272
2006	80,906,272	4,713,963	11,574		85,608,661
2007	85,608,661	6,600,473	90,817	(413,655)	91,704,663
2008	91,704,663	9,397,907	385,319		100,717,251
2009	100,717,251	5,167,543	325,014	1,107,978	106,667,758
2010	106,667,758	6,563,272	170,037		113,060,993
2011	113,060,993	8,339,833	186,046		121,214,780
2012	121,214,780	12,820,763	459,446	(155,892)	133,420,205
2013	133,420,205	10,175,469	680,233	(2,047,063)	140,868,377
2014	140,868,377	15,585,124	570,167	(2,090)	155,881,244
2015	155,881,244	10,831,597	1,912,500	(146,194)	164,654,148
2016	164,654,148	11,911,388	105,347	(17,000,382)	159,459,807
2017	159,459,807	12,062,026	588,328	(567,023)	170,366,482
2018	170,366,482	11,328,473	144,628		181,550,327
2019	181,550,327	9,340,247	259,087	(4,667,822)	185,963,666
2020	185,963,666	27,777,181	452,224		213,288,623

TEXAS GAS SERVICE COMPANY
West Texas Service Area
Distribution Plant
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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	60,491,145	3,350,433	145,790	182	63,695,971
2000	63,695,971	2,913,877	374,240	8,349	66,243,957
2001	66,243,957	2,737,910	2,865,546		66,116,321
2002	66,116,321	1,373,287	137,130		67,352,478
2003	67,352,478	4,757,134	564		72,109,048
2004	72,109,048	5,655,908	106,551		77,658,406
2005	77,658,406	4,305,085	146,673		81,816,818
2006	81,816,818	4,607,553	11,574		86,412,797
2007	86,412,797	5,519,782	83,374	(413,655)	91,435,550
2008	91,435,550	10,575,418	384,425		101,626,544
2009	101,626,544	4,480,983	322,792	1,107,978	106,892,713
2010	106,892,713	6,864,999	170,275		113,587,436
2011	113,587,436	8,078,354	186,046		121,479,744
2012	121,479,744	12,922,159	443,992	(155,892)	133,802,019
2013	133,802,019	11,845,995	671,900	(2,047,063)	142,929,052
2014	142,929,052	14,957,614	553,172	(2,090)	157,331,404
2015	157,331,404	11,713,658	1,960,656	(146,194)	166,938,212
2016	166,938,212	11,296,224	108,743	(16,999,931)	161,125,761
2017	161,125,761	12,068,178	588,328	(567,023)	172,038,587
2018	172,038,587	12,328,818	144,628		184,222,778
2019	184,222,778	9,606,907	259,087	(4,667,822)	188,902,776
2020	188,902,776	24,838,549	452,702		213,288,623

TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2021
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	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	72.0	L0	10.03	114.5	O3 *	17.44	58.6	R1 *	8.56
2000-2004	11.9	98.9	O3	6.99	137.4	SC *	14.01	64.6	R1 *	12.66
2001-2005	13.5	104.9	O2	8.55	139.7	SC *	16.01	64.5	R1.5 *	13.28
2002-2006	28.0	151.8	R1	14.31	88.7	R2.5	5.71	79.7	R3	13.72
2003-2007	11.2	138.5	R0.5	24.41	82.0	R2.5	6.11	75.1	R3	6.68
2004-2008	0.2	127.2	SC	29.53	78.1	R2	10.99	71.7	R3	4.29
2005-2009	0.0	108.5	S-.5	25.67	74.3	R2	9.95	68.6	R3	3.46
2006-2010	1.8	110.7	SC	25.36	77.9	R1.5	12.80	69.4	R3	3.84
2007-2011	0.8	105.6	SC	24.81	78.7	R1	14.98	68.8	R2.5	4.56
2008-2012	1.0	98.8	L0	21.92	77.4	R1	13.32	68.0	R2.5 *	2.57
2009-2013	1.1	81.7	L0.5	17.00	68.0	R1.5	8.52	63.9	R2.5 *	2.14
2010-2014	2.3	84.7	L1	17.25	71.8	R1.5	9.72	65.9	R2.5 *	2.99
2011-2015	0.8	68.8	L1.5*	11.18	63.1	S1	6.25	60.8	R2 *	3.44
2012-2016	0.0	70.3	L1.5*	13.13	64.1	S1	7.77	61.5	R2 *	4.37
2013-2017	0.0	71.5	L1.5*	13.74	65.2	S1	8.25	62.4	R2 *	4.80
2014-2018	0.0	81.9	L1.5*	18.77	73.6	S1	13.35	69.1	R2 *	9.14
2015-2019	0.0	85.6	L1.5*	20.74	75.6	S1	14.25	71.5	R2.5 *	10.62
2016-2020	0.0	103.1	L1	28.54	83.8	S1.5	19.31	74.9	R3 *	11.18
2017-2021	0.0	100.3	L1	27.38	82.4	S1	18.76	74.6	R2.5 *	11.83

TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2021
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	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
1999-2021	0.0	86.5	L0.5	16.96	74.4	S0.5	9.75	67.2	R2 *	1.92
2001-2021	0.0	87.9	L0.5	16.89	76.1	S0.5	10.30	67.7	R2 *	2.64
2003-2021	0.0	90.3	L1	17.83	75.0	S1	8.35	69.2	R2.5 *	2.67
2005-2021	0.0	88.2	L1	17.04	74.3	S1	8.16	68.7	R2.5 *	2.60
2007-2021	0.0	86.4	L1	16.41	73.8	S1	8.34	68.1	R2.5 *	2.55
2009-2021	0.0	84.8	L1	15.67	73.6	S1	8.44	67.9	R2.5 *	2.69
2011-2021	0.0	84.2	L1	15.23	73.4	S1	7.93	68.3	R2.5 *	3.00
2013-2021	0.0	82.8	L1 *	19.02	72.8	S1	12.41	68.0	R2.5 *	7.42
2015-2021	0.0	85.6	L1 *	20.31	75.5	S1	14.25	70.6	R2 *	9.82
2017-2021	0.0	100.3	L1	27.38	82.4	S1	18.76	74.6	R2.5 *	11.83
2019-2021	0.0	94.4	L0.5	10.89	80.8	S0.5	7.02	72.9	R2	10.75
2021-2021	46.8	97.9	L0	5.37	81.5	R1	10.76	73.6	R1.5	17.92

TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2021
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

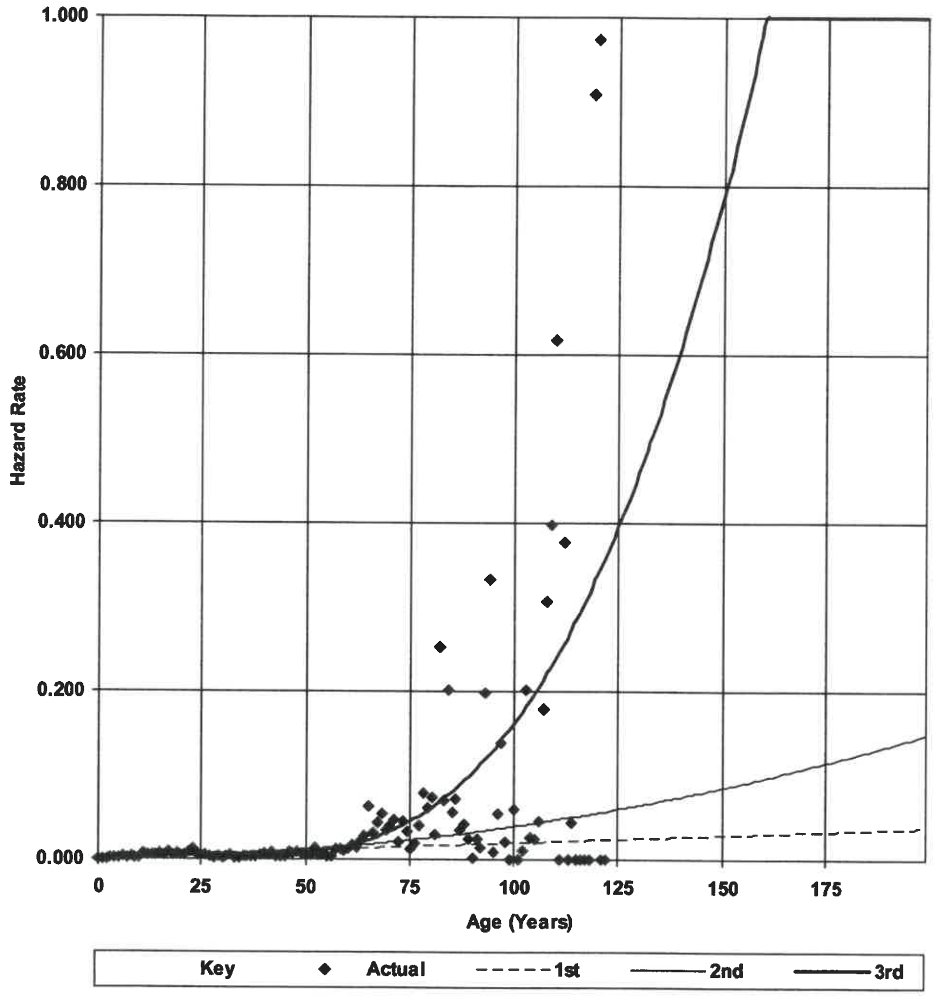
Observation Band	Censoring	First Degree Average Life	First Degree Disper-sion	First Degree Conf. Index	Second Degree Average Life	Second Degree Disper-sion	Second Degree Conf. Index	Third Degree Average Life	Third Degree Disper-sion	Third Degree Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2000	0.0	65.4	L1.5*	13.09	56.9	R2.5	6.04	57.2	R3	6.71
1999-2002	0.6	60.7	O2	7.91	99.0	O4*	14.88	53.3	R1*	7.90
1999-2004	0.9	80.6	O2	12.28	110.2	O3*	16.26	60.5	R1.5*	7.49
1999-2006	3.3	91.6	L0	14.09	83.7	L0.5	12.28	64.3	R2*	7.26
1999-2008	1.0	96.6	L0	18.95	78.3	R0.5	12.96	65.6	R2	4.64
1999-2010	1.5	96.4	L0	19.44	78.1	R0.5	13.18	65.6	R2	3.68
1999-2012	1.0	96.1	L0	19.77	77.7	S0	12.70	66.5	R2*	2.58
1999-2014	0.9	88.7	L0.5	18.30	73.1	R1	10.43	65.2	R2.5*	2.14
1999-2016	0.3	81.1	L0.5	15.35	70.3	S0.5	8.69	64.2	R2*	1.54
1999-2018	0.4	84.6	L0.5	16.79	72.7	S0.5	9.60	65.9	R2.5*	1.83
1999-2020	0.0	85.7	L1	16.91	73.9	S0.5	9.79	66.8	R2.5*	1.91
1999-2021	0.0	86.5	L0.5	16.96	74.4	S0.5	9.75	67.2	R2*	1.92

TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2021 Observation Band: 1999-2021
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Functions

1st: 86.5-L0.5 2nd: 74.4-S0.5 3rd: 67.2-R2

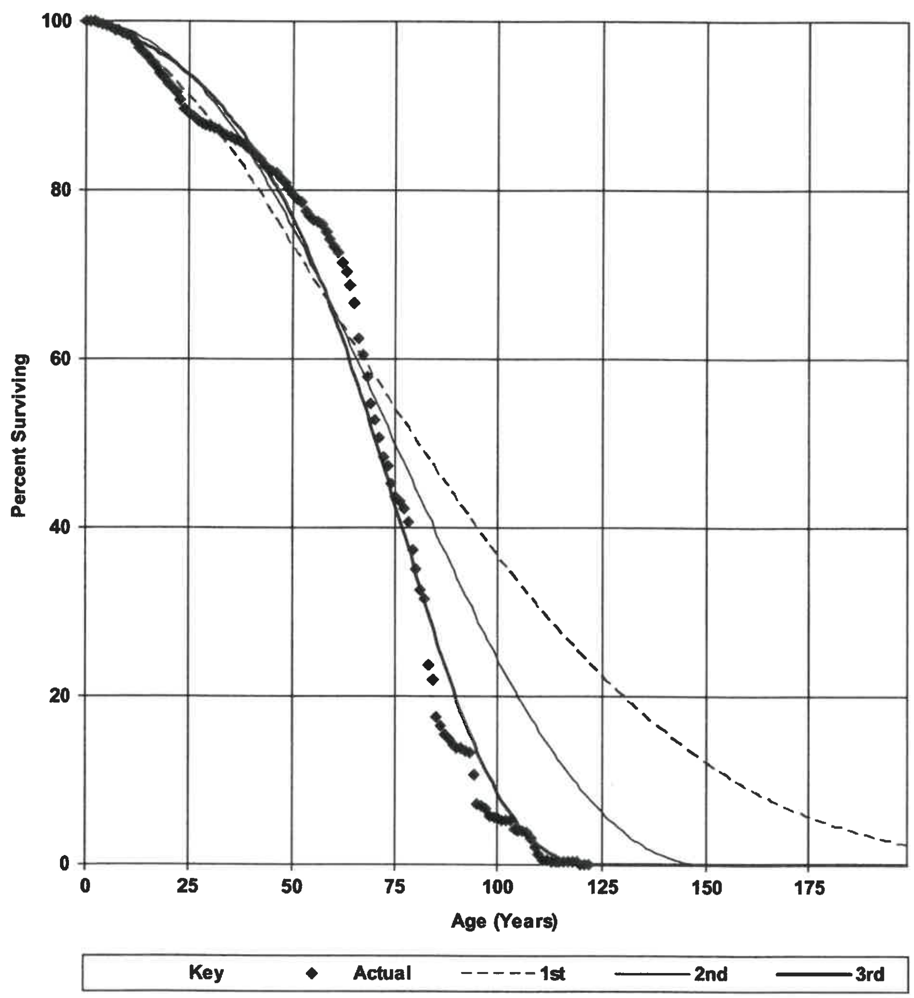


TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2021 Observation Band: 1999-2021
Hazard Function: Proportion Retired
Weighting: Exposures

Survivorship Functions

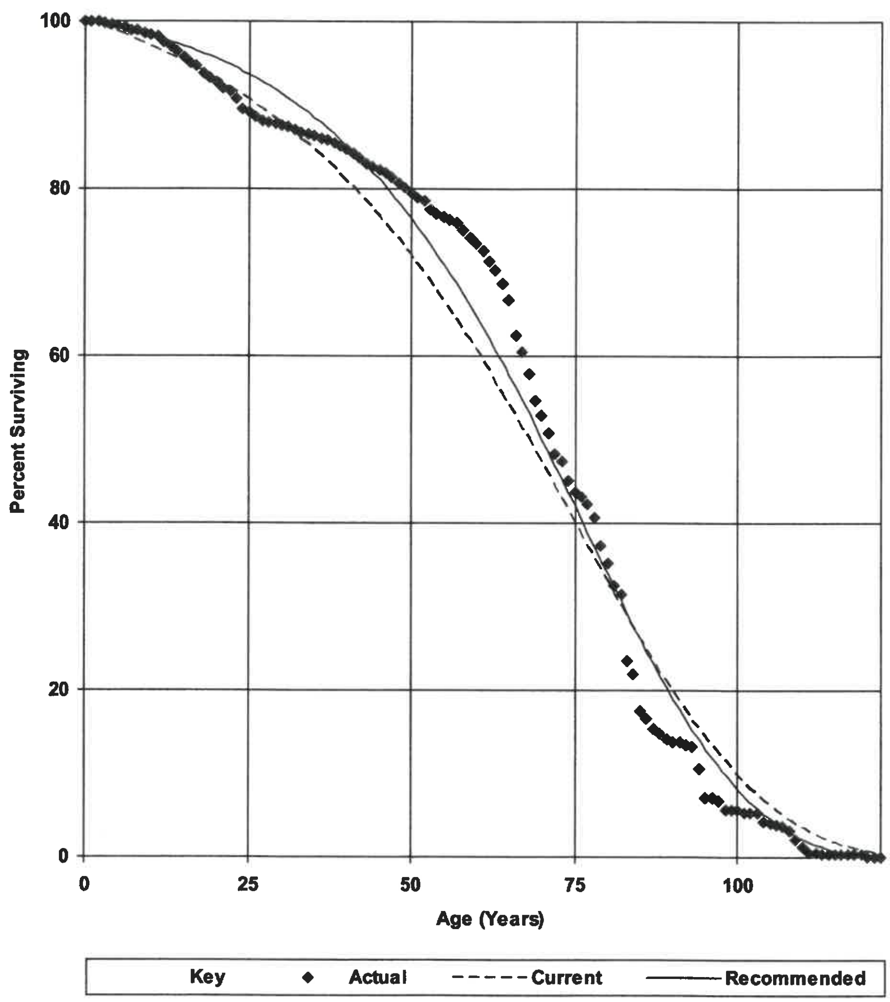
1st: 86.5-L0.5 2nd: 74.4-S0.5 3rd: 67.2-R2



TEXAS GAS SERVICE COMPANY
Distribution Plant
Account: 376.00 Mains

T-Cut: None
Placement Band: 1900-2021
Observation Band: 1999-2021

Projection Life Curves **Current: 65.0-R1.5** **Proposed: 67.0-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
Total	35,697,589	177,005	0.5		71,166,451	199.4		(70,989,446)	-198.9	

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
Total	35,201,460	9,891	0.0		71,166,451	202.2		(71,156,561)	-202.1	

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 16th day of June 2022.

LYNNETTE A. JAY
Notary Public - State of Florida
My Comm. Expires March 7, 2025
Commission # HH75921

Lynnette A. Jay
Notary Public in and for the State of Florida

CASE NO. 00009896

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	§ § § § § § § § §	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

BRUCE H. FAIRCHILD

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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Schedule 9	Risk Premium Method
Schedule 10	Comparable Earnings Method

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 proposed West North Service Area ("WNSA").

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 RATE OF RETURN 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") is taking in the aftermath of the COVID-19 pandemic and recent jumps in the Consumer Price Index ("CPI"). With this background, I develop a mix of investor-supplied capital (i.e., debt and equity) to be used as weightings in calculating an overall rate of return. An average cost of debt applicable to the debt component of the capital structure is then calculated. Next, various analyses are conducted to determine a fair rate of return on common equity ("ROE"). These analyses include applications of the discounted cash flow ("DCF") model, capital asset pricing model ("CAPM"), risk premium method, and comparable earnings method to develop a cost of equity range, from which TGS's requested ROE is selected. Finally, these components are combined to calculate my recommended overall rate of return for TGS's proposed WNSA.

C. Summary of Conclusions

Q. WHAT IS YOUR RATE OF RETURN RECOMMENDATION?

A. As developed on Schedule 1, I recommend an overall rate of return for TGS on the invested capital in its proposed WNSA of 7.77%. This rate of return is based on capital structure ratios of 40.26% debt and 59.74% equity, a cost of debt of 4.09%, and an ROE of 10.25%.

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED CAPITAL STRUCTURE RATIOS FOR TGS?

A. My recommended capital structure ratios of 40.26% debt and 59.74% equity are based on the capitalization of ONE Gas, Inc. ("ONE Gas"), of which TGS is a division, at December 31, 2021. These ratios are consistent with the capital structure ONE Gas has maintained since it was spun off from ONEOK Inc. into a stand-alone company in 2014. They reflect ONE Gas' need to maintain a credit profile supporting an historical industry standard, single-A bond rating, which will enable it to continue to attract new capital on reasonable terms and maintain its financial integrity. The ratios also reflect the need for ONE Gas to have sufficient creditworthiness and financial flexibility to meet unexpected financial requirements, such as those resulting from the 2021 February winter weather event ("Winter Storm Uri"). Besides being TGS's actual capital structure, ONE Gas' year-end permanent 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 over the last five years.

Q. HOW DID YOU ARRIVE AT YOUR RECOMMENDED COST OF DEBT FOR TGS?

A. My recommended 4.09% cost of debt is the average cost associated with the $1.6 billion of permanent long-term debt issued by ONE Gas and outstanding at December 31, 2021.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ROE OF 10.25%?

A. Based on applications of the DCF, CAPM, risk premium, and comparable earnings methods to an industry group of publicly traded LDCs, I conclude that investors currently require an ROE in the range of 9.5% to 10.5%. The ROE being used to establish rates in this case should reflect capital market conditions that will prevail when the rates are in effect. To curb skyrocketing inflation, the Fed is aggressively hiking the federal funds rate and significantly reducing its $9 trillion bond inventory, actions that have already begun, and are expected to continue, to raise interest rates and, in turn, the cost of equity. To account for the higher capital costs when rates for TGS's proposed WNSA will be in effect, I recommend an allowed ROE midway between the middle and top of my cost of equity range, or 10.25%.

II. FUNDAMENTAL ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. As a predicate to subsequent quantitative analyses, this section briefly reviews the operations and finances of TGS and ONE Gas. It also examines the natural gas distribution industry along with conditions in the capital markets and U.S. economy.

A. Texas Gas Service Company

Q. BRIEFLY DESCRIBE TGS.

A. TGS is the operating division of ONE Gas that distributes natural gas to approximately 689,000 sales and transport customers in 100 communities throughout Texas. In addition to its proposed WNSA, which includes El Paso, TGS also serves the Rio Grande Valley and cities of Austin, Galveston, and Port Arthur. In total, TGS serves approximately 13% of the natural gas customers in Texas. At December 31, 2021, TGS had total assets of approximately $1.8 billion, with operating revenues for calendar year being approximately $446 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 2.2 million customers. ONE Gas was created when ONEOK, Inc. spun off its natural gas distribution operations into a separate entity on January 31, 2014. At December 31, 2021, ONE Gas had total assets of approximately $8.4 billion, with revenues during 2021 totaling more than $1.8 billion. ONE Gas' common stock is traded on the New York Stock Exchange, and its debt is rated BBB+ by Standard & Poor's Financial Services LLC ("S&P") and A3 by Moody's Investors Services, Inc. ("Moody's"), ratings that are discussed more later in my testimony.

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 an exclusive 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.

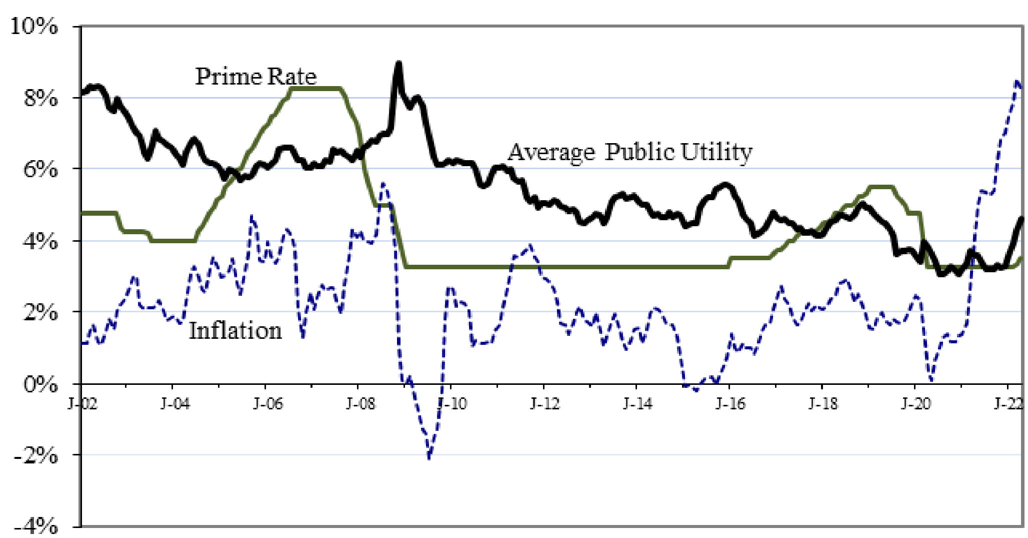
Q. IS TGS EXPOSED TO THESE INDUSTRY RISKS?

A. Yes. Attached to my testimony as Appendix C are the fifteen pages from ONE Gas' 2021 Form 10-K filed with the Securities and Exchange Commission that describe the operational risks; regulatory and legislative risks; financial, economic, and market risks; common stock risks; and general risks faced by ONE Gas. This discussion documents that TGS is exposed to the same risks as the LDC industry generally, as well as other risks unique to it and its service areas.

C. Capital Markets

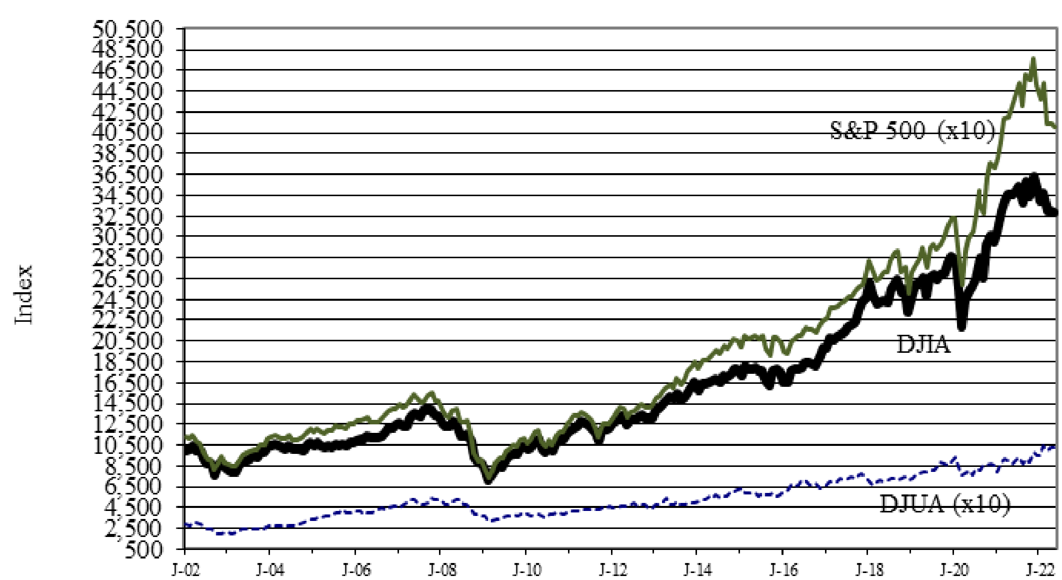
Q. WHAT HAS BEEN THE PATTERN OF INTEREST RATES OVER THE LAST TWO DECADES?

A. Average long-term public utility bond rates, the borrowing prime rate, and inflation as measured by the CPI over the last twenty years are plotted in the graph below. Beginning in 2002, the average yield on long-term public utility bonds generally fell because of monetary and fiscal policies designed to keep the economy growing. This decline ended abruptly with the 2008 financial market meltdown and global recession. Investors became exceedingly risk averse, causing interest rates on corporate bonds to spike, while government policies pushed down short-term interest rates and depressed economic conditions and lower energy prices reduced inflation. Over the next decade, various actions by the Fed to stimulate the economy through easy-money policies resulted in short- and long-term interest rates reaching record lows. These conditions were interrupted in early 2020 by the coronavirus pandemic and worldwide economic shutdown, although the impact on interest rates was moderated by extraordinary actions taken by the Fed in response. However, in late 2021 and the first five months of 2022, CPI inflation skyrocketed, jumping from an average of around 2% over the prior 20 years to 7.04% in 2021 and to 8.26% for the twelve months ended May 2022:



Q. HOW HAS THE MARKET FOR COMMON EQUITY CAPITAL PERFORMED OVER THIS SAME PERIOD?

A. In the early 2000s, stock prices moved steadily higher as one of the longest bull markets in U.S. history continued unabated. In mid-2000, mounting concerns over prospects for future growth, particularly for firms in the high technology and telecommunications sectors, pushed equity prices lower, in some cases precipitously. Common stock prices generally recovered and reached record highs, buoyed in large part by widespread acquisition activity, until the capital market crisis and Great Recession hit in 2008. Stock prices tumbled by some 40%, and while they recovered and reached all-time highs over the next decade, they crashed again in early 2020 due to the coronavirus pandemic. Since then, most stock indices reached all-time highs, although they have recently receded some 20% into bear market territory in response to inflation worries, soaring energy prices, and global events (e.g., the Russian invasion of Ukraine). Additionally, the stock market has become extraordinarily volatile, with share prices routinely changing more than full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the S&P 500, and the Dow Jones Utility Average since 2002 (the latter two indices were scaled for comparability):



Q. WHAT IS THE OUTLOOK FOR THE U.S. ECONOMY?

A. The U.S. economy had fully recovered from the Great Recession when the coronavirus pandemic struck in early 2020 and the world economy came to a virtual stand-still. More than 30 million U.S. jobs were lost, and unemployment reached almost 15%, not counting furloughed workers, throwing the U.S. into a recession overnight. To address the crisis, the U.S. Congress provided some $4.5 trillion in aid and stimulus spending, and the Fed held short-term interest rates near zero and purchased up to $120 billion a month in Treasury debt and mortgage backed securities to suppress long-term interest rates. The combined effect of these fiscal and monetary policies, along with the population becoming vaccinated, is that U.S. economic activity has increased to greater than prior to the coronavirus pandemic and unemployment has fallen to below 4%. As noted earlier, however, inflation began to increase markedly in 2021. After initially attributing the increase to supply-chain problems and then the Russian invasion of Ukraine, the Fed concluded that the dramatic rise in prices was not "transitory," and beginning in March 2022 embarked on its most aggressive effort in more than two decades to curb inflation. This includes increasing short-term interest rates, announcing that more hikes in the federal funds rate would follow, and reducing its $9 trillion inventory of Treasury debt and mortgage backed securities up to $95 billion a month by not replacing maturing bonds. Whether these unprecedented actions by the Fed will succeed in reducing inflation without significantly raising unemployment and causing a recession is unknown, but they affect every segment of the U.S. economy.

Q. HOW WILL THE FED'S ACTIONS AFFECT THE COST OF CAPITAL?

A. Hikes in the federal funds rate by the Fed and significant reductions in its long-term bond inventory are intended to increase the cost of all borrowing, including by LDCs. As will be explained more later, higher interest rates will, in turn, increase the cost of more risky equity capital. This, coupled with the greater volatility in stock prices that increases the risk of investing in common equities, implies that the relatively low capital cost environment that has existed for the last decade is ending. As a result, the cost of debt and equity will be higher in the coming years, and the ROEs authorized for LDCs over the last few years, including those allowed by the Commission, must be increased to fairly compensate a utility's investors, enable it to attract new capital on reasonable terms, and maintain its 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 for use in calculating 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 ARE THE SOURCES OF CAPITAL USED TO FINANCE ONE GAS?

A. ONE Gas' financing at test year-end, December 31, 2021, is shown below (dollar amounts in 000s):

Capital Component	Amount
Long-term Debt	$ 3,683,378
Common Equity	2,349,532
Total	$ 6,032,910

Q. ARE ANY ADJUSTMENTS TO ONE GAS' YEAR-END CAPITAL STRUCTURE NECESSARY FOR PRESENT PURPOSES?

A. Yes. Approximately $2.1 billion of the $3.7 billion of long-term debt outstanding at year-end 2021 is attributable to three debt issuances used to finance extraordinary gas costs incurred during Winter Storm Uri, which were capitalized as regulatory assets. These debt issuances are expected to be repaid primarily with proceeds from the securitizations of the regulatory assets approved by regulators in Texas, Oklahoma, and Kansas. Deducting this $2.1 billion in temporary debt from the $3.7 billion total leaves approximately $1.6 billion in permanent debt:

Capital Component	Amount	% of Total
Long-term Debt	$ 1,583,378	40.26%
Common Equity	2,349,532	59.74%
Total	$ 3,932,910	100.00%

Thus, ONE Gas' permanent capital structure ratios that support the invested capital of TGS at test year-end are 40.26% debt and 59.74% equity.

Q. HOW DO THESE ADJUSTED CAPITAL STRUCTURE RATIOS COMPARE TO THOSE HISTORICALLY MAINTAINED BY ONE GAS?

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%

As evidenced above, ONE Gas' permanent capital structure ratios have generally been in the approximately 40% debt and 60% equity vicinity since its inception.

Q. WHAT CONSIDERATIONS WENT INTO HOW ONE GAS WAS FINANCED WHEN IT WAS SPUN OFF FROM ONEOK, INC.?

A. The Registration Form 10 filed with the Securities and Exchange Commission in connection with the spinoff of ONE Gas from ONEOK, Inc. 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. Of additional importance is that ONE Gas' capital structure and single-A bond ratings enabled it to issue its initial debt in 2014, refinance $300 million and raise an additional $100 million of debt in 2019, and issue $300 million of debt in 2020 on favorable terms, which has been a direct benefit to customers.

Q. HOW DO ONE GAS' CAPITAL STRUCTURE RATIOS COMPARE WITH THOSE OF OTHER LDCS?

A. Based on data published by the American Gas Association, the gas distribution industry maintained the following composite capital structure ratios between 2016 and 2020:

Capital Component	2020	2019	2018	2017	2016
Long-term Debt	42.3%	41.0%	41.9%	41.6%	40.1%
Preferred Stock	0.0%	0.9%	0.1%	0.1%	1.1%
Common Equity	57.7%	58.1%	58.0%	58.3%	58.8%
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.

Alternatively, Schedule 2 displays the capital structure ratios at each fiscal year-end between 2017 and 2021 for an industry group of publicly traded LDCs, excluding ONE Gas. Beginning with the ten companies included in *The Value Line Investment Survey's* ("*Value Line*") Natural Gas Utility industry, I excluded those that are not predominantly engaged in natural gas distribution (i.e., UGI Corp.). This resulted in an industry group consisting of the following nine LDCs: 1) Atmos Energy, 2) Chesapeake Utilities, 3) New Jersey Resources, 4) NiSource, Inc., 5) Northwest Natural Gas, 6) ONE Gas, 7) South Jersey Industries, 8) Southwest Gas Holdings, and 9) Spire, Inc. While ONE Gas' test year-end 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 well within industry bounds.

Q. HAS ANYTHING OCCURRED THAT ILLUSTRATES THE BENEFIT OF ONE GAS MAINTAINING DEBT AND EQUITY RATIOS AT THE LOWER AND UPPER ENDS, RESPECTIVELY, OF INDUSTRY NORMS?

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. DO S&P AND MOODY'S STILL RATE ONE GAS' BONDS SINGLE-A?

A. Following Winter Storm Uri, S&P lowered its rating of ONE Gas' bonds from A to BBB+, a two-notch downgrade, and Moody's reduced its rating of ONE Gas' bonds from A2 to A3. These downgrades were related to uncertainties regarding the recovery of incremental gas costs incurred during Winter Storm Uri and the associated impact on ONE Gas' cash flows, which affects debt service coverage.

ONE Gas is working with regulators, including this Commission, to extend the recovery periods of the extraordinary gas costs to lessen the immediate impact on customers. The ultimate resolutions of the recovery of these gas costs will be a significant factor in ONE Gas' prospective bond ratings and their impact on ONE Gas' credit metrics.

Q. DID ONE GAS' CAPITAL STRUCTURE PLAY A ROLE IN WINTER STORM URI?

A. Yes. Because ONE Gas' equity ratio is above LDC industry averages, 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. 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 larger 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 Cen-	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 Entex -- 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 Entex – 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 Tex	39.88%	60.12%
05/21/2019	10920	CP Entex-Beaumont/ET	43.05%	56.95%
08/04/2020	10928	TGS -- CSSA	41.00%	59.00%

Q. WHAT CAPITAL STRUCTURE RATIOS DO YOU RECOMMEND BE USED TO CALCULATE TGS'S RATE OF RETURN?

A. I recommend that TGS's rate of return be calculated using ONE Gas' December 31, 2021 permanent capital structure ratios of 40.26% debt and 59.74% equity. Besides reflecting how TGS is actually financed, my recommendation follows the Commission's practice of using the utility's actual capital structure ratios when they are generally consistent with and fall within the range of those maintained by other LDCs, which ONE Gas' do. It is also consistent with the capital structure ratios approved by the Commission in rate cases for TGS's service areas, as well as those approved by the Commission for the other two major LDCs in Texas—Atmos and CenterPoint Energy. These capital structure ratios are also generally consistent with ONE Gas' financial policies of maintaining single-A credit metrics and a level of creditworthiness and flexibility to meet unexpected financial requirements. Finally, determining TGS's rate of return using its December 31, 2021 permanent capital structure ratios should contribute to ONE Gas regaining its historical single-A rating by both major bond rating agencies, which has benefited customers both through lower debt costs and 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.

Q. PLEASE DESCRIBE THE LONG-TERM DEBT INCLUDED IN ONE GAS' PERMANENT CAPITAL STRUCTURE.

A. There are four issues of long-term senior notes outstanding comprising ONE Gas' December 31, 2021 permanent capital structure, which have a total face value of $1.6 billion. Two of the issues were sold in 2014 when ONE Gas was spun-off from ONEOK, Inc.—$300 million due in 2024 having an interest rate of 3.61% and $600 million maturing in 2044 with an interest rate of 4.658%. As noted earlier, ONE Gas issued $400 million in senior notes in 2019 that mature in 2048 and bear an interest rate of 4.50%, with $300 million of 2.00% senior notes maturing in 2030 having been sold in 2020. Reducing the balance of the notes at December 31, 2021 was approximately $17.9 million in unamortized issuance costs and $4.9 million in unamortized costs associated with previously retired debt.

Q. WHAT IS THE AVERAGE COST OF ONE GAS' DEBT?

A. As developed below, the weighted average cost of ONE Gas' outstanding debt at test year-end, December 31, 2021, was 4.09% (dollar amounts in 000s):

Description	Amount	Interest Rate	Annual Expense
3.61% due 2024	$ 300,000	3.610%	$ 10,830
4.658% due 2044	600,000	4.658%	27,948
4.50% due 2048	400,000	4.500%	18,000
2.0% due 2030	300,000	2.000%	6,000
Debt Issuance Costs	(17,872)		977
Debt Retirement Costs	(4,881)		723
Total	**$ 1,577,246**		**$ 64,478**
Cost of Debt		**4.09%**	

I recommend this 4.09% cost be applied to the debt component of TGS's permanent capital structure.

V. RETURN ON EQUITY

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The purpose of this section is to develop a cost of equity range for an industry group of LDCs having similar risks to TGS. It begins by introducing the cost of equity concept, explaining the risk-return tradeoff principle fundamental to capital markets, and discussing the importance of using multiple approaches to estimate the cost of equity. The DCF model is then developed and applied to the industry group of publicly traded LDCs to estimate their current cost of equity. Next, the CAPM is described and alternative cost of equity estimates developed for the industry group using this method. Cost of equity estimates are also developed using the risk premium method based on ROEs previously authorized for other LDCs, and a comparable earnings method is applied. The results of these analyses are then combined to arrive at a current cost of equity range for LDCs having similar risks to TGS, from which I select my recommended ROE for TGS's proposed WNSA.

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 May 2022 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.

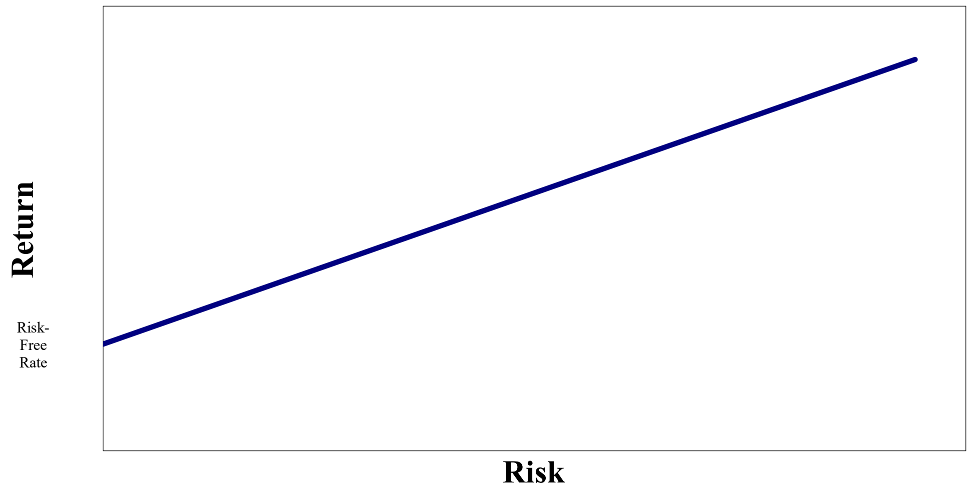
Bond and Rating	**May 2022 Yield**	**Risk Premium Over 30-Year Treasury**
U.S. Treasury		
30-Year	3.07%	--
Public Utility		
Aa	4.55%	1.48%
A	4.75%	1.68%
Baa	5.07%	2.00%

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. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. As discussed earlier, the securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky because mortgage bondholders have a direct claim on the utility's property. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as debentures. The last investors in line are common shareholders. They only receive the net revenues, if any, that remain after all other claimants have been paid. As a result, the minimum rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

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. HOW DID YOU ESTIMATE THE COST OF EQUITY USING THE DCF MODEL?

A. I applied the constant growth form of the DCF model to the industry group of publicly traded LDCs identified earlier, which are nine companies included in

Value Line's Natural Gas Utility industry predominantly engaged in natural gas distribution.

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* June 2, 2022 edition, by the average closing price of each firm's stock during the month of May 2022. The expected dividends, representative price, and resulting dividend yield for each of the nine gas utilities are displayed on Schedule 3. As calculated there, the average dividend yield for the industry group is 3.05%. Also shown is the median for the group of 3.11%, 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" 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 nine gas utilities reported by *Value Line*, Refinitiv's *Institutional Brokers Estimate System* ("*I/B/E/S*"), and *Zacks Investment Research* ("*Zacks*") are displayed on Schedule 4, with the averages for the group being 8.0%, 5.9%, and 5.7%, respectively. Again, to eliminate the impact of extreme values, the medians for the group are also shown, which range between 5.0% and 7.5%.

Also shown on Schedule 4 are the 10-year and 5-year historical earnings growth rates reported by *Value Line* for each of the nine gas utilities, which average 4.2% and 4.9%, respectively, and have medians of 4.0% in both cases.

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 gas utilities in the industry group based on *Value Line's* projections for 2025-2027 is developed in Schedule 5. As shown there, the sustainable growth method implies an average long-term growth rate for the gas utility group of 6.9%, and 5.8% based on the median.

Q. WHAT ARE OTHER PROJECTED AND HISTORICAL GROWTH RATES FOR THE INDUSTRY GROUP?

A. Schedule 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 nine gas utilities in the industry group. The averages for the LDC group range from a low of 3.3% (5-year historical growth in share price) to a high of 8.6% (10-year historical growth in share price), with the medians ranging from 2.6% to 7.8%. Besides the fact that some of these growth rates, when combined with the group's approximately 3.1% dividend yield, imply implausible cost of equity estimates, the variation in these other growth rates results in them providing limited guidance as to the prospective growth that investors expect.

Q. WHAT IS YOUR CONCLUSION AS TO THE GROWTH THAT INVESTORS ARE EXPECTING FROM THE INDUSTRY GROUP?

A. After excluding clearly unreliable indicators of growth, the plausible growth rates shown on Schedules 4, 5, and 6 indicate a range for the LDC group of between approximately 5.5% and 7.5%, which compares with *Zacks* projected earnings growth rate for its gas distribution industry of 6.3%. Taken together, I conclude that investors expect long-term growth from the LDC group in the 6.0% to 7.0% range.

Q. WHAT CURRENT DCF COST OF EQUITY ESTIMATES DO THESE GROWTH RATE RANGES IMPLY FOR THE GAS UTILITY GROUP?

A. Summing the LDC group's average dividend yield of approximately 3.1% with a 6.0% to 7.0% growth rate range indicates a DCF cost of equity for the industry group of between approximately 9.1% and 10.1%.

C. Capital Asset Pricing Model

Q. HOW ELSE DID YOU ESTIMATE THE COST OF EQUITY?

A. The cost of equity to 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. Most recently, Kroll reports that the annual rate of return realized on the S&P 500 averaged 12.30% over the period 1926 through 2021 while the annual average income rate of return on 30-year Treasury bonds over this same period averaged 4.90%. Thus, the market risk premium based on historical average annual rates of return is 7.40%.

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. 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 7, summing the 1.95% expected dividend yield for this market group, which is composed primarily of non-regulated firms, with the average *Value Line*, *I/B/E/S*, and *Zacks* projected growth rate of 10.60% produces a required rate of return from the market portfolio (R_m) of 12.54%.

Q. WHAT IS THE MARKET RISK PREMIUM BASED ON FORWARD-LOOKING REQUIRED RATES OF RETURN?

A. From the 12.54% 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 May 2022 of 3.07%. This produces a forward-looking market risk premium of 9.48%.

Q. WHAT IS THE NEXT STEP IN APPLYING THE CAPM?

A. Having calculated market risk premiums of 7.40% and 9.48% 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 0.85, calculated using firm betas obtained from *Value Line* and shown on Schedule 8, which produces industry risk premiums of 6.29% and 8.05%.

Q. WHAT ARE THE RESULTING THEORETICAL CAPM COST OF EQUITY ESTIMATES FOR THE LDC GROUP?

A. As developed in Schedule 7, summing the industry risk premiums of 6.29% and 8.05% with the May 2022 yield on 30-year Treasury bonds of 3.07% produces theoretical CAPM cost of equity estimates for the LDC industry group of 9.36% and 11.12%.

Q. ARE THESE THEORETICAL CAPM COST OF EQUITY ESTIMATES ACCURATE 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 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.

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 rate of return 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 being reproduced in the lower portion of Schedule 8. In the far right columns of the table in the upper portion of Schedule 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 0.88%. This means that the theoretical CAPM cost of equity estimates need to be increased by 0.88% to account for the industry group's relatively smaller size. As shown on Schedule 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 10.23% and 12.00%, 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 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.

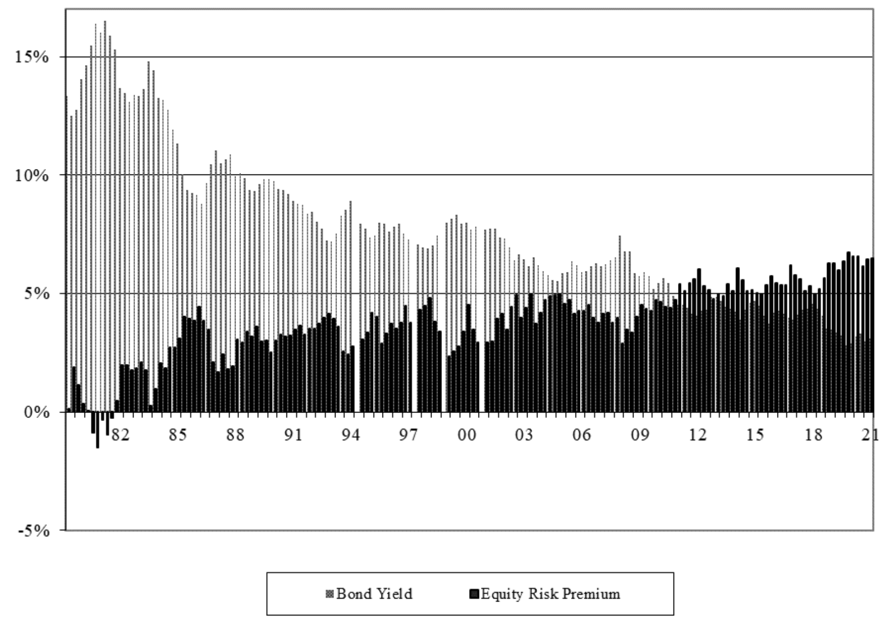
A. Application of the risk premium method based on authorized ROEs is predicated on the presumption that allowed returns reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final orders. A current risk premium is estimated based on the 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.

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 2022 are displayed in Schedule 9. As shown there, the ROEs granted LDCs over this approximately 42-year period have averaged 11.45%, while the average utility bond yield has averaged 7.65%, resulting in an average risk premium of 3.80%.

Q. IS THIS 3.80% 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 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 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 9, substituting the May 2022 yield of 4.79% on average utility bonds into the regression equations indicates that the equity risk premium for an LDC at current interest rate levels is between approximately 5.12% and 5.29%.

Q. WHAT CURRENT COST OF EQUITY DOES THIS RISK PREMIUM IMPLY FOR THE GROUP OF LDCS?

A. As shown on Schedule 8, the average Moody's bond rating for the LDC industry group is A3 and the average S&P bond rating is BBB+. Adding the 5.12% and 5.29% equity risk premiums developed on Schedule 9 to the average of the May 2022 yield on single-A and triple-B utility bonds of 4.91% produces a current risk premium cost of equity range of between 10.03% and 10.20%.

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 10 displays the return on book equity projected for each of the eight LDCs other than ONE Gas in the industry group for the 2022, 2023, and the 2025-2027 timeframes, calculated by dividing *Value Line's* projected earnings per share by average book value per share. As shown there, the average expected book ROE for this group is 9.7% in 2022, 9.9% for 2023, and 10.4% for 2025-2027, with medians of 9.1%, 9.9%, and 10.5%, respectively.

F. Recommended Rate of 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 9.1% and 10.1%, and the CAPM indicates a cost of equity range of between approximately 10.2% and 12.0%. Meanwhile, the risk premium method based on the authorized ROEs for LDCs and current interest rates indicates a cost of equity of between approximately 10.0% and 10.2%, and the comparable earnings method shows that other LDCs are expected to earn between 9.1% and 10.5% on their book equity. Taken together, I conclude that investors currently require a ROE from the LDC industry group in the 9.5% to 10.5% range.

Q. WHAT ROE DO YOU RECOMMEND FOR TGS'S WNSA?

A. So that TGS is able to offer investors a competitive return, attract capital on reasonable terms, and maintain its financial integrity, its allowed ROE should reflect capital market requirements when rates are in effect. As discussed earlier, the Fed has embarked on its most aggressive effort in more than two decades to curb inflation by hiking the federal funds rate and significantly reducing its long-term bond inventory, actions that have already begun, and are expected to continue, to raise interest rates and, in turn, the cost of equity. Thus, to account for the higher capital costs when rates for TGS's proposed WNSA are in effect, I recommend an allowed ROE midway between the middle and top of my cost of equity range, or 10.25%.

Q. HAVE YOU CONDUCTED ANY CHECKS OF REASONABLENESS OF YOUR RECOMMENDED ROE?

A. Yes. The reasonableness of my recommended 10.25% ROE for TGS's proposed WNSA 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 Cen-	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 Entex -- Houston	9.60%
12/05/2017	10640	Atmos -- Dallas	10.10%
03/20/2018	10656	TGS -- RGV	9.50%
05/22/2018	10669	CP Entex – S. Texas	9.80%
11/13/2018	10739	TGS -- NTSA	9.75%
12/11/2018	10742	Atmos – Mid-Tex	9.80%
12/11/2018	10743	Atmos – West Texas	9.80%
02/05/2019	10766	TGS -- BSSA	9.75%
05/21/2019	10779	Atmos – Mid-Tex	9.80%
04/21/2020	10900	Atmos – West Texas	9.80%
04/21/2020	10920	CP Entex-Beaumont/ET	9.65%
08/04/2020	10928	TGS -- CGSA	9.50%

Although the allowed ROE range of 9.50% to 10.10% is below my recommended 10.25%, these 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 4.79% today. Additionally, as discussed earlier, in its effort to control skyrocketing inflation, the Fed has committed to raise interest rates aggressively, which will further increase the cost of equity. Because of the increase in capital costs that has already occurred and is expected to continue, an ROE in the 9.5% to 10.1% range allowed by the Commission over the last few years is no longer sufficient to fairly compensate a utility's investors, enable it to attract new capital on reasonable terms, and maintain its financial integrity. Therefore, after adjusting the ROEs previously granted by the Commission for today's higher capital costs, as well as those that will prevail when the service rates for TGS's WNSA are in effect, my recommended 10.25% ROE is reasonable.

VI. OVERALL RATE OF RETURN

Q. WHAT OVERALL RATE OF RETURN DO YOU RECOMMEND BE APPLIED TO THE INVESTED CAPITAL OF TGS'S PROPOSED WNSA?

A. I recommend that the Commission authorize an overall rate of return on the invested capital in TGS's proposed WNSA of 7.77%. As developed in Schedule 1, this overall rate of return is the result of combining ONE Gas' December 30, 2021 capital structure ratios of 40.26% debt and 59.74% equity with its average cost of debt of 4.09% and an ROE of 10.25%.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

APPENDIX A

BRUCE H. FAIRCHILD

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Summary of Qualifications

M.B.A. and Ph.D. in finance, accounting, and economics; Certified Public Accountant. Extensive consulting experience involving regulated industries, valuation of closely-held businesses, and other economic analyses. Previously held managerial and technical positions in government, academia, and business, and taught at the undergraduate, graduate, and executive education levels. Broad experience in technical research, computer modeling, and expert witness testimony.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included revenue requirements, rate of return, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Other assignments have involved some seventy valuations as well as various economic (e.g., damage) analyses, typically in connection with litigation. Presented expert witness testimony before courts and regulatory agencies on over one hundred occasions.
Adjunct Assistant Professor, University of Texas at Austin (Sep. 1979 to May. 1981)	Taught undergraduate courses in finance: Fin. 370 – Integrative Finance and Fin. 357 – Managerial Finance.
Assistant Director, Economic Research Division, Public Utility Commission of Texas (Sep. 1976 to Aug. 1979)	Division consisted of approximately twenty-five financial analysts, economists, and systems analysts responsible for rate of return, rate design, special projects, and computer systems. Directed Staff participation in rate cases, presented testimony on approximately thirty-five occasions, and was involved in some forty other cases ultimately settled. Instrumental in the initial development of rate of return and financial policy for newly-created agency. Performed independent research and managed State and Federal funded projects. Assisted in preparing appeals to the Texas Supreme Court and testimony presented before the Interstate Commerce Commission and Department of Energy. Maintained communications with financial community, industry representatives, media, and consumer groups. Appointed by Commissioners as Acting Director.

Assistant Professor, College of Business Administration, University of Colorado at Boulder (Jan. 1977 to Dec. 1978)	Taught graduate and undergraduate courses in finance: Fin. 305 – Introductory Finance, Fin. 401 – Managerial Finance, Fin. 402 – Case Problems in Finance, and Fin. 602 – Graduate Corporate Finance.
Teaching Assistant, University of Texas at Austin (Jan. 1973 to Dec. 1976)	Taught undergraduate courses in finance and accounting: Acc. 311 – Financial Accounting, Acc. 312 – Managerial Accounting, and Fin. 357 – Managerial Finance. Elected to College of Business Administration Teaching Assistants' Committee.
Internal Auditor, Sears, Roebuck and Company, Dallas, Texas (Nov. 1970 to Aug 1972)	Performed audits on internal operations involving cash, accounts receivable, merchandise, accounting, and operational controls, purchasing, payroll, etc. Developed operating and administrative policy and instruction. Performed special assignments on inventory irregularities and Justice Department Civil Investigative Demands.
Accounts Payable Clerk, Transcontinental Gas Pipeline Corp., Houston, Texas (May. 1969 to Aug. 1969)	Processed documentation and authorized payments to suppliers and creditors.

Education

Ph.D., Finance, Accounting, and Economics, University of Texas at Austin (Sep. 1974 to May 1980)	Doctoral program included coursework in corporate finance, investment theory, accounting, and economics. Elected to honor society of Phi Kappa Phi. Received University outstanding doctoral dissertation award. Dissertation: *Estimating the Cost of Equity to Texas Public Utility Companies*
M.B.A., Finance and Accounting, University of Texas at Austin, (Sep. 1972 to Aug. 1974)	Awarded Wright Patman Scholarship by World and Texas Credit Union Leagues. Professional Report: *Planning a Small Business Enterprise in Austin, Texas*
B.B.A., Accounting and Finance, Southern Methodist University, Dallas, Texas (Sep. 1967 to Dec. 1971)	Dean's List 1967-1971 and member of Phi Gamma Delta Fraternity.

Other Professional Activities

Certified Public Accountant, Texas Certificate No. 13,710 (October 1974); entire exam passed in May 1972. Member of the American Institute of Certified Public Accountants (Honorary).

Participated as session chairman, moderator, and paper discussant at annual meetings of Financial Management Association, Southwestern Finance Association, American Finance Association, and other professional associations.

Visiting lecturer in Executive M.B.A program at the University of Stellenbosch Graduate Business School, Belleville, South Africa (1983 and 1984).

Associate Editor of *Austin Financial Digest*, 1974-1975. Wrote and edited a series of investment and economic articles published in a local investment advisory service.

Military

Texas Army National Guard, Feb. 1970 to Sep. 1976. Specialist 5th Class with duty assignments including recovery vehicle operator for armor unit and company clerk for finance unit.

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“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).

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"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).

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"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

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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

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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

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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

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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

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

Bruce H. Fairchild
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	OR18-7-002	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

Bruce H. Fairchild
Summary of Testimony Before Regulatory Agencies

(Continued)

No.	Utility Case	Agency	Docket	Date	Nature of Testimony
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

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, 2021.
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 ☐

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 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 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, 2021, was $3.8 billion.

On February 21, 2022, we had 53,633,445 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 26, 2022, are incorporated by reference in Part III.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

All executive officers are elected annually by our Board of Directors and each serves until such person resigns, is removed or is otherwise disqualified to serve or until such officer's successor is duly elected. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 officers.

Name	Age*		Business Experience in Past Five Years
Robert S. McAnnally	58	2021 to present	President, Chief Executive Officer and Director
		2020 to 2021	Senior Vice President and Chief Operating Officer
		2015 to 2020	Senior Vice President, Operations
Caron A. Lawhorn	60	2019 to present	Senior Vice President and Chief Financial Officer
		2014 to 2019	Senior Vice President, Commercial
Joseph L. McCormick	62	2014 to present	Senior Vice President, General Counsel and Assistant Secretary
Curtis L. Dinan	54	2021 to present	Senior Vice President and Chief Operating Officer
		2020 to 2021	Senior Vice President and Chief Commercial Officer
		2019 to 2020	Senior Vice President, Commercial
		2018 to 2019	Senior Vice President and Chief Financial Officer
		2014 to 2018	Senior Vice President, Chief Financial Officer and Treasurer
Mark A. Bender	57	2015 to present	Senior Vice President, Administration and Chief Information Officer
Jeffrey J. Husen	50	2018 to present	Vice President, Chief Accounting Officer and Controller
		2014 to 2018	Controller

* As of January 1, 2022

No family relationship exists between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

AVAILABLE INFORMATION

We make available, free of charge, on our website (www.onegas.com) our Annual Reports, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC, which also makes these materials available on its website (www.sec.gov). Our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Certificate of Incorporation, bylaws, the written charters of our Audit Committee, Executive Compensation Committee, Corporate Governance Committee and Executive Committee and our ESG Report are also available on our website, and copies of these documents are available upon request.

In addition to filings with the SEC and materials posted on our website, we also use social media platforms as channels of information distribution to reach public investors. Information contained on our website and posted on or disseminated through our social media accounts is not incorporated by reference into this report.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we believe we have discussed the key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including Forward-Looking Statements, which are included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

RISK FACTORS INHERENT IN OUR BUSINESS

Operational Risks

Pandemics or other health crises could have an adverse effect on our business.

Our business and our customers could be materially and adversely affected by the risks, or the public perception of the risks, related to a pandemic or other health crisis, such as the outbreak of COVID-19. The COVID-19 pandemic has had an unprecedented impact on the U.S. and its economy and continues to create significant uncertainties about the potential adverse effect of the pandemic on the economy, our customers, our employees and supply chain partners.

As an essential business, we implemented business continuity and emergency response plans at the beginning of the pandemic that allowed us to continue to provide natural gas services to customers and support our operations, while taking health and safety measures such as implementing worker distancing measures and using a remote workforce where possible.

To the extent the COVID-19 pandemic adversely affects our business, it may also have the effect of heightening many of the other risks described in Item 1A of this Annual Report.

Our business increasingly relies on technology, the failure of which, or the occurrence of cyber breaches or physical security attacks thereon, or those of third parties, may adversely affect our financial results and cash flows.

Due to increased technology advances, we have become more reliant on technology to effectively operate our business. We use computer programs to help run our financial and operations organizations, including an enterprise resource planning system that integrates data and reporting activities across our Company. The failure of these or other similarly important technologies, the lack of alternative technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could hinder our operations and adversely impact our financial condition and results of operations. The use of technological programs, systems and tools may subject our business to increased risks.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. As part of our operations, we come into contact with sensitive information, including personally identifiable information. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee or third party causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee or third-party tampering or manipulation of those systems will result in losses that are difficult to detect or mitigate.

Additionally, certain portions of our IT, customer service, resource management, pipeline and infrastructure installation and maintenance, engineering, payroll and human resources functions that we rely on are provided by third-party vendors. Services provided by third parties could be disrupted due to events and circumstances beyond our control which could adversely impact our business, financial condition, results of operations and cash flows.

In March 2020, remote working arrangements for our employees increased as a result of the COVID-19 pandemic, requiring enhancements and modifications to our IT infrastructure (e.g. Internet, Virtual Private Network, remote collaboration systems, etc.). Experts have observed an increase in the volume and the sophistication of cyberattacks since the beginning of the COVID-19 pandemic.

Any cyber breaches or physical security attacks, or threats of such attacks, that affect our information technology systems, distribution facilities, our customers, our suppliers and third-party service providers or any financial data could disrupt normal business operations, expose sensitive information, and/or lead to physical damages that may have a material adverse effect on our business. Physical damage due to a cyber security incident or acts of cyber terrorism could impact services and could lead to material liabilities. As cyber or physical security attacks become more frequent and sophisticated, we could be required to incur increased costs to strengthen our systems or to obtain additional insurance coverage against potential losses. Federal and state regulatory agencies are increasingly focused on risks related to physical security and cybersecurity in general and have implemented more stringent security requirements specifically for certain federal contractors and critical infrastructure sectors, including natural gas distribution. In addition, cyber or physical attacks or threats on our suppliers, third-party service providers or our Company, customer and employee data may result in a financial loss and may adversely impact our business, financial condition, results of operations and cash flows. Third-party systems on which we rely could also suffer such attacks or operational system failure.

While we continue to bolster our physical security and cybersecurity practices, including the implementation of certain security measures required by the federal government and the continued evaluation and improvement of existing policies, procedures, protective technologies, and controls to prevent and detect cyber breaches or physical security attacks, there is no guarantee that these efforts (or any similar efforts by third parties on which we rely) will be effective against any particular cyber breach or physical attack or protect us from unauthorized access or damage to our systems. A severe attack or security breach could adversely affect our business reputation, diminish customer confidence, disrupt operations, subject us to financial liability or increased regulation, increase our costs and expose us to material legal claims and liability which may not be fully covered by insurance, and our business, financial condition, results of operations and cash flows could be adversely affected.

We are subject to pipeline safety and system integrity laws and regulations that may require significant expenditures, significant increases in operating costs or, in the case of noncompliance, substantial fines or penalties.

We are subject to regulation under federal pipeline safety statutes and any analogous state regulations. These include safety requirements for the design, construction, operation, and maintenance of pipelines, including transmission and distribution pipelines. These requirements are subject to change, either as a result of new statutes or regulations or modifications to the existing statutes or regulations. Compliance with existing or new laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers or may impact materially our competitive position relative to other energy providers. The failure to comply with these laws, regulations and other requirements could expose us to civil or criminal liability, enforcement actions, fines, penalties or injunctive measures that may not be recoverable from customers in rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows, and reputation.

We are subject to strict regulations at many of our facilities and job sites regarding employee safety, and failure to comply with these regulations could adversely affect our financial results or result in significant fines or penalties.

The workplaces associated with our facilities are subject to the requirements of DOT and OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. The failure to comply with DOT, OSHA and state requirements or general industry standards, including keeping adequate records or preventing occupational exposure to regulated substances, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows. Although we employ safety procedures in the design and operation of our facilities, there is a risk that an accident or injury to one of our employees could occur in one of our facilities. Any accident or injury to our employees could result in litigation, operational delays and harm to our reputation, which could negatively affect our business, operating results and financial condition.

Our business is subject to operational hazards and unforeseen interruptions that could materially and adversely affect our business and for which we may not be insured adequately.

We are subject to all of the risks and hazards typically associated with the natural gas distribution business. Operating risks include, but are not limited to, leaks, pipeline ruptures and the breakdown or failure of equipment or processes. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment or vehicles with our pipeline facilities (for example, this may occur if a third-party were to perform excavation or construction work near our facilities or vehicles colliding with above-ground pipeline facilities) and catastrophic events, such as severe weather events, hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, earthquakes, floods or other similar events beyond our control. Disruptions to the operations of natural gas producers who supply us with natural gas, including due to the loss of power or extreme temperatures, could disrupt our ability to serve our customers. It is also possible that our facilities, or those of our counterparties or service providers, could be direct targets or indirect casualties of an act of terrorism, including cyber-attacks. Lapses in judgement or failure to follow protocols by our employees or service providers could lead to warranty and indemnification liabilities or catastrophic accidents, causing property damage or personal injury. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage caused to or by employees, customers, contractors, vendors and other third parties. The location of pipeline facilities near populated areas, including residential areas, commercial business centers and industrial gathering places, could increase the level of damages resulting from these risks. Liabilities incurred and interruptions to the operations of our pipelines or other facilities caused by such an event could reduce revenues generated by us and increase expenses, which could have a material adverse effect on our financial condition, results of operations and cash flows. Additionally, our regulators may not allow us to recover part or all of the increased cost related to the foregoing events from our customers, which would adversely affect our earnings and cash flows.

Unanticipated events or a combination of events, failure in resources needed to respond to events, or slow or inadequate response to events may have an adverse impact on our financial condition, results of operations and cash flows.

While we have general liability, cyber, and property insurance currently in place in amounts that we consider appropriate based on our assessment of business risk and best practices in our industry and in general business, such policies are subject to certain limits, deductibles and policy exclusions. Further, we are not fully insured against all risks inherent in our business, including certain types of catastrophic events. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and, in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Consequently, we may not be able to renew existing insurance policies or purchase other desirable insurance on commercially reasonable terms, if at all.

The insurance proceeds received for any loss of, or any damage to, any of our systems or facilities or to third parties may not be sufficient to restore the total loss or damage. Further, the proceeds of any such insurance may not be paid in a timely manner. The occurrence of any of the foregoing could have a material adverse effect on our financial condition, results of operations and cash flows.

The availability of adequate natural gas pipeline transportation and storage capacity and natural gas supply may decrease and impair our ability to meet customers' natural gas requirements and our financial condition may be adversely affected.

In order to meet customers' natural gas demands, we rely on and must obtain sufficient natural gas supplies, pipeline transportation and storage capacity from third parties. We must contract for reliable and adequate delivery capacity for our transmission and distribution systems, while considering the dynamics of the interstate and intrastate pipeline capacity markets, our own in-system resources, as well as the characteristics of our customer base. If we are unable to obtain these, our ability to meet our customers' natural gas requirements could be impaired. A significant disruption to or reduction in natural gas supply, pipeline capacity or storage capacity due to events including, but not limited to, operational failures or disruptions, severe weather events, hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, earthquakes, floods, freeze off of natural gas wells, terrorist or cyber-attacks or other acts of war, or legislative or regulatory actions, could reduce our available supply of natural gas. Such severe events may also cause significant reductions in our natural gas in storage, which will take time to replenish, and cause gas restrictions or curtailment of operations and delivery of natural gas to customers including, for example, restrictions and curtailments imposed by regulators during Winter Storm Uri in February 2021. These types of events and disruptions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We may not be able to complete necessary or desirable expansion or infrastructure development projects, which may delay or prevent us from serving our customers or expanding our business.

In order to serve new customers or expand our service to existing customers, we may need to maintain, expand or upgrade our distribution and/or transmission infrastructure, including laying new distribution lines. Various factors may prevent or delay us from completing such projects or make completion more costly, such as the inability to obtain required approvals from local, state and/or federal regulatory and governmental bodies, public opposition to the project, inability to obtain adequate financing, right-of-way acquisition, competition for labor and materials, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to construction or other material components of an infrastructure development project. As a result, we may not be able to adequately serve existing customers or support customer growth, which would adversely impact our business, stakeholder perception, financial condition, results of operations and cash flows.

Our risk-management policies and procedures may not be effective, and employees may violate our risk-management policies.

We have implemented a set of policies and procedures that involve both our senior management and the Audit Committee of our Board of Directors to assist us in managing risks associated with our business. These risk-management policies and procedures are intended to align strategies, processes, people, IT and business knowledge so that risk is managed throughout the organization. However, as conditions change and become more complex, current risk measures may fail to assess adequately the relevant risks associated with our business and the presence of risks previously unknown to us. Additionally, if employees fail to adhere to our policies and procedures or if our policies and procedures are not effective, potentially because of future conditions or risks outside of our control, we may be exposed to greater risk than we had intended. Ineffective risk-management policies and procedures or violation of risk-management policies and procedures could have a material adverse effect on our earnings, financial condition and cash flows.

Failure to maintain the security of personally identifiable information could adversely affect us.

In connection with our business we and our vendors, suppliers and contractors collect and retain personally identifiable information (e.g., information of our customers, shareholders, suppliers, third-party service providers and employees), and there is an expectation that we and such third parties will adequately protect that information. The U.S. regulatory environment surrounding information security and privacy is increasingly demanding. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and could potentially elevate our costs. Any failure by us to comply with these laws and regulations, including as a result of a security or privacy breach, could result in significant penalties and liabilities for us. A significant theft, loss or fraudulent use of the personally identifiable information we maintain or failure of our vendors, suppliers and contractors to use or maintain such data in accordance with contractual provisions could adversely impact our reputation and could result in significant costs, fines and litigation.

Our business could be adversely affected by strikes or work stoppages by our unionized employees, which may impact our operations, cash flows and earnings.

At February 1, 2022, approximately 700 of our estimated 3,600 employees were represented by collective-bargaining units under collective-bargaining agreements. We are involved periodically in discussions with collective-bargaining units representing some of our employees to negotiate or renegotiate labor agreements. We cannot predict the results of these negotiations, including whether any failure to reach new agreements will have a negative effect on our business, financial condition and results of operations or whether we will be able to reach any agreement with the collective-bargaining units. Any failure to reach agreement on new labor contracts might result in a work stoppage. Any future work stoppage could, depending on the operations and the length of the work stoppage, have a material adverse effect on our financial condition, results of operations and cash flows.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs, which could adversely affect operations, cash flows and earnings. Further, we may be unable to attract and retain management and professional and technical employees, which could adversely impact our operations, earnings and cash flows.

Our operations require skilled and experienced workers with proficiency in multiple tasks. A shortage of workers trained in various skills associated with the natural gas distribution business could cause us to conduct certain operations without full staff, thus hiring outside resources, which may decrease productivity and increase costs. This shortage of trained workers can result from experienced workers reaching retirement age and increased competition for workers in certain areas, combined with the challenges of attracting new qualified workers to the natural gas distribution industry. A shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on our productivity and costs and our ability to meet the needs of our customers, which could adversely affect our business and cash flows.

Our ability to implement our business strategy, satisfy our regulatory requirements, and serve our customers is dependent upon our ability to continue to recruit and employ talented management and professionals while retaining a skilled, agile, diverse and engaged workforce. We are subject to the risk that we will not be able to effectively replace or transfer the knowledge and expertise of retiring management or employees. Without effective succession, our ability to provide quality service to our customers and satisfy our regulatory requirements will be challenged, and this could adversely impact our business, financial condition, results of operations and cash flows.

We are subject to environmental regulations and failure to comply with these regulations could result in significant fines or penalties and could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to environmental and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, protection of natural and cultural resources, as well as work practices related to employee health and safety. Many of these laws or regulations require us to obtain permits for certain of our operations, and we may not always be able to obtain such permits on terms satisfactory for our operations or planned timelines. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Certain laws provide for strict, joint and several liability, without regard to fault or the legality of the original act. The failure to comply with any laws, regulations, permits and other requirements, or the discovery of presently unknown environmental conditions, could expose us to civil or criminal liability, enforcement actions and regulatory fines and penalties that may not be recoverable through our rates or insurance and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We also own or retain legal responsibility for certain environmental conditions at certain former MGP sites. A number of environmental issues may exist with respect to these former MGP sites. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation, changing technology and governmental regulations and could be material to our financial condition, results of operations and cash flows.

With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, which could adversely affect our financial condition, results of operations and cash flows.

We are subject to various risks associated with climate change, which may adversely affect our financial results, growth, cash flows and results of operations.

Our business is subject to both transition and physical risks due to climate change. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. Climate change is projected to increase the likelihood of extreme weather in our service territory, and our customers' energy use could increase or decrease depending on the duration and magnitude of any changes. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues and cash flows. Extreme weather conditions in general require increased system resiliency, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues and cash flows by affecting natural gas prices. Severe weather impacts our operating territories primarily through severe weather events, including hurricanes, thunderstorms, tornadoes, sustained extreme temperatures, snow and ice storms, earthquakes, floods or other similar events beyond our control. To the extent the frequency of extreme weather events increases, our costs of providing service and our working capital requirements could increase. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks.

In addition, to the extent climate change adversely impacts the economic health of our operating territory, it could adversely impact customer demand or our customers' ability to pay. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could adversely affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Financial institutions are increasingly making commitments to achieve net-zero financed greenhouse gas emissions. As they take steps to implement these commitments, they may adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. The adoption of such policies may be hastened by government actions, including regulations from the Biden Administration to address climate risk in the financial sector and the Federal Reserve's implementation of recommendations from the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. A material reduction in the capital available or an increase in the cost of capital could make it more difficult for us to finance the investments necessary to maintain the safety and reliability of our distribution system. In addition, increases in the cost of capital or limited availability of capital to the fossil fuel industry could result in decreased supplies of natural gas available for distribution, or otherwise negatively impact our financial performance, growth, cash flows, or results of operations. For more information, see our risk factors titled "Increases in the price of natural gas could reduce our earnings, increase our working capital requirements, and adversely impact our customer base" and "We may be unable to access capital or our cost of capital may increase significantly which may adversely affect our results of operations, cash flows and financial condition."

Our business could be affected by lawsuits related to climate change. Various parties (including individuals, local governments, and environmental groups) have brought suit in a number of jurisdictions seeking to hold greenhouse gas emitters liable for the impacts of climate change. Although novel legal theories continue to be developed, many of these suits are brought on one of the following themes: (1) oil and gas companies are liable for various asserted damages associated with the production or sale of fuels that contributed to climate change and (2) oil and gas companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts to investors or consumers. Although we are not currently named in any such suits, the success of such suits could adversely impact our business, results of operations and cash flows.

We are also subject to political, regulatory, and legislative risks. For more information, see our risk factor titled "Carbon neutral, energy-efficiency or other legislation or regulations intended to address climate change could increase our operating costs or restrict our market opportunities, adversely affecting our financial results, growth, cash flows and results of operations."

Regulatory and Legislative Risks

Regulatory actions could impact our ability to earn a reasonable rate of return on our invested capital and to fully recover our invested capital, operating costs and natural gas costs.

We are subject to regulation by the OCC, KCC, RRC and various municipalities in Texas, who set the rates that we charge our customers for our services. Our ability to obtain timely future rate increases depends on regulatory discretion. Significant events, including severe weather events, such as Winter Storm Uri, may result in us experiencing extraordinary costs, including unforeseeable and unprecedented market pricing for gas costs and financing costs related to the payment of gas costs, all or a part of which may not be recoverable through our tariffs in each state where we operate. As such, there can be no assurance that we will be able to obtain rate increases, fully recover our extraordinary costs or that our authorized rates of return will continue at the current levels.

We monitor and compare the rates of return we achieve with our allowed rates of return and initiate general and specific rate proceedings as needed. If a regulatory agency were to prohibit us from setting rates that allow for the timely recovery of our costs and a reasonable return by significantly lowering our allowed return or adversely altering our cost allocation, rate design or other tariff provisions, modifying or eliminating cost trackers, prohibiting recovery of regulatory assets or disallowing portions of our expenses, then our earnings could be adversely impacted. Regulatory proceedings also involve a risk of rate reduction, because once a proceeding has been filed, it is subject to challenge by various intervenors. Risks and uncertainties relating to delays in obtaining, or failure to obtain, regulatory approvals, conditions imposed in regulatory approvals, and determinations in regulatory proceedings can also impact our financial performance. In particular, the timing and amount of rate relief can materially impact our results of operations, financial condition and cash flows.

Further, accounting principles that govern our Company permit certain assets that result from the regulatory process to be recorded on our consolidated balance sheets that could not be recorded under GAAP for nonregulated entities. We consider factors such as rate orders from regulators, previous rate orders for substantially similar costs, written approval from our regulators and analysis of recoverability by internal and external legal counsel to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time, which would adversely affect our financial condition, results of operations and cash flows. Regulatory authorities also review whether our natural gas costs are prudent and can adjust the amount of our natural gas costs that we pass through to our customers. In certain instances, including in the event of significant and severe weather events, we may apply to regulators seeking authority to timely recover extraordinary costs, and our application may not be approved. If any of our natural gas costs or related expenses were disallowed, our results of operations and cash flows would be adversely affected.

In the normal course of business in the regulatory environment, assets are placed in service before regulatory action is taken, such as filing a rate case or for interim recovery under a capital tracking mechanism that could result in an adjustment of our returns. Once we make a regulatory filing, regulatory bodies have the authority to suspend implementation of the new rates while studying the filing. Because of this process, we may suffer the negative financial effects of having placed assets in service that do not initially earn our authorized rate of return or may not be allowed recovery on such expenditures at all.

The profitability of our operations is dependent on our ability to timely recover the costs related to providing natural gas service to our customers. However, we are unable to predict the impact that new regulatory requirements will have on our operating expenses or the level of capital expenditures and we cannot give assurance that our regulators will continue to allow recovery of such expenditures in the future. Changes in the regulatory environment applicable to our business or the imposition of additional regulation could impair our ability to recover costs absorbed historically by our customers, and adversely impact our results of operations, financial condition and cash flows.

A successful challenge to the securitization statute in Oklahoma could adversely affect our financial condition, earnings and cash flows.

There is a legal challenge to the securitization statute in Oklahoma. If successful, this legal challenge is not expected to affect our ability to recover the extraordinary costs associated with Winter Storm Uri. However, we would not be able to finance these costs through a securitization. Instead, Oklahoma Natural Gas would have to seek regulatory approval for an alternate cost recovery method. Under such a scenario, customers would likely see an increase in the charge for the extraordinary costs relative to the charge we would expect with securitization, which could make it more difficult for customers to pay their bills, leading to slow collections and higher-than-normal levels of accounts receivable, which in turn could increase our financing requirements and bad debt expense and could adversely affect our results of operations, financial condition and cash flows.

We are subject to comprehensive energy regulation by governmental agencies, and the recovery of our costs is dependent on regulatory action.

We are subject to comprehensive regulation by several state and municipal utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility regulatory authorities in Oklahoma, Kansas and Texas regulate many aspects of our utility operations, including organization, safety, financing, affiliate transactions, customer service and the terms of service to customers, including the rates that we can charge customers.

The profitability of our operations is dependent on our ability to recover costs, including income taxes, related to providing natural gas to our customers by filing periodic rate cases or other filings. The regulatory environment applicable to our operations could impair our ability to recover costs historically included in the rates billed to our customers. In addition, as the regulatory environment applicable to our operations increases in complexity, the risk of inadvertent noncompliance could also increase. Our failure to comply with applicable laws and regulations could result in the imposition of fines, penalties or other enforcement actions by the authorities that regulate our operations that may not be recoverable in our rates.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operations. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition and results of operations. Further, the results of our operations could be impacted adversely if our authorized cost-recovery mechanisms do not function as anticipated.

Our business and operations are subject to regulation by a number of federal agencies, including FERC, DOT, OSHA, EPA, CFTC and various regulatory agencies in Oklahoma, Kansas and Texas, and we are subject to numerous federal and state laws and regulations. Future changes to laws, regulations and policies may impair our ability to compete for business or to recover costs and may increase the cost of our operations. Furthermore, because the language in some laws and regulations is not prescriptive, there is a risk that our interpretation of these laws and regulations may not be consistent with expectations of regulators. Any compliance failure related to these laws and regulations may result in fines, penalties or injunctive measures affecting our operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938, as amended, to impose penalties of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. The fines or penalties for noncompliance with laws and regulations may not be recoverable through our rates. Our failure to comply with applicable regulations could result in a material adverse effect on our business, financial condition, results of operations and cash flows.

Carbon neutral, energy-efficiency or other legislation or regulations intended to address climate change could increase our operating costs or restrict our opportunities in new or existing markets, adversely affecting our financial results, growth, cash flows and results of operations.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to regulate greenhouse gas emissions, including carbon dioxide and methane, as a response to the threat of climate change. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that greenhouse gas emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for greenhouse gas emissions from certain large stationary sources and require the monitoring and annual reporting of greenhouse gas emissions from certain fossil fuel systems (including certain of our operations). The regulation of methane from oil and gas facilities, including systems to transport and distribute natural gas, has been subject to uncertainty in recent years; in September 2020, the Trump Administration revised prior regulations, rescinding certain methane standards and removing the transmission and storage segments from the source category for certain regulations. However, on January 20, 2021, President Biden signed an executive order calling for the suspension, revision, or recission of the September 2020 rule and the establishment of new standards applicable to existing oil and gas operations, including the transmission and storage segments.

President Biden has announced that climate change will be a focus of his administration and has signed several executive orders on the subject. For example, on January 27, 2021, President Biden issued an executive order that commits to substantial action on climate change, calling for, among other things, the increased production of renewable energy on federal lands and waters, the elimination of subsidies provided to the fossil fuel industry, and increased emphasis on climate-related risk across governmental agencies and economic sectors. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as greenhouse gas cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. Such laws or regulations could impose costs tied to carbon emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also provide a cost advantage to alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates. For example, as part of the Consolidated Appropriations Act, 2021, Congress has provided extensions for key renewable energy tax credits. Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emission reduction targets every five years after 2020. Although the United States had withdrawn from the agreement, President Biden has signed executive orders recommitting the United States to the agreement and calling on the federal government to begin formulating the United States' nationally determined emissions reduction targets under the agreement.

The focus on climate change could adversely impact the reputation of fossil fuel products or services. The occurrence of the foregoing events could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and the prices we charge to customers, reduce the demand for natural gas or cause fuel switching to other energy sources, and impact the competitive position of natural gas and the ability to serve new or existing customers, adversely affecting our business, results of operations and cash flows.

Certain of our operations occur on lands that may be subject to various indigenous rights.

Parts of our operations cross lands that historically have been held by or within the jurisdiction of various Native American tribes, who may exercise significant jurisdiction and sovereignty over their lands. Our operations may be impacted to the extent these tribal governments are found to have and choose to act upon such jurisdiction over lands where we operate. For example, a U.S. Supreme Court ruling in 2020 found that the Muscogee (Creek) Nation reservation in Eastern Oklahoma has not been disestablished. State courts in Oklahoma, applying the analysis in the U.S. Supreme Court's ruling regarding the Muscogee (Creek) Nation, have ruled that the Cherokee, Chickasaw, Seminole, Choctaw, and Quapaw reservations likewise have not been disestablished. The U.S. Supreme Court's ruling and these companion decisions could lead to some confusion as to which agencies have authority to regulate activities in these areas of Oklahoma. Costs associated with compliance with these additional regulatory requirements could be material and could adversely affect our business, results of operations and cash flows.

We are involved in legal or administrative proceedings before various courts and governmental bodies that could adversely affect our financial condition, results of operations and cash flows.

In the normal course of business, we are involved in legal or administrative proceedings before various courts and governmental bodies with respect to general claims, rates, environmental issues, gas cost prudence reviews and other matters. Adverse decisions regarding these matters, to the extent they require us to make payments in excess of amounts provided for in our consolidated financial statements, or to the extent they are not covered by insurance, could adversely affect our financial condition, results of operations and cash flows.

Changes in federal and state fiscal, tax and monetary policy could significantly increase our costs and decrease our cash flows.

Changes in federal and state fiscal, tax and monetary policy may result in increased taxes, interest rates, and inflationary pressures on the costs of goods, services and labor or may result in refunding amounts previously collected for deferred taxes to customers on an accelerated basis. This could increase our expenses and capital spending and decrease our cash flows if we are not able to recover or recover timely such increased costs from our customers. This series of events may cause us to seek increases in the rates we charge customers and thus may adversely impact customer growth. Changes in tax rates could adversely affect our cash flows and may increase the cash we pay for income taxes in the future. Changes in monetary or other policies of the federal or state governments may adversely affect the economic climate for the United States, the regions in which we operate or particular industries, such as ours or those of our customers. Any of these events could adversely affect our cash flows, restrict our ability to make capital investments and may cause us to increase debt and take other actions to conserve cash.

Financial, Economic and Market Risks

Unfavorable economic and market conditions could adversely affect our financial condition, earnings and cash flows.

Weakening economic activity in our markets could result in a loss of existing customers, fewer new customers, especially in newly constructed homes and other buildings, or a decline in energy consumption, any of which could adversely affect our revenues or restrict our future growth. These conditions may make it more difficult for customers to pay their natural gas bills, leading to slow collections and higher-than-normal levels of accounts receivable, which in turn could increase our financing requirements and bad debt expense. Customers may also experience difficulties paying their natural gas bills in the instance of severe weather events that result in higher usage and higher natural gas prices, exacerbating impacts on our ability to collect and furthering our increasing financing requirements and bad debt expense, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects.

We cannot predict the timing, strength, or duration of any future economic slowdowns. Fluctuations and uncertainties in the economy make it challenging for us to accurately forecast and plan future business activities and to identify risks that may affect our business, financial condition, results of operations and cash flows. The foregoing could adversely affect our business, financial condition, results of operations and cash flows.

Increases in the price of natural gas could reduce our earnings, increase our working capital requirements, and adversely impact our customer base.

Changes in supply and demand within the natural gas markets, as well as other factors, could cause an increase in the price of natural gas. The increased production in the U.S. of natural gas from shale formations generally has put downward pressure on the wholesale cost of natural gas in recent years; however, other factors could put upward pressure on natural gas prices, including weather-related events, restrictions or regulations on shale natural gas production and waste water disposal, increased demand from natural gas fueled electric power generation and increases in natural gas exports. Market conditions can also lead to short-term price spikes in natural gas prices, such as high demand during periods of extreme cold weather or system constraints at specific delivery locations.

Natural gas costs are passed through to our customers based on the actual cost of the natural gas we purchase and a customer's consumption. Regulatory authorities review whether our natural gas costs are prudent and can adjust the amount of our natural gas costs that we pass through to our customers. The disallowance of or delay in recovery of our natural gas costs could adversely affect our financial condition, results of operations and cash flows. Additionally, an increase in the price of natural gas could cause us to experience a significant increase in short-term debt because we must pay suppliers for natural gas when purchased.

Further, higher and more volatile natural gas prices may adversely impact our customers' perception of natural gas. Substantial fluctuations in natural gas prices can occur from year to year and sustained periods of high natural gas prices or of pronounced natural gas price volatility may lead to customers selecting other energy alternatives, such as electricity, and to increased scrutiny of the prudence of our natural gas procurement strategies and practices by our regulators. It may also cause new home developers, builders and new customers to select alternative sources of energy. Additionally, high natural gas prices may cause customers to conserve more and may also adversely impact our accounts receivable collections, resulting in higher bad debt expense. The occurrence of any of the foregoing could adversely affect our business, financial condition, results of operations and cash flows, as well as our future growth opportunities.

Our business is subject to competition that could adversely affect our results of operations.

The natural gas distribution business is competitive, and we face competition from other companies that supply energy, including electric companies, private generation, solar energy producers, propane dealers, other renewable energy providers and from other sources of energy for power generation, such as coal or nuclear energy. We also compete with other natural gas providers in certain areas. Significant competitive factors include efficiency, quality and reliability of the services we provide and the price we charge.

The most significant product competition occurs between natural gas and electricity in the residential and small commercial markets. Natural gas competes with electricity for water and space heating, cooking, clothes drying and other general energy needs. Increases in the price of natural gas or decreases in the price of other energy sources could adversely impact our competitive position by decreasing the price benefits of natural gas to the consumer. Customers and builders typically make the decision on the type of equipment at initial installation and use the chosen energy source for the life of the equipment. Changes in the competitive position of natural gas relative to electricity and other energy products have the potential to cause a decline in consumption or in the number of natural gas customers.

Consumer or government-mandated conservation efforts, bans on natural gas infrastructure in new construction, higher natural gas costs or decreases in the price of other energy sources also may encourage decreases in natural gas consumption and allow competition from alternative energy sources for applications that have used natural gas, encouraging some customers to move away from natural gas-powered equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety, environmental and other nonprice factors. Technological improvements in other energy sources, energy storage, conservation, efficiency and events that impair the public perception of the nonprice attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers, and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using natural gas, thereby reducing our ability to make capital expenditures and otherwise grow our business and adversely affecting our financial condition, results of operations and cash flows.

Our business activities are concentrated in three states.

We provide natural gas distribution services to customers in Oklahoma, Kansas and Texas. Changes in the regional economies, politics, regulations and weather patterns of these states could adversely impact the growth opportunities available to us and the usage patterns and financial condition of our customers. This could adversely affect our financial condition, results of operations and cash flows.

A downgrade in our credit ratings or placing those ratings on negative outlook or watch could adversely affect our cost of and ability to access capital.

Our ability to obtain adequate and cost-effective financing depends in part on our credit ratings. Our credit ratings are subject to change at any time in the discretion of the applicable rating agencies. Numerous factors, including many of which are not within our control, are considered by the rating agencies in connection with assigning credit ratings. A reduction in our ratings by our rating agencies could adversely affect our costs of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit or delay our access to public and private credit markets and increase the costs of borrowing under available credit lines. While the current Moody's and S&P issuer credit ratings for ONE Gas are investment grade, there is no assurance that these credit ratings will not be downgraded. A downgrade of our credit ratings may materially and adversely affect the market prices of our equity and debt securities, the interest rates at which borrowings are made and debt securities and commercial paper are issued, and the various fees on credit facilities. This could make it significantly more costly for us to borrow money, to issue debt securities and to raise certain other types of capital and/or complete additional financings. Such negative credit rating actions, as well as the reasons for such actions, could materially and adversely affect our cash flows, results of operations and financial condition and the market price of, and our ability to pay the principal of and interest on, our debt securities. Should our credit ratings be downgraded, it could limit or delay our ability to obtain additional financing in the future for working capital, capital expenditures and acquisitions when necessary or desirable. In addition, our pool of investors and prospective creditors would likely decrease. An increase in borrowing costs without the ability to recover these higher costs in the rates charged to our customers could adversely affect our results of operations, financial condition and cash flows by limiting our ability to earn our allowed rate of return.

Moreover, most of our large suppliers and counterparties require an expected level of creditworthiness in order for them to enter into transactions with us. If our credit ratings decline, the costs to operate our business could increase because counterparties could require the posting of collateral in the form of cash-related instruments, or counterparties could decline to do business with us.

Demand for natural gas is highly weather sensitive and seasonal, and weather conditions may cause our earnings to vary from year to year.

Our earnings can vary from year to year, depending in part on weather conditions, which directly influence the volume of natural gas delivered to customers. Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating during the winter months. Warmer-than-normal weather can reduce our revenues as customer consumption declines. We have implemented WNA mechanisms for our sales to customers in Oklahoma, Kansas and Texas, which are designed to reduce our earnings sensitivity to weather. Through these mechanisms, we increase customer billings to offset lower natural gas usage when weather is warmer than normal and decrease customer billings to offset higher natural gas usage when weather is colder than normal. If our rates and tariffs are modified to curtail such weather protection programs, then we would be exposed to additional risk associated with weather. As a result of occurrences of the foregoing, our results of operations, financial condition and cash flows could vary and be impacted adversely.

Emerging technologies may cause disruption in utility services, which may adversely affect our current customer base, our customer growth, earnings and cash flows.

Commercial technologies that advance electrification and increase energy efficiency in some aspects of the economy, such as transportation or heating, could negatively impact the demand for natural gas. We may not be able to quickly adapt to changes resulting from rapidly advancing technologies that may result in a reduction in demand for our services. This could slow customer growth and even cause customers to reduce or cease using natural gas which could have a material adverse effect on our financial condition, results of operations and cash flows.

An impairment of goodwill and long-lived assets could reduce our earnings.

At December 31, 2021, we had approximately $158 million of goodwill recorded on our Consolidated Balance Sheet. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on our equity and balance sheet leverage as measured by debt to total capitalization, which could adversely impact our financial condition and results of operations.

We may be unable to access capital or our cost of capital may increase significantly which may adversely affect our results of operations, cash flows and financial condition.

Our ability to obtain adequate and cost-effective financing is dependent upon the liquidity of the financial markets, in addition to our financial condition and credit ratings. Disruptions in the capital and credit markets could adversely affect our ability to access short-term and long-term capital. Access to funds under our ONE Gas Credit Agreement and our commercial paper program is dependent on the ability of the participating banks to meet their funding commitments and lenders to continue purchasing our commercial paper. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions and volatility in the global credit markets could cause the interest rate we pay under our ONE Gas Credit Agreement and our commercial paper program to increase. This could result in higher interest rates on future financings and could impact the liquidity of the lenders under our ONE Gas Credit Agreement, potentially impairing their ability to meet their funding commitments to us. Disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation or failures of significant financial institutions could adversely affect our access to capital needed for our business. The inability to access adequate capital or an increase in the cost of capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate our dividend or other discretionary uses of cash. A significant reduction in our liquidity could cause a negative change in our ratings outlook or a reduction in our credit ratings. This could in turn further limit our access to credit markets and increase our costs of borrowing.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part, which may adversely affect our results of operations, cash flows and financial condition.

The terms of our debt agreements contain cross-default provisions, which provide that we will be in default under such agreements in the event of certain defaults under other debt agreements. Accordingly, should an event of default occur under any of those agreements, we would face the prospect of being in default under many or all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness under many or all such agreements simultaneously. In such an event, we may not have sufficient funds available to satisfy all of our outstanding obligations and may not be able to obtain alternative financing or, if we are able to obtain such financing, we may not be able to obtain it on terms acceptable to us, which would adversely affect our ability to implement our business plan, have flexibility in planning for, or reacting to, changes in our business, make capital expenditures and finance our operations.

The cost of providing pension and other postemployment health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values, changing demographics and other factors and may increase our costs. In addition, the passage of the Patient Protection and Affordable Care Act in 2010 and the Consolidated Appropriations Act in 2021 and the potential revision, repeal and/or replacement of either of these acts could increase the cost of health care benefits for our employees. Further, the costs to us of providing such benefits and related funding requirements are subject to the continued and timely recovery of such costs through our rates which may adversely affect our cash flows and earnings.

We have defined benefit pension plans and other postemployment welfare plans for certain eligible employees. Our defined benefit plans are closed to new participants. Our other postemployment welfare plans subsidize costs for providing postemployment medical benefits and life insurance. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension and other postemployment benefit plan assets, changing demographics, including longer life expectancy of plan participants and their beneficiaries, current and future legislative changes, and changes in health care costs, discount rates used to calculate liability, and various actuarial calculations and assumptions.

Any sustained declines in equity markets and reductions in bond values may have a material adverse effect on the value of our pension and other postemployment benefit plan assets. In these circumstances, additional cash contributions to our pension and other postemployment benefit plans may be required, which could have a material adverse impact on our financial condition and cash flows.

In addition, the costs of providing health care benefits to our employees could increase over the next several years due in large part to the Patient Protection and Affordable Care Act of 2010 and the Consolidated Appropriations Act, 2021, and the potential revision, repeal and/or replacement of either of these acts. The future costs of compliance with the provisions are difficult to measure at this time. Also, our costs of providing such benefits and related funding requirements could also materially increase in the future, depending on the timing of the recovery, if any, of such costs through our rates, which could adversely impact our financial condition and cash flows.

Our financing arrangements subject us to various restrictions that could limit our operating flexibility, earnings and cash flows.

The covenants in the indenture governing our Senior Notes and our ONE Gas Credit Agreement restrict our ability to create or permit certain liens, to consolidate or merge or to convey, transfer or lease substantially all of our properties and assets.

The ONE Gas Credit Agreement includes a requirement that our debt to total capital ratio may not exceed 72.5 percent at the end of any calendar quarter through December 31, 2021, and 70 percent as of the end of any calendar quarter thereafter. Events beyond our control could impair our ability to satisfy this requirement. As long as our indebtedness remains outstanding, these restrictive covenants could impair our ability to expand or pursue our growth strategy.

In addition, the breach of any covenants or any payment obligations in any of these debt agreements will result in an event of default under the applicable debt instrument. If there were an event of default under one of our debt agreements, the holders of the defaulted debt may have the ability to cause all amounts outstanding with respect to that debt to be due and payable, subject to applicable grace periods. This could trigger cross-defaults under our other debt agreements, including our Senior Notes. Forced repayment of some or all of our indebtedness would reduce our available cash and have an adverse impact on our financial condition, results of operations and cash flows.

Some of our debt, including borrowings under our ONE Gas Credit Agreement, our floating-rate senior notes, and our commercial paper program, is based on variable rates of interest, which could result in higher interest expenses in the event of an increase in interest rates.

We are exposed to fluctuations in variable interest rates. This increases our exposure to fluctuations in market interest rates. Our floating-rate senior notes, and amounts borrowed under the ONE Gas Credit Agreement and commercial paper program are based on variable rates of interest. If these rates rise, the interest rate on this debt will also increase. Therefore, an increase in these rates will increase our interest payment obligations and have a negative effect on our cash flows and financial position.

Conditions in the financial markets and economic conditions generally may materially adversely affect us.

Our business is capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations.

Limitations on the availability of credit and increases in interest rates or credit spreads may materially adversely affect our businesses, cash flows, results of operations, financial condition and/or prospects, as well as our ability to meet contractual and other commitments. In difficult credit market environments, we may find it necessary to fund our operations and capital expenditures at a higher cost or we may be unable to raise as much funding as we need to support new or ongoing business activities. This could cause us to reduce non-safety related capital expenditures and could increase our cost of servicing debt, both of which could significantly reduce our short-term and long-term profitability.

Other factors can affect the availability and cost of credit for our business, as well as the terms of equity and debt financing, including:

- adverse changes to laws and regulations in the states in which we operate;
- the overall health of the energy industry;

- volatility in natural gas prices;
- changes in tax law;
- credit ratings downgrades;
- general economic and financial market conditions; and
- the availability of capital to the fossil fuel industry.

We are dependent on continued access to the credit and capital markets to execute our business strategy.

Our long-term debt is currently rated as "investment grade" by both of our rating agencies. We rely upon access to both short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions or a downgrade in our ratings outlook were to cause a significant limitation on our access to the private credit and public capital markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or a reduction in our credit ratings by one or both of our rating agencies. Such a downgrade could further limit our access to private credit and/or public capital markets and increase our costs of borrowing.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly or there are regulatory constraints on our ability to recover gas or financing costs. The future effects on our business, liquidity and financial results of a deterioration of current conditions in the credit and capital markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate.

RISKS RELATING TO OUR COMMON STOCK

Provisions in our certificate of incorporation, our bylaws and Oklahoma law, as well as regulatory approvals, may prevent or delay an acquisition of our Company, which could decrease the trading price of our common stock.

Our certificate of incorporation, bylaws and Oklahoma law contain provisions that are intended to deter coercive takeover practices and inadequate takeover bids by making such practices or bids unacceptably expensive to the raider and to encourage prospective acquirers to negotiate with our Board of Directors rather than to attempt a hostile takeover. These provisions include, among others:

- rules regarding how shareholders may present proposals or nominate directors for election at shareholder meetings; and
- the right of our Board of Directors to issue preferred stock without shareholder approval.

Oklahoma law also imposes some restrictions on mergers and other business combinations between us and any holder of 15 percent or more of our outstanding common stock.

We believe these provisions protect our shareholders from coercive or otherwise potentially unfair takeover tactics by requiring potential acquirers to negotiate with our Board of Directors and by providing our Board of Directors with more time to assess any acquisition proposal. These provisions are not intended to make our Company immune from takeovers. However, these provisions apply even if the offer may be considered beneficial by some shareholders and could delay or prevent an acquisition that our Board of Directors determines is not in the best interests of our Company and our shareholders.

Additionally, any acquisition of our Company would need to be approved by certain regulatory bodies including the OCC, KCC and various regulators in Texas, which could delay or prevent an acquisition.

Our ability to pay dividends on our common stock will depend on our ability to generate sufficient positive earnings and cash flows.

Our ability to pay dividends in the future will depend upon, among other things, our future earnings, cash flows and restrictive covenants, if any, under future credit agreements to which we may be a party. Our cash available for dividends will principally be generated from our operations. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to maintain future dividends at the levels we expect or at all. Our ability to pay dividends depends primarily on cash flows, including cash flows from changes in working capital, and not solely on profitability, which is affected by noncash items. As a result, we may pay dividends during periods when we record net losses and may be unable to pay cash dividends during periods when we record net income.

GENERAL RISK FACTORS

Federal, state, and local jurisdictions may challenge our tax return positions.

The preparation of our federal and state tax return filings requires significant judgments, use of estimates and the interpretation and application of complex tax laws. Significant judgment also is required in assessing the timing and amounts of deductible and taxable items, and in determining the amount of any reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by taxing authorities. Despite management's expectation that our tax return positions will be fully supportable, certain positions may be challenged successfully by federal, state, and local jurisdictions, which could adversely impact our results of operations, cash flows and financial condition.

We may pursue acquisitions, divestitures, and other strategic opportunities which, if not successful, may adversely impact our results of operations, cash flows and financial condition.

As part of our strategic objectives, we may pursue acquisitions to complement or expand our business, as well as divestitures and other strategic opportunities. We may not be able to successfully negotiate, finance or receive regulatory approval for future acquisitions or integrate the acquired businesses with our existing business and services. These efforts may also distract our management and employees from day-to-day operations and require substantial commitments of time and resources. Future acquisitions could result in potentially dilutive issuances of equity securities, a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition, the incurrence of debt, contingent liabilities and amortization expenses and substantial goodwill. The effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously approved by regulators) to the detriment of the Company. We may be materially and adversely affected if we are unable to successfully integrate businesses that we acquire.

Changes in accounting standards may adversely impact our financial condition, results of operations and cash flows.

We are subject to additional changes in GAAP, SEC regulations and other interpretations of financial reporting requirements for public utilities. We neither have control over the impact these changes may have on our financial condition or results of operations nor the timing of such changes.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The following table sets forth the approximate miles of distribution mains and transmission pipelines as of December 31, 2021:

Properties (miles)	OK	KS	TX	Total
Distribution	19,200	11,700	10,700	41,600
Transmission	600	1,500	300	2,400
Total properties	19,800	13,200	11,000	44,000

We lease approximately 300 thousand square feet of office space and other facilities for our operations. In addition, we have 51.4 Bcf of natural gas storage capacity under contract, with maximum allowable daily withdrawal capacity of approximately 1.4 Bcf.

ITEM 3. LEGAL PROCEEDINGS

See Note 16 of the Notes to Consolidated Financial Statements in this Annual Report for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

OVERALL RATE OF RETURN

Capital Component	Percent of Total	Component Cost	Weighted Cost
Long-term Debt	40.26%	4.09%	1.65%
Common Equity	59.74%	10.25%	6.12%
Total	**100.00%**		**7.77%**

TEXAS GAS SERVICE
A Division of ONE Gas, Inc.
West North Texas Service Area

LDC INDUSTRY GROUP CAPITAL STRUCTURE RATIOS (a)

	Fiscal Year-end 2021		**Fiscal Year-end 2020**		**Fiscal Year-end 2019**		**Fiscal Year-end 2018**		**Fiscal Year-end 2017**	
Company	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**	**Debt**	**Equity**
Atmos Energy	38.4%	61.6%	40.0%	60.0%	38.0%	62.0%	34.3%	65.7%	44.0%	56.0%
Chesapeake Utilities	41.5%	58.5%	42.2%	57.8%	43.9%	56.1%	37.9%	62.1%	28.9%	71.1%
New Jersey Resources	57.0%	43.0%	55.1%	44.9%	49.8%	50.2%	45.4%	54.6%	44.6%	55.4%
NiSource	56.9%	43.1%	61.2%	38.8%	56.8%	43.2%	55.3%	44.7%	63.5%	36.5%
Northwest Natural Gas	52.8%	47.2%	49.2%	50.8%	48.2%	51.8%	48.1%	51.9%	47.9%	52.1%
South Jersey Industries	(b)	(b)	(b)	(b)	(b)	(b)	(b)	(b)	48.5%	51.5%
Southwest Gas	58.2%	41.8%	50.5%	49.5%	47.9%	52.1%	48.3%	51.7%	49.8%	50.2%
Spire	52.5%	47.5%	49.0%	51.0%	45.0%	55.0%	45.7%	54.3%	50.0%	50.0%
LDC GROUP AVERAGE	**51.0%**	**49.0%**	**49.6%**	**50.4%**	**47.1%**	**52.9%**	**45.0%**	**55.0%**	**47.2%**	**52.9%**
Minimum	38.4%	41.8%	40.0%	38.8%	38.0%	43.2%	34.3%	44.7%	28.9%	36.5%
Maximum	58.2%	61.6%	61.2%	60.0%	56.8%	62.0%	55.3%	65.7%	63.5%	71.1%

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 27, 2022).
(b) Capital structure ratios distorted due to major acquisition during 2018 financed principally with debt.

TEXAS GAS SERVICE
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West North Texas Service Area

DCF MODEL -- DIVIDEND YIELD

Company		Expected Dividend (a)	Price (b)	Dividend Yield (c)
Atmos Energy	ATO	$ 2.87	$ 113.91	2.52%
Chesapeake Utilities	CPK	$ 2.18	$ 129.25	1.69%
New Jersey Resources	NJR	$ 1.45	$ 44.74	3.24%
NiSource	NI	$ 0.94	$ 30.24	3.11%
Northwest Natural Gas	NWN	$ 1.93	$ 51.10	3.78%
ONE Gas	OGS	$ 2.56	$ 85.98	2.98%
South Jersey Industries	SJI	$ 1.25	$ 34.09	3.67%
Southwest Gas	SWX	$ 2.51	$ 91.24	2.75%
Spire	SR	$ 2.80	$ 75.60	3.70%
AVERAGE				**3.05%**
MEDIAN				**3.11%**

(a) *The Value Line Investment Survey* "Summary & Index" (June 3, 2022).
(b) Fidelity Investments Stock Research "Price History" (Average of daily May 2022 closing prices).
(c) Expected Dividend / Price.

DCF MODEL -- EARNINGS GROWTH RATES

	Projected Growth			Historical Growth	
Company	**Value Line (a)**	**I/B/E/S (b)**	**Zacks (c)**	**10-Year (d)**	**5-Year (d)**
Atmos Energy	7.5%	8.6%	7.3%	8.5%	8.5%
Chesapeake Utilities	7.5%	N/R	N/R	9.5%	9.5%
New Jersey Resources	5.0%	6.0%	6.0%	5.0%	2.5%
NiSource	9.5%	7.2%	7.2%	3.0%	4.0%
Northwest Natural Gas	6.5%	5.9%	4.7%	-1.0%	2.5%
ONE Gas	6.5%	5.0%	5.0%	N/R	9.5%
South Jersey Industries	10.5%	N/R	N/R	1.0%	0.5%
Southwest Gas	10.0%	4.0%	5.0%	5.5%	4.5%
Spire	9.0%	4.3%	5.0%	2.0%	2.5%
AVERAGE	**8.0%**	**5.9%**	**5.7%**	**4.2%**	**4.9%**
MEDIAN	**7.5%**	**5.9%**	**5.0%**	**4.0%**	**4.0%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 27, 2022).
(b) REFINITIV "Stock Reports Plus" (May 31, 2022).
(c) Zacks.com "Detailed Earnings Estimates" (Retrieved June 1, 2022).

N/R -- None reported.

DCF MODEL -- SUSTAINABLE GROWTH RATES

	2025-2027 Projected (a)				Shares Outstanding (a)		Earnings Retention Growth			External Financing Growth					
Company	Earnings per Share	Dividends per Share	Book Value per Share	Price per Share	2021	Proj. 25-27	Retention Ratio	Return on Equity	"b x r"	2025-2027 Market-to-Book Ratio	Growth Rate in Shares	"s"	"v"	"s x v"	Sustainable Growth
Atmos Energy	$ 7.30	$ 3.50	$ 82.85	$ 145.00	132.42	155.00	52.1%	8.8%	4.6%	1.75	3.2%	5.6%	42.9%	2.4%	7.0%
Chesapeake Utilities	$ 6.50	$ 2.75	$ 56.15	$ 147.50	17.66	23.50	57.7%	11.6%	6.7%	2.63	5.9%	15.4%	61.9%	9.6%	16.2%
New Jersey Resources	$ 2.80	$ 1.70	$ 23.15	$ 47.50	94.95	100.00	39.3%	12.1%	4.8%	2.05	1.0%	2.1%	51.3%	1.1%	5.8%
NiSource	$ 2.30	$ 1.08	$ 17.40	$ 45.00	404.30	415.00	53.0%	13.2%	7.0%	2.59	0.5%	1.4%	61.3%	0.8%	7.8%
Northwest Natural Gas	$ 3.45	$ 1.96	$ 37.20	$ 70.00	31.13	32.00	43.2%	9.3%	4.0%	1.88	0.6%	1.0%	46.9%	0.5%	4.5%
ONE Gas	$ 5.30	$ 3.12	$ 71.60	$ 125.00	53.63	57.00	41.1%	7.4%	3.0%	1.75	1.2%	2.1%	42.7%	0.9%	4.0%
South Jersey Industries	$ 2.70	$ 1.50	$ 24.80	$ 42.50	117.34	125.00	44.4%	10.9%	4.8%	1.71	1.3%	2.2%	41.6%	0.9%	5.7%
Southwest Gas	$ 6.75	$ 3.10	$ 72.00	$ 107.50	60.42	75.00	54.1%	9.4%	5.1%	1.49	4.4%	6.6%	33.0%	2.2%	7.2%
Spire	$ 5.50	$ 3.30	$ 67.10	$ 112.50	51.70	55.00	40.0%	8.2%	3.3%	1.68	1.2%	2.1%	40.4%	0.8%	4.1%
AVERAGE									**4.8%**					**2.1%**	**6.9%**
MEDIAN									**4.8%**					**0.9%**	**5.8%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 27, 2022).

DCF MODEL -- OTHER PROJECTED AND HISTORICAL GROWTH RATES

	Net Book Value (a)			Dividends per Share (a)			Price per Share		
	Pro-	Historical		Pro-	Historical		Pro-	Historical (b)	
Company	**jected**	**10-Year**	**5-Year**	**jected**	**10-Year**	**5-Year**	**jected (a)**	**10-Year**	**5-Year**
Atmos Energy	7.5%	8.5%	11.0%	7.0%	5.5%	8.0%	6.2%	13.3%	6.9%
Chesapeake Utilities	6.0%	9.5%	10.5%	8.5%	7.0%	8.5%	3.4%	16.5%	12.2%
New Jersey Resources	4.5%	7.5%	7.0%	5.0%	6.5%	6.5%	1.5%	7.6%	1.9%
NiSource	5.0%	-3.0%	-2.5%	4.5%	-1.0%	N/R	10.4%	11.9%	4.2%
Northwest Natural Gas	4.0%	1.0%	0.5%	0.5%	1.5%	0.5%	8.2%	1.1%	-3.1%
ONE Gas	9.5%	3.5%	N/R	6.5%	13.5%	N/R	9.8%	N/A	4.5%
South Jersey Industries	5.0%	5.5%	2.0%	4.0%	6.0%	3.5%	5.7%	3.6%	-1.0%
Southwest Gas	7.5%	6.5%	7.0%	5.5%	8.5%	7.0%	4.2%	8.0%	2.6%
Spire	7.0%	6.5%	4.5%	5.0%	4.5%	6.0%	10.4%	6.9%	1.7%
AVERAGE	**6.2%**	**5.1%**	**5.0%**	**5.2%**	**5.8%**	**5.7%**	**6.6%**	**8.6%**	**3.3%**
MEDIAN	**6.0%**	**6.5%**	**5.8%**	**5.0%**	**6.0%**	**6.5%**	**6.2%**	**7.8%**	**2.6%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 27, 2022).
(b) Fidelity Investments Stock Research "Price History" (Average of daily May 2012, May 2017, and May 2022 closing prices).

N/R -- None reported.
N/A -- Not available.

CAPITAL ASSET PRICING MODEL

	Historical Rates of Return (a)	Forward-Looking Rates of Return (b)
Market Required Rate of Return	12.30%	12.54%
Long-term Government Bond Return (a)(c)	4.90%	3.07%
Market Risk Premium (d)	7.40%	9.48%
LDC Group Beta (e)	0.85	0.85
LDC Group Risk Premium (f)	6.29%	8.05%
Risk-free Rate of Interest (c)	3.07%	3.07%
Theoretical CAPM Cost of Equity Estimate (g)	9.36%	11.12%
Size Premium (e)	0.88%	0.88%
CAPM Cost of Equity Estimates (h)	**10.23%**	**12.00%**

(a) *Kroll; Summary of Statistics of Annual Total Returns, Income Returns, and Capital Appreciation Returns of Basic U.S. Asset Classes (1926-2021).*

(b) Calculated by applying DCF model applied to S&P 500 firms paying dividends (May 31, 2022):

Expected Dividend Yield		1.95%
Projected Earnings Growth Rate:		
Value Line	10.64%	
I/B/E/S	11.03%	
Zacks	10.12%	
Average		10.60%
Market Required Rate of Return		12.54%

(c) May 2022 yield on 30-year U.S. Treasury bonds (Federal Reserve). 3.07%

(d) Market Required Rate of Return minus Long-term Government Bond Return.

(e) Schedule 8.

(f) Market risk premium times beta.

(g) Sum of Risk Premium and Risk-free Rate of Interest.

(h) Sum of Unadjusted 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-	A1	0.80	$ 15,700	0.57%
Chesapeake Utilities	N/R	N/R	0.75	$ 2,300	1.20%
New Jersey Resources	N/R	A1	0.95	$ 4,300	0.91%
NiSource	BBB+	Baa2	0.85	$ 12,400	0.57%
Northwest Natural Gas	A+	Baa1	0.80	$ 1,600	1.36%
ONE Gas	BBB+	A3	0.80	$ 4,600	0.91%
South Jersey Industries	BBB	A3	1.00	$ 4,100	0.91%
Southwest Gas	BBB-	Baa1	0.90	$ 6,100	0.56%
Spire	A-	Baa2	0.80	$ 3,900	0.91%
LDC GROUP AVERAGE	**BBB+**	**A3**	**0.85**	**$ 6,111**	**0.88%**

CRSP Deciles Size Premiums (e)

Decile	Market Capitalization of Smallest Company (in millions)		Market Capitalization of Largest Company (in millions)	Size Premium (Return in Excess of CAPM)
1-Largest	$ 36,160.584	-	$ 2,324,390.219	-0.17%
2	16,759.390	-	36,099.221	0.44%
3	8,216.356	-	16,738.364	0.57%
4	5,019.883	-	8,212.638	0.56%
5	3,281.009	-	5,003.747	0.91%
6	2,170.315	-	3,276.553	1.20%
7	1,306.402	-	2,164.524	1.36%
8	629.118	-	1,306.038	1.28%
9	290.002	-	627.803	2.11%
10- Smallest	10.588	-	289.007	4.85%

(a) StandardandPoors.com (June 2, 2022)
(b) Moody's.com (June 6, 2022).
(c) *The Value Line Investment Survey* "Summary & Index" (June 3, 2022).
(d) *The Value Line Investment Survey* "Ratings & Reports" (May 27, 2022).

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%

Year	Qtr.	Allowed ROE (a)	Average Utility Bond Yield (b)	Risk Premium
2001	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	9.74%	3.46%	6.28%
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%
Average		**11.45%**	**7.65%**	**3.80%**

Unadusted:

Risk Premium = Intercept + (Slope X Interest Rate(d))

RP	=	0.07340	+	-0.46317	X	4.79%
RP	=	0.07340	+	-0.02219		
RP	**=**	**5.12%**				

Adjusted (Using Iterative Prais-Winsten algorithm):

Risk Premium = Intercept + (Slope X Interest Rate(d))

RP	=	0.07804	+	-0.52552	X	4.79%
RP	=	0.07804	+	-0.02517		
RP	**=**	**5.29%**				

(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 utlity bond yield for May 2022.

COMPARABLE EARNINGS METHOD

Company	**Projected Earned Return on Book Equity (a)** 2022	2023	2025-27
Atmos Energy	8.9%	8.9%	8.8%
Chesapeake Utilities	11.0%	10.8%	11.6%
New Jersey Resources	12.8%	12.5%	12.1%
NiSource	10.7%	11.4%	13.2%
Northwest Natural Gas	8.6%	9.6%	9.3%
South Jersey Industries	9.3%	9.0%	10.9%
Southwest Gas	8.3%	9.0%	9.4%
Spire	7.9%	8.0%	8.2%
LDC GROUP AVERAGE	**9.7%**	**9.9%**	**10.4%**
MEDIAN	**9.1%**	**9.9%**	**10.5%**

(a) *The Value Line Investment Survey* "Ratings & Reports" (May 27, 2022).

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 14th day of June 2022.

Notary Public in and for the State of Texas

STEPHANIE TANNER
Notary Public, State of Texas
Notary ID 12852236-6
My Commission Exp. 02-09-2023

CASE NO. 00009896

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	**§ § § § § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

TERESA SERNA

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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III.	REVENUE ADJUSTMENTS	4
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LIST OF EXHIBITS

EXHIBIT TDS-1	West North Service Area - Class Cost of Service Study
EXHIBIT TDS-2	West North Service Area - Class Revenue Allocation
EXHIBIT TDS-3	West Texas Service Area - Class Cost of Service Study
EXHIBIT TDS-4	West Texas Service Area - Class Revenue Allocation
EXHIBIT TDS-5	North Texas Service Area - Class Cost of Service Study
EXHIBIT TDS-6	North Texas Service Area - Class Revenue Allocation
EXHIBIT TDS-7	Borger Skellytown Service Area - Class Cost of Service Study
EXHIBIT TDS-8	Borger Skellytown 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 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 Bachelor of Business Administration Degree in finance from Texas State University in August 2009. I am currently pursuing an MBA from West Texas A&M University. I began my career with TGS in November 2009 as a Rates Analyst II and since January 2020, I have been in the role of Rates Specialist. In my current position at TGS, my responsibilities include analyzing revenue related issues, preparing studies, reports, and testimony related to cost of service, and providing data to support rate design.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes, I have filed testimony on behalf of TGS in Gas Utilities Docket ("GUD") Nos. 10526, 10506, 10488, 10094, and 10285 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:

1. The revenue adjustments used to develop the requested system-wide revenue requirement for TGS's proposed West North Service Area ("WNSA"), which is the proposed consolidation of the existing West Texas Service Area ("WTSA"), North Texas Service Area ("NTSA"), and Borger Skellytown Service Area ("BSSA").
2. The class cost of service ("CCOS") study I prepared for the proposed WNSA and the class revenue allocation based on the CCOS study results. Should consolidation not be approved, I have also prepared individual CCOS studies and their respective class revenue allocations for WTSA, NTSA, and BSSA. I support the CCOS study tabs listed in the table below in the proposed WNSA, WTSA, and BSSA integrated models.[1]

[1] The NTSA integrated model is the only model that does not contain the Study Summary for Rate Design tab because no customer classes are being consolidated for rate design purposes.

Study Summary
Study Summary for Rate Design
Classified Rate Base
Classified Cost of Service
Classification Factors
Allocated Rate Base
Allocated Cost of Service
Allocation Factors
WKP Plant
WKP Admin&Gen
WKP Selected Data
903 Factors
904 Factors
Bill Determinants Summary
Customer Deposit Factors
Mains Study Summary
Meter and Regulator Factors
Odorization Summary
Peak Demand
Service Charges Summary
Service Line Factors
As Adjusted Revenues Summary
Class Revenue Allocation

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I am sponsoring Schedules G-1 through G-3 for the proposed WNSA and for the stand-alone schedules for the WTSA, NTSA, and BSSA.

Q. WERE THESE SCHEDULES PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, they were.

III. 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 ("CGC") rather than through base rates. Schedule G-2 shows the derivation of the test year base sales revenue through the removal of the cost of gas revenue from total per book revenues. Schedule G-2 also contains the various adjustments to test year base revenue attributable to Gas Sales customers that are necessary to make test year revenues representative of expected annual revenues for purposes of setting rates in this filing. Finally, Schedule G-3 contains adjustments to base revenue attributable to transportation customers and other utility revenue that are required to normalize test year revenue in this filing.

Q. PLEASE EXPLAIN THE ADJUSTMENTS ON SCHEDULE G-1.

A. Gas costs are recovered through the Company's CGC instead of through base rates because: (1) the Company does not make a profit on gas costs, and (2) fluctuations in the cost of gas are outside the control of the Company. Therefore, it is necessary to remove gas costs and revenues from the test year cost of service. Line 1 of Schedule G-1 is the cost of gas revenue collected via the CGC, which is removed from Base Sales Revenue on Schedule G-2. Line 2 is the test year cost of gas expense that is removed from this filing as shown on Schedule G. Schedule G is sponsored by Company witness Stacey L. McTaggart.

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, 2021, is shown on line 1 of Schedule G-2. This total includes revenue derived from: (1) charges for the cost of gas, and (2) charges for sales service. Line 2 is the total per book revenue attributable to recovery of the cost of gas. The revenue on line 2 is subtracted from the revenue on line 1 to remove all revenue associated with gas costs from the total per book revenues to yield Base Sales Revenue as shown on line 3.

Q. PLEASE EXPLAIN THE WEATHER NORMALIZATION ADJUSTMENT ON LINE 4 OF SCHEDULE G-2.

A. TGS currently has weather normalization adjustments ("WNA") in effect for the WTSA, NTSA, and the BSSA. In this statement of intent, TGS proposes a WNA that would be applicable to the proposed WNSA. 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 for the proposed WNSA to reflect revenues that would have been expected if weather had been normal. In effect, this causes the WNA to be counted twice in the calculation of the Company's revenue requirement. To avoid this redundancy, it is necessary to remove the revenue recognized through the WNA during the test year. This is accomplished through the adjustment of $(675,828) on line 4 of Schedule G-2.

Q. PLEASE EXPLAIN A HEATING DEGREE DAY.

A. A heating degree day ("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, 2021.

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 GUD No. 10506, which was fully litigated, and GUD Nos. 9988, 10928, 10488, 10526, 10656, 10739 and 10766, pursuant to settlement. It is also consistent with the practice of other Texas gas utilities and Commission decisions[2] and has been found reasonable and precluded from further litigation in prior proceedings.[3]

Q. WHAT IS THE IMPACT OF THE UPDATED TEN YEAR NORMAL?

A. Current normal weather in the WTSA, NTSA, and BSSA is calculated based on a ten-year average from the prior rate case.[4] On a volume-weighted basis, the new normal in the proposed WNSA is 8% warmer than the current normal. This results in a $(834,895) reduction to gas sales test year revenues.

Q. PLEASE EXPLAIN HOW THE WNA SHOWN ON LINE 5 OF SCHEDULE G-2 WAS DEVELOPED.

A. The adjustment on line 5 of Schedule G-2 is required to weather normalize revenues. The analysis for the proposed WNSA was developed based on data from

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[2] *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).

[3] *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, 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 re-litigated in this proceeding.").

[4] *Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the El Paso Service Area (EPSA), Permian Service Area (PSA), and Dell City Service Area (DCSA)*, GUD No. 10506 consol., Final Order (Sept. 27, 2016) normalized weather based on 10-year periods 2005-2014 (Oct-Dec) and 2006-2015 (Jan-Sep). *Statement of Intent of Texas Gas Service, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the North Texas Service Area,* GUD No. 10739, Final Order (Nov. 13, 2018) and *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) normalized based on a 10-year period ending December 31, 2017.

four weather stations: (1) El Paso International Airport ("KELP"); (2) Midland International Air and Space Port Airport ("KMAF"); (3) Abilene Regional Airport ("KABI"); and (4) Rick Husband Amarillo International Airport ("KAMA"). A separate analysis is conducted for each customer class in the proposed WNSA to reflect usage patterns and to price adjustments at the appropriate tariffed 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.[5] This volume adjustment was then priced at the test year tariff rates to yield the revenue adjustment, a $(144,456) decrease to test year base sales revenues, as shown on line 5 of Schedule G-2. This adjustment

[5] This methodology was utilized in the Company's Central Gulf Service Area (S*tatement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc. ("TGS") to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area and Gulf Coast Service Area*, GUD No. 10928 consol., Final Order (Aug. 4, 2020)); Gulf Coast Service Area (*Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Galveston Service Area (GSA) and South Jefferson County Service Area (SJCSA)*, GUD No. 10488, Final Order (May 3, 2016)); West Texas Service Area (GUD No. 10506, Final Order); Central Texas Service Area (*Statement of Intent of Texas Gas Service Company (TGS), a Division of ONE Gas, Inc., to Change Gas Utility Rates Within the Unincorporated Areas of the Central Texas Service Area (CTSA) and South Texas Service Area (STSA)*, GUD No. 10526, Final Order (Nov. 15, 2016)); Rio Grande Valley Service Area (*Statement of Intent of Texas Gas Service Company, a Division of ONE Gas, Inc., to Increase Gas Utility Rates Within the Unincorporated Areas of the Rio Grande Valley Service Area*, GUD No. 10656, Final Order (Mar. 20, 2018)); North Texas Service Area (GUD No. 10739, Final Order); and the Borger-Skellytown Service Area (GUD No. 10766, Final Order).

decreases base sales revenues in recognition of the fact that the volumes and resulting revenues were abnormally high because temperatures in the test year period were 1% colder than normal.[6] By adjusting sales volumes downward to reflect normal weather conditions in the proposed WNSA 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 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 EXPLAIN THE REVENUE ADJUSTMENT SHOWN ON LINE 6 OF SCHEDULE G-2.

A. The adjustment on line 6 of Schedule G-2 increases base sales revenue by $34,507 to account for the revenues gained from a public authority customer that switched from transportation to gas sales service during the test year. Because the customer's switch to gas sales service has already occurred, normalizing the test year revenues for this known and measurable change is reasonable and appropriate.

Q. PLEASE EXPLAIN THE CUSTOMER GROWTH ADJUSTMENT ON LINE 7 OF SCHEDULE G-2.

A. To account for customer growth or loss, the Company includes an adjustment to quantify customer growth or loss patterns and adjusts customer counts accordingly. For each customer class within the proposed WNSA, this adjustment annualizes the growth or loss in customers that occurred during the twelve months ended

[6] This percentage was calculated on a volume weighted basis among the four weather stations.

December 31, 2021 by adjusting bill counts and volumes in each month of the test year to reflect the levels observed at the end of the test year. This adjustment is necessary to ensure that test year revenues accurately reflect the number of customers served when new rates take effect.

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.[7] The change in customers as of December 31, 2021, was calculated by comparing the number of active customers at December 31, 2020, to the number of active customers at December 31, 2021. The adjustment shown on line 7 on Schedule G-2 annualizes the growth in the proposed WNSA in the amount of $344,280.

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ON LINE 8 OF SCHEDULE G-2.

A. The adjustment shown on line 8 on Schedule G-2 removes revenue collected through a Gas Reliability Infrastructure Program ("GRIP") adjustment in the WTSA, BSSA, and the unincorporated areas of the NTSA during the twelve months ended December 31, 2021. This adjustment is necessary because the Company's test year cost of service calculation already includes a GRIP annualization.

[7] The bill change for the WTSA is priced out at rates proposed in a WTSA GRIP filed on March 14, 2022 and expected to become effective June 27, 2022.

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ON LINE 9 OF SCHEDULE G-2.

A. On March 14, 2022, TGS filed a GRIP adjustment for the environs and incorporated areas of the WTSA. The annualization of this revenue impact over the entire test year based upon the rates requested in that filing results in a $30,752,557 increase to base sales revenues. On January 27, 2022, TGS implemented a GRIP adjustment for the BSSA, which when annualized for the test year results in a $89,248 increase to base sales revenues. Additionally, on October 27, 2021, TGS implemented a GRIP adjustment for the environs areas of the NTSA. The annualization of this revenue impact results in a $227,725 increase to base sales revenues. The combined impact of these adjustments for the proposed WNSA is a $31,069,529 increase to base sales revenues.

Q. PLEASE EXPLAIN THE REVENUE ADJUSTMENT ON LINE 10 OF SCHEDULE G-2.

A. On July 28, 2021, TGS implemented a Cost of Service Adjustment (“COSA”) for the incorporated areas of the NTSA. The annualization of this revenue impact over the entire test year results in a $1,023,439 increase to base sales revenues.

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 $11,082,471, as shown on line 11 of Schedule G-2. This results in a total Base Sales Revenue amount, as adjusted, of $120,932,709 as shown on line 12 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. Transportation customers are not billed until shortly after the billing system closes for the month. As a result, transportation revenue must be estimated each month and those estimates are reversed out in the following month when actual revenue is recorded on the Company's books. Removing these estimates restores transportation revenues to the actual amount billed during the test year, which decreases transportation revenues by $(2,533).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO NORMAL WEATHER ON LINE 3 OF SCHEDULE G-3.

A. This adjustment decreases transportation revenue in recognition of the fact that the volumes and resulting revenues in the Company's proposed WNSA were abnormally high because temperatures during the test year were colder than normal. This adjustment decreases transportation revenue by $(5,450).

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 4 OF SCHEDULE G-3.

A. The adjustment on line 4 decreases transportation revenue by $(37,183) to account for the revenues associated with a public authority transportation customer that switched to gas sales service during the test year. As noted above, the Company is making a similar adjustment to gas sales revenues. Because the customer's switch to gas sales service has already occurred, normalizing test year revenues for this known and measurable adjustment is reasonable and appropriate.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 5 OF SCHEDULE G-3.

A. The adjustment on line 5 decreases transportation revenue by $(2,937) and removes the revenue of an industrial transportation customer that terminated service during the test year.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 6 OF SCHEDULE G-3.

A. Line 6 reflects a revenue adjustment of $(87,836) to remove GRIP revenue collected in the WTSA, BSSA, and unincorporated areas of the NTSA during the twelve months ended December 31, 2021. As previously noted, this adjustment is necessary because the Company's test year cost of service calculation already includes a GRIP annualization.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 7 OF SCHEDULE G-3.

A. As previously described, on March 14, 2022, TGS filed a GRIP adjustment for the WTSA. The annualization of this revenue impact over the entire test year results in a $140,105 increase to transportation revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 8 OF SCHEDULE G-3.

A. On May 15, 2021, TGS implemented an annual recalculation of the contract rate charge ("CRC") for gas utility service at Fort Bliss. This adjustment increased monthly revenues by $3,111. 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 $15,555 increase to transportation revenues.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSPORTATION REVENUE ON LINE 9 OF SCHEDULE G-3.

A. The adjustment on line 9 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. 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 $319,721, as shown on line 10 of Schedule G-3.

Q. PLEASE EXPLAIN THE ADJUSTMENT TO SERVICE FEES ON LINE 13 OF SCHEDULE G-3.

A. Line 13 of Schedule G-3 contains two adjustments: (1) annualizing the change to service fees and (2) annualizing the test year based on a three-year average to reflect normal business operations. The Company temporarily suspended disconnections of service during the COVID-19 pandemic for a period of time. As a result, revenues associated with reconnects during the test year decreased significantly compared to previous years. Therefore, a three year-average instead of the test year amount was utilized in order to more accurately reflect revenues in this filing. The three-year average includes 2019, 2020, and 2021. The direct testimony of Ms. McTaggart outlines the proposed service fee changes in greater detail. These changes will have the effect of increasing the revenues the Company would otherwise recover under its existing service fees. To account for these changes, an increase of $376,717 test year revenues is included on line 14 of Schedule G-3.

Q. WHAT IS INCLUDED ON LINE 15 OF SCHEDULE G-3?

A. Line 15 presents Other Utility Revenue, which includes revenue accrued for interest on storage gas.

Q. PLEASE EXPLAIN THE ADJUSTMENT ON LINE 16 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 $(284,645) decrease to revenues.

Q. WHAT IS THE TOTAL TRANSPORTATION, SERVICE FEES AND OTHER UTILITY REVENUE AS ADJUSTED?

A. As shown on line 18 of Schedule G-3, the total amount as adjusted is $6,533,067.

Q. DOES THE PROPOSED WNSA CONSOLIDATION IMPACT GAS SALES AND TRANSPORTATION REVENUE ADJUSTMENTS?

A. No. The consolidation does not impact the calculation for gas sales and revenue adjustments. For example, the weather adjustment is developed based on the data from weather stations KELP, KMAF, KABI, and KAMA. The individual adjustments produced from these weather stations are totaled to derive the WNSA consolidated adjustment.

IV. <u>CLASS COST OF SERVICE STUDY</u>

Q. WHAT IS A CLASS COST OF SERVICE STUDY?

A. A CCOS study is 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 Mr. 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 costs, (2) demand-related costs, (3) commodity-related costs, 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.[8]

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.

[8] 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, Supervision and Engineering Expense (Account 885) 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' annual volumes relative to total annual volumes. Revenue-related costs are allocated to customer classes based on relative annual revenues.[9]

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' 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 residential class and, to the extent practicable, to each of the non-residential classes.[10]

[9] 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.

[10] The test year amounts for these cost of service components are available and direct assignments are made to the residential, commercial, public authority, and industrial classes, including industrial transportation service. Within the existing non-residential classes, the assigned amounts are split between public authority and municipal water pumping, school/municipal and public authority, commercial transportation and compressed natural gas transportation, and public authority transportation and compressed natural gas transportation classes. For each of these classes, assigned service charge revenue, customer deposits, and bad debt expense factors are split based on relative margin.

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 GUD No. 10506 and found that the study was "reasonable to use" and that it "classifies and allocates costs in a fair, just, and reasonable manner."[11]

Q. PLEASE DESCRIBE EXHIBIT TDS-1, WHICH IS THE CCOS STUDY IN THIS CASE.

A. The CCOS study results for the proposed WNSA are provided in Exhibit TDS-1.[12] Page 1 of Exhibit TDS-1 provides a summary of the results. Line 4 shows each class' 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, lines 1 through 3 provide the customer-related, demand-related, and commodity-related costs that total to the cost of service for each class on line 4.

Q. WHAT ADDITIONAL REVENUES ARE INCLUDED IN THE REVENUE ALLOCATION?

A. To determine how much revenue must be recovered through recurring monthly customer and usage charges from each class to meet the cost of service, revenue

[11] GUD No. 10506, Final Order at Findings of Fact 98-99 (Sept. 27, 2016).

[12] On Exhibit TDS-1, cogeneration transportation cost-of-service results have been combined into the commercial transportation class. Additionally, commercial air conditioning results have been combined into the commercial class, and public authority air conditioning results into the public authority class.

from other sources must be credited to the cost of service. The revenue credit is comprised of revenue from service charges, special contracts, and the irrigation class. Service charge revenue is directly assigned to the customer classes. Special contract revenue is associated with contract rates negotiated to keep these customers from bypassing the Company's system. Special contract revenue and irrigation revenue are credited to customer classes based on each class' cost of service relative to the total cost of service. The resulting revenue credits are shown on line 5 of Exhibit TDS-1. Line 6 shows the cost of service net of these revenue credits. Line 7 shows the current revenue for each customer class, and line 8 provides the required revenue change net of these revenue credits for each class. Line 8 shows the amounts that must be collected through monthly customer and usage charges from each class in order for each class to pay its cost of service.

Q. PLEASE DESCRIBE THE COST RATIOS FOUND IN EXHIBIT TDS-1 ON PAGE 1.

A. A revenue-to-cost ratio of one indicates that a class' revenue matches the cost to serve the class. A ratio of less than one indicates that a class' 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 and Fort Bliss currently have a revenue-to-cost ratio less than one [line 10, column (c and m)], indicating that the class is paying less than its cost of service today. The revenue-to-cost ratios of all other non-residential classes are all greater than one [line 10, columns (d) through (l)], indicating that each class is currently paying more than its cost of service. Line 11 demonstrates that each class will pay its cost of service if the revenue changes shown on line 8 are assigned to each class.

Q. PLEASE EXPLAIN WHERE THE CLASSIFICATION STEP IS FOUND IN EXHIBIT TDS-1.

A. Pages 3 through 15 of Exhibit TDS-1 contain details on the classification step of the cost of service study, including the classification of individual plant accounts and other rate base items on pages 3 through 5. Pages 6 through 9 of Exhibit TDS-1 show the classification of the individual components of the cost of service, or revenue requirement. Pages 10 through 15 provide the classification factors used on pages 3 through 9 of Exhibit TDS-1.

Q. PLEASE EXPLAIN WHERE THE ALLOCATION STEP IS FOUND IN EXHIBIT TDS-1.

A. Pages 16 through 29 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 16 through 19. The allocation of each of the classified components of the cost of service to customer classes is shown on pages 20 through 27 of Exhibit TDS-1. The components of the allocated cost of service before revenue credits (shown on page 27, lines 488 through 491) are carried forward to lines 1 through 4 of the Cost of Service Study Summary (pages 1 and 2, Exhibit TDS-1). Pages 28 and 29 of Exhibit TDS-1 provide the customer, demand, and commodity allocation factors applied in the allocation of the rate base (pages 16 through 19) and the cost of service (pages 20 through 27) components.

Q. DID YOU PREPARE INDIVIDUAL CCOS STUDIES FOR THE WTSA, NTSA, AND BSSA?

A. Yes. I prepared individual CCOS studies based on the separate WTSA, NTSA and BSSA revenue requirements in order to set rates if the Company's request for consolidation is not approved. Exhibit TDS-3 provides the CCOS study for the WTSA, Exhibit TDS-5 provides the CCOS study for the NTSA, and Exhibit TDS-7 provides the CCOS study for the BSSA based on each area's separate revenue requirement. Each of these studies is presented in the same format as the WNSA CCOS study in Exhibit TDS-1. Thus, my explanation of the content of Exhibit TDS-1 applies to Exhibit TDS-3, Exhibit TDS-5, and to Exhibit TDS-7.

V. <u>CLASS REVENUE ALLOCATION</u>

Q. PLEASE EXPLAIN THE CONCEPT OF CLASS REVENUE ALLOCATION.

A. Class revenue allocation is the assignment of revenue to each customer class so that the total revenue assigned equals the revenue requirement. Upon assignment of revenue to each class, recurring monthly rates must be designed to collect the annual revenue assigned to the class. Conceptually, revenues should be fairly allocated to customer classes and rates should be designed to more accurately capture fixed and variable costs. Equitable class revenue allocations and rate designs are effective in attracting and retaining customers in all classes and keeping their rates reasonable. Interclass inequities that result from residential customers paying less than their cost of service could, at some point, cause non-residential customers to find gas service unattractive compared to other energy sources. If these customers switch to other energy sources, residential customers will end up paying higher rates in future rate cases in order to cover the Company's cost of service. Similarly, maintaining lower customer charges with higher usage charges could cause moderate- and high-use customers to consider alternatives to gas service.

Q. HOW ARE THE CCOS STUDY RESULTS USED TO ASSIGN REVENUE TO EACH CLASS?

A. The WNSA CCOS study results that are used for the proposed WNSA class revenue allocation are shown on page 2 of Exhibit TDS-1.[13] 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.

Page 2 of Exhibit TDS-1 combines both the sales and transportation services. Additionally, water pumping and school/municipal classes have been consolidated into the public authority class. This is reasonable because the rate design proposed in this case by Mr. Raab is based on identical usage blocks and usage rates for sales service and corresponding transportation service.

Q. WHAT FACTORS DID YOU CONSIDER TO DEVELOP THE PROPOSED WNSA CLASS REVENUE ALLOCATION?

A. The factors I considered in developing my recommendation were class costs and the concept of gradualism. First, the Company supports basing the class revenue allocation on the actual WNSA CCOS study results so that each class pay its own cost of service. If cost-based revenue assignments are not made, a portion of the

[13] With the separate WTSA, NTSA, and BSSA revenue requirements, see page 2 of Exhibits TDS-3, TDS-5, TDS-7 for the WTSA, NTSA, and BSSA, respectively.

cost to serve certain classes (those paying less than the cost to serve them) are unfairly borne by other classes (those paying more than the cost of service). Implementing cost-based revenue assignments in this case requires revenue increases for the proposed WNSA residential and Fort Bliss classes and revenue decreases for each of the non-residential classes.[14]

However, it is also important to consider the bill 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' 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 the residential class' cost of service in this rate case. I also considered these same factors in developing appropriate class revenue allocations for the WTSA, NTSA, and BSSA if the Company's request for consolidation is not approved.

Q. PLEASE EXPLAIN EXHIBIT TDS-2.

A. The three class revenue allocations for the proposed WNSA that I considered are shown on Exhibit TDS-2. Each class' 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.[15]

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[14] The WTSA, NTSA, and BSSA CCOS studies based on the separate revenue requirement for each area show that cost-based revenue assignments required residential revenue increases and non-residential revenue decreases in each service area.

[15] 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 CONSIDERED FOR THE PROPOSED WNSA.

A. Revenue Allocation One assigns revenue so that each class pays its actual cost of service.[16] The resulting revenue change for each class is shown on line 5 of Exhibit TDS-2.

Revenue Allocation Two incorporates the principle of gradualism into the allocation process. For each class for which a cost-based revenue decrease is required, Revenue Allocation Two assigns 20% of the cost-based required decrease to those classes. The benefit from not assigning the full cost-based decrease to these classes is assigned to the residential class. The revenue change for each class is shown on line 10 of Exhibit TDS-2. Importantly, the residential revenue increase in Revenue Allocation Two is smaller than the cost-based required increase, but there is still significant movement toward cost-based revenue assignments for each class, as shown by comparing the revenue-to-cost ratios in line 1 to those in line 9 for each customer class.

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 14, in column (c). Furthermore, this revenue allocation results in no movement toward

[16] Fort Bliss rates are set by contract and are not adjusted in this proceeding. The Fort Bliss' revenue assignment in Revenue Allocation One, Revenue Allocation Two, and Revenue Allocation Three is the cost-based revenue assignment shown for Fort Bliss in the WNSA CCOS study. This Fort Bliss revenue assignment ensures that no other customer class will pay any of the Fort Bliss cost of service.

cost-based revenue assignments for the commercial, industrial, public authority and compressed natural gas classes, as shown by comparing the revenue-to-cost ratios in line 1 to those in line 14, in columns (d), (e), (f), and (g).

Q. WHAT REVENUE ALLOCATION DO YOU RECOMMEND FOR THE PROPOSED WNSA?

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 commercial, industrial, and public authority classes. I recommend Allocation Two because it incorporates the principle of gradualism and improves the equity in the collection of revenue from all customer classes compared to today's revenue collection, and is consistent with Commission precedent regarding cost-based revenue assignments.[17]

Q. PLEASE EXPLAIN EXHIBITS TDS-4, TDS-6, AND TDS-8.

A. If the Company's request for consolidation is not approved, I have prepared class revenue allocations specific to each of the WTSA, NTSA, and BSSA that, together, are comparable to those developed for the proposed WNSA. The WTSA revenue allocations are shown in Exhibit TDS-4, the NTSA revenue allocations are shown in Exhibit TDS-6, and the BSSA revenue allocations are shown in Exhibit TDS-8, based on their separate revenue requirements. These three exhibits are structured

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[17] *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, Proposal For Decision at 45 (Sept. 27, 2016). The Examiners explained that the Commission in previous dockets has expressed a policy of moving toward cost-based revenue assignments.

in the same manner as Exhibit TDS-2. If the proposed service area consolidation is not approved, I recommend Revenue Allocation Two for the WTSA, NTSA and BSSA as shown in Exhibits TDS-4, TDS-6, and TDS-8.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: SUMMARY

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Customer Costs	$ 107,044,548	$ 98,176,625	$ 7,368,917	$ 32,152	$ 732,168	$ 30,872	$ 12,969	$ 21,145	$ 14,646	$ 6,758	$ 4,024	$ 644,272
2	Demand Costs	$ 32,587,813	$ 21,010,892	$ 6,031,698	$ 116,708	$ 2,352,133	$ 86,556	$ 50,517	$ 541,557	$ 289,752	$ 218,976	$ 190,247	$ 1,698,777
3	Commodity Costs	$ 828,542	$ 480,552	$ 180,143	$ 5,279	$ 39,643	$ 1,275	$ 5,727	$ 31,722	$ 25,279	$ 8,449	$ 19,882	$ 30,592
4	Cost of Service Before Revenue Credits	$ 140,460,903	$ 119,668,070	$ 13,580,758	$ 154,139	$ 3,123,943	$ 118,703	$ 69,213	$ 594,423	$ 329,676	$ 234,184	$ 214,153	$ 2,373,641
5	Revenues Credited to Cost of Service (1)	$ 3,068,852	$ 2,735,711	$ 254,430	$ 1,694	$ 34,816	$ 1,376	$ 748	$ 6,361	$ 3,534	$ 2,509	$ 2,298	$ 25,375
6	Total Cost of Service	$ 137,392,051	$ 116,932,358	$ 13,326,328	$ 152,446	$ 3,089,128	$ 117,327	$ 68,465	$ 588,062	$ 326,143	$ 231,675	$ 211,854	$ 2,348,266
7	Revenue at Current Rates	$ 124,396,924	$ 94,066,743	$ 20,232,521	$ 634,581	$ 4,551,682	$ 266,348	$ 153,220	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 2,299,383
8	Revenue Deficiency	$ 12,995,128	$ 22,865,615	$ (6,906,193)	$ (482,136)	$ (1,462,554)	$ (149,021)	$ (84,755)	$ (7,179)	$ (553,209)	$ (18,578)	$ (255,745)	$ 48,883
9	Revenue-to-Cost Ratios:												
10	Current Revenue	0.9075	0.8089	1.5085	4.1279	1.4682	2.2554	2.2246	1.0121	2.6780	1.0793	2.1942	0.9794
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge (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	$ 1,567,287
Special Contract	$ 1,067,474
Irrigation	$ 434,091
Other Revenue	$ -
	$ 3,068,852

CLASS COST OF SERVICE STUDY: SUMMARY FOR RATE DESIGN

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Costs	$ 107,044,548	$ 98,176,625	$ 7,390,062	$ 46,798	$ 782,767	$ 4,024	$ 644,272
2	Demand Costs	$ 32,587,813	$ 21,010,892	$ 6,573,255	$ 406,460	$ 2,708,182	$ 190,247	$ 1,698,777
3	Commodity Costs	$ 828,542	$ 480,552	$ 211,865	$ 30,557	$ 55,094	$ 19,882	$ 30,592
4	Cost of Service Before Revenue Credits	$ 140,460,903	$ 119,668,070	$ 14,175,182	$ 483,816	$ 3,546,043	$ 214,153	$ 2,373,641
5	Revenues Credited to Cost of Service	$ 3,068,852	$ 2,735,711	$ 260,791	$ 5,227	$ 39,448	$ 2,298	$ 25,375
6	Total Cost of Service	$ 137,392,051	$ 116,932,358	$ 13,914,391	$ 478,588	$ 3,506,594	$ 211,854	$ 2,348,266
7	Revenue at Current Rates	$ 124,396,924	$ 94,066,743	$ 20,827,763	$ 1,513,933	$ 5,221,502	$ 467,600	$ 2,299,383
8	Revenue Deficiency	$ 12,995,128	$ 22,865,615	$ (6,913,372)	$ (1,035,345)	$ (1,714,908)	$ (255,745)	$ 48,883
9	Revenue-to-Cost Ratios							
10	Current Revenue	0.9075	0.8089	1.4877	3.1400	1.4836	2.1942	0.9794
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
12	Customer and Demand Costs Per Bill		$ 35.01	$ 67.00	$ 679.55	$ 213.89	$ 4,047.31	$ 10,231.65
13	Commodity Cost Per Ccf	$ 0.0039						

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Intangible Plant					
1	301	Organization	NONINTPLT	$ 130,422	$ 94,064	$ 36,156	$ 202
2	302	Franchises and Consents	NONINTPLT	$ 9,496	$ 6,849	$ 2,633	$ 15
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 893,065	$ 644,102	$ 247,580	$ 1,384
4		Total Intangible Plant		$ 1,032,983	$ 745,015	$ 286,368	$ 1,600
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	$ 44,997,719	$ -	$ 44,997,719	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 2,964,422	$ -	$ 2,964,422	$ -
12	369	Odorization Tank	COM	$ 101,675	$ -	$ -	$ 101,675
13	371	Other Equipment	DEM	$ -	$ -	$ -	$ -
14		Total Transmission Plant		$ 48,254,659	$ -	$ 48,152,984	$ 101,675
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 1,682,306	$ 1,031,838	$ 650,468	$ -
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ 19,533	$ 8,458	$ 11,076	$ -
19	375	Structures and Improvements	DIS376-379-ALL	$ 305,151	$ 187,164	$ 117,987	$ -
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 312,570,914	$ 204,927,048	$ 107,643,866	$ -
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
22	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
23	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 14,880,562	$ -	$ 14,880,562	$ -
24	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ 632,107	$ -	$ 632,107	$ -
25	378	Odorization Tank	COM	$ 207,194	$ -	$ -	$ 207,194
26	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 6,660,931	$ -	$ 6,660,931	$ -
27	379	Odorization Tank	COM	$ 765,618	$ -	$ -	$ 765,618
28	380	Services - Allocated	CUS	$ 191,939,948	$ 191,939,948	$ -	$ -
29	380	Services - Directly Assigned	CUS	$ 916,397	$ 916,397	$ -	$ -
30	381	Meters - Allocated	CUS	$ 58,670,292	$ 58,670,292	$ -	$ -
31	381	Meters - Directly Assigned	CUS	$ 147,452	$ 147,452	$ -	$ -
32	382	Meter Installations	CUS	$ 93,748	$ 93,748	$ -	$ -
33	383	House Regulators - Allocated	CUS	$ 15,318,721	$ 15,318,721	$ -	$ -
34	383	House Regulators - Directly Assigned	CUS	$ 92,302	$ 92,302	$ -	$ -
35	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 17,084,299	$ -	$ 17,084,299	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Distribution Plant (Cont'd)					
36	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ 330,071	$ -	$ 330,071	$ -
37	386	Other Property - Customer Premises	CUS	$ 638,227	$ 638,227	$ -	$ -
38	387	Other Equipment	DIS376-379-ALL	$ -	$ -	$ -	$ -
39		Total Distribution Plant		$ 628,328,837	$ 476,571,818	$ 150,784,206	$ 972,813
40							
41		**General Plant**					
42	389	Land & Land Rights	GENPLT	$ 517,798	$ 440,422	$ 76,880	$ 496
43	390	Structures & Improvements	GENPLT	$ 11,376,233	$ 9,434,114	$ 1,929,669	$ 12,450
44	391	Office Furniture and Equipment	GENPLT	$ 31,931,891	$ 31,328,215	$ 599,807	$ 3,870
45	392	Transportation Equipment	GENPLT	$ 10,613,209	$ 8,049,855	$ 2,546,922	$ 16,432
46	393	Stores Equipment	GENPLT	$ 30,503	$ 23,136	$ 7,320	$ 47
47	394	Tools, Shop & Garage - Allocated	GENPLT	$ 6,631,900	$ 5,031,542	$ 1,590,099	$ 10,259
48	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ 11,690	$ 5,860	$ 5,830	$ -
49	394	Odorization Tank	COM	$ 25,769	$ -	$ -	$ 25,769
50	395	CNG Equipment	GENPLT	$ -	$ -	$ -	$ -
51	396	Major Work Equipment	GENPLT	$ 2,380,590	$ 1,805,619	$ 571,286	$ 3,686
52	397	Communication Equipment - Allocated	GENPLT	$ 26,088,838	$ 19,917,979	$ 6,131,302	$ 39,557
53	397	Communication Equipment - Dir. Assn.	GENPLT	$ 48,893	$ 24,507	$ 24,385	$ -
54	398	Miscellaneous General Plant	GENPLT	$ -	$ -	$ -	$ -
55		Total General Plant		$ 89,657,313	$ 76,061,248	$ 13,483,501	$ 112,565
56							
57		Total Plant in Service		$ 767,273,792	$ 553,378,080	$ 212,707,059	$ 1,188,653
58							
59		**Depreciation & Amortization Reserve**					
60	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (486,283)	$ (385,157)	$ (100,039)	$ (1,088)
61	325-371	Transmission Plant	DEM	$ (3,240,665)	$ -	$ (3,240,665)	$ -
62	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (97,807,490)	$ (77,467,660)	$ (20,121,060)	$ (218,771)
63	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ (6,316)	$ (2,735)	$ (3,581)	$ -
64	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ (784,772)	$ (379,780)	$ (404,992)	$ -
65	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ (34,385)	$ -	$ (34,385)	$ -
66	380	Services - Directly Assigned	CUS	$ (158,249)	$ (158,249)	$ -	$ -
67	381	Meters - Directly Assigned	CUS	$ (47,576)	$ (47,576)	$ -	$ -
68	383	House Regulators - Directly Assigned	CUS	$ (15,489)	$ (15,489)	$ -	$ -
69	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ (36,930)	$ -	$ (36,930)	$ -
70	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (28,040,510)	$ (24,575,931)	$ (3,435,034)	$ (29,546)
71	389-398	General Plant - Directly Assigned	GEN-DARES	$ (19,685)	$ (9,867)	$ (9,818)	$ -
72		Total Depreciation & Amortization Reserve		$ (130,678,349)	$ (103,042,442)	$ (27,386,502)	$ (249,405)

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
73							
74		Net Plant in Service		$ 636,595,444	$ 450,335,638	$ 185,320,557	$ 939,248
75							
76		Customer Deposits	CUS	$ (7,838,323)	$ (7,838,323)	$ -	$ -
77							
78		Customer Advances	MAINS/SVCS	$ (3,132,466)	$ (2,455,339)	$ (677,127)	$ -
79							
80		Accumulated Deferred Income Taxes	TOTPLT	$ (50,432,867)	$ (36,373,513)	$ (13,981,224)	$ (78,130)
81							
82		Excess Deferred Income Taxes	TOTPLT	$ (14,871,247)	$ (10,725,535)	$ (4,122,673)	$ (23,038)
83							
84		Materials and Supplies	TOTPLT	$ 5,675,575	$ 4,093,374	$ 1,573,408	$ 8,793
85							
86		Prepayments	OPEXP	$ 3,292,141	$ 2,688,427	$ 560,256	$ 43,458
87							
88		Pension & FAS 106 Regulatory Asset	OPEXP	$ 20,010,546	$ 16,341,006	$ 3,405,391	$ 264,148
89							
90		DIMP Deferrals	OPEXP	$ 1,843,921	$ 1,505,782	$ 313,798	$ 24,341
91							
92		Regulatory Assets	OPEXP	$ 1,788,715	$ 1,460,700	$ 304,403	$ 23,612
93							
94		Cash Working Capital	OPEXP	$ (3,535,483)	$ (2,887,145)	$ (601,668)	$ (46,670)
95							
96		Total Rate Base		$ 589,395,955	$ 416,145,073	$ 172,095,122	$ 1,155,761

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Transmission & Distribution Operations Exp.**					
2	814-866	Transmission Expenses	DEM	$ 1,708,777	$ -	$ 1,708,777	$ -
3	8700	Operation Supervision & Engineering	DIS871-879	$ 921,752	$ 764,375	$ 135,275	$ 22,102
4	8710	Distribution Load Dispatch	COM	$ 228,149	$ -	$ -	$ 228,149
5	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 4,295,976	$ 3,379,375	$ 916,602	$ -
6	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ 53,575	$ 29,955	$ 23,620	$ -
7	8740	Odorization	COM	$ 1,545	$ -	$ -	$ 1,545
8	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 347,458	$ -	$ 347,458	$ -
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ 17,235	$ -	$ 17,235	$ -
10	8750	Odorization	COM	$ 58,281	$ -	$ -	$ 58,281
11	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 27,483	$ -	$ 27,483	$ -
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ 531	$ -	$ 531	$ -
13	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 63,441	$ -	$ 63,441	$ -
14	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 4,331,875	$ 4,331,875	$ -	$ -
15	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ 14,037	$ 14,037	$ -	$ -
16	8780	Odorization	COM	$ 56	$ -	$ -	$ 56
17	8790	Customer Installation Expenses	CUS	$ 134,987	$ 134,987	$ -	$ -
18	8800	Other Expenses	DIS871-879	$ 860,384	$ 713,485	$ 126,269	$ 20,631
19	8810	Rents	DIS871-879	$ 61,075	$ 50,647	$ 8,963	$ 1,464
20	8820	Corporate & Div. Exp.	DEM	$ -	$ -	$ -	$ -
21		Total Transmission & Distribution Oper. Exp.		$ 13,126,616	$ 9,418,736	$ 3,375,653	$ 332,228
22							
23		**Distribution Maintenance Expenses**					
24	8850	Maintenance Supervision and Engineering	DIS887-893	$ 24,613	$ 14,988	$ 9,625	$ -
25	8860	Structures and Improvements	DIS887-893	$ 504,182	$ 307,020	$ 197,163	$ -
26	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 3,192,611	$ 2,093,133	$ 1,099,479	$ -
27	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ 54,881	$ 26,559	$ 28,322	$ -
28	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 506,952	$ -	$ 506,952	$ -
29	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ 25,946	$ -	$ 25,946	$ -
30	8890	Odorization	COM	$ 103,847	$ -	$ -	$ 103,847
31	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 387,292	$ -	$ 387,292	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
32		**Distribution Maintenance Expenses (Cont'd)**					
33	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ 7,483	$ -	$ 7,483	$ -
34	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 6,436	$ -	$ 6,436	$ -
35	8920	Maintenance of Services - Allocated	CUS	$ 1,085,912	$ 1,085,912	$ -	$ -
36	8920	Maintenance of Services - Directly Assn.	CUS	$ 5,185	$ 5,185	$ -	$ -
37	8930	Main. of Meters & House Reg. - Allocated	CUS	$ -	$ -	$ -	$ -
38	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ -	$ -	$ -	$ -
39	8940	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
40	8950	Clearing - Meter Shop - Small Meters	CUS	$ -	$ -	$ -	$ -
41	8960	Clearing - Meter Shop - Large Meters	CUS	$ -	$ -	$ -	$ -
42		Total Distribution Maintenance Expenses		$ 5,905,339	$ 3,532,796	$ 2,268,696	$ 103,847
43							
44		Total Operations & Maintenance Expenses		$ 19,031,955	$ 12,951,532	$ 5,644,349	$ 436,075
45							
46		**Customer Accounts Expenses**					
47	9010	Supervision	CUS	$ 115,800	$ 115,800	$ -	$ -
48	9020	Meter Reading Expense	CUS	$ 616,390	$ 616,390	$ -	$ -
49	9030	Customer Accounting	CUS	$ 3,123,314	$ 3,123,314	$ -	$ -
50	9040	Bad Debts (includes gross up)	CUS	$ 972,692	$ 972,692	$ -	$ -
51	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 417,099	$ 417,099	$ -	$ -
52		Total Customer Accounts Expenses		$ 5,245,295	$ 5,245,295	$ -	$ -
53							
54		**Customer Information Expenses**					
55	9070	Supervision	CUS	$ -	$ -	$ -	$ -
56	9080	Customer Assistance	CUS	$ 671,047	$ 671,047	$ -	$ -
57	9090	Informational and Instructional Advertising	CUS	$ 48,036	$ 48,036	$ -	$ -
58	9100	Customer Service & Informational Svc.	CUS	$ -	$ -	$ -	$ -
59		Total Customer Information Expenses		$ 719,083	$ 719,083	$ -	$ -
60							

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
61		**Sales and Advertising Expenses**					
62	9110	Supervision	CUS	$ -	$ -	$ -	$ -
63	9120	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
64	9130	Advertising	CUS	$ 4,501	$ 4,501	$ -	$ -
65	9140	Employee Sales Referrals	CUS	$ -	$ -	$ -	$ -
66	9163	Misc. Gas Sales Expense	CUS	$ -	$ -	$ -	$ -
67		Total Sales and Advertising Expenses		$ 4,501	$ 4,501	$ -	$ -
68							
69		**Administrative & General Expenses**					
70	920-940	Administrative & General Expenses	ADMINGEN	$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631
71		Total Administrative & General Expenses		$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631
72							
73		**Depreciation and Amortization Expense**					
74	301-303	Intangible Plant	PLT301-03	$ 16,818	$ 12,130	$ 4,662	$ 26
75	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -
76	366	Meas. and Reg. Station Structures	PLT366	$ -	$ -	$ -	$ -
77	367	Transmission Mains	PLT367	$ 1,142,945	$ -	$ 1,142,945	$ -
78	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
79	369	Measuring and Reg. Station Equipment	PLT369	$ 107,007	$ -	$ 107,007	$ -
80	371	Other Equipment	PLT371	$ -	$ -	$ -	$ -
81	375	Structures and Improvements	PLT375	$ 10,650	$ 6,532	$ 4,118	$ -
82	376	Mains - Allocated	MAINS-ALLOC	$ 8,306,857	$ 5,446,123	$ 2,860,734	$ -
83	376	Mains - Directly Assigned	MAINS-DA	$ 128,866	$ 62,363	$ 66,503	$ -
84	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
85	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 333,435	$ -	$ 333,435	$ -
86	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ 14,159	$ -	$ 14,159	$ -
87	378	Odorization Tank	COM	$ 4,641	$ -	$ -	$ 4,641
88	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 135,900	$ -	$ 135,900	$ -
89	379	Odorization Tank	COM	$ 15,619	$ -	$ -	$ 15,619
90	380	Services - Allocated	PLT380	$ 6,216,101	$ 6,216,101	$ -	$ -
91	380	Services - Directly Assigned	PLT380	$ 29,508	$ 29,508	$ -	$ -
92	381	Meters - Allocated	PLT381	$ 2,388,003	$ 2,388,003	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
93		**Depreciation and Amortization Expense (Cont'd)**					
94	381	Meters - Directly Assigned	PLT381	$ 6,001	$ 6,001	$ -	$ -
95	382	Meter Installations	PLT382	$ -	$ -	$ -	$ -
96	383	House Regulators - Allocated	PLT383	$ 542,385	$ 542,385	$ -	$ -
97	383	House Regulators - Directly Assigned	PLT383	$ 3,267	$ 3,267	$ -	$ -
98	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 406,969	$ -	$ 406,969	$ -
99	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ 7,856	$ -	$ 7,856	$ -
100	386	Other Property - Customer Premises	PLT386	$ 90,947	$ 90,947	$ -	$ -
101	387	Other Equipment	PLT387	$ -	$ -	$ -	$ -
102	389-398	General Plant - Allocated	GENDEP	$ 5,484,769	$ 4,838,866	$ 640,070	$ 5,833
103	389-398	General Plant - Directly Assigned	GENDEP	$ 4,039	$ 3,563	$ 471	$ 4
104	389-398	General Plant - Odorization	COM	$ 1,718	$ -	$ -	$ 1,718
105	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ 237,913	$ 194,285	$ 40,488	$ 3,141
106		Total Depreciation and Amortization Expense		$ 25,636,372	$ 19,840,074	$ 5,765,317	$ 30,981
107							
108		**Taxes Other Than Income**					
109	4080	Payroll and Other	OPEXP	$ 2,731,498	$ 2,230,595	$ 464,846	$ 36,057
110	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 7,112,217	$ 5,145,111	$ 1,955,978	$ 11,128
111	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ 70,883	$ 35,530	$ 35,353	$ -
112	4080	Revenue Related (includes gross up)	CUS	$ 97,463	$ 97,463	$ -	$ -
113		Total Taxes Other Than Income		$ 10,012,061	$ 7,508,699	$ 2,456,177	$ 47,185
114							
115	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ (14,455)	$ (7,110)	$ (7,345)	$ -
116	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (1,408,211)	$ (999,302)	$ (406,810)	$ (2,099)
117							
118	4310	Interest on Customer Deposits	CUS	$ 4,703	$ 4,703	$ -	$ -
119							
120		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 45,326,077	$ 32,164,519	$ 13,093,996	$ 67,562
121		Required Return - Directly Assigned	RB-DA	$ 465,262	$ 228,851	$ 236,411	$ -
122		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 9,531,958	$ 6,764,116	$ 2,753,634	$ 14,208
123		Income Taxes - Directly Assigned	RB-DA	$ 97,843	$ 48,127	$ 49,717	$ -
124		Total Cost of Service Before Revenue Credits		$ 140,460,903	$ 107,044,548	$ 32,587,813	$ 828,542

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7			Total Transmission Plant	$ 48,254,659	$ -	$ 48,152,984	$ 101,675
8			Total Distribution Plant	$ 628,328,837	$ 476,571,818	$ 150,784,206	$ 972,813
9			Total General Plant	$ 89,657,313	$ 76,061,248	$ 13,483,501	$ 112,565
10			Total Non-Intangible Plant	$ 766,240,809	$ 552,633,066	$ 212,420,691	$ 1,187,053
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.72123	0.27722	0.00155
12							
13	376		Distribution Mains-Allocated	$ 312,570,914	$ 204,927,048	$ 107,643,866	$ -
14	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 14,880,562	$ -	$ 14,880,562	$ -
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 6,660,931	$ -	$ 6,660,931	$ -
17			Total Accounts 376-379	$ 334,112,407	$ 204,927,048	$ 129,185,359	$ -
18		DIS376-379-All	Accounts 376-379 Allocated Factor	1.00000	0.61335	0.38665	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ 632,107	$ -	$ 632,107	$ -
22			Total Accounts 376-379 Directly Assigned	$ 6,005,171	$ 2,600,224	$ 3,404,946	$ -
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	1.00000	0.43300	0.56700	0.00000
24							
25	376		Mains-Allocated	$ 312,570,914	$ 204,927,048	$ 107,643,866	$ -
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.65562	0.34438	0.00000
27							
28	376		Mains-Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.48394	0.51606	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ 6,289,461	$ 3,516,621	$ 2,772,839	$ -
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	1.00000	0.55913	0.44087	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 504,510,861	$ 396,866,996	$ 107,643,866	$ -
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.78664	0.21336	0.00000
36							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
37	376/380		Mains and Services	$ 510,800,322	$ 400,383,617	$ 110,416,705	$ -
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.78384	0.21616	0.00000
39							
40	374-387		Total Distribution Plant	$ 628,328,837	$ 476,571,818	$ 150,784,206	$ 972,813
41		DISPLT	Distribution Plant Factor	1.00000	0.75848	0.23998	0.00155
42							
43	374		Land & Land Rights - Directly Assigned	$ 19,533	$ 8,458	$ 11,076	$ -
44	376		Mains - Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ 632,107	$ -	$ 632,107	$ -
46	380		Service - Directly Assigned	$ 916,397	$ 916,397	$ -	$ -
47	381		Meters - Directly Assigned	$ 147,452	$ 147,452	$ -	$ -
48	383		House Regulators - Directly Assigned	$ 92,302	$ 92,302	$ -	$ -
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ 330,071	$ -	$ 330,071	$ -
50			Total Distribution Plant - Directly Assigned	$ 7,510,927	$ 3,764,833	$ 3,746,093	$ -
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	1.00000	0.50125	0.49875	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (47,006)	$ (28,831)	$ (18,175)	$ -
54	375		Structures and Improvements	$ (149,046)	$ (91,417)	$ (57,629)	$ -
55	376		Distribution Mains - Allocated	$ (43,947,969)	$ (28,813,070)	$ (15,134,899)	$ -
56	377		Compressor Station Equipment	$ -	$ -		
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (1,013,107)	$ -	$ (1,013,107)	$ -
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (747,871)	$ -	$ (747,871)	$ -
59	378-379		Odorization Tank	$ (218,771)	$ -	$ -	$ (218,771)
60	380		Services - Allocated	$ (26,297,732)	$ (26,297,732)	$ -	$ -
61	381		Meters - Allocated	$ (16,835,649)	$ (16,835,649)	$ -	$ -
62	382		Meter Installations	$ (8,293)	$ (8,293)	$ -	$ -
63	383		House Regulators - Allocated	$ (5,122,147)	$ (5,122,147)	$ -	$ -
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (2,978,842)	$ -	$ (2,978,842)	$ -
65	386		Other Property-Customer Premises	$ (441,058)	$ (270,522)	$ (170,536)	$ -
66	387		Other Equipment	$ -	$ -	$ -	$ -
67			Total Distribution Plant - Allocated Reserve	$ (97,807,490)	$ (77,467,660)	$ (20,121,060)	$ (218,771)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.79204	0.20572	0.00224
69							
70	376		Distribution Mains - Directly Assigned	$ (784,772)	$ (379,780)	$ (404,992)	$ -
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	1.00000	0.48394	0.51606	0.00000
72							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
73			General Plant - Allocated Reserve	$ (28,040,510)	$ (24,575,931)	$ (3,435,034)	$ (29,546)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.87644	0.12250	0.00105
75							
76			General Plant - Directly Assigned Reserve	$ (19,685)	$ (9,867)	$ (9,818)	$ -
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	1.00000	0.50125	0.49875	0.00000
78							
79			Total Plant - Allocated	$ 759,702,283	$ 549,582,880	$ 208,930,750	$ 1,188,653
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.72342	0.27502	0.00156
81							
82			Total Plant - Directly Assigned	$ 7,571,509	$ 3,795,200	$ 3,776,309	$ -
83		TPLT-DA	Total Plant Directly Assigned Factor	$ 1.00000	$ 0.50125	$ 0.49875	$ -
84							
85			Total Plant	$ 767,273,792	$ 553,378,080	$ 212,707,059	$ 1,188,653
86		TOTPLT	Total Plant Factor	1.00000	0.72123	0.27722	0.00155
87							
88			Total Operations and Maintenance Expenses	$ 19,031,955	$ 12,951,532	$ 5,644,349	$ 436,075
89			Total Customer Accounts Expenses	$ 5,245,295	$ 5,245,295	$ -	$ -
90			Total Customer Service Expenses	$ 719,083	$ 719,083	$ -	$ -
91			Total Sales and Advertising Expenses	$ 4,501	$ 4,501	$ -	$ -
92			Administrative and General Expenses	$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631
93			Total Operating Expenses	$ 50,809,292	$ 41,491,870	$ 8,646,717	$ 670,705
94		OPEXP	Operating Expense Factor	1.00000	0.81662	0.17018	0.01320
95							
96	8710		Distribution Load Dispatch	$ 228,149	$ -	$ -	$ 228,149
97	8740		Mains and Services Expenses - Allocated	$ 4,295,976	$ 3,379,375	$ 916,602	$ -
98	8740		Mains and Services Expenses - Dir. Assn.	$ 53,575	$ 29,955	$ 23,620	$ -
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 347,458	$ -	$ 347,458	$ -
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ 17,235	$ -	$ 17,235	$ -
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 27,483	$ -	$ 27,483	$ -
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ 531	$ -	$ 531	$ -
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 63,441	$ -	$ 63,441	$ -
104	8780		Meter and House Regulator Exp.- Allocated	$ 4,331,875	$ 4,331,875	$ -	$ -
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ 14,037	$ 14,037	$ -	$ -
106	8790		Customer Installation Expenses	$ 134,987	$ 134,987	$ -	$ -
107			Total Accounts 871-879	$ 9,514,748	$ 7,890,230	$ 1,396,369	$ 228,149
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.82926	0.14676	0.02398
109							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
110	8870		Maintenance of Mains-Allocated	$ 3,192,611	$ 2,093,133	$ 1,099,479	$ -
111	8870		Maintenance of Mains - Directly Assn.	$ 54,881	$ 26,559	$ 28,322	$ -
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 506,952	$ -	$ 506,952	$ -
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ 25,946	$ -	$ 25,946	$ -
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 387,292	$ -	$ 387,292	$ -
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ 7,483	$ -	$ 7,483	$ -
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 6,436	$ -	$ 6,436	$ -
117	8920		Maintenance of Services - Allocated	$ 1,085,912	$ 1,085,912	$ -	$ -
118	8920		Maintenance of Services - Directly Assn.	$ 5,185	$ 5,185	$ -	$ -
119	8930		Main. of Meters & House Reg. - Allocated	$ -	$ -	$ -	$ -
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ -	$ -	$ -	$ -
121			Total Accounts 887-893	$ 5,272,697	$ 3,210,788	$ 2,061,909	$ -
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.60895	0.39105	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 19,031,955	$ 12,951,532	$ 5,644,349	$ 436,075
125			Total Customer Accounts Expenses	$ 5,245,295	$ 5,245,295	$ -	$ -
126			Total Customer Service Expenses	$ 719,083	$ 719,083	$ -	$ -
127			Total Sales and Advertising Expenses	$ 4,501	$ 4,501	$ -	$ -
128			Total Operating Exp. Without A&G Expenses	$ 25,000,834	$ 18,920,411	$ 5,644,349	$ 436,075
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.75679	0.22577	0.01744
130							
131	920-932		Administrative and General Expenses	$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.87458	0.11633	0.00909
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	$ 44,997,719	$ -	$ 44,997,719	$ -
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	$ 2,964,422	$ -	$ 2,964,422	$ -
144		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
145							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
146	371		Other Equipment	$ -	$ -	$ -	$ -
147		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
148							
149	375		Structures and Improvements	$ 305,151	$ 187,164	$ 117,987	$ -
150		PLT375	Structures and Improvements Factor	1.00000	0.61335	0.38665	0.00000
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 14,880,562	$ -	$ 14,880,562	$ -
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	$ 6,660,931	$ -	$ 6,660,931	$ -
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services - Allocated	$ 191,939,948	$ 191,939,948	$ -	$ -
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters - Allocated	$ 58,670,292	$ 58,670,292	$ -	$ -
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
163							
164	382		Meter Installations	$ 93,748	$ 93,748	$ -	$ -
165		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000
166							
167	383		House Regulators - Allocated	$ 15,318,721	$ 15,318,721	$ -	$ -
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 17,084,299	$ -	$ 17,084,299	$ -
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	$ 745,015	$ 286,368	$ 1,600
180		PLT301-03	Intangible Plant	1.00000	0.72123	0.27722	0.00155
181							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
182	389-398		General Plant Depreciation Expense	$ 5,490,525	$ 4,843,945	$ 640,742	$ 5,839
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.88224	0.11670	0.00106
184							
185			Net Plant Directly Assigned	$ 6,468,109	$ 3,181,505	$ 3,286,604	$ -
186		NETPLT-DA	Net Plant Directly Assigned Factor	1.00000	0.49188	0.50812	0.00000
187							
188			Net Plant Allocated	$ 630,127,335	$ 447,154,133	$ 182,033,953	$ 939,248
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.70963	0.28888	0.00149
190							
191			Rate Base Directly Assigned	$ 5,988,540	$ 2,945,617	$ 3,042,923	$ -
192		RB-DA	Rate Base Directly Assigned Factor	1.00000	0.49188	0.50812	0.00000
193							
194			Rate Base Allocated	$ 583,407,416	$ 414,000,509	$ 168,537,298	$ 869,609
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.70963	0.28888	0.00149
196							
197			Required Return	$ 45,791,339	$ 32,393,370	$ 13,330,407	$ 67,562
198		REQRET	Required Return Factor	1.00000	0.70741	0.29111	0.00148
199							
200			Non-Plant Rate Base	$ (47,199,488)	$ (34,190,566)	$ (13,225,435)	$ 216,512
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.72438	0.28020	-0.00459

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	301-303	**Intangible Plant**													
2		Customer	NONINCUS	$ 745,015	$ 698,691	$ 42,726	$ 100	$ 3,180	$ 103	$ 49	$ 54	$ 37	$ 17	$ 10	$ 47
3		Demand	NONINDEM	$ 286,368	$ 195,453	$ 49,891	$ 965	$ 19,455	$ 716	$ 418	$ 4,479	$ 2,397	$ 1,811	$ 1,574	$ 9,209
4		Commodity	COM	$ 1,600	$ 928	$ 348	$ 10	$ 77	$ 2	$ 11	$ 61	$ 49	$ 16	$ 38	$ 59
5		Total Intangible Plant		$ 1,032,983	$ 895,071	$ 92,965	$ 1,076	$ 22,712	$ 822	$ 478	$ 4,595	$ 2,482	$ 1,845	$ 1,622	$ 9,315
6	365-371	**Transmission Plant**													
7		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	DEM	$ 48,152,984	$ 32,865,460	$ 8,389,153	$ 162,323	$ 3,271,451	$ 120,385	$ 70,261	$ 753,221	$ 403,000	$ 304,562	$ 264,604	$ 1,548,563
9		Commodity	COM	$ 101,675	$ 58,972	$ 22,106	$ 648	$ 4,865	$ 156	$ 703	$ 3,893	$ 3,102	$ 1,037	$ 2,440	$ 3,754
10		Total Transmission Plant		$ 48,254,659	$ 32,924,431	$ 8,411,260	$ 162,971	$ 3,276,315	$ 120,542	$ 70,964	$ 757,114	$ 406,102	$ 305,599	$ 267,044	$ 1,552,317
11		**Distribution Plant**													
12	374	**Land & Land Rights - Allocated**													
13		Customer	376-379CUS	$ 1,031,838	$ 955,555	$ 58,434	$ 137	$ 4,349	$ 141	$ 67	$ 74	$ 51	$ 24	$ 13	$ 12,993
14		Demand	DEM	$ 650,468	$ 443,958	$ 113,324	$ 2,193	$ 44,192	$ 1,626	$ 949	$ 10,175	$ 5,444	$ 4,114	$ 3,574	$ 20,919
15		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16		Total Land & Land Rights - Allocated		$ 1,682,306	$ 1,399,513	$ 171,758	$ 2,329	$ 48,541	$ 1,768	$ 1,016	$ 10,249	$ 5,494	$ 4,138	$ 3,588	$ 33,911
17	374	**Land & Land Rights - DA**													
18		Customer	CUS-DA	$ 8,458	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,458
19		Demand	DEM-DA	$ 11,076	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,076
20		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Total Land & Rights - DA		$ 19,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,533
22	375	**Structures and Improvements**													
23		Customer	376-379CUS	$ 187,164	$ 173,327	$ 10,599	$ 25	$ 789	$ 26	$ 12	$ 13	$ 9	$ 4	$ 2	$ 2,357
24		Demand	DEM	$ 117,987	$ 80,529	$ 20,556	$ 398	$ 8,016	$ 295	$ 172	$ 1,846	$ 987	$ 746	$ 648	$ 3,794
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Total Structures and Improvements		$ 305,151	$ 253,856	$ 31,155	$ 423	$ 8,805	$ 321	$ 184	$ 1,859	$ 997	$ 751	$ 651	$ 6,151
27	376	**Distribution Mains-Allocated**													
28		Customer	CUS	$ 204,927,048	$ 192,184,905	$ 11,752,444	$ 27,496	$ 874,746	$ 28,456	$ 13,550	$ 14,905	$ 10,163	$ 4,743	$ 2,710	$ 12,929
29		Demand	DEM	$ 107,643,866	$ 73,469,282	$ 18,753,581	$ 362,866	$ 7,313,183	$ 269,116	$ 157,066	$ 1,683,792	$ 900,888	$ 680,835	$ 591,511	$ 3,461,745
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31		Total Distribution Mains - Allocated		$ 312,570,914	$ 265,654,187	$ 30,506,025	$ 390,362	$ 8,187,929	$ 297,572	$ 170,616	$ 1,698,698	$ 911,051	$ 685,578	$ 594,221	$ 3,474,674
32		**Distribution Mains - Directly Assn.**													
33		Customer	CUS-DA	$ 2,600,224	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,600,224
34		Demand	DEM-DA	$ 2,772,839	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,772,839
35		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Distribution Mains - Dir. Assn.		$ 5,373,064	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,373,064
37	377	**Compressor Station Equipment**													
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**													
43		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	DEM	$ 14,880,562	$ 10,156,307	$ 2,592,473	$ 50,162	$ 1,010,966	$ 37,202	$ 21,713	$ 232,765	$ 124,538	$ 94,118	$ 81,770	$ 478,548
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 14,880,562	$ 10,156,307	$ 2,592,473	$ 50,162	$ 1,010,966	$ 37,202	$ 21,713	$ 232,765	$ 124,538	$ 94,118	$ 81,770	$ 478,548
47	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**													
48		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM-DA	$ 632,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 632,107
50		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 632,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 632,107
52	378	**Odorization Tank**													
53		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ 207,194	$ 120,173	$ 45,049	$ 1,320	$ 9,914	$ 319	$ 1,432	$ 7,933	$ 6,322	$ 2,113	$ 4,972	$ 7,649
56		Total Odorization Tank		$ 207,194	$ 120,173	$ 45,049	$ 1,320	$ 9,914	$ 319	$ 1,432	$ 7,933	$ 6,322	$ 2,113	$ 4,972	$ 7,649

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
57		**Distribution Plant (Cont'd)**													
58	379	**Meas. & Reg. Station - City Gate**													
59		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	DEM	$ 6,660,931	$ 4,546,231	$ 1,160,459	$ 22,454	$ 452,535	$ 16,653	$ 9,719	$ 104,192	$ 55,746	$ 42,130	$ 36,602	$ 214,210
61		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62		Total Meas. & Reg. Equip.-City Gate		$ 6,660,931	$ 4,546,231	$ 1,160,459	$ 22,454	$ 452,535	$ 16,653	$ 9,719	$ 104,192	$ 55,746	$ 42,130	$ 36,602	$ 214,210
63	379	**Odorization Tank**													
64		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		Commodity	COM	$ 765,618	$ 444,059	$ 166,463	$ 4,878	$ 36,632	$ 1,178	$ 5,292	$ 29,313	$ 23,359	$ 7,807	$ 18,372	$ 28,265
67		Total Odorization Tank		$ 765,618	$ 444,059	$ 166,463	$ 4,878	$ 36,632	$ 1,178	$ 5,292	$ 29,313	$ 23,359	$ 7,807	$ 18,372	$ 28,265
68	380	**Services - Allocated**													
69		Customer	SERCUS-ALL	$ 191,939,948	$ 176,017,191	$ 14,675,429	$ 51,771	$ 1,084,355	$ 36,718	$ 13,369	$ 28,011	$ 19,098	$ 8,913	$ 5,093	$ -
70		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72		Total Services - Allocated		$ 191,939,948	$ 176,017,191	$ 14,675,429	$ 51,771	$ 1,084,355	$ 36,718	$ 13,369	$ 28,011	$ 19,098	$ 8,913	$ 5,093	$ -
73	380	**Services-Directly Assigned**													
74		Customer	CUS-DA	$ 916,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 916,397
75		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77		Total Services - Directly Assigned		$ 916,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 916,397
78	381	**Meters - Allocated**													
79		Customer	METCUS-ALL	$ 58,670,292	$ 50,706,813	$ 6,459,866	$ 62,112	$ 1,238,955	$ 67,297	$ 24,323	$ 50,759	$ 34,711	$ 16,199	$ 9,256	$ -
80		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82		Total Meters - Allocated		$ 58,670,292	$ 50,706,813	$ 6,459,866	$ 62,112	$ 1,238,955	$ 67,297	$ 24,323	$ 50,759	$ 34,711	$ 16,199	$ 9,256	$ -
83	381	**Meters-Directly Assigned**													
84		Customer	CUS-DA	$ 147,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,452
85		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87		Total Meters - Directly Assigned		$ 147,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,452
88	382	**Meter Installations**													
89		Customer	METCUS-ALL	$ 93,748	$ 81,023	$ 10,322	$ 99	$ 1,980	$ 108	$ 39	$ 81	$ 55	$ 26	$ 15	$ -
90		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92		Total Meter Installations		$ 93,748	$ 81,023	$ 10,322	$ 99	$ 1,980	$ 108	$ 39	$ 81	$ 55	$ 26	$ 15	$ -
93	383	**House Regulators - Allocated**													
94		Customer	REGCUS-ALL	$ 15,318,721	$ 12,971,782	$ 1,914,208	$ 16,797	$ 360,998	$ 17,916	$ 7,404	$ 13,574	$ 9,255	$ 4,319	$ 2,468	$ -
95		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97		Total House Regulators - Allocated		$ 15,318,721	$ 12,971,782	$ 1,914,208	$ 16,797	$ 360,998	$ 17,916	$ 7,404	$ 13,574	$ 9,255	$ 4,319	$ 2,468	$ -
98	383	**House Regulators - Directly Assigned**													
99		Customer	CUS-DA	$ 92,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,302
100		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102		Total House Regulators - Dir. Assigned		$ 92,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,302
103	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**													
104		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105		Demand	NRDEM	$ 17,084,299	$ -	$ 9,375,148	$ 181,401	$ 3,655,951	$ 134,535	$ 78,519	$ 841,749	$ 450,365	$ 340,358	$ 295,704	$ 1,730,569
106		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 17,084,299	$ -	$ 9,375,148	$ 181,401	$ 3,655,951	$ 134,535	$ 78,519	$ 841,749	$ 450,365	$ 340,358	$ 295,704	$ 1,730,569
108	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**													
109		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110		Demand	DEM-DA	$ 330,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,071
111		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ 330,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,071
113	386	**Other Prop.-Customer Premises**													
114		Customer	CUS	$ 638,227	$ 598,543	$ 36,602	$ 86	$ 2,724	$ 89	$ 42	$ 46	$ 32	$ 15	$ 8	$ 40
115		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117		Total Other Prop.- Cust. Premises		$ 638,227	$ 598,543	$ 36,602	$ 86	$ 2,724	$ 89	$ 42	$ 46	$ 32	$ 15	$ 8	$ 40
118	387	**Other Equipment**													
119		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
123		**Total Distribution Plant**													
124		Customer		$ 476,571,818	$ 433,689,139	$ 34,917,904	$ 158,521	$ 3,568,896	$ 150,751	$ 58,807	$ 107,465	$ 73,374	$ 34,241	$ 19,566	$ 3,793,153
125		Demand		$ 150,784,206	$ 88,696,307	$ 32,015,540	$ 619,473	$ 12,484,843	$ 459,427	$ 268,138	$ 2,874,519	$ 1,537,969	$ 1,162,301	$ 1,009,810	$ 9,655,878
126		Commodity		$ 972,813	$ 564,231	$ 211,512	$ 6,198	$ 46,546	$ 1,497	$ 6,725	$ 37,246	$ 29,681	$ 9,920	$ 23,344	$ 35,914
127		Total Distribution Plant		$ 628,328,837	$ 522,949,678	$ 67,144,956	$ 784,192	$ 16,100,284	$ 611,675	$ 333,669	$ 3,019,229	$ 1,641,024	$ 1,206,463	$ 1,052,720	$ 13,484,945
128		**General Plant**													
129		**General Plant - Allocated**													
130		Customer	GENPTCUS	$ 76,030,881	$ 70,120,801	$ 5,037,448	$ 18,642	$ 461,508	$ 18,106	$ 7,463	$ 12,028	$ 8,210	$ 3,831	$ 2,189	$ 340,653
131		Demand	DISPLTDEM	$ 13,453,285	$ 7,913,672	$ 2,856,494	$ 55,271	$ 1,113,924	$ 40,991	$ 23,924	$ 256,471	$ 137,221	$ 103,703	$ 90,097	$ 861,518
132		Commodity	COM	$ 112,565	$ 65,288	$ 24,474	$ 717	$ 5,386	$ 173	$ 778	$ 4,310	$ 3,434	$ 1,148	$ 2,701	$ 4,156
133		Total General Plant - Allocated		$ 89,596,731	$ 78,099,761	$ 7,918,417	$ 74,630	$ 1,580,818	$ 59,270	$ 32,165	$ 272,808	$ 148,865	$ 108,682	$ 94,988	$ 1,206,326
134		**Total General Plant - Directly Assigned**													
135		Customer	CUS-DA	$ 30,367	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,367
136		Demand	DEM-DA	$ 30,216	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,216
137		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138		Total General Plant - Directly Assigned		$ 60,583	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,583
139		**Total General Plant**													
140		Customer		$ 76,061,248	$ 70,120,801	$ 5,037,448	$ 18,642	$ 461,508	$ 18,106	$ 7,463	$ 12,028	$ 8,210	$ 3,831	$ 2,189	$ 371,020
141		Demand		$ 13,483,501	$ 7,913,672	$ 2,856,494	$ 55,271	$ 1,113,924	$ 40,991	$ 23,924	$ 256,471	$ 137,221	$ 103,703	$ 90,097	$ 891,734
142		Commodity		$ 112,565	$ 65,288	$ 24,474	$ 717	$ 5,386	$ 173	$ 778	$ 4,310	$ 3,434	$ 1,148	$ 2,701	$ 4,156
143		Total General Plant		$ 89,657,313	$ 78,099,761	$ 7,918,417	$ 74,630	$ 1,580,818	$ 59,270	$ 32,165	$ 272,808	$ 148,865	$ 108,682	$ 94,988	$ 1,266,909
144		**Total Plant in Service**													
145		Customer		$ 553,378,080	$ 504,508,632	$ 39,998,079	$ 177,264	$ 4,033,584	$ 168,960	$ 66,319	$ 119,547	$ 81,621	$ 38,090	$ 21,766	$ 4,164,219
146		Demand		$ 212,707,059	$ 129,670,891	$ 43,311,078	$ 838,032	$ 16,889,673	$ 621,520	$ 362,741	$ 3,888,690	$ 2,080,586	$ 1,572,378	$ 1,366,086	$ 12,105,385
147		Commodity		$ 1,188,653	$ 689,419	$ 258,440	$ 7,573	$ 56,873	$ 1,829	$ 8,217	$ 45,509	$ 36,266	$ 12,121	$ 28,523	$ 43,883
148		Total Plant in Service		$ 767,273,792	$ 634,868,941	$ 83,567,598	$ 1,022,869	$ 20,980,130	$ 792,309	$ 437,277	$ 4,053,746	$ 2,198,473	$ 1,622,589	$ 1,416,374	$ 16,313,487
149		**Depreciation & Amort. Reserve**													
150		**Intangible Plant**													
151		Customer	NONINCUS	$ (385,157)	$ (361,208)	$ (22,089)	$ (52)	$ (1,644)	$ (53)	$ (25)	$ (28)	$ (19)	$ (9)	$ (5)	$ (24)
152		Demand	NONINDEM	$ (100,039)	$ (68,279)	$ (17,429)	$ (337)	$ (6,796)	$ (250)	$ (146)	$ (1,565)	$ (837)	$ (633)	$ (550)	$ (3,217)
153		Commodity	COM	$ (1,088)	$ (631)	$ (236)	$ (7)	$ (52)	$ (2)	$ (8)	$ (42)	$ (33)	$ (11)	$ (26)	$ (40)
154		Total Intangible Plant		$ (486,283)	$ (430,118)	$ (39,754)	$ (396)	$ (8,493)	$ (305)	$ (179)	$ (1,634)	$ (890)	$ (653)	$ (581)	$ (3,282)
155		**Transmission Plant**													
156		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157		Demand	DEM	$ (3,240,665)	$ (2,211,824)	$ (564,585)	$ (10,924)	$ (220,166)	$ (8,102)	$ (4,729)	$ (50,691)	$ (27,122)	$ (20,497)	$ (17,808)	$ (104,217)
158		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
159		Total Transmission Plant		$ (3,240,665)	$ (2,211,824)	$ (564,585)	$ (10,924)	$ (220,166)	$ (8,102)	$ (4,729)	$ (50,691)	$ (27,122)	$ (20,497)	$ (17,808)	$ (104,217)
160		**Distribution Plant - Allocated**													
161		Customer	DISPLTCUS	$ (77,467,660)	$ (70,496,998)	$ (5,675,972)	$ (25,768)	$ (580,131)	$ (24,505)	$ (9,559)	$ (17,469)	$ (11,927)	$ (5,566)	$ (3,181)	$ (616,584)
162		Demand	DISPLTDEM	$ (20,121,060)	$ (11,835,879)	$ (4,272,242)	$ (82,664)	$ (1,666,012)	$ (61,307)	$ (35,781)	$ (383,584)	$ (205,231)	$ (155,101)	$ (134,752)	$ (1,288,507)
163		Commodity	COM	$ (218,771)	$ (126,887)	$ (47,566)	$ (1,394)	$ (10,467)	$ (337)	$ (1,512)	$ (8,376)	$ (6,675)	$ (2,231)	$ (5,250)	$ (8,077)
164		Total Distribution Plant - Allocated		$ (97,807,490)	$ (82,459,765)	$ (9,995,780)	$ (109,826)	$ (2,256,610)	$ (86,149)	$ (46,852)	$ (409,428)	$ (223,833)	$ (162,898)	$ (143,182)	$ (1,913,168)
165		**Distribution Plant - Dir. Assn.**													
166		Customer	CUS-DA	$ (603,828)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (603,828)
167		Demand	DEM-DA	$ (479,887)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (479,887)
168		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169		Total Distribution Plant - Dir. Assn.		$ (1,083,716)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,083,716)
170		**General Plant - Allocated**													
171		Customer	GENPTCUS	$ (24,575,931)	$ (22,665,579)	$ (1,628,286)	$ (6,026)	$ (149,176)	$ (5,852)	$ (2,412)	$ (3,888)	$ (2,654)	$ (1,238)	$ (708)	$ (110,111)
172		Demand	DISPLTDEM	$ (3,435,034)	$ (2,020,602)	$ (729,350)	$ (14,112)	$ (284,419)	$ (10,466)	$ (6,108)	$ (65,485)	$ (35,037)	$ (26,479)	$ (23,005)	$ (219,972)
173		Commodity	COM	$ (29,546)	$ (17,137)	$ (6,424)	$ (188)	$ (1,414)	$ (45)	$ (204)	$ (1,131)	$ (901)	$ (301)	$ (709)	$ (1,091)
174		Total General Plant - Allocated		$ (28,040,510)	$ (24,703,317)	$ (2,364,060)	$ (20,326)	$ (435,008)	$ (16,364)	$ (8,725)	$ (70,504)	$ (38,592)	$ (28,018)	$ (24,421)	$ (331,174)
175		**General Plant - Directly Assigned**													
176		Customer	CUS-DA	$ (9,867)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,867)
177		Demand	DEM-DA	$ (9,818)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,818)
178		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179		Total General Plant - Directly Assn.		$ (19,685)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,685)
180		**Total Depr. & Amort. Reserve**													
181		Customer		$ (103,042,442)	$ (93,523,785)	$ (7,326,346)	$ (31,846)	$ (730,951)	$ (30,411)	$ (11,997)	$ (21,384)	$ (14,600)	$ (6,813)	$ (3,893)	$ (1,340,415)
182		Demand		$ (27,386,502)	$ (16,136,584)	$ (5,583,605)	$ (108,038)	$ (2,177,394)	$ (80,125)	$ (46,764)	$ (501,325)	$ (268,226)	$ (202,709)	$ (176,114)	$ (2,105,618)
183		Commodity		$ (249,405)	$ (144,655)	$ (54,226)	$ (1,589)	$ (11,933)	$ (384)	$ (1,724)	$ (9,549)	$ (7,609)	$ (2,543)	$ (5,985)	$ (9,208)
184		Total Depr. & Amortization Reserve		$ (130,678,349)	$ (109,805,024)	$ (12,964,177)	$ (141,472)	$ (2,920,278)	$ (110,920)	$ (60,485)	$ (532,258)	$ (290,436)	$ (212,065)	$ (185,992)	$ (3,455,241)
185		**Net Plant in Service**													
186		Customer		$ 450,335,638	$ 410,984,846	$ 32,671,733	$ 145,418	$ 3,302,633	$ 138,549	$ 54,322	$ 98,162	$ 67,021	$ 31,277	$ 17,872	$ 2,823,804
187		Demand		$ 185,320,557	$ 113,534,307	$ 37,727,473	$ 729,994	$ 14,712,279	$ 541,394	$ 315,977	$ 3,387,365	$ 1,812,360	$ 1,369,669	$ 1,189,972	$ 9,999,766
188		Commodity		$ 939,248	$ 544,764	$ 204,214	$ 5,984	$ 44,940	$ 1,445	$ 6,493	$ 35,961	$ 28,656	$ 9,578	$ 22,538	$ 34,675
189		Total Net Plant in Service		$ 636,595,444	$ 525,063,917	$ 70,603,420	$ 881,396	$ 18,059,852	$ 681,389	$ 376,792	$ 3,521,488	$ 1,908,038	$ 1,410,523	$ 1,230,382	$ 12,858,245
190		**Customer Deposits**													
191		Customer	DEPCUS	$ (7,838,323)	$ (4,548,685)	$ (3,129,742)	$ (39,642)	$ (40,374)	$ (3,122)	$ (371)	$ (65,205)	$ -	$ -	$ (11,183)	$ -
192		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
193		Commodity	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194		Total Customer Deposits		$ (7,838,323)	$ (4,548,685)	$ (3,129,742)	$ (39,642)	$ (40,374)	$ (3,122)	$ (371)	$ (65,205)	$ -	$ -	$ (11,183)	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
195		**Customer Advances**													
196		Customer	MSCUS-ALL	$ (2,455,339)	$ (2,277,995)	$ (163,504)	$ (490)	$ (12,121)	$ (403)	$ (167)	$ (266)	$ (181)	$ (84)	$ (48)	$ (80)
197		Demand	DEM	$ (677,127)	$ (462,154)	$ (117,968)	$ (2,283)	$ (46,003)	$ (1,693)	$ (988)	$ (10,592)	$ (5,667)	$ (4,283)	$ (3,721)	$ (21,776)
198		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199		Total Customer Advances		$ (3,132,466)	$ (2,740,149)	$ (281,472)	$ (2,773)	$ (58,124)	$ (2,096)	$ (1,155)	$ (10,857)	$ (5,848)	$ (4,367)	$ (3,769)	$ (21,856)
200		**Accum. Deferred Income Taxes**													
201		Customer	TPLTCUS	$ (36,373,513)	$ (33,161,326)	$ (2,629,072)	$ (11,652)	$ (265,127)	$ (11,106)	$ (4,359)	$ (7,858)	$ (5,365)	$ (2,504)	$ (1,431)	$ (273,714)
202		Demand	TPLTDEM	$ (13,981,224)	$ (8,523,261)	$ (2,846,835)	$ (55,084)	$ (1,110,157)	$ (40,852)	$ (23,843)	$ (255,603)	$ (136,757)	$ (103,352)	$ (89,793)	$ (795,686)
203		Commodity	COM	$ (78,130)	$ (45,315)	$ (16,987)	$ (498)	$ (3,738)	$ (120)	$ (540)	$ (2,991)	$ (2,384)	$ (797)	$ (1,875)	$ (2,884)
204		Total Accum. Deferred Inc. Taxes		$ (50,432,867)	$ (41,729,903)	$ (5,492,894)	$ (67,233)	$ (1,379,023)	$ (52,078)	$ (28,742)	$ (266,453)	$ (144,506)	$ (106,653)	$ (93,098)	$ (1,072,285)
205		**Excess Deferred Income Taxes**													
206		Customer	TPLTCUS	$ (10,725,535)	$ (9,778,351)	$ (775,240)	$ (3,436)	$ (78,179)	$ (3,275)	$ (1,285)	$ (2,317)	$ (1,582)	$ (738)	$ (422)	$ (80,711)
207		Demand	TPLTDEM	$ (4,122,673)	$ (2,513,272)	$ (839,452)	$ (16,243)	$ (327,354)	$ (12,046)	$ (7,031)	$ (75,370)	$ (40,326)	$ (30,476)	$ (26,477)	$ (234,626)
208		Commodity	COM	$ (23,038)	$ (13,362)	$ (5,009)	$ (147)	$ (1,102)	$ (35)	$ (159)	$ (882)	$ (703)	$ (235)	$ (553)	$ (851)
209		**Total Excess Deferred Income Taxes**		$ (14,871,247)	$ (12,304,985)	$ (1,619,701)	$ (19,825)	$ (406,635)	$ (15,356)	$ (8,475)	$ (78,569)	$ (42,611)	$ (31,449)	$ (27,452)	$ (316,187)
210		**Materials and Supplies**													
211		Customer	TPLTCUS	$ 4,093,374	$ 3,731,884	$ 295,868	$ 1,311	$ 29,837	$ 1,250	$ 491	$ 884	$ 604	$ 282	$ 161	$ 30,803
212		Demand	TPLTDEM	$ 1,573,408	$ 959,184	$ 320,375	$ 6,199	$ 124,934	$ 4,597	$ 2,683	$ 28,765	$ 15,390	$ 11,631	$ 10,105	$ 89,544
213		Commodity	COM	$ 8,793	$ 5,100	$ 1,912	$ 56	$ 421	$ 14	$ 61	$ 337	$ 268	$ 90	$ 211	$ 325
214		Total Materials and Supplies		$ 5,675,575	$ 4,696,168	$ 618,155	$ 7,566	$ 155,191	$ 5,861	$ 3,235	$ 29,986	$ 16,262	$ 12,002	$ 10,477	$ 120,672
215		**Prepayments**													
216		Customer	OPEXPCUS	$ 2,688,427	$ 2,440,815	$ 206,313	$ 1,090	$ 23,012	$ 1,045	$ 413	$ 748	$ 511	$ 239	$ 136	$ 14,105
217		Demand	OPEXPDEM	$ 560,256	$ 344,102	$ 113,011	$ 2,187	$ 44,070	$ 1,622	$ 946	$ 10,147	$ 5,429	$ 4,103	$ 3,564	$ 31,076
218		Commodity	COM	$ 43,458	$ 25,205	$ 9,449	$ 277	$ 2,079	$ 67	$ 300	$ 1,664	$ 1,326	$ 443	$ 1,043	$ 1,604
219		Total Prepayments		$ 3,292,141	$ 2,810,123	$ 328,772	$ 3,554	$ 69,161	$ 2,733	$ 1,659	$ 12,559	$ 7,266	$ 4,785	$ 4,744	$ 46,785
220		**Pension & FAS 106 Reg. Asset**													
221		Customer	OPEXPCUS	$ 16,341,006	$ 14,835,952	$ 1,254,026	$ 6,627	$ 139,873	$ 6,349	$ 2,508	$ 4,547	$ 3,108	$ 1,450	$ 829	$ 85,736
222		Demand	OPEXPDEM	$ 3,405,391	$ 2,091,550	$ 686,909	$ 13,291	$ 267,869	$ 9,857	$ 5,753	$ 61,674	$ 32,998	$ 24,938	$ 21,666	$ 188,886
223		Commodity	COM	$ 264,148	$ 153,206	$ 57,432	$ 1,683	$ 12,639	$ 406	$ 1,826	$ 10,113	$ 8,059	$ 2,694	$ 6,339	$ 9,752
224		Total Pen. & FAS 106 Reg. Asset		$ 20,010,546	$ 17,080,708	$ 1,998,367	$ 21,601	$ 420,380	$ 16,613	$ 10,087	$ 76,335	$ 44,165	$ 29,082	$ 28,833	$ 284,374
225		**DIMP Deferrals**													
226		Customer	TPLTCUS	$ 1,505,782	$ 1,372,805	$ 108,838	$ 482	$ 10,976	$ 460	$ 180	$ 325	$ 222	$ 104	$ 59	$ 11,331
227		Demand	TPLTDEM	$ 313,798	$ 191,298	$ 63,895	$ 1,236	$ 24,917	$ 917	$ 535	$ 5,737	$ 3,069	$ 2,320	$ 2,015	$ 17,859
228		Commodity	COM	$ 24,341	$ 14,118	$ 5,292	$ 155	$ 1,165	$ 37	$ 168	$ 932	$ 743	$ 248	$ 584	$ 899
229		Total DIMP Deferrals		$ 1,843,921	$ 1,578,221	$ 178,025	$ 1,874	$ 37,057	$ 1,414	$ 884	$ 6,994	$ 4,034	$ 2,672	$ 2,659	$ 30,088
230		**Regulatory Asset**													
231		Customer	TPLTCUS	$ 1,460,700	$ 1,331,704	$ 105,579	$ 468	$ 10,647	$ 446	$ 175	$ 316	$ 215	$ 101	$ 57	$ 10,992
232		Demand	TPLTDEM	$ 304,403	$ 185,571	$ 61,982	$ 1,199	$ 24,171	$ 889	$ 519	$ 5,565	$ 2,978	$ 2,250	$ 1,955	$ 17,324
233		Commodity	COM	$ 23,612	$ 13,695	$ 5,134	$ 150	$ 1,130	$ 36	$ 163	$ 904	$ 720	$ 241	$ 567	$ 872
234		**Total Regulatory Asset**		$ 1,788,715	$ 1,530,969	$ 172,695	$ 1,818	$ 35,947	$ 1,372	$ 857	$ 6,785	$ 3,913	$ 2,592	$ 2,579	$ 29,188
235		**Cash Working Capital**													
236		Customer	OPEXPCUS	$ (2,887,145)	$ (2,621,231)	$ (221,563)	$ (1,171)	$ (24,713)	$ (1,122)	$ (443)	$ (803)	$ (549)	$ (256)	$ (146)	$ (15,148)
237		Demand	OPEXPDEM	$ (601,668)	$ (369,537)	$ (121,364)	$ (2,348)	$ (47,327)	$ (1,742)	$ (1,016)	$ (10,897)	$ (5,830)	$ (4,406)	$ (3,828)	$ (33,373)
238		Commodity	COM	$ (46,670)	$ (27,069)	$ (10,147)	$ (297)	$ (2,233)	$ (72)	$ (323)	$ (1,787)	$ (1,424)	$ (476)	$ (1,120)	$ (1,723)
239		Total Cash Working Capital		$ (3,535,483)	$ (3,017,836)	$ (353,074)	$ (3,816)	$ (74,273)	$ (2,935)	$ (1,782)	$ (13,487)	$ (7,803)	$ (5,138)	$ (5,094)	$ (50,243)
240		**Total Rate Base**													
241		Customer		$ 416,145,073	$ 382,310,419	$ 27,723,237	$ 99,006	$ 3,096,465	$ 129,071	$ 51,464	$ 28,534	$ 64,005	$ 29,869	$ 5,885	$ 2,607,119
242		Demand		$ 172,095,122	$ 105,437,789	$ 35,048,026	$ 678,149	$ 13,667,397	$ 502,944	$ 293,536	$ 3,146,791	$ 1,683,644	$ 1,272,393	$ 1,105,459	$ 9,258,995
243		Commodity		$ 1,155,761	$ 670,341	$ 251,289	$ 7,364	$ 55,299	$ 1,778	$ 7,989	$ 44,250	$ 35,262	$ 11,786	$ 27,734	$ 42,668
244		Total Rate Base		$ 589,395,955	$ 488,418,549	$ 63,022,552	$ 784,518	$ 16,819,161	$ 633,793	$ 352,989	$ 3,219,575	$ 1,782,911	$ 1,314,048	$ 1,139,078	$ 11,908,782

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1		**Transmission and Distribution Op. Exp.**													
2	814-866	**Transmission Expenses**													
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 1,708,777	$ 1,166,277	$ 297,701	$ 5,760	$ 116,092	$ 4,272	$ 2,493	$ 26,729	$ 14,301	$ 10,808	$ 9,390	$ 54,953
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 1,708,777	$ 1,166,277	$ 297,701	$ 5,760	$ 116,092	$ 4,272	$ 2,493	$ 26,729	$ 14,301	$ 10,808	$ 9,390	$ 54,953
7	8700	**Operation Supervision & Engineering**													
8		Customer	871-879CUS	$ 764,375	$ 679,476	$ 71,583	$ 531	$ 11,102	$ 556	$ 211	$ 415	$ 283	$ 132	$ 76	$ 11
9		Demand	DEM	$ 135,275	$ 92,328	$ 23,567	$ 456	$ 9,190	$ 338	$ 197	$ 2,116	$ 1,132	$ 856	$ 743	$ 4,350
10		Commodity	COM	$ 22,102	$ 12,819	$ 4,806	$ 141	$ 1,058	$ 34	$ 153	$ 846	$ 674	$ 225	$ 530	$ 816
11		Total Supervision & Engineering		$ 921,752	$ 784,623	$ 99,956	$ 1,128	$ 21,350	$ 928	$ 561	$ 3,377	$ 2,090	$ 1,213	$ 1,349	$ 5,177
12	8710	**Distribution Load Dispatch**													
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 228,149	$ 132,326	$ 49,605	$ 1,454	$ 10,916	$ 351	$ 1,577	$ 8,735	$ 6,961	$ 2,327	$ 5,475	$ 8,423
16		Total Distribution Load Dispatch		$ 228,149	$ 132,326	$ 49,605	$ 1,454	$ 10,916	$ 351	$ 1,577	$ 8,735	$ 6,961	$ 2,327	$ 5,475	$ 8,423
17	8740	**Mains & Services - Allocated**													
18		Customer	MSCUS-ALL	$ 3,379,375	$ 3,135,289	$ 225,037	$ 675	$ 16,682	$ 555	$ 229	$ 365	$ 249	$ 116	$ 66	$ 110
19		Demand	DEM	$ 916,602	$ 625,601	$ 159,689	$ 3,090	$ 62,273	$ 2,292	$ 1,337	$ 14,338	$ 7,671	$ 5,797	$ 5,037	$ 29,477
20		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Total Mains & Services - Allocated		$ 4,295,976	$ 3,760,890	$ 384,726	$ 3,765	$ 78,955	$ 2,847	$ 1,567	$ 14,703	$ 7,920	$ 5,914	$ 5,103	$ 29,587
22	8740	**Mains & Services - Dir. Assn.**													
23		Customer	MSCUS-DA	$ 29,955	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,955
24		Demand	DEM-DA	$ 23,620	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,620
25		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Total Mains & Services - Dir. Assn.		$ 53,575	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53,575
27	8740	**Odorization**													
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Commodity	COM	$ 1,545	$ 896	$ 336	$ 10	$ 74	$ 2	$ 11	$ 59	$ 47	$ 16	$ 37	$ 57
31		Total Odorization		$ 1,545	$ 896	$ 336	$ 10	$ 74	$ 2	$ 11	$ 59	$ 47	$ 16	$ 37	$ 57
32	8750	**Meas. & Reg. Station - Gen. - Allocated**													
33		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM	$ 347,458	$ 237,148	$ 60,534	$ 1,171	$ 23,606	$ 869	$ 507	$ 5,435	$ 2,908	$ 2,198	$ 1,909	$ 11,174
35		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Meas. & Reg. Station - Gen. - Allocated		$ 347,458	$ 237,148	$ 60,534	$ 1,171	$ 23,606	$ 869	$ 507	$ 5,435	$ 2,908	$ 2,198	$ 1,909	$ 11,174
37		**Meas. & Reg. Station - Gen. - DA**													
38	8750	Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM-DA	$ 17,235	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,235
40		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Total Meas. & Reg. Station - Gen. - DA		$ 17,235	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,235
42	8750	**Odorization**													
43		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45		Commodity	COM	$ 58,281	$ 33,803	$ 12,672	$ 371	$ 2,789	$ 90	$ 403	$ 2,231	$ 1,778	$ 594	$ 1,399	$ 2,152
46		Total Odorization		$ 58,281	$ 33,803	$ 12,672	$ 371	$ 2,789	$ 90	$ 403	$ 2,231	$ 1,778	$ 594	$ 1,399	$ 2,152
47	8760	**Meas. & Reg. Stat. - Ind. - Allocated**													
48		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	NRDEM	$ 27,483	$ -	$ 15,082	$ 292	$ 5,881	$ 216	$ 126	$ 1,354	$ 724	$ 548	$ 476	$ 2,784
50		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 27,483	$ -	$ 15,082	$ 292	$ 5,881	$ 216	$ 126	$ 1,354	$ 724	$ 548	$ 476	$ 2,784
52	8760	**Meas. & Reg. Stat. - Ind. - DA**													
53		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Demand	DEM-DA	$ 531	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 531
55		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56		Total Meas. & Reg. Stat. - Ind. - DA		$ 531	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 531
57	8770	**Meas. & Reg. Stat.- City Gate**													
58		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59		Demand	DEM	$ 63,441	$ 43,300	$ 11,053	$ 214	$ 4,310	$ 159	$ 93	$ 992	$ 531	$ 401	$ 349	$ 2,040
60		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Total Meas. & Reg. Stat. - City Gate		$ 63,441	$ 43,300	$ 11,053	$ 214	$ 4,310	$ 159	$ 93	$ 992	$ 531	$ 401	$ 349	$ 2,040

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
62		**Transmission and Distribution Op. Exp. (Cont'd)**													
63	8780	**Meter & House Reg. Exp. - Alloc.**													
64		Customer	MTRGCUS-ALL	$ 4,331,875	$ 3,722,803	$ 494,891	$ 4,632	$ 94,433	$ 4,996	$ 1,879	$ 3,773	$ 2,578	$ 1,203	$ 687	$ -
65		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67		Total Meter & House Reg. Exp. - Alloc.		$ 4,331,875	$ 3,722,803	$ 494,891	$ 4,632	$ 94,433	$ 4,996	$ 1,879	$ 3,773	$ 2,578	$ 1,203	$ 687	$ -
68	8780	**Meter & House Reg. Exp - Dir. Assn.**													
69		Customer	CUS-DA	$ 14,037	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,037
70		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72		Total Meter & House Reg. Exp. - DA		$ 14,037	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,037
73	8780	**Odorization**													
74		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76		Commodity	COM	$ 56	$ 32	$ 12	$ 0	$ 3	$ 0	$ 0	$ 2	$ 2	$ 1	$ 1	$ 2
77		Total Odorization		$ 56	$ 32	$ 12	$ 0	$ 3	$ 0	$ 0	$ 2	$ 2	$ 1	$ 1	$ 2
78	8790	**Customer Installation Expense**													
79		Customer	METCUS-ALL	$ 134,987	$ 116,665	$ 14,863	$ 143	$ 2,851	$ 155	$ 56	$ 117	$ 80	$ 37	$ 21	$ -
80		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82		Total Customer Install. Expense		$ 134,987	$ 116,665	$ 14,863	$ 143	$ 2,851	$ 155	$ 56	$ 117	$ 80	$ 37	$ 21	$ -
83	8800	**Other Expenses**													
84		Customer	871-879CUS	$ 713,485	$ 634,238	$ 66,817	$ 496	$ 10,363	$ 519	$ 197	$ 387	$ 264	$ 123	$ 70	$ 10
85		Demand	DEM	$ 126,269	$ 86,181	$ 21,998	$ 426	$ 8,579	$ 316	$ 184	$ 1,975	$ 1,057	$ 799	$ 694	$ 4,061
86		Commodity	COM	$ 20,631	$ 11,966	$ 4,486	$ 131	$ 987	$ 32	$ 143	$ 790	$ 629	$ 210	$ 495	$ 762
87		Total Other Expenses		$ 860,384	$ 732,385	$ 93,301	$ 1,053	$ 19,929	$ 866	$ 524	$ 3,152	$ 1,951	$ 1,132	$ 1,259	$ 4,832
88	8810	**Rents**													
89		Customer	871-879CUS	$ 50,647	$ 45,022	$ 4,743	$ 35	$ 736	$ 37	$ 14	$ 27	$ 19	$ 9	$ 5	$ 1
90		Demand	DEM	$ 8,963	$ 6,118	$ 1,562	$ 30	$ 609	$ 22	$ 13	$ 140	$ 75	$ 57	$ 49	$ 288
91		Commodity	COM	$ 1,464	$ 849	$ 318	$ 9	$ 70	$ 2	$ 10	$ 56	$ 45	$ 15	$ 35	$ 54
92		Total Rents		$ 61,075	$ 51,989	$ 6,623	$ 75	$ 1,415	$ 61	$ 37	$ 224	$ 138	$ 80	$ 89	$ 343
93	8820	**Corporate & Div. Exp.**													
94		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97		Total Corporate & Div. Exp.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98		**Total Distr. & Trans. Op. Expense**													
99		Customer		$ 9,418,736	$ 8,333,492	$ 877,934	$ 6,511	$ 136,166	$ 6,817	$ 2,586	$ 5,084	$ 3,473	$ 1,621	$ 926	$ 44,124
100		Demand		$ 3,375,653	$ 2,256,952	$ 591,185	$ 11,439	$ 230,540	$ 8,484	$ 4,951	$ 53,080	$ 28,399	$ 21,463	$ 18,647	$ 150,513
101		Commodity		$ 332,228	$ 192,692	$ 72,234	$ 2,117	$ 15,896	$ 511	$ 2,297	$ 12,720	$ 10,136	$ 3,388	$ 7,972	$ 12,265
102		Total Distr. & Trans. Operations Exp.		$ 13,126,616	$ 10,783,136	$ 1,541,353	$ 20,067	$ 382,602	$ 15,812	$ 9,834	$ 70,884	$ 42,009	$ 26,471	$ 27,545	$ 206,903
103		**Distribution Maintenance Expenses**													
104	8850	**Maintenance Supervision and Engineering**													
105		Customer	887-893CUS	$ 14,988	$ 13,950	$ 957	$ 3	$ 71	$ 2	$ 1	$ 1	$ 1	$ 0	$ 0	$ 1
106		Demand	887-893DEM	$ 9,625	$ 5,297	$ 2,375	$ 46	$ 926	$ 34	$ 20	$ 213	$ 114	$ 86	$ 75	$ 438
107		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
108		Total Supervision and Engineering		$ 24,613	$ 19,247	$ 3,332	$ 49	$ 997	$ 36	$ 21	$ 215	$ 115	$ 87	$ 75	$ 439
109	8860	**Structures and Improvements**													
110		Customer	887-893CUS	$ 307,020	$ 285,751	$ 19,611	$ 55	$ 1,455	$ 48	$ 21	$ 30	$ 20	$ 10	$ 5	$ 13
111		Demand	887-893DEM	$ 197,163	$ 108,511	$ 48,648	$ 941	$ 18,971	$ 698	$ 407	$ 4,368	$ 2,337	$ 1,766	$ 1,534	$ 8,980
112		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113		Total Structures and Improvements		$ 504,182	$ 394,262	$ 68,260	$ 997	$ 20,426	$ 746	$ 428	$ 4,398	$ 2,357	$ 1,776	$ 1,540	$ 8,993
114	8870	**Maintenance of Mains-Allocated**													
115		Customer	CUS	$ 2,093,133	$ 1,962,984	$ 120,040	$ 281	$ 8,935	$ 291	$ 138	$ 152	$ 104	$ 48	$ 28	$ 132
116		Demand	DEM	$ 1,099,479	$ 750,418	$ 191,550	$ 3,706	$ 74,697	$ 2,749	$ 1,604	$ 17,198	$ 9,202	$ 6,954	$ 6,042	$ 35,358
117		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118		Total Mains - Allocated		$ 3,192,611	$ 2,713,402	$ 311,590	$ 3,987	$ 83,632	$ 3,039	$ 1,743	$ 17,351	$ 9,306	$ 7,003	$ 6,069	$ 35,490
119	8870	**Maintenance of Mains - Directly Assigned**													
120		Customer	CUS-DA	$ 26,559	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26,559
121		Demand	DEM-DA	$ 28,322	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,322
122		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123		Total Mains - Directly Assigned		$ 54,881	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,881
124	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**													
125		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126		Demand	DEM	$ 506,952	$ 346,006	$ 88,321	$ 1,709	$ 34,442	$ 1,267	$ 740	$ 7,930	$ 4,243	$ 3,206	$ 2,786	$ 16,303
127		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
128		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 506,952	$ 346,006	$ 88,321	$ 1,709	$ 34,442	$ 1,267	$ 740	$ 7,930	$ 4,243	$ 3,206	$ 2,786	$ 16,303

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
129		**Distribution Maintenance Expenses (Cont'd)**													
130	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**													
131		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132		Demand	DEM-DA	$ 25,946	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,946
133		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
134		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 25,946	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,946
135	8890	**Odorization**													
136		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138		Commodity	COM	$ 103,847	$ 60,231	$ 22,579	$ 662	$ 4,969	$ 160	$ 718	$ 3,976	$ 3,168	$ 1,059	$ 2,492	$ 3,834
139		Total Odorization		$ 103,847	$ 60,231	$ 22,579	$ 662	$ 4,969	$ 160	$ 718	$ 3,976	$ 3,168	$ 1,059	$ 2,492	$ 3,834
140	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**													
141		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142		Demand	NRDEM	$ 387,292	$ -	$ 212,529	$ 4,112	$ 82,878	$ 3,050	$ 1,780	$ 19,082	$ 10,210	$ 7,716	$ 6,703	$ 39,231
143		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
144		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 387,292	$ -	$ 212,529	$ 4,112	$ 82,878	$ 3,050	$ 1,780	$ 19,082	$ 10,210	$ 7,716	$ 6,703	$ 39,231
145	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**													
146		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147		Demand	DEM-DA	$ 7,483	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,483
148		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ 7,483	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,483
150	8910	**Meas. & Reg. Sta. Eq.- City Gate**													
151		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Demand	DEM	$ 6,436	$ 4,393	$ 1,121	$ 22	$ 437	$ 16	$ 9	$ 101	$ 54	$ 41	$ 35	$ 207
153		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
154		Total Meas. & Reg. Sta. Eq.- City Gate		$ 6,436	$ 4,393	$ 1,121	$ 22	$ 437	$ 16	$ 9	$ 101	$ 54	$ 41	$ 35	$ 207
155	8920	**Services - Allocated**													
156		Customer	SERCUS-ALL	$ 1,085,912	$ 995,828	$ 83,027	$ 293	$ 6,135	$ 208	$ 76	$ 158	$ 108	$ 50	$ 29	$ -
157		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
159		Total Services - Allocated		$ 1,085,912	$ 995,828	$ 83,027	$ 293	$ 6,135	$ 208	$ 76	$ 158	$ 108	$ 50	$ 29	$ -
160	8920	**Services - Directly Assigned**													
161		Customer	CUS-DA	$ 5,185	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,185
162		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
164		Total Services - Directly Assigned		$ 5,185	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,185
165	8930	**Meters & House Regulators - Alloc.**													
166		Customer	MTRGCUS-ALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169		Total Meters & House Regulators - Alloc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
170	8930	**Meters & House Regulators - DA**													
171		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
174		Total Meters & House Regulators - DA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	8940	**Maintenance of Other Equipment**													
176		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179		Total Maintenance of Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
180	8950	**Clearing - Meter Shop - Small Meters**													
181		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
182		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
184		Total Clearing-Meter-Shop-Small Meters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
185	8960	**Clearing - Meter Shop - Large Meters**													
186		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
187		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
188		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189		Total Clearing-Meter Shop-Large Meters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
190		**Total Distr. Maintenance Expense**													
191		Customer		$ 3,532,796	$ 3,258,513	$ 223,636	$ 632	$ 16,596	$ 549	$ 236	$ 342	$ 233	$ 109	$ 62	$ 31,889
192		Demand		$ 2,268,696	$ 1,214,625	$ 544,544	$ 10,536	$ 212,351	$ 7,814	$ 4,561	$ 48,892	$ 26,159	$ 19,769	$ 17,176	$ 162,268
193		Commodity		$ 103,847	$ 60,231	$ 22,579	$ 662	$ 4,969	$ 160	$ 718	$ 3,976	$ 3,168	$ 1,059	$ 2,492	$ 3,834
194		Total Distr. Maintenance Expense		$ 5,905,339	$ 4,533,369	$ 790,759	$ 11,830	$ 233,916	$ 8,523	$ 5,514	$ 53,210	$ 29,561	$ 20,937	$ 19,730	$ 197,991
195		**Total Oper. & Maint. Expense**													
196		Customer		$ 12,951,532	$ 11,592,005	$ 1,101,570	$ 7,143	$ 152,762	$ 7,366	$ 2,822	$ 5,426	$ 3,707	$ 1,730	$ 988	$ 76,013
197		Demand		$ 5,644,349	$ 3,471,577	$ 1,135,729	$ 21,975	$ 442,891	$ 16,298	$ 9,512	$ 101,972	$ 54,558	$ 41,232	$ 35,822	$ 312,782
198		Commodity		$ 436,075	$ 252,923	$ 94,813	$ 2,778	$ 20,865	$ 671	$ 3,014	$ 16,696	$ 13,305	$ 4,447	$ 10,464	$ 16,099
199		Total Operations & Maint. Expense		$ 19,031,955	$ 15,316,505	$ 2,332,112	$ 31,897	$ 616,518	$ 24,335	$ 15,348	$ 124,094	$ 71,570	$ 47,408	$ 47,275	$ 404,894

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
200		**Customer Accounts Expense**													
201	901	**Supervision**													
202		Customer	902-904CUS	$ 115,800	$ 106,879	$ 8,282	$ 38	$ 523	$ 24	$ 12	$ 15	$ 10	$ 5	$ 3	$ 11
203		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205		Total Supervision		$ 115,800	$ 106,879	$ 8,282	$ 38	$ 523	$ 24	$ 12	$ 15	$ 10	$ 5	$ 3	$ 11
206	902	**Meter Reading Expense**													
207		Customer	METCUS-TOT	$ 616,390	$ 532,412	$ 67,827	$ 652	$ 13,009	$ 707	$ 255	$ 533	$ 364	$ 170	$ 97	$ 363
208		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
210		Total Meter Reading Expense		$ 616,390	$ 532,412	$ 67,827	$ 652	$ 13,009	$ 707	$ 255	$ 533	$ 364	$ 170	$ 97	$ 363
211	903	**Customer Accounting**													
212		Customer	903CUS	$ 3,123,314	$ 2,965,743	$ 150,563	$ 268	$ 6,188	$ 100	$ 228	$ 69	$ 52	$ 24	$ 14	$ 66
213		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215		Total Customer Accounting		$ 3,123,314	$ 2,965,743	$ 150,563	$ 268	$ 6,188	$ 100	$ 228	$ 69	$ 52	$ 24	$ 14	$ 66
216	904	**Bad Debt Expense**													
217		Customer	904CUS	$ 972,692	$ 851,205	$ 118,618	$ 626	$ 2,079	$ 163	$ -	$ -	$ -	$ -	$ -	$ -
218		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
219		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
220		Total Bad Debt Expense		$ 972,692	$ 851,205	$ 118,618	$ 626	$ 2,079	$ 163	$ -	$ -	$ -	$ -	$ -	$ -
221	905	**Miscellaneous Customer Accounts**													
222		Customer	902-904CUS	$ 417,099	$ 384,967	$ 29,829	$ 137	$ 1,883	$ 86	$ 43	$ 53	$ 37	$ 17	$ 10	$ 38
223		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
224		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
225		Total Misc. Customer Accounts		$ 417,099	$ 384,967	$ 29,829	$ 137	$ 1,883	$ 86	$ 43	$ 53	$ 37	$ 17	$ 10	$ 38
226	907-910	**Customer Information Expense**													
227		Customer	CUS	$ 719,083	$ 674,371	$ 41,239	$ 96	$ 3,069	$ 100	$ 48	$ 52	$ 36	$ 17	$ 10	$ 45
228		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
229		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
230		Total Customer Information Expense		$ 719,083	$ 674,371	$ 41,239	$ 96	$ 3,069	$ 100	$ 48	$ 52	$ 36	$ 17	$ 10	$ 45
231		**Sales and Advertising Expense**													
232	911	**Supervision**													
233		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
234		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
235		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236		Total Supervision Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
237	912	**Demonstrating and Selling**													
238		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
239		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
242	913	**Advertising**													
243		Customer	CUS	$ 4,501	$ 4,221	$ 258	$ 1	$ 19	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
244		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
245		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246		Total Advertising		$ 4,501	$ 4,221	$ 258	$ 1	$ 19	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
247	914	**Employee Sales Referrals**													
248		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
251		Total Employee Sales Referrals		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252	916	**Misc. Gas Sales Expense**													
253		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
255		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256		Total Misc. Gas Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
257		**Administrative & General Exp.**													
258	920-940	**Administrative & General Expenses**													
259		Customer	OPEXPCUS	$ 22,571,459	$ 20,492,563	$ 1,732,158	$ 9,153	$ 193,204	$ 8,770	$ 3,464	$ 6,281	$ 4,293	$ 2,003	$ 1,145	$ 118,425
260		Demand	OPEXPDEM	$ 3,002,368	$ 1,844,018	$ 605,615	$ 11,718	$ 236,167	$ 8,691	$ 5,072	$ 54,375	$ 29,093	$ 21,986	$ 19,102	$ 166,532
261		Commodity	COM	$ 234,631	$ 136,086	$ 51,014	$ 1,495	$ 11,226	$ 361	$ 1,622	$ 8,983	$ 7,159	$ 2,393	$ 5,630	$ 8,662
262		Total Administrative & General Exp.		$ 25,808,458	$ 22,472,666	$ 2,388,787	$ 22,366	$ 440,597	$ 17,822	$ 10,158	$ 69,640	$ 40,544	$ 26,382	$ 25,877	$ 293,619

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
263		**Depreciation & Amortization Expense**													
264	301-303	**Intangible Plant**													
265		Customer	CUS	12,130	11,376	696	2	52	2	1	1	1	0	0	1
266		Demand	DEM	4,662	3,182	812	16	317	12	7	73	39	29	26	150
267		Commodity	COM	26	15	6	0	1	0	0	1	1	0	1	1
268		Total Intangible Plant		16,818	14,573	1,514	18	370	13	8	75	40	30	26	152
269	365	**Land and Land Rights**													
270		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
271		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
272		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
273		Total Land and Land Rights		-	-	-	-	-	-	-	-	-	-	-	-
274	366	**Meas. and Reg. Station Structures**													
275		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
276		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
277		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
278		Total Measuring and Reg. Stat. Struct.		-	-	-	-	-	-	-	-	-	-	-	-
279	367	**Transmission Mains**													
280		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
281		Demand	DEM	1,142,945	780,085	199,122	3,853	77,650	2,857	1,668	17,878	9,565	7,229	6,281	36,756
282		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
283		Total Transmission Mains		1,142,945	780,085	199,122	3,853	77,650	2,857	1,668	17,878	9,565	7,229	6,281	36,756
284	368	**Compression Station Equipment**													
285		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
286		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
287		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
288		Total Compression Sta. Equipment		-	-	-	-	-	-	-	-	-	-	-	-
289	369	**Meas. & Reg. Station Equipment**													
290		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
291		Demand	DEM	107,007	73,034	18,643	361	7,270	268	156	1,674	896	677	588	3,441
292		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
293		Total Meas. & Reg. Stat. Equipment		107,007	73,034	18,643	361	7,270	268	156	1,674	896	677	588	3,441
294	371	**Other Equipment**													
295		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
296		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
297		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
298		Total Other Equipment		-	-	-	-	-	-	-	-	-	-	-	-
299	375	**Structures and Improvements**													
300		Customer	376-379CUS	6,532	6,049	370	1	28	1	0	0	0	0	0	82
301		Demand	DEM	4,118	2,810	717	14	280	10	6	64	34	26	23	132
302		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
303		Total Structures and Improvements		10,650	8,860	1,087	15	307	11	6	65	35	26	23	215
304	376	**Distribution Mains - Allocated**													
305		Customer	CUS	5,446,123	5,107,489	312,332	731	23,247	756	360	396	270	126	72	344
306		Demand	DEM	2,860,734	1,952,513	498,393	9,643	194,354	7,152	4,174	44,748	23,942	18,094	15,720	91,999
307		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
308		Total Distribution Mains - Allocated		8,306,857	7,060,002	810,725	10,374	217,602	7,908	4,534	45,144	24,212	18,220	15,792	92,343
309	376	**Distribution Mains - Directly Assigned**													
310		Customer	CUS-DA	62,363	-	-	-	-	-	-	-	-	-	-	62,363
311		Demand	DEM-DA	66,503	-	-	-	-	-	-	-	-	-	-	66,503
312		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
313		Distribution Mains - Directly Assigned		128,866	-	-	-	-	-	-	-	-	-	-	128,866
314	377	**Compressor Station Equipment**													
315		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
316		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
317		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
318		Total Compressor Station Equipment		-	-	-	-	-	-	-	-	-	-	-	-
319	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**													
320		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
321		Demand	DEM	333,435	227,577	58,091	1,124	22,653	834	487	5,216	2,791	2,109	1,832	10,723
322		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
323		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		333,435	227,577	58,091	1,124	22,653	834	487	5,216	2,791	2,109	1,832	10,723
324	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**													
325		Customer	CUS-DA	-	-	-	-	-	-	-	-	-	-	-	-
326		Demand	DEM-DA	14,159	-	-	-	-	-	-	-	-	-	-	14,159
327		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
328		Total Meas. & Reg. Sta. Eq. - Gen. - DA		14,159	-	-	-	-	-	-	-	-	-	-	14,159

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
329		**Depreciation & Amortization Expense (Cont'd)**													
330	378	**Odorization Tank**													
331		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
332		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
333		Commodity	COM	$ 4,641	$ 2,692	$ 1,009	$ 30	$ 222	$ 7	$ 32	$ 178	$ 142	$ 47	$ 111	$ 171
334		Total Odorization Tank		$ 4,641	$ 2,692	$ 1,009	$ 30	$ 222	$ 7	$ 32	$ 178	$ 142	$ 47	$ 111	$ 171
335	379	**Meas.& Reg. Sta. Equip.- City Gate**													
336		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
337		Demand	DEM	$ 135,900	$ 92,755	$ 23,676	$ 458	$ 9,233	$ 340	$ 198	$ 2,126	$ 1,137	$ 860	$ 747	$ 4,370
338		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
339		Total Meas. & Reg. Sta. Eq.- City Gate		$ 135,900	$ 92,755	$ 23,676	$ 458	$ 9,233	$ 340	$ 198	$ 2,126	$ 1,137	$ 860	$ 747	$ 4,370
340	379	**Odorization Tank**													
341		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
342		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
343		Commodity	COM	$ 15,619	$ 9,059	$ 3,396	$ 100	$ 747	$ 24	$ 108	$ 598	$ 477	$ 159	$ 375	$ 577
344		Total Odorization Tank		$ 15,619	$ 9,059	$ 3,396	$ 100	$ 747	$ 24	$ 108	$ 598	$ 477	$ 159	$ 375	$ 577
345	380	**Services - Allocated**													
346		Customer	SERCUS-ALL	$ 6,216,101	$ 5,700,432	$ 475,273	$ 1,677	$ 35,118	$ 1,189	$ 433	$ 907	$ 619	$ 289	$ 165	$ -
347		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
348		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
349		Total Services - Allocated		$ 6,216,101	$ 5,700,432	$ 475,273	$ 1,677	$ 35,118	$ 1,189	$ 433	$ 907	$ 619	$ 289	$ 165	$ -
350	380	**Services - Directly Assigned**													
351		Customer	CUS-DA	$ 29,508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,508
352		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
353		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
354		Total Services - Directly Assigned		$ 29,508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29,508
355	381	**Meters - Allocated**													
356		Customer	METCUS-ALL	$ 2,388,003	$ 2,063,872	$ 262,930	$ 2,528	$ 50,428	$ 2,739	$ 990	$ 2,066	$ 1,413	$ 659	$ 377	$ -
357		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
358		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
359		Total Meters - Allocated		$ 2,388,003	$ 2,063,872	$ 262,930	$ 2,528	$ 50,428	$ 2,739	$ 990	$ 2,066	$ 1,413	$ 659	$ 377	$ -
360	381	**Meters - Directly Assigned**													
361		Customer	CUS-DA	$ 6,001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,001
362		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
363		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
364		Total Meters - Directly Assigned		$ 6,001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,001
365	382	**Meter Installations**													
366		Customer	METCUS-TOT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
368		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
369		Total Meter Installations		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
370	383	**House Regulators - Allocated**													
371		Customer	REGCUS-ALL	$ 542,385	$ 459,288	$ 67,776	$ 595	$ 12,782	$ 634	$ 262	$ 481	$ 328	$ 153	$ 87	$ -
372		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
373		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
374		Total House Regulators - Allocated		$ 542,385	$ 459,288	$ 67,776	$ 595	$ 12,782	$ 634	$ 262	$ 481	$ 328	$ 153	$ 87	$ -
375	383	**House Regulators - Directly Assn.**													
376		Customer	CUS-DA	$ 3,267	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,267
377		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
378		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
379		House Regulators - Directly Assn.		$ 3,267	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,267
380	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**													
381		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
382		Demand	NRDEM	$ 406,969	$ -	$ 223,327	$ 4,321	$ 87,089	$ 3,205	$ 1,870	$ 20,051	$ 10,728	$ 8,108	$ 7,044	$ 41,224
383		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
384		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 406,969	$ -	$ 223,327	$ 4,321	$ 87,089	$ 3,205	$ 1,870	$ 20,051	$ 10,728	$ 8,108	$ 7,044	$ 41,224
385	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**													
386		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
387		Demand	DEM-DA	$ 7,856	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,856
388		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
389		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ 7,856	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,856
390	386	**Other Prop.- Customer Premises**													
391		Customer	CUS	$ 90,947	$ 85,292	$ 5,216	$ 12	$ 388	$ 13	$ 6	$ 7	$ 5	$ 2	$ 1	$ 6
392		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
393		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
394		Total Other Prop. - Customer Premises		$ 90,947	$ 85,292	$ 5,216	$ 12	$ 388	$ 13	$ 6	$ 7	$ 5	$ 2	$ 1	$ 6

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
395		**Depreciation & Amortization Expense (Cont'd)**													
396	387	**Other Equipment**													
397		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
398		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
399		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
400		Total Other Equipment		-	-	-	-	-	-	-	-	-	-	-	-
401	389-98	**General Plant - Allocated**													
402		Customer	GENPTCUS	4,838,866	4,462,728	320,601	1,186	29,372	1,152	475	765	523	244	139	21,680
403		Demand	DISPLTDEM	640,070	376,510	135,904	2,630	52,997	1,950	1,138	12,202	6,529	4,934	4,287	40,989
404		Commodity	COM	5,833	3,383	1,268	37	279	9	40	223	178	59	140	215
405		Total General Plant - Allocated		5,484,769	4,842,622	457,773	3,853	82,648	3,112	1,654	13,191	7,229	5,237	4,566	62,884
406	389-98	**General Plant - Directly Assigned**													
407		Customer	CUS-DA	3,563	-	-	-	-	-	-	-	-	-	-	3,563
408		Demand	DEM-DA	471	-	-	-	-	-	-	-	-	-	-	471
409		Commodity	COM-DA	4	-	-	-	-	-	-	-	-	-	-	4
410		Total General Plant - Directly Assn.		4,039	-	-	-	-	-	-	-	-	-	-	4,039
411	389-98	**General Plant - Odorization**													
412		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
413		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
414		Commodity	COM	1,718	996	374	11	82	3	12	66	52	18	41	63
415		Total General Plant - Odorization		1,718	996	374	11	82	3	12	66	52	18	41	63
416	40730	**Pension & FAS 106 Amort. Expense**													
417		Customer	CUS	194,285	182,204	11,142	26	829	27	13	14	10	4	3	12
418		Demand	DEM	40,488	27,634	7,054	136	2,751	101	59	633	339	256	222	1,302
419		Commodity	COM	3,141	1,822	683	20	150	5	22	120	96	32	75	116
420		Total Pension & FAS 106 Amort. Exp.		237,913	211,660	18,879	183	3,730	133	94	768	444	293	300	1,430
421		**Total Depreciation & Amort. Exp.**													
422		Customer		19,840,074	18,078,731	1,456,335	6,757	152,243	6,513	2,540	4,637	3,167	1,478	844	126,828
423		Demand		5,765,317	3,536,101	1,165,740	22,556	454,594	16,729	9,763	104,666	56,000	42,321	36,769	320,076
424		Commodity		30,981	17,967	6,735	197	1,482	48	214	1,186	945	316	743	1,148
425		Total Depreciation & Amort. Expense		25,636,372	21,632,798	2,628,811	29,511	608,320	23,290	12,518	110,490	60,112	44,115	38,357	448,052
426		**Taxes Other Than Income**													
427	4081	**Payroll and Other Taxes**													
428		Customer	OPEXPCUS	2,230,595	2,025,151	171,178	905	19,093	867	342	621	424	198	113	11,703
429		Demand	OPEXPDEM	464,846	285,503	93,765	1,814	36,565	1,346	785	8,419	4,504	3,404	2,957	25,784
430		Commodity	COM	36,057	20,913	7,840	230	1,725	55	249	1,380	1,100	368	865	1,331
431		Total Payroll and Other Taxes		2,731,498	2,331,566	272,783	2,949	57,383	2,268	1,377	10,420	6,029	3,970	3,936	38,818
432	4081	**Ad Valorem Taxes - Allocated**													
433		Customer	CUS	5,145,111	4,825,194	295,069	690	21,962	714	340	374	255	119	68	325
434		Demand	DEM	1,955,978	1,334,997	340,768	6,594	132,887	4,890	2,854	30,596	16,370	12,371	10,748	62,903
435		Commodity	COM	11,128	6,454	2,419	71	532	17	77	426	340	113	267	411
436		Total Ad Valorem Taxes - Allocated		7,112,217	6,166,645	638,257	7,355	155,381	5,622	3,271	31,396	16,965	12,604	11,083	63,638
437	4081	**Ad Valorem Taxes - Directly Assn.**													
438		Customer	CUS-DA	35,530	-	-	-	-	-	-	-	-	-	-	35,530
439		Demand	DEM-DA	35,353	-	-	-	-	-	-	-	-	-	-	35,353
440		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
441		Total Ad Valorem Taxes - Directly Assn.		70,883	-	-	-	-	-	-	-	-	-	-	70,883
442		**Revenue Related Taxes**													
443		Customer	TOTREVCUS	97,463	69,527	18,888	573	4,204	192	367	284	420	119	223	2,665
444		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
445		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
446		Total Revenue Related Taxes		97,463	69,527	18,888	573	4,204	192	367	284	420	119	223	2,665
447		**Total Taxes Other Than Income**													
448		Customer		7,508,699	6,919,872	485,135	2,168	45,259	1,774	1,049	1,279	1,099	437	404	50,223
449		Demand		2,456,177	1,620,500	434,533	8,408	169,451	6,236	3,639	39,015	20,874	15,775	13,706	124,040
450		Commodity		47,185	27,367	10,259	301	2,258	73	326	1,807	1,440	481	1,132	1,742
451		Total Taxes Other Than Income		10,012,061	8,567,739	929,928	10,877	216,968	8,082	5,015	42,100	23,413	16,693	15,242	176,004
452		**Excess Def. Income Tax Amort. - Directly Assn.**													
453		Customer	CUS-DA	(7,110)	-	-	-	-	-	-	-	-	-	-	(7,110)
454		Demand	DEM-DA	(7,345)	-	-	-	-	-	-	-	-	-	-	(7,345)
455		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
456		**Total Excess Def. Income Tax Amort. - DA**		(14,455)	-	-	-	-	-	-	-	-	-	-	(14,455)
457		**Excess Def. Income Tax Amort. - Alloc.**													
458		Customer	CUS	(999,302)	(937,166)	(57,309)	(134)	(4,266)	(139)	(66)	(73)	(50)	(23)	(13)	(63)
459		Demand	DEM	(406,810)	(277,657)	(70,874)	(1,371)	(27,638)	(1,017)	(594)	(6,363)	(3,405)	(2,573)	(2,235)	(13,083)
460		Commodity	COM	(2,099)	(1,217)	(456)	(13)	(100)	(3)	(15)	(80)	(64)	(21)	(50)	(77)
461		**Total Excess Def. Income Tax Amort. - Alloc.**		(1,408,211)	(1,216,040)	(128,640)	(1,519)	(32,004)	(1,159)	(674)	(6,516)	(3,518)	(2,618)	(2,299)	(13,223)

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
462		**Interest on Customer Deposits**													
463		Customer	DEPCUS	$ 4,703	$ 2,729	$ 1,878	$ 24	$ 24	$ 2	$ 0	$ 39	$ -	$ -	$ 7	$ -
464		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
465		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
466		Total Interest on Cust. Deposits		$ 4,703	$ 2,729	$ 1,878	$ 24	$ 24	$ 2	$ 0	$ 39	$ -	$ -	$ 7	$ -
467		**Req. Return - Other Than Directly Assn.**													
468		Customer	CUS	$ 32,164,519	$ 30,164,564	$ 1,844,616	$ 4,316	$ 137,297	$ 4,466	$ 2,127	$ 2,340	$ 1,595	$ 744	$ 425	$ 2,029
469		Demand	DEM	$ 13,093,996	$ 8,936,938	$ 2,281,220	$ 44,140	$ 889,589	$ 32,736	$ 19,106	$ 204,820	$ 109,586	$ 82,818	$ 71,953	$ 421,093
470		Commodity	COM	$ 67,562	$ 39,186	$ 14,689	$ 430	$ 3,233	$ 104	$ 467	$ 2,587	$ 2,061	$ 689	$ 1,621	$ 2,494
471		Tot. Req. Return - Other Than Dir. Assn.		$ 45,326,077	$ 39,140,688	$ 4,140,525	$ 48,886	$ 1,030,118	$ 37,306	$ 21,700	$ 209,746	$ 113,242	$ 84,251	$ 73,999	$ 425,617
472		**Req. Return - Directly Assigned**													
473		Customer	CUS-DA	$ 228,851	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,851
474		Demand	DEM-DA	$ 236,411	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,411
475		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
476		Tot. Req. Return - Directly Assigned		$ 465,262	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 465,262
477		**Income Taxes - Other Than DA**													
478		Customer	CUS	$ 6,764,116	$ 6,343,531	$ 387,918	$ 908	$ 28,873	$ 939	$ 447	$ 492	$ 335	$ 157	$ 89	$ 427
479		Demand	DEM	$ 2,753,634	$ 1,879,415	$ 479,735	$ 9,282	$ 187,078	$ 6,884	$ 4,018	$ 43,073	$ 23,046	$ 17,416	$ 15,131	$ 88,555
480		Commodity	COM	$ 14,208	$ 8,241	$ 3,089	$ 91	$ 680	$ 22	$ 98	$ 544	$ 433	$ 145	$ 341	$ 525
481		Total Income Taxes - Other Than DA		$ 9,531,958	$ 8,231,186	$ 870,742	$ 10,281	$ 216,631	$ 7,845	$ 4,563	$ 44,109	$ 23,815	$ 17,718	$ 15,562	$ 89,506
482		**Income Taxes - Directly Assigned**													
483		Customer	CUS-DA	$ 48,127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,127
484		Demand	DEM-DA	$ 49,717	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 49,717
485		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
486		Total Income Taxes - Dir. Assigned		$ 97,843	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97,843
487		**Total Cost of Service Before Revenue Credits**													
488		Customer		$ 107,044,548	$ 98,176,625	$ 7,368,917	$ 32,152	$ 732,168	$ 30,872	$ 12,969	$ 21,145	$ 14,646	$ 6,758	$ 4,024	$ 644,272
489		Demand		$ 32,587,813	$ 21,010,892	$ 6,031,698	$ 116,708	$ 2,352,133	$ 86,556	$ 50,517	$ 541,557	$ 289,752	$ 218,976	$ 190,247	$1,698,777
490		Commodity		$ 828,542	$ 480,552	$ 180,143	$ 5,279	$ 39,643	$ 1,275	$ 5,727	$ 31,722	$ 25,279	$ 8,449	$ 19,882	$ 30,592
491		**Total Cost of Service Before Revenue Credits**		$ 140,460,903	$ 119,668,070	$ 13,580,758	$ 154,139	$ 3,123,943	$ 118,703	$ 69,213	$ 594,423	$ 329,676	$ 234,184	$ 214,153	$2,373,641

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUB. AUTH TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Cost Allocation Factors													
2														
3	Total Customers		302,465	283,659	17,346	41	1,291	42	20	22	15	7	4	19
4	Total Customers Factor (CUS)	CUS	1.00000	0.93782	0.05735	0.00013	0.00427	0.00014	0.00007	0.00007	0.00005	0.00002	0.00001	0.00006
5														
6	Customers - Directly Assigned		19	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	1.00000
8														
9	Services - Allocated Weighting			1.00000	1.36341	2.05578	1.35349	1.40888	1.07720	2.05186	2.05186	2.05186	2.05186	0.00000
10	Weighted Customers		309,319	283,659	23,650	83	1,747	59	22	45	31	14	8	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.91704	0.07646	0.00027	0.00565	0.00019	0.00007	0.00015	0.00010	0.00005	0.00003	0.00000
12														
13	Meters - Allocated Weighting			1.00000	2.08328	8.56160	5.36817	8.96348	6.80322	12.90694	12.94521	12.94521	12.94521	0.00000
14	Weighted Customers		328,207	283,659	36,137	347	6,931	376	136	284	194	91	52	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.86427	0.11010	0.00106	0.02112	0.00115	0.00041	0.00087	0.00059	0.00028	0.00016	0.00000
16														
17	Meters - Total Weighting			1.00000	2.08328	8.56160	5.36817	8.96348	6.80322	12.90694	12.94521	12.94521	12.94521	10.13457
18	Weighted Customers		328,400	283,659	36,137	347	6,931	376	136	284	194	91	52	193
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.86376	0.11004	0.00106	0.02110	0.00115	0.00041	0.00086	0.00059	0.00028	0.00016	0.00059
20														
21	Regulators - Allocated Weighting			1.00000	2.41313	9.05047	6.11424	9.32803	8.09525	13.49204	13.49204	13.49204	13.49204	0.00000
22	Weighted Customers		334,980	283,659	41,859	367	7,894	392	162	297	202	94	54	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.84679	0.12496	0.00110	0.02357	0.00117	0.00048	0.00089	0.00060	0.00028	0.00016	0.00000
24														
25	Meters and Regulators - Allocated Weighting			1.00000	2.17386	8.69581	5.57300	9.06357	7.15953	13.06760	13.09536	13.09536	13.09536	0.00000
26	Weighted Customers		330,067	283,659	37,708	353	7,195	381	143	287	196	92	52	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.85940	0.11424	0.00107	0.02180	0.00115	0.00043	0.00087	0.00060	0.00028	0.00016	0.00000
28														
29	Non-Residential Customers		18,807	0	17,346	41	1,291	42	20	22	15	7	4	19
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.92233	0.00216	0.06865	0.00223	0.00106	0.00117	0.00080	0.00037	0.00021	0.00101
31														
32	Customer Cost Allocation Factors													
33														
34	Distribution Plant Customer Costs		$ 476,571,818	$ 433,689,139	$ 34,917,904	$ 158,521	$ 3,568,896	$ 150,751	$ 58,807	$ 107,465	$ 73,374	$ 34,241	$ 19,566	$ 3,793,153
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.91002	0.07327	0.00033	0.00749	0.00032	0.00012	0.00023	0.00015	0.00007	0.00004	0.00796
36														
37	Account 376-379 Customer Costs		$ 207,527,272	$ 192,184,905	$ 11,752,444	$ 27,496	$ 874,746	$ 28,456	$ 13,550	$ 14,905	$ 10,163	$ 4,743	$ 2,710	$ 2,613,154
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.92607	0.05663	0.00013	0.00422	0.00014	0.00007	0.00007	0.00005	0.00002	0.00001	0.01259
39														
40	Total Revenue (inc. cost of gas)		$ 204,154,608	$ 145,637,489	$ 39,564,691	$ 1,201,073	$ 8,805,953	$ 403,171	$ 767,846	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 5,581,939
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.71337	0.19380	0.00588	0.04313	0.00197	0.00376	0.00292	0.00431	0.00123	0.00229	0.02734
42														
43	Mains - Allocated Customer Cost Factor		0.51636	0.48426	0.02961	0.00007	0.00220	0.00007	0.00003	0.00004	0.00003	0.00001	0.00001	0.00003
44	Services - Allocated Customer Cost Factor		0.48364	0.44352	0.03698	0.00013	0.00273	0.00009	0.00003	0.00007	0.00005	0.00002	0.00001	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.92777	0.06659	0.00020	0.00494	0.00016	0.00007	0.00011	0.00007	0.00003	0.00002	0.00003
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	1.00000
48														
49	Total Plant Customer		$ 553,378,080	$ 504,508,632	$ 39,998,079	$ 177,264	$ 4,033,584	$ 168,960	$ 66,319	$ 119,547	$ 81,621	$ 38,090	$ 21,766	$ 4,164,219
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.91169	0.07228	0.00032	0.00729	0.00031	0.00012	0.00022	0.00015	0.00007	0.00004	0.00753
51														
52	Non-Intangible Plant Customer													
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 552,633,066	$ 518,270,938	$ 31,693,176	$ 74,150	$ 2,358,954	$ 76,738	$ 36,542	$ 40,196	$ 27,406	$ 12,790	$ 7,308	$ 34,867
54		NONINCUS	1.00000	0.93782	0.05735	0.00013	0.00427	0.00014	0.00007	0.00007	0.00005	0.00002	0.00001	0.00006
55														
56	Account 871-879 Customer Costs		$ 7,846,237	$ 6,974,757	$ 734,791	$ 5,449	$ 113,965	$ 5,706	$ 2,164	$ 4,255	$ 2,907	$ 1,357	$ 775	$ 110
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.88893	0.09365	0.00069	0.01452	0.00073	0.00028	0.00054	0.00037	0.00017	0.00010	0.00001
58														
59	Account 887-893 Customer Costs		$ 3,179,045	$ 2,958,812	$ 203,067	$ 574	$ 15,069	$ 498	$ 214	$ 311	$ 212	$ 99	$ 56	$ 132
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.93072	0.06388	0.00018	0.00474	0.00016	0.00007	0.00010	0.00007	0.00003	0.00002	0.00004
61														
62	Account 903 Customer		$ 3,123,314	$ 2,965,743	$ 150,563	$ 268	$ 6,188	$ 100	$ 228	$ 69	$ 52	$ 24	$ 14	$ 66
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.94955	0.04821	0.00009	0.00198	0.00003	0.00007	0.00002	0.00002	0.00001	0.00000	0.00002
64														

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUB. AUTH TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
65	Customer Cost Allocation Factors													
66														
67	Account 904 Customer		$ 972,692	$ 851,205	$ 118,618	$ 626	$ 2,079	$ 163	$ -	$ -	$ -	$ -	$ -	$ -
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.87510	0.12195	0.00064	0.00214	0.00017	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
69														
70	Accounts 902-904 Customer		$ 4,712,396	$ 4,349,360	$ 337,009	$ 1,546	$ 21,276	$ 970	$ 483	$ 602	$ 416	$ 194	$ 111	$ 429
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.92296	0.07152	0.00033	0.00451	0.00021	0.00010	0.00013	0.00009	0.00004	0.00002	0.00009
72														
73	Operating Expense Customer		$ 38,760,485	$ 35,190,533	$ 2,974,521	$ 15,718	$ 331,776	$ 15,060	$ 5,948	$ 10,786	$ 7,372	$ 3,440	$ 1,966	$ 203,363
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.90790	0.07674	0.00041	0.00856	0.00039	0.00015	0.00028	0.00019	0.00009	0.00005	0.00525
75														
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 42,551,110	$ 38,722,294	$ 3,117,674	$ 14,154	$ 318,652	$ 13,460	$ 5,251	$ 9,595	$ 6,551	$ 3,057	$ 1,747	$ 338,675
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 33,510,138	$ 31,426,513	$ 1,921,786	$ 4,496	$ 143,040	$ 4,653	$ 2,216	$ 2,437	$ 1,662	$ 776	$ 443	$ 2,114
78	Total General Plant Customer Costs		$ 76,061,248	$ 70,148,808	$ 5,039,460	$ 18,650	$ 461,692	$ 18,113	$ 7,466	$ 12,032	$ 8,213	$ 3,833	$ 2,190	$ 340,789
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.92227	0.06626	0.00025	0.00607	0.00024	0.00010	0.00016	0.00011	0.00005	0.00003	0.00448
80														
81	Customer Deposits		$ (7,838,323)	$ (4,548,685)	$ (3,129,742)	$ (39,642)	$ (40,374)	$ (3,122)	$ (371)	$ (65,205)	$ -	$ -	$ (11,183)	$ -
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.58031	0.39929	0.00506	0.00515	0.00040	0.00005	0.00832	0.00000	0.00000	0.00143	0.00000
83														
84	Demand Cost Allocation Factors													
85														
86	System Demand													
87	**System Demand Factor (DEM)**	DEM	1.00000	0.68252	0.17422	0.00337	0.06794	0.00250	0.00146	0.01564	0.00837	0.00632	0.00550	0.03216
88														
89	Non-Residential Demand													
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.54876	0.01062	0.21399	0.00787	0.00460	0.04927	0.02636	0.01992	0.01731	0.10130
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	1.00000
94														
95	Distribution Plant Demand		$ 150,784,206	$ 88,696,307	$ 32,015,540	$ 619,473	$ 12,484,843	$ 459,427	$ 268,138	$ 2,874,519	$ 1,537,969	$ 1,162,301	$ 1,009,810	$ 9,655,878
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.58823	0.21233	0.00411	0.08280	0.00305	0.00178	0.01906	0.01020	0.00771	0.00670	0.06404
97														
98	Demand Cost Allocation Factors													
99														
100	Non-Intangible Plant Demand		$ 212,420,691	$ 144,981,746	$ 37,007,669	$ 716,066	$ 14,431,583	$ 531,065	$ 309,949	$ 3,322,738	$ 1,777,782	$ 1,343,537	$ 1,167,268	$ 6,831,288
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.68252	0.17422	0.00337	0.06794	0.00250	0.00146	0.01564	0.00837	0.00632	0.00550	0.03216
102														
103	Total Plant Demand		$ 212,707,059	$ 129,670,891	$ 43,311,078	$ 838,032	$ 16,889,673	$ 621,520	$ 362,741	$ 3,888,690	$ 2,080,586	$ 1,572,378	$ 1,366,086	$ 12,105,385
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.60962	0.20362	0.00394	0.07940	0.00292	0.00171	0.01828	0.00978	0.00739	0.00642	0.05691
105														
106	Operating Expense Demand		$ 11,409,666	$ 7,007,678	$ 2,301,470	$ 44,531	$ 897,486	$ 33,026	$ 19,275	$ 206,638	$ 110,558	$ 83,553	$ 72,591	$ 632,858
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.61419	0.20171	0.00390	0.07866	0.00289	0.00169	0.01811	0.00969	0.00732	0.00636	0.05547
108														
109	Acct. 887-893 Demand		$ 2,000,158	$ 1,100,816	$ 493,521	$ 9,549	$ 192,454	$ 7,082	$ 4,133	$ 44,311	$ 23,708	$ 17,917	$ 15,566	$ 91,100
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.55036	0.24674	0.00477	0.09622	0.00354	0.00207	0.02215	0.01185	0.00896	0.00778	0.04555
111														
112	Rate Base Demand		$ 172,095,122	$ 105,437,789	$ 35,048,026	$ 678,149	$ 13,667,397	$ 502,944	$ 293,536	$ 3,146,791	$ 1,683,644	$ 1,272,393	$ 1,105,459	$ 9,258,995
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.61267	0.20365	0.00394	0.07942	0.00292	0.00171	0.01829	0.00978	0.00739	0.00642	0.05380
114														
115	Commodity Cost Allocation Factors													
116														
117	Annual Distribution Volumes (Ccf)		215,045,986	124,726,694	46,755,918	1,370,091	10,289,191	330,915	1,486,506	8,233,369	6,561,058	2,192,902	5,160,298	7,939,044
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.58000	0.21742	0.00637	0.04785	0.00154	0.00691	0.03829	0.03051	0.01020	0.02400	0.03692
119														
120	Commodity - Direct Assignment		7,939,044	0	0	0	0	0	0	0	0	0	0	7,939,044
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	1.00000

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Current Revenue-to-Cost Ratio (1)	0.9075	0.8089	1.4877	3.1400	1.4836	2.1942	0.9794
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	1.0000
5	Rate Design Revenue Increase	$ 12,995,128	$ 22,865,615	$ (6,913,372)	$ (1,035,345)	$ (1,714,908)	$ (255,745)	$ 48,883
6	% Increase - Non-Gas Revenue (2)	10.19%	23.62%	-32.78%	-68.15%	-32.60%	-54.43%	2.10%
7	% Increase - Total Revenue (3)	6.27%	15.41%	-17.10%	-49.64%	-16.70%	-54.43%	0.87%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)							
9	Revenue-to-Cost Ratio	1.0000	0.9337	1.3902	2.7120	1.3869	1.9554	1.0000
10	Rate Design Revenue Increase	$ 12,995,128	$ 14,930,119	$ (1,382,674)	$ (207,069)	$ (342,982)	$ (51,149)	$ 48,883
11	% Increase - Non-Gas Revenue (2)	10.19%	15.42%	-6.56%	-13.63%	-6.52%	-10.89%	2.10%
12	% Increase - Total Revenue (3)	6.27%	10.06%	-3.42%	-9.93%	-3.34%	-10.89%	0.87%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)							
14	Revenue-to-Cost Ratio	1.0000	0.9171	1.4877	3.1400	1.4836	2.1942	1.0000
15	Rate Design Revenue Increase	$ 12,995,128	$ 12,946,245	$ -	$ -	$ -	$ -	$ 48,883
16	% Increase - Non-Gas Revenue (2)	10.19%	13.37%	0.00%	0.00%	0.00%	0.00%	2.10%
17	% Increase - Total Revenue (3)	6.27%	8.73%	0.00%	0.00%	0.00%	0.00%	0.87%

(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,
(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
(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
(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

CLASS COST OF SERVICE STUDY: SUMMARY

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUB. AUTH. TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Customer Costs	$ 93,590,524	$ 86,212,237	$ 6,064,882	$ 24,889	$ 586,808	$ 14,630	$ 20,283	$ 14,043	$ 6,447	$ 3,860	$ 642,445
2	Demand Costs	$ 27,580,032	$ 18,030,044	$ 4,673,520	$ 89,842	$ 1,898,838	$ 81,648	$ 510,853	$ 273,324	$ 206,561	$ 180,298	$ 1,635,103
3	Commodity Costs	$ 780,578	$ 458,956	$ 155,935	$ 4,521	$ 35,168	$ 5,932	$ 32,856	$ 26,182	$ 8,751	$ 20,592	$ 31,685
4	Cost of Service Before Revenue Credits	$ 121,951,134	$ 104,701,238	$ 10,894,337	$ 119,252	$ 2,520,814	$ 102,210	$ 563,991	$ 313,549	$ 221,759	$ 204,751	$ 2,309,233
5	Revenues Credited to Cost of Service (1)	$ 2,694,621	$ 2,416,825	$ 210,662	$ 1,277	$ 27,374	$ 1,161	$ 5,827	$ 3,245	$ 2,294	$ 2,122	$ 23,832
6	Total Cost of Service	$ 119,256,513	$ 102,284,412	$ 10,683,675	$ 117,975	$ 2,493,440	$ 101,048	$ 558,164	$ 310,304	$ 219,465	$ 202,628	$ 2,285,401
7	Revenue at Current Rates	$ 108,210,711	$ 85,411,414	$ 14,190,974	$ 455,768	$ 3,394,378	$ 266,348	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 2,299,383
8	Revenue Deficiency	$ 11,045,802	$ 16,872,998	$ (3,507,299)	$ (337,792)	$ (900,939)	$ (165,299)	$ (37,078)	$ (569,048)	$ (30,788)	$ (264,971)	$ (13,982)
9	Revenue-to-Cost Ratios:											
10	Current Revenue	0.9094	0.8388	1.3219	3.8326	1.3574	2.6173	1.0657	2.8149	1.1388	2.2941	1.0061
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge 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	$ 1,436,028
Special Contract	$ 824,502
Irrigation	$ 434,091
Other Revenue	$ -
	$ 2,694,621

CLASS COST OF SERVICE STUDY: SUMMARY FOR RATE DESIGN

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Costs	$ 93,590,524	$ 86,212,237	$ 6,085,165	$ 38,932	$ 607,884	$ 3,860	$ 642,445
2	Demand Costs	$ 27,580,032	$ 18,030,044	$ 5,184,373	$ 363,166	$ 2,187,048	$ 180,298	$ 1,635,103
3	Commodity Costs	$ 780,578	$ 458,956	$ 188,791	$ 30,703	$ 49,851	$ 20,592	$ 31,685
4	Cost of Service Before Revenue Credits	$ 121,951,134	$ 104,701,238	$ 11,458,328	$ 432,801	$ 2,844,783	$ 204,751	$ 2,309,233
5	Revenues Credited to Cost of Service	$ 2,694,621	$ 2,416,825	$ 216,489	$ 4,522	$ 30,830	$ 2,122	$ 23,832
6	Total Cost of Service	$ 119,256,513	$ 102,284,412	$ 11,241,839	$ 428,279	$ 2,813,953	$ 202,628	$ 2,285,401
7	Revenue at Current Rates	$ 108,210,711	$ 85,411,414	$ 14,786,216	$ 1,335,120	$ 3,910,979	$ 467,600	$ 2,299,383
8	Revenue Deficiency	$ 11,045,802	$ 16,872,998	$ (3,544,377)	$ (906,840)	$ (1,097,026)	$ (264,971)	$ (13,982)
9	Revenue-to-Cost Ratios							
10	Current Revenue	0.9094	0.8388	1.3093	3.0953	1.3856	2.2941	1.0061
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
12	Customer and Demand Costs Per Bill		$ 32.84	$ 62.90	$ 704.20	$ 212.49	$ 3,836.63	$ 9,945.63
13	Commodity Cost Per Ccf	$ 0.0040						

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Intangible Plant					
1	301	Organization	NONINTPLT	$ 40,840	$ 29,560	$ 11,211	$ 69
2	302	Franchises and Consents	NONINTPLT	$ 7,208	$ 5,218	$ 1,979	$ 12
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 726,412	$ 525,784	$ 199,404	$ 1,225
4		Total Intangible Plant		$ 774,461	$ 560,562	$ 212,593	$ 1,306
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ 77,482	$ -	$ 77,482	$ -
8	366	Meas. and Reg. Station Structures	DEM	$ -	$ -	$ -	$ -
9	367	Transmission Mains	DEM	$ 43,275,627	$ -	$ 43,275,627	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 2,214,028	$ -	$ 2,214,028	$ -
12	369	Odorization Tank	COM	$ 101,675	$ -	$ -	$ 101,675
13	371	Other Equipment	DEM	$ -	$ -	$ -	$ -
14		Total Transmission Plant		$ 45,668,813	$ -	$ 45,567,137	$ 101,675
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 1,618,202	$ 985,057	$ 628,724	$ 4,421
18	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ 19,533	$ 8,458	$ 11,076	$ -
19	375	Structures and Improvements	DIS376-379-ALL	$ 269,615	$ 164,124	$ 104,754	$ 737
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 250,319,387	$ 162,729,662	$ 87,589,725	$ -
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
22	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
23	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 11,292,293	$ -	$ 11,292,293	$ -
24	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ 632,107	$ -	$ 632,107	$ -
25	378	Odorization Tank	COM	$ 183,414	$ -	$ -	$ 183,414
26	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 4,982,025	$ -	$ 4,982,025	$ -
27	379	Odorization Tank	COM	$ 730,374	$ -	$ -	$ 730,374
28	380	Services-Allocated	CUS	$ 172,299,269	$ 172,299,269	$ -	$ -
29	380	Services-Directly Assigned	CUS	$ 916,397	$ 916,397	$ -	$ -
30	381	Meters -Allocated	CUS	$ 54,653,429	$ 54,653,429	$ -	$ -
31	381	Meters - Directly Assigned	CUS	$ 147,452	$ 147,452	$ -	$ -
32	382	Meter Installations	CUS	$ 91,105	$ 91,105	$ -	$ -
33	383	House Regulators - Allocated	CUS	$ 14,141,148	$ 14,141,148	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
34		**Distribution Plant (Cont'd)**					
35	383	House Regulators - Directly Assigned	CUS	$ 92,302	$ 92,302	$ -	$ -
36	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 15,882,413	$ -	$ 15,882,413	$ -
37							
38	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ 330,071	$ -	$ 330,071	$ -
39	386	Other Property - Customer Premises	CUS	$ 624,137	$ 624,137	$ -	$ -
40	387	Other Equipment	DIS376-379-ALL	$ -	$ -	$ -	$ -
41		Total Distribution Plant		$ 534,597,739	$ 409,452,764	$ 124,226,028	$ 918,946
42							
43		**General Plant**					
44	389	Land & Land Rights	GENPLT	$ 385,689	$ 338,298	$ 47,043	$ 348
45	390	Structures & Improvements	GENPLT	$ 9,434,011	$ 7,950,200	$ 1,472,915	$ 10,896
46	391	Office Furniture and Equipment	GENPLT	$ 29,581,132	$ 29,051,077	$ 526,163	$ 3,892
47	392	Transportation Equipment	GENPLT	$ 7,816,844	$ 5,986,984	$ 1,816,423	$ 13,437
48	393	Stores Equipment	GENPLT	$ 26,647	$ 20,409	$ 6,192	$ 46
49	394	Tools, Shop & Garage - Allocated	GENPLT	$ 5,135,386	$ 3,934,503	$ 1,192,065	$ 8,818
50	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ 11,690	$ 5,860	$ 5,830	$ -
51	394	Odorization Tank	COM	$ 8,737	$ -	$ -	$ 8,737
52	395	CNG Equipment	GENPLT	$ -	$ -	$ -	$ -
53	396	Major Work Equipment	GENPLT	$ 1,740,384	$ 1,332,975	$ 404,418	$ 2,992
54	397	Communication Equipment - Allocated	GENPLT	$ 23,997,880	$ 18,497,332	$ 5,460,157	$ 40,391
55	397	Communication Equipment - Dir. Assn.	GENPLT	$ 48,893	$ 24,507	$ 24,385	$ -
56	398	Miscellaneous General Plant	GENPLT	$ -	$ -	$ -	$ -
57		Total General Plant		$ 78,187,291	$ 67,142,144	$ 10,955,591	$ 89,556
58							
59		Total Plant in Service		$ 659,228,303	$ 477,155,470	$ 180,961,350	$ 1,111,483
60							

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
61		**Depreciation & Amortization Reserve**					
62	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (358,631)	$ (285,666)	$ (72,085)	$ (879)
63	325-371	Transmission Plant	DEM	$ (2,907,255)	$ -	$ (2,907,255)	$ -
64	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (88,751,166)	$ (70,694,382)	$ (17,839,155)	$ (217,629)
65	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ (6,316)	$ (2,735)	$ (3,581)	$ -
66	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ (784,772)	$ (379,780)	$ (404,992)	$ -
67	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ (34,385)	$ -	$ (34,385)	$ -
68	380	Services - Directly Assigned	CUS	$ (158,249)	$ (158,249)	$ -	$ -
69	381	Meters - Directly Assigned	CUS	$ (47,576)	$ (47,576)	$ -	$ -
70	383	House Regulators - Directly Assigned	CUS	$ (15,489)	$ (15,489)	$ -	$ -
71	385	Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	DEM	$ (36,930)	$ -	$ (36,930)	$ -
72	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (23,451,796)	$ (20,942,535)	$ (2,490,748)	$ (18,512)
73	389-398	General Plant - Directly Assigned	GEN-DARES	$ (19,685)	$ (9,867)	$ (9,818)	$ -
74		Total Depreciation & Amortization Reserve		$ (116,572,248)	$ (92,536,278)	$ (23,798,950)	$ (237,021)
75							
76		Net Plant in Service		$ 542,656,055	$ 384,619,192	$ 157,162,400	$ 874,462
77							
78		Customer Deposits	CUS	$ (7,026,858)	$ (7,026,858)	$ -	$ -
79							
80		Customer Advances	MAINS/SVCS	$ (2,973,102)	$ (2,346,728)	$ (626,375)	$ -
81							
82		Accumulated Deferred Income Taxes	TOTPLT	$ (38,896,854)	$ (28,153,898)	$ (10,677,374)	$ (65,581)
83							
84		Excess Deferred Income Tax	TOTPLT	$ (11,790,309)	$ (8,533,933)	$ (3,236,497)	$ (19,879)
85							
86		Materials and Supplies	TOTPLT	$ 4,735,248	$ 3,427,416	$ 1,299,848	$ 7,984
87							
88		Prepayments	OPEXP	$ 3,055,500	$ 2,526,405	$ 485,143	$ 43,952
89							
90		Pension & FAS 106 Regulatory Asset	OPEXP	$ 18,636,646	$ 15,409,499	$ 2,959,069	$ 268,078
91							
92		DIMP Deferrals	OPEXP	$ 1,377,375	$ 1,138,867	$ 218,695	$ 19,813
93							
94		Regulatory Assets	OPEXP	$ 1,623,697	$ 1,342,535	$ 257,806	$ 23,356
95							
96		Cash Working Capital	OPEXP	$ (3,379,316)	$ (2,794,149)	$ (536,557)	$ (48,610)
97							
98		Total Rate Base		$ 508,018,082	$ 359,608,349	$ 147,306,159	$ 1,103,574

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Transmission & Distribution Operations Exp.**					
2	814-866	Transmission Expenses	DEM	$ 1,383,447	$ -	$ 1,383,447	$ -
3	8700	Operation Supervision & Engineering	DIS871-879	$ 827,183	$ 683,850	$ 120,969	$ 22,365
4	8710	Distribution Load Dispatch	COM	$ 211,750	$ -	$ -	$ 211,750
5	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 3,481,686	$ 2,760,090	$ 721,596	$ -
6	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ 51,815	$ 28,971	$ 22,844	$ -
7	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 291,973	$ -	$ 291,973	$ -
8	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ 19,601	$ -	$ 19,601	$ -
9	8750	Odorization	COM	$ 58,181	$ -	$ -	$ 58,181
10	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 25,471	$ -	$ 25,471	$ -
11	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ 529	$ -	$ 529	$ -
12	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 63,314	$ -	$ 63,314	$ -
13	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 3,537,652	$ 3,537,652	$ -	$ -
14	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ 12,329	$ 12,329	$ -	$ -
15	8780	Odorization	COM	$ 56	$ -	$ -	$ 56
16	8790	Customer Installation Expenses	CUS	$ 135,636	$ 135,636	$ -	$ -
17	8800	Other Expenses	DIS871-879	$ 763,201	$ 630,954	$ 111,612	$ 20,635
18	8810	Rents	DIS871-879	$ 45,934	$ 37,975	$ 6,717	$ 1,242
19	8820	Corporate & Div. Exp.	DEM	$ -	$ -	$ -	$ -
20		Total Transmission & Distribution Oper. Exp.		$ 10,909,757	$ 7,827,456	$ 2,768,073	$ 314,228
21							
22		**Distribution Maintenance Expenses**					
23	8850	Maintenance Supervision and Engineering	DIS887-893	$ 24,735	$ 14,931	$ 9,804	$ -
24	8860	Structures and Improvements	DIS887-893	$ 337,505	$ 203,734	$ 133,771	$ -
25	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 2,453,740	$ 1,595,147	$ 858,593	$ -
26	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ 52,669	$ 25,489	$ 27,181	$ -
27	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 367,583	$ -	$ 367,583	$ -
28	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ 25,490	$ -	$ 25,490	$ -
29	8890	Odorization	COM	$ 87,787	$ -	$ -	$ 87,787
30	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 256,051	$ -	$ 256,051	$ -
31	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ 5,321	$ -	$ 5,321	$ -
32	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 4,437	$ -	$ 4,437	$ -
33	8920	Maintenance of Services - Allocated	CUS	$ 734,099	$ 734,099	$ -	$ -
34	8920	Maintenance of Services - Directly Assn.	CUS	$ 3,904	$ 3,904	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
35		**Distribution Maintenance Expenses (Cont'd)**					
36	8930	Main. of Meters & House Reg. - Allocated	CUS	$ (6,092)	$ (6,092)	$ -	$ -
37	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ (21)	$ (21)	$ -	$ -
38	8940	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
39	8950	Clearing - Meter Shop - Small Meters	DEM	$ -	$ -	$ -	$ -
40	8960	Clearing - Meter Shop - Large Meters	DEM	$ -	$ -	$ -	$ -
41		Total Distribution Maintenance Expenses		$ 4,347,209	$ 2,571,191	$ 1,688,230	$ 87,787
42							
43		Total Operations & Maintenance Expenses		$ 15,256,965	$ 10,398,648	$ 4,456,303	$ 402,015
44							
45		**Customer Accounts Expenses**					
46	9010	Supervision	CUS	$ 107,476	$ 107,476	$ -	$ -
47	9020	Meter Reading Expense	CUS	$ 581,671	$ 581,671	$ -	$ -
48	9030	Customer Accounting	CUS	$ 2,894,519	$ 2,894,519	$ -	$ -
49	9040	Bad Debts (includes gross up)	CUS	$ 854,390	$ 854,390	$ -	$ -
50	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 388,943	$ 388,943	$ -	$ -
51		Total Customer Accounts Expenses		$ 4,826,998	$ 4,826,998	$ -	$ -
52							
53		**Customer Information Expenses**					
54	9070	Supervision	CUS	$ -	$ -	$ -	$ -
55	9080	Customer Assistance	CUS	$ 523,241	$ 523,241	$ -	$ -
56	9090	Informational and Instructional Advertising	CUS	$ 44,615	$ 44,615	$ -	$ -
57	9100	Customer Service & Informational Svc.	CUS	$ -	$ -	$ -	$ -
58		Total Customer Information Expenses		$ 567,855	$ 567,855	$ -	$ -
59							
60		**Sales and Advertising Expenses**					
61	9110	Supervision					
62	9120	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
63	9130	Advertising	CUS	$ 4,444	$ 4,444	$ -	$ -
64	9140	Employee Sales Referrals	CUS	$ -	$ -	$ -	$ -
65	9163	Misc. Gas Sales Expense	CUS	$ -	$ -	$ -	$ -
66		Total Sales and Advertising Expenses		$ 4,444	$ 4,444	$ -	$ -
67							
68		**Administrative & General Expenses**					
69	920-940	Administrative & General Expenses	ADMINGEN	$ 23,320,529	$ 20,563,766	$ 2,526,196	$ 230,567
70		Total Administrative & General Expenses		$ 23,320,529	$ 20,563,766	$ 2,526,196	$ 230,567
71							

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
72		**Depreciation and Amortization Expense**					
73	301-303	Intangible Plant	PLT301-03	$ 10,206	$ 7,387	$ 2,802	$ 17
74	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -
75	366	Meas. and Reg. Station Structures	PLT366	$ -	$ -	$ -	$ -
76	367	Transmission Mains	PLT367	$ 1,099,234	$ -	$ 1,099,234	$ -
77	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
78	369	Measuring and Reg. Station Equipment	PLT369	$ 80,123	$ -	$ 80,123	$ -
79	371	Other Equipment	PLT371	$ -	$ -	$ -	$ -
80	375	Structures and Improvements	PLT375	$ 8,870	$ 5,400	$ 3,446	$ 24
81	376	Mains - Allocated	MAINS-ALLOC	$ 6,675,845	$ 4,339,888	$ 2,335,958	$ -
82	376	Mains - Directly Assigned	MAINS-DA	$ 123,088	$ 59,567	$ 63,521	$ -
83	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
84	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 254,098	$ -	$ 254,098	$ -
85	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ 13,337	$ -	$ 13,337	$ -
86	378	Odorization Tank	COM	$ 4,127	$ -	$ -	$ 4,127
87	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 101,651	$ -	$ 101,651	$ -
88	379	Odorization Tank	COM	$ 14,900	$ -	$ -	$ 14,900
89	380	Services - Allocated	PLT380	$ 5,546,433	$ 5,546,433	$ -	$ -
90	380	Services - Directly Assigned	PLT380	$ 28,042	$ 28,042	$ -	$ -
91	381	Meters - Allocated	PLT381	$ 2,208,080	$ 2,208,080	$ -	$ -
92	381	Meters - Directly Assigned	PLT381	$ 6,340	$ 6,340	$ -	$ -
93	382	Meter Installations	PLT382	$ -	$ -	$ -	$ -
94	383	House Regulators - Allocated	PLT383	$ 500,597	$ 500,597	$ -	$ -
95	383	House Regulators - Directly Assigned	PLT383	$ 3,203	$ 3,203	$ -	$ -
96	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 378,344	$ -	$ 378,344	$ -
97	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ 7,658	$ -	$ 7,658	$ -
98	386	Other Property - Customer Premises	PLT386	$ 86,693	$ 86,693	$ -	$ -
99	387	Other Equipment	PLT387	$ -	$ -	$ -	$ -
100	389-398	General Plant - Allocated	GENDEP	$ 4,973,341	$ 4,420,330	$ 548,387	$ 4,624
101	389-398	General Plant - Directly Assigned	GENDEP	$ 4,039	$ 3,590	$ 445	$ 4
102	389-398	General Plant - Odorization	COM	$ 582	$ -	$ -	$ 582
103	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ 237,913	$ 196,716	$ 37,775	$ 3,422
104		Total Depreciation and Amortization Expense		$ 22,366,744	$ 17,412,264	$ 4,926,780	$ 27,700
105							

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
106		**Taxes Other Than Income**					
107	4080	Payroll and Other	OPEXP	$ 2,375,539	$ 1,964,187	$ 377,181	$ 34,171
108	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 6,418,294	$ 4,662,217	$ 1,745,130	$ 10,947
109	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ 74,573	$ 37,380	$ 37,194	$ -
110	4080	Revenue Related (includes gross up)	CUS	$ 82,844	$ 82,844	$ -	$ -
111		Total Taxes Other Than Income		$ 8,951,249	$ 6,746,627	$ 2,159,504	$ 45,118
112							
113	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ (13,343)	$ (6,563)	$ (6,780)	$ -
114	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (1,106,056)	$ (786,835)	$ (317,417)	$ (1,804)
115							
116	4310	Interest on Customer Deposits	CUS	$ 4,216	$ 4,216	$ -	$ -
117							
118		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 38,998,488	$ 27,743,058	$ 11,191,828	$ 63,602
119		Required Return - Directly Assigned	RB-DA	$ 470,444	$ 231,400	$ 239,044	$ -
120		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 8,203,636	$ 5,835,969	$ 2,354,288	$ 13,379
121		Income Taxes - Directly Assigned	RB-DA	$ 98,962	$ 48,677	$ 50,285	$ -
122		Total Cost of Service Before Revenue Credits		$ 121,951,134	$ 93,590,524	$ 27,580,032	$ 780,578

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7			Total Transmission Plant	$ 45,668,813	$ -	$ 45,567,137	$ 101,675
8			Total Distribution Plant	$ 534,597,739	$ 409,452,764	$ 124,226,028	$ 918,946
9			Total General Plant	$ 78,187,291	$ 67,142,144	$ 10,955,591	$ 89,556
10			Total Non-Intangible Plant	$ 658,453,842	$ 476,594,908	$ 180,748,757	$ 1,110,177
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.72381	0.27450	0.00169
12							
13	376		Distribution Mains-Allocated	$ 250,319,387	$ 162,729,662	$ 87,589,725	$ -
14	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 11,292,293	$ -	$ 11,292,293	$ -
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 5,712,399	$ -	$ 4,982,025	$ 730,374
17			Total Accounts 376-379	$ 267,324,080	$ 162,729,662	$ 103,864,044	$ 730,374
18		DIS376-379-All	Accounts 376-379 Allocated Factor	1.00000	0.60874	0.38853	0.00273
19							
20	376		Distribution Mains-Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ 632,107	$ -	$ 632,107	$ -
22			Total Accounts 376-379 Directly Assigned	$ 6,005,171	$ 2,600,224	$ 3,404,946	$ -
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	1.00000	0.43300	0.56700	0.00000
24							
25	376		Mains-Allocated	$ 250,319,387	$ 162,729,662	$ 87,589,725	$ -
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.65009	0.34991	0.00000
27							
28	376		Mains-Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.48394	0.51606	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ 6,289,461	$ 3,516,621	$ 2,772,839	$ -
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	1.00000	0.55913	0.44087	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 422,618,656	$ 335,028,931	$ 87,589,725	$ -
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.79275	0.20725	0.00000
36							
37	376/380		Mains and Services	$ 428,908,116	$ 338,545,552	$ 90,362,564	$ -
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.78932	0.21068	0.00000
39							
40	374-87		Total Distribution Plant	$ 534,597,739	$ 409,452,764	$ 124,226,028	$ 918,946
41		DISPLT	Distribution Plant Factor	1.00000	0.76591	0.23237	0.00172
42							
43	374		Land & Land Rights - Directly Assigned	$ 19,533	$ 8,458	$ 11,076	$ -
44	376		Mains - Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ 632,107	$ -	$ 632,107	$ -
46	380		Service - Directly Assigned	$ 916,397	$ 916,397	$ -	$ -
47	381		Meters - Directly Assigned	$ 147,452	$ 147,452	$ -	$ -
48	383		House Regulators - Directly Assigned	$ 92,302	$ 92,302	$ -	$ -
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ 330,071	$ -	$ 330,071	$ -
50			Total Distribution Plant - Directly Assigned	$ 7,510,927	$ 3,764,833	$ 3,746,093	$ -
51		DISPLT-DA	Distribution Plant Directly Assn. Factor	1.00000	0.50125	0.49875	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (46,956)	$ (28,584)	$ (18,244)	$ (128)
54	375		Structures and Improvements	$ (130,169)	$ (79,238)	$ (50,575)	$ (356)
55	376		Distribution Mains - Allocated	$ (37,599,986)	$ (24,443,304)	$ (13,156,681)	$ -

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
56	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (919,825)	$ -	$ (919,825)	$ -
58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (660,683)	$ -	$ (660,683)	$ -
59	378-379		Odorization Tank	$ (215,959)	$ -	$ -	$ (215,959)
60	380		Services - Allocated	$ (24,788,412)	$ (24,788,412)	$ -	$ -
61	381		Meters - Allocated	$ (16,211,468)	$ (16,211,468)	$ -	$ -
62	382		Meter Installations	$ (1,462)	$ (1,462)	$ -	$ -
63	383		House Regulators - Allocated	$ (4,877,530)	$ (4,877,530)	$ -	$ -
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (2,864,401)	$ -	$ (2,864,401)	$ -
65	386		Other Property-Customer Premises	$ (434,315)	$ (264,383)	$ (168,746)	$ (1,187)
66	387		Other Equipment	$ -	$ -	$ -	$ -
67			Total Distribution Plant - Allocated Reserve	$ (88,751,166)	$ (70,694,382)	$ (17,839,155)	$ (217,629)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.79655	0.20100	0.00245
69							
70	376		Distribution Mains - Directly Assigned	$ (784,772)	$ (379,780)	$ (404,992)	$ -
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	1.00000	0.48394	0.51606	0.00000
72							
73			General Plant - Allocated Reserve	$ (23,451,796)	$ (20,942,535)	$ (2,490,748)	$ (18,512)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.89300	0.10621	0.00079
75							
76			General Plant - Directly Assigned Reserve	$ (19,685)	$ (9,867)	$ (9,818)	$ -
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	1.00000	0.50125	0.49875	0.00000
78							
79			Total Plant - Allocated	$ 651,656,794	$ 473,360,270	$ 177,185,041	$ 1,111,483
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.72640	0.27190	0.00171
81							
82			Total Plant - Directly Assigned	$ 7,571,509	$ 3,795,200	$ 3,776,309	$ -
83		TPLT-DA	Total Plant Directly Assigned Factor	$ 1.00000	$ 0.50125	$ 0.49875	$ -
84							
85			Total Plant	$ 659,228,303	$ 477,155,470	$ 180,961,350	$ 1,111,483
86		TOTPLT	Total Plant Factor	1.00000	0.72381	0.27450	0.00169
87							
88			Total Operations and Maintenance Expenses	$ 15,256,965	$ 10,398,648	$ 4,456,303	$ 402,015
89			Total Customer Accounts Expenses	$ 4,826,998	$ 4,826,998	$ -	$ -
90			Total Customer Service Expenses	$ 567,855	$ 567,855	$ -	$ -
91			Total Sales and Advertising Expenses	$ 4,444	$ 4,444	$ -	$ -
92			Administrative and General Expenses	$ 23,320,529	$ 20,563,766	$ 2,526,196	$ 230,567
93			Total Operating Expenses	$ 43,976,793	$ 36,361,711	$ 6,982,499	$ 632,582
94		OPEXP	Operating Expense Factor	1.00000	0.82684	0.15878	0.01438
95							
96	8710		Distribution Load Dispatch	$ 211,750	$ -	$ -	$ 211,750
97	8740		Mains & Services - Allocated	$ 3,481,686	$ 2,760,090	$ 721,596	$ -
98	8740		Mains and Services Expenses - Dir. Assn.	$ 51,815	$ 28,971	$ 22,844	$ -
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 291,973	$ -	$ 291,973	$ -
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ 19,601	$ -	$ 19,601	$ -
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 25,471	$ -	$ 25,471	$ -
102	8760		Meas. & Reg. Stat. Exp.-Ind.-Dir. Assn.	$ 529	$ -	$ 529	$ -
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 63,314	$ -	$ 63,314	$ -
104	8780		Meter and House Regulator Exp.- Allocated	$ 3,537,652	$ 3,537,652	$ -	$ -
105	8780		Meter and House Regulator Exp.-Dir. Assn.	$ 12,329	$ 12,329	$ -	$ -
106	8790		Customer Installation Expenses	$ 135,636	$ 135,636	$ -	$ -
107			Total Accounts 871-879	$ 7,831,755	$ 6,474,678	$ 1,145,328	$ 211,750
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.82672	0.14624	0.02704
109							
110	8870		Maintenance of Mains-Allocated	$ 2,453,740	$ 1,595,147	$ 858,593	$ -

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
111	8870		Maintenance of Mains - Directly Assn.	$ 52,669	$ 25,489	$ 27,181	$ -
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 367,583	$ -	$ 367,583	$ -
113	8890		Maint. of Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn.	$ 25,490	$ -	$ 25,490	$ -
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 256,051	$ -	$ 256,051	$ -
115	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	$ 5,321	$ -	$ 5,321	$ -
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 4,437	$ -	$ 4,437	$ -
117	8920		Maintenance of Services - Allocated	$ 734,099	$ 734,099	$ -	$ -
118	8920		Maintenance of Services - Directly Assn.	$ 3,904	$ 3,904	$ -	$ -
119	8930		Main. of Meters & House Reg. - Allocated	$ (6,092)	$ (6,092)	$ -	$ -
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ (21)	$ (21)	$ -	$ -
121			Total Accounts 887-893	$ 3,897,182	$ 2,352,526	$ 1,544,656	$ -
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.60365	0.39635	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 15,256,965	$ 10,398,648	$ 4,456,303	$ 402,015
125			Total Customer Accounts Expenses	$ 4,826,998	$ 4,826,998	$ -	$ -
126			Total Customer Service Expenses	$ 567,855	$ 567,855	$ -	$ -
127			Total Sales and Advertising Expenses	$ 4,444	$ 4,444	$ -	$ -
128			Total Operating Exp. Without A&G Expenses	$ 20,656,263	$ 15,797,946	$ 4,456,303	$ 402,015
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.76480	0.21574	0.01946
130							
131	920-932		Administrative and General Expenses	$ 23,320,529	$ 20,563,766	$ 2,526,196	$ 230,567
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.88179	0.10833	0.00989
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	$ 43,275,627	$ -	$ 43,275,627	$ -
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	$ 2,214,028	$ -	$ 2,214,028	$ -
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	$ 269,615	$ 164,124	$ 104,754	$ 737
150		PLT375	Structures and Improvements Factor	1.00000	0.60874	0.38853	0.00273
151							
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 11,292,293	$ -	$ 11,292,293	$ -
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	$ 4,982,025	$ -	$ 4,982,025	$ -
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
157							
158	380		Services-Allocated	$ 172,299,269	$ 172,299,269	$ -	$ -
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
160							
161	381		Meters -Allocated	$ 54,653,429	$ 54,653,429	$ -	$ -
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
163							
164	382		Meter Installations	$ 91,105	$ 91,105	$ -	$ -
165		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
166							
167	383		House Regulators - Allocated	$ 14,141,148	$ 14,141,148	$ -	$ -
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
169							
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 15,882,413	$ -	$ 15,882,413	$ -
171		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
172							
173	386		Other Property - Customer Premises	$ 624,137	$ 624,137	$ -	$ -
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	301-03		Intangible Plant	$ 774,461	$ 560,562	$ 212,593	$ 1,306
180		PLT301-03	Intangible Plant	1.00000	0.72381	0.27450	0.00169
181							
182	389-98		General Plant Depreciation Expense	$ 4,977,962	$ 4,424,437	$ 548,897	$ 4,628
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.88880	0.11027	0.00093
184							
185			Net Plant Directly Assigned	$ 6,468,109	$ 3,181,505	$ 3,286,604	$ -
186		NETPLT-DA	Net Plant Directly Assigned Factor	1.00000	0.49188	0.50812	0.00000
187							
188			Net Plant Allocated	$ 536,187,946	$ 381,437,688	$ 153,875,796	$ 874,462
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.71139	0.28698	0.00163
190							
191			Rate Base Directly Assigned	$ 6,055,246	$ 2,978,428	$ 3,076,819	$ -
192		RB-DA	Rate Base Directly Assigned Factor	1.00000	0.49188	0.50812	0.00000
193							
194			Rate Base Allocated	$ 501,962,835	$ 357,090,353	$ 144,053,837	$ 818,644
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.71139	0.28698	0.00163
196							
197			Required Return	$ 39,468,932	$ 27,974,458	$ 11,430,872	$ 63,602
198		REQRET	Required Return Factor	1.00000	0.70877	0.28962	0.00161
199							
200			Non-Plant Rate Base	$ (34,637,973)	$ (25,010,844)	$ (9,856,242)	$ 229,112
201		NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.72206	0.28455	-0.00661

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	301-303	**Intangible Plant**												
2		Customer	NONINCUS	$ 560,562	$ 528,408	$ 29,780	$ 65	$ 2,135	$ 40	$ 44	$ 30	$ 14	$ 8	$ 38
3		Demand	NONINDEM	$ 212,593	$ 147,390	$ 33,993	$ 653	$ 13,811	$ 594	$ 3,716	$ 1,988	$ 1,502	$ 1,305	$ 7,639
4		Commodity	COM	$ 1,306	$ 768	$ 261	$ 8	$ 59	$ 10	$ 55	$ 44	$ 15	$ 34	$ 53
5		Total Intangible Plant		$ 774,461	$ 676,566	$ 64,034	$ 726	$ 16,006	$ 644	$ 3,815	$ 2,062	$ 1,531	$ 1,348	$ 7,730
6	365-371	**Transmission Plant**												
7		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	DEM	$ 45,567,137	$ 31,591,552	$ 7,286,127	$ 140,066	$ 2,960,333	$ 127,292	$ 796,431	$ 426,119	$ 322,034	$ 279,784	$ 1,637,400
9		Commodity	COM	$ 101,675	$ 59,782	$ 20,312	$ 589	$ 4,581	$ 773	$ 4,280	$ 3,410	$ 1,140	$ 2,682	$ 4,127
10		Total Transmission Plant		$ 45,668,813	$ 31,651,334	$ 7,306,438	$ 140,655	$ 2,964,914	$ 128,064	$ 800,711	$ 429,529	$ 323,174	$ 282,466	$ 1,641,527
11		**Distribution Plant**												
12	374	**Land & Land Rights - Allocated**												
13		Customer	CUS	$ 985,057	$ 928,554	$ 52,331	$ 114	$ 3,752	$ 70	$ 77	$ 53	$ 25	$ 14	$ 67
14		Demand	DEM	$ 628,724	$ 435,892	$ 100,532	$ 1,933	$ 40,846	$ 1,756	$ 10,989	$ 5,879	$ 4,443	$ 3,860	$ 22,592
15		Commodity	COM	$ 4,421	$ 2,600	$ 883	$ 26	$ 199	$ 34	$ 186	$ 148	$ 50	$ 117	$ 179
16		Total Land & Land Rights		$ 1,618,202	$ 1,367,046	$ 153,746	$ 2,073	$ 44,798	$ 1,860	$ 11,252	$ 6,080	$ 4,517	$ 3,991	$ 22,839
17	374	**Land & Land Rights - DA**												
18		Customer	CUS-DA	$ 8,458	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,458
19		Demand	DEM-DA	$ 11,076	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,076
20		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Total Land & Rights - DA		$ 19,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,533
22	375	**Structures and Improvements**												
23		Customer	376-379CUS	$ 164,124	$ 154,710	$ 8,719	$ 19	$ 625	$ 12	$ 13	$ 9	$ 4	$ 2	$ 11
24		Demand	DEM	$ 104,754	$ 72,626	$ 16,750	$ 322	$ 6,806	$ 293	$ 1,831	$ 980	$ 740	$ 643	$ 3,764
25		Commodity	COM	$ 737	$ 433	$ 147	$ 4	$ 33	$ 6	$ 31	$ 25	$ 8	$ 19	$ 30
26		Total Structures and Improvements		$ 269,615	$ 227,769	$ 25,616	$ 345	$ 7,464	$ 310	$ 1,875	$ 1,013	$ 753	$ 665	$ 3,805
27	376	**Distribution Mains-Allocated**												
28		Customer	CUS	$ 162,729,662	$ 153,395,429	$ 8,644,956	$ 18,893	$ 619,890	$ 11,597	$ 12,756	$ 8,697	$ 4,059	$ 2,319	$ 11,065
29		Demand	DEM	$ 87,589,725	$ 60,725,680	$ 14,005,484	$ 269,236	$ 5,690,389	$ 244,682	$ 1,530,910	$ 819,091	$ 619,018	$ 537,804	$ 3,147,431
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31		Total Distribution Mains - Allocated		$ 250,319,387	$ 214,121,109	$ 22,650,440	$ 288,129	$ 6,310,280	$ 256,278	$ 1,543,666	$ 827,788	$ 623,077	$ 540,124	$ 3,158,496
32		**Distribution Mains - Directly Assn.**												
33		Customer	CUS-DA	$ 2,600,224	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,600,224
34		Demand	DEM-DA	$ 2,772,839	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,772,839
35		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Distribution Mains - Dir. Assn.		$ 5,373,064	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,373,064
37	377	**Compressor Station Equipment**												
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**												
43		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	DEM	$ 11,292,293	$ 7,828,911	$ 1,805,623	$ 34,711	$ 733,620	$ 31,545	$ 197,369	$ 105,599	$ 79,805	$ 69,335	$ 405,775
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 11,292,293	$ 7,828,911	$ 1,805,623	$ 34,711	$ 733,620	$ 31,545	$ 197,369	$ 105,599	$ 79,805	$ 69,335	$ 405,775
47	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**												
48		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM-DA	$ 632,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 632,107
50		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 632,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 632,107
52	378	**Odorization Tank**												
53		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ 183,414	$ 107,843	$ 36,641	$ 1,062	$ 8,264	$ 1,394	$ 7,720	$ 6,152	$ 2,056	$ 4,839	$ 7,444
56		Total Odorization Tank		$ 183,414	$ 107,843	$ 36,641	$ 1,062	$ 8,264	$ 1,394	$ 7,720	$ 6,152	$ 2,056	$ 4,839	$ 7,444

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
57		**Distribution Plant (Cont'd)**												
58	379	**Meas. & Reg. Station - City Gate**												
59		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	DEM	$ 4,982,025	$ 3,454,022	$ 796,619	$ 15,314	$ 323,664	$ 13,917	$ 87,077	$ 46,589	$ 35,209	$ 30,590	$ 179,023
61		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62		Total Meas. & Reg. Equip.-City Gate		$ 4,982,025	$ 3,454,022	$ 796,619	$ 15,314	$ 323,664	$ 13,917	$ 87,077	$ 46,589	$ 35,209	$ 30,590	$ 179,023
63	379	**Odorization Tank**												
64		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		Commodity	COM	$ 730,374	$ 429,440	$ 145,907	$ 4,230	$ 32,906	$ 5,550	$ 30,743	$ 24,498	$ 8,188	$ 19,268	$ 29,644
67		Total Odorization Tank		$ 730,374	$ 429,440	$ 145,907	$ 4,230	$ 32,906	$ 5,550	$ 30,743	$ 24,498	$ 8,188	$ 19,268	$ 29,644
68	380	**Services-Allocated**												
69		Customer	SERCUS-ALL	$ 172,299,269	$ 158,680,428	$ 12,599,323	$ 40,101	$ 903,440	$ 16,901	$ 27,076	$ 18,461	$ 8,615	$ 4,923	$ -
70		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72		Total Services - Allocated		$ 172,299,269	$ 158,680,428	$ 12,599,323	$ 40,101	$ 903,440	$ 16,901	$ 27,076	$ 18,461	$ 8,615	$ 4,923	$ -
73	380	**Services-Directly Assigned**												
74		Customer	CUS-DA	$ 916,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 916,397
75		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77		Total Services - Directly Assigned		$ 916,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 916,397
78	381	**Meters -Allocated**												
79		Customer	METCUS-ALL	$ 54,653,429	$ 47,766,581	$ 5,632,793	$ 50,176	$ 1,059,470	$ 32,368	$ 51,270	$ 35,060	$ 16,361	$ 9,349	$ -
80		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82		Total Meters - Allocated		$ 54,653,429	$ 47,766,581	$ 5,632,793	$ 50,176	$ 1,059,470	$ 32,368	$ 51,270	$ 35,060	$ 16,361	$ 9,349	$ -
83	381	**Meters-Directly Assigned**												
84		Customer	CUS-DA	$ 147,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,452
85		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87		Total Meters - Directly Assigned		$ 147,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,452
88	382	**Meter Installations**												
89		Customer	METCUS-ALL	$ 91,105	$ 79,625	$ 9,390	$ 84	$ 1,766	$ 54	$ 85	$ 58	$ 27	$ 16	$ -
90		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92		Total Meter Installations		$ 91,105	$ 79,625	$ 9,390	$ 84	$ 1,766	$ 54	$ 85	$ 58	$ 27	$ 16	$ -
93	383	**House Regulators - Allocated**												
94		Customer	REGCUS-ALL	$ 14,141,148	$ 12,131,436	$ 1,652,937	$ 13,480	$ 305,043	$ 8,555	$ 13,611	$ 9,280	$ 4,331	$ 2,475	$ -
95		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97		Total House Regulators - Allocated		$ 14,141,148	$ 12,131,436	$ 1,652,937	$ 13,480	$ 305,043	$ 8,555	$ 13,611	$ 9,280	$ 4,331	$ 2,475	$ -
98	383	**House Regulators - Directly Assigned**												
99		Customer	CUS-DA	$ 92,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,302
100		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102		Total House Regulators - Dir. Assigned		$ 92,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,302
103	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**												
104		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105		Demand	NRDEM	$ 15,882,413	$ -	$ 8,280,245	$ 159,176	$ 3,364,240	$ 144,659	$ 905,096	$ 484,258	$ 365,972	$ 317,958	$ 1,860,807
106		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
107		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 15,882,413	$ -	$ 8,280,245	$ 159,176	$ 3,364,240	$ 144,659	$ 905,096	$ 484,258	$ 365,972	$ 317,958	$ 1,860,807
108	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**												
109		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110		Demand	DEM-DA	$ 330,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,071
111		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ 330,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,071

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
113		**Distribution Plant (Cont'd)**												
114	386	**Other Prop.-Customer Premises**												
115		Customer	CUS	$ 624,137	$ 588,336	$ 33,157	$ 72	$ 2,378	$ 44	$ 49	$ 33	$ 16	$ 9	$ 42
116		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118		Total Other Prop.- Cust. Premises		$ 624,137	$ 588,336	$ 33,157	$ 72	$ 2,378	$ 44	$ 49	$ 33	$ 16	$ 9	$ 42
119	387	**Other Equipment**												
120		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
124		**Total Distribution Plant**												
125		Customer		$ 409,452,764	$ 373,725,099	$ 28,633,606	$ 122,939	$ 2,896,365	$ 69,602	$ 104,938	$ 71,652	$ 33,438	$ 19,107	$ 3,776,019
126		Demand		$ 124,226,028	$ 72,517,131	$ 25,005,254	$ 480,692	$ 10,159,565	$ 436,852	$ 2,733,272	$ 1,462,397	$ 1,105,189	$ 960,190	$ 9,365,486
127		Commodity		$ 918,946	$ 540,315	$ 183,578	$ 5,322	$ 41,402	$ 6,984	$ 38,680	$ 30,824	$ 10,302	$ 24,243	$ 37,297
128		Total Distribution Plant		$ 534,597,739	$ 446,782,546	$ 53,822,438	$ 608,952	$ 13,097,332	$ 513,437	$ 2,876,890	$ 1,564,873	$ 1,148,928	$ 1,003,541	$ 13,178,802
129		**General Plant**												
130		**Total General Plant - Allocated**												
131		Customer	GENPTCUS	$ 67,111,777	$ 62,185,208	$ 4,170,743	$ 14,426	$ 373,250	$ 8,339	$ 11,670	$ 7,966	$ 3,717	$ 2,124	$ 334,335
132		Demand	DISPLTDEM	$ 10,925,375	$ 6,370,269	$ 2,196,587	$ 42,226	$ 892,467	$ 38,375	$ 240,104	$ 128,464	$ 97,085	$ 97,085	$ 822,711
133		Commodity	COM	$ 89,556	$ 52,656	$ 17,891	$ 519	$ 4,035	$ 681	$ 3,770	$ 3,004	$ 1,004	$ 2,363	$ 3,635
134		Total General Plant - Allocated		$ 78,126,708	$ 68,608,133	$ 6,385,221	$ 57,171	$ 1,269,752	$ 47,395	$ 255,543	$ 139,434	$ 101,807	$ 101,572	$ 1,160,681
135		**Total General Plant - Directly Assigned**												
136		Customer	CUS-DA	$ 30,367	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,367
137		Demand	DEM-DA	$ 30,216	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,216
138		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
139		Total General Plant - Directly Assigned		$ 60,583	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,583
140		**Total General Plant**												
141		Customer		$ 67,142,144	$ 62,185,208	$ 4,170,743	$ 14,426	$ 373,250	$ 8,339	$ 11,670	$ 7,966	$ 3,717	$ 2,124	$ 364,702
142		Demand		$ 10,955,591	$ 6,370,269	$ 2,196,587	$ 42,226	$ 892,467	$ 38,375	$ 240,104	$ 128,464	$ 97,085	$ 97,085	$ 852,927
143		Commodity		$ 89,556	$ 52,656	$ 17,891	$ 519	$ 4,035	$ 681	$ 3,770	$ 3,004	$ 1,004	$ 2,363	$ 3,635
144		Total General Plant		$ 78,187,291	$ 68,608,133	$ 6,385,221	$ 57,171	$ 1,269,752	$ 47,395	$ 255,543	$ 139,434	$ 101,807	$ 101,572	$ 1,221,264
145		**Total Plant in Service**												
146		Customer		$ 477,155,470	$ 436,438,715	$ 32,834,129	$ 137,429	$ 3,271,750	$ 77,981	$ 116,651	$ 79,648	$ 37,169	$ 21,239	$ 4,140,759
147		Demand		$ 180,961,350	$ 110,626,343	$ 34,521,961	$ 663,637	$ 14,026,177	$ 603,113	$ 3,773,523	$ 2,018,968	$ 1,525,810	$ 1,338,365	$ 11,863,452
148		Commodity		$ 1,111,483	$ 653,521	$ 222,041	$ 6,437	$ 50,076	$ 8,447	$ 46,784	$ 37,282	$ 12,461	$ 29,322	$ 45,112
149		Total Plant in Service		$ 659,228,303	$ 547,718,579	$ 67,578,131	$ 807,504	$ 17,348,003	$ 689,540	$ 3,936,959	$ 2,135,898	$ 1,575,440	$ 1,388,927	$ 16,049,323
150		**Depreciation & Amort. Reserve**												
151		**Intangible Plant**												
152		Customer	NONINCUS	$ (285,666)	$ (269,280)	$ (15,176)	$ (33)	$ (1,088)	$ (20)	$ (22)	$ (15)	$ (7)	$ (4)	$ (19)
153		Demand	NONINDEM	$ (72,085)	$ (49,977)	$ (11,526)	$ (222)	$ (4,683)	$ (201)	$ (1,260)	$ (674)	$ (509)	$ (443)	$ (2,590)
154		Commodity	COM	$ (879)	$ (517)	$ (176)	$ (5)	$ (40)	$ (7)	$ (37)	$ (29)	$ (10)	$ (23)	$ (36)
155		Total Intangible Plant		$ (358,631)	$ (319,774)	$ (26,878)	$ (260)	$ (5,811)	$ (228)	$ (1,319)	$ (719)	$ (526)	$ (470)	$ (2,645)
156		**Transmission Plant**												
157		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158		Demand	DEM	$ (2,907,255)	$ (2,015,591)	$ (464,866)	$ (8,936)	$ (188,874)	$ (8,121)	$ (50,814)	$ (27,187)	$ (20,546)	$ (17,851)	$ (104,469)
159		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
160		Total Transmission Plant		$ (2,907,255)	$ (2,015,591)	$ (464,866)	$ (8,936)	$ (188,874)	$ (8,121)	$ (50,814)	$ (27,187)	$ (20,546)	$ (17,851)	$ (104,469)
161		**Distribution Plant - Allocated**												
162		Customer	DISPLTCUS	$ (70,694,382)	$ (64,525,794)	$ (4,943,757)	$ (21,226)	$ (500,074)	$ (12,017)	$ (18,118)	$ (12,371)	$ (5,773)	$ (3,299)	$ (651,951)
163		Demand	DISPLTDEM	$ (17,839,155)	$ (10,401,493)	$ (3,586,628)	$ (68,948)	$ (1,457,237)	$ (62,660)	$ (392,047)	$ (209,759)	$ (158,523)	$ (158,523)	$ (1,343,338)
164		Commodity	COM	$ (217,629)	$ (127,960)	$ (43,476)	$ (1,260)	$ (9,805)	$ (1,654)	$ (9,160)	$ (7,300)	$ (2,440)	$ (5,741)	$ (8,833)
165		Total Distribution Plant - Allocated		$ (88,751,166)	$ (75,055,247)	$ (8,573,861)	$ (91,434)	$ (1,967,116)	$ (76,331)	$ (419,325)	$ (229,430)	$ (166,736)	$ (167,563)	$ (2,004,123)
166		**Distribution Plant - Dir. Assn.**												
167		Customer	CUS-DA	$ (603,828)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (603,828)
168		Demand	DEM-DA	$ (479,887)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (479,887)
169		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
170		Total Distribution Plant - Dir. Assn.		$ (1,083,716)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,083,716)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
171		**General Plant - Allocated**												
172		Customer	GENPTCUS	$ (20,942,535)	$ (19,405,177)	$ (1,301,499)	$ (4,502)	$ (116,474)	$ (2,602)	$ (3,642)	$ (2,486)	$ (1,160)	$ (663)	$ (104,331)
173		Demand	DISPLTDEM	$ (2,490,748)	$ (1,452,283)	$ (500,774)	$ (9,627)	$ (203,463)	$ (8,749)	$ (54,739)	$ (29,287)	$ (22,133)	$ (22,133)	$ (187,560)
174		Commodity	COM	$ (18,512)	$ (10,885)	$ (3,698)	$ (107)	$ (834)	$ (141)	$ (779)	$ (621)	$ (208)	$ (488)	$ (751)
175		Total General Plant - Allocated		$ (23,451,796)	$ (20,868,344)	$ (1,805,972)	$ (14,235)	$ (320,771)	$ (11,492)	$ (59,159)	$ (32,394)	$ (23,501)	$ (23,285)	$ (292,643)
176		**General Plant - Directly Assigned**												
177		Customer	CUS-DA	$ (9,867)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,867)
178		Demand	DEM-DA	$ (9,818)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,818)
179		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
180		Total General Plant - Directly Assn.		$ (19,685)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,685)
181		**Total Depr. & Amort. Reserve**												
182		Customer		$ (92,536,278)	$ (84,200,251)	$ (6,260,432)	$ (25,761)	$ (617,637)	$ (14,640)	$ (21,782)	$ (14,872)	$ (6,940)	$ (3,966)	$ (1,369,997)
183		Demand		$ (23,798,950)	$ (13,919,344)	$ (4,563,795)	$ (87,733)	$ (1,854,257)	$ (79,731)	$ (498,859)	$ (266,907)	$ (201,712)	$ (198,949)	$ (2,127,663)
184		Commodity		$ (237,021)	$ (139,362)	$ (47,350)	$ (1,373)	$ (10,679)	$ (1,801)	$ (9,977)	$ (7,950)	$ (2,657)	$ (6,253)	$ (9,620)
185		Total Depr. & Amortization Reserve		$ (116,572,248)	$ (98,258,956)	$ (10,871,577)	$ (114,866)	$ (2,482,572)	$ (96,172)	$ (530,618)	$ (289,729)	$ (211,309)	$ (209,168)	$ (3,507,280)
186		**Net Plant in Service**												
187		Customer		$ 384,619,192	$ 352,238,464	$ 26,573,696	$ 111,669	$ 2,654,113	$ 63,341	$ 94,869	$ 64,776	$ 30,229	$ 17,274	$ 2,770,762
188		Demand		$ 157,162,400	$ 96,706,999	$ 29,958,166	$ 575,905	$ 12,171,920	$ 523,382	$ 3,274,664	$ 1,752,061	$ 1,324,099	$ 1,139,416	$ 9,735,789
189		Commodity		$ 874,462	$ 514,160	$ 174,691	$ 5,064	$ 39,398	$ 6,645	$ 36,808	$ 29,331	$ 9,803	$ 23,069	$ 35,492
190		Total Net Plant in Service		$ 542,656,055	$ 449,459,623	$ 56,706,554	$ 692,637	$ 14,865,431	$ 593,368	$ 3,406,341	$ 1,846,168	$ 1,364,131	$ 1,179,759	$ 12,542,043
191		**Customer Deposits**												
192		Customer	DEPCUS	$ (7,026,858)	$ (4,183,526)	$ (2,684,022)	$ (39,658)	$ (39,904)	$ (3,131)	$ (65,401)	$ -	$ -	$ (11,216)	$ -
193		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194		Commodity	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
195		Total Customer Deposits		$ (7,026,858)	$ (4,183,526)	$ (2,684,022)	$ (39,658)	$ (39,904)	$ (3,131)	$ (65,401)	$ -	$ -	$ (11,216)	$ -
196		**Customer Advances**												
197		Customer	MSCUS-ALL	$ (2,346,728)	$ (2,185,952)	$ (148,807)	$ (413)	$ (10,670)	$ (200)	$ (279)	$ (190)	$ (89)	$ (51)	$ (78)
198		Demand	DEM	$ (626,375)	$ (434,263)	$ (100,156)	$ (1,925)	$ (40,693)	$ (1,750)	$ (10,948)	$ (5,858)	$ (4,427)	$ (3,846)	$ (22,508)
199		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200		Total Customer Advances		$ (2,973,102)	$ (2,620,215)	$ (248,963)	$ (2,339)	$ (51,364)	$ (1,949)	$ (11,227)	$ (6,048)	$ (4,516)	$ (3,897)	$ (22,586)
201		**Accum. Deferred Income Taxes**												
202		Customer	TPLTCUS	$ (28,153,898)	$ (25,751,463)	$ (1,937,332)	$ (8,109)	$ (193,045)	$ (4,601)	$ (6,883)	$ (4,700)	$ (2,193)	$ (1,253)	$ (244,320)
203		Demand	TPLTDEM	$ (10,677,374)	$ (6,520,600)	$ (2,034,813)	$ (39,116)	$ (826,739)	$ (35,549)	$ (222,421)	$ (119,003)	$ (89,935)	$ (89,935)	$ (699,262)
204		Commodity	COM	$ (65,581)	$ (38,560)	$ (13,101)	$ (380)	$ (2,955)	$ (498)	$ (2,760)	$ (2,200)	$ (735)	$ (1,730)	$ (2,662)
205		Total Accum. Deferred Inc. Taxes		$ (38,896,854)	$ (32,310,623)	$ (3,985,246)	$ (47,605)	$ (1,022,739)	$ (40,649)	$ (232,064)	$ (125,902)	$ (92,863)	$ (92,918)	$ (946,244)
206		**Excess Deferred Income Taxes**												
207		Customer	TPLTCUS	$ (8,533,933)	$ (7,805,713)	$ (587,239)	$ (2,458)	$ (58,515)	$ (1,395)	$ (2,086)	$ (1,425)	$ (665)	$ (380)	$ (74,058)
208		Demand	TPLTDEM	$ (3,236,497)	$ (1,976,507)	$ (616,787)	$ (11,857)	$ (250,599)	$ (10,776)	$ (67,420)	$ (36,072)	$ (27,261)	$ (27,261)	$ (211,958)
209		Commodity	COM	$ (19,879)	$ (11,688)	$ (3,971)	$ (115)	$ (896)	$ (151)	$ (837)	$ (667)	$ (223)	$ (524)	$ (807)
210		**Total Excess Deferred Income Taxes**		$ (11,790,309)	$ (9,793,908)	$ (1,207,997)	$ (14,430)	$ (310,010)	$ (12,321)	$ (70,343)	$ (38,163)	$ (28,149)	$ (28,165)	$ (286,823)
211		**Materials and Supplies**												
212		Customer	TPLTCUS	$ 3,427,416	$ 3,134,947	$ 235,848	$ 987	$ 23,501	$ 560	$ 838	$ 572	$ 267	$ 153	$ 29,743
213		Demand	TPLTDEM	$ 1,299,848	$ 793,809	$ 247,715	$ 4,762	$ 100,646	$ 4,328	$ 27,077	$ 14,487	$ 10,949	$ 10,949	$ 85,127
214		Commodity	COM	$ 7,984	$ 4,694	$ 1,595	$ 46	$ 360	$ 61	$ 336	$ 268	$ 90	$ 211	$ 324
215		Total Materials and Supplies		$ 4,735,248	$ 3,933,449	$ 485,158	$ 5,795	$ 124,507	$ 4,948	$ 28,251	$ 15,327	$ 11,305	$ 11,312	$ 115,194
216		**Prepayments**												
217		Customer	OPEXPCUS	$ 2,526,405	$ 2,304,500	$ 184,006	$ 911	$ 19,983	$ 524	$ 772	$ 527	$ 245	$ 141	$ 14,797
218		Demand	OPEXPDEM	$ 485,143	$ 302,018	$ 89,997	$ 1,730	$ 36,566	$ 1,572	$ 9,837	$ 5,263	$ 3,978	$ 3,489	$ 30,692
219		Commodity	COM	$ 43,952	$ 25,842	$ 8,780	$ 255	$ 1,980	$ 334	$ 1,850	$ 1,474	$ 493	$ 1,159	$ 1,784
220		Total Prepayments		$ 3,055,500	$ 2,632,360	$ 282,784	$ 2,895	$ 58,529	$ 2,430	$ 12,459	$ 7,265	$ 4,715	$ 4,789	$ 47,273
221		**Pension & FAS 106 Reg. Asset**												
222		Customer	OPEXPCUS	$ 15,409,499	$ 14,056,016	$ 1,122,324	$ 5,555	$ 121,886	$ 3,195	$ 4,708	$ 3,216	$ 1,492	$ 858	$ 90,250
223		Demand	OPEXPDEM	$ 2,959,069	$ 1,842,120	$ 548,928	$ 10,552	$ 223,028	$ 9,590	$ 60,002	$ 32,103	$ 24,262	$ 21,280	$ 187,203
224		Commodity	COM	$ 268,078	$ 157,622	$ 53,554	$ 1,553	$ 12,078	$ 2,037	$ 11,284	$ 8,992	$ 3,005	$ 7,072	$ 10,880
225		Total Pen. & FAS 106 Reg. Asset		$ 18,636,646	$ 16,055,758	$ 1,724,806	$ 17,660	$ 356,992	$ 14,822	$ 75,994	$ 44,311	$ 28,759	$ 29,210	$ 288,334
226		**DIMP Deferrals**												
227		Customer	TPLTCUS	$ 1,138,867	$ 1,041,685	$ 78,368	$ 328	$ 7,809	$ 186	$ 278	$ 190	$ 89	$ 51	$ 9,883
228		Demand	TPLTDEM	$ 218,695	$ 133,556	$ 41,677	$ 801	$ 16,933	$ 728	$ 4,556	$ 2,437	$ 1,842	$ 1,842	$ 14,322
229		Commodity	COM	$ 19,813	$ 11,649	$ 3,958	$ 115	$ 893	$ 151	$ 834	$ 665	$ 222	$ 523	$ 804
230		Total DIMP Deferrals		$ 1,377,375	$ 1,186,890	$ 124,003	$ 1,244	$ 25,635	$ 1,065	$ 5,668	$ 3,292	$ 2,153	$ 2,415	$ 25,010

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
231		**Regulatory Assets**												
232		Customer	TPLTCUS	$ 1,342,535	$ 1,227,974	$ 92,383	$ 387	$ 9,205	$ 219	$ 328	$ 224	$ 105	$ 60	$ 11,651
233		Demand	TPLTDEM	$ 257,806	$ 157,440	$ 49,131	$ 944	$ 19,962	$ 858	$ 5,370	$ 2,873	$ 2,171	$ 2,171	$ 16,884
234		Commodity	COM	$ 23,356	$ 13,733	$ 4,666	$ 135	$ 1,052	$ 177	$ 983	$ 783	$ 262	$ 616	$ 948
235		**Total Regulatory Assets**		$ 1,623,697	$ 1,399,146	$ 146,179	$ 1,466	$ 30,219	$ 1,255	$ 6,682	$ 3,881	$ 2,538	$ 2,847	$ 29,482
236		**Cash Working Capital**												
237		Customer	OPEXPCUS	$ (2,794,149)	$ (2,548,727)	$ (203,507)	$ (1,007)	$ (22,101)	$ (579)	$ (854)	$ (583)	$ (271)	$ (155)	$ (16,365)
238		Demand	OPEXPDEM	$ (536,557)	$ (334,025)	$ (99,535)	$ (1,913)	$ (40,441)	$ (1,739)	$ (10,880)	$ (5,821)	$ (4,399)	$ (3,859)	$ (33,945)
239		Commodity	COM	$ (48,610)	$ (28,581)	$ (9,711)	$ (282)	$ (2,190)	$ (369)	$ (2,046)	$ (1,630)	$ (545)	$ (1,282)	$ (1,973)
240		Total Cash Working Capital		$ (3,379,316)	$ (2,911,333)	$ (312,753)	$ (3,202)	$ (64,732)	$ (2,688)	$ (13,780)	$ (8,035)	$ (5,215)	$ (5,297)	$ (52,283)
241		**Total Rate Base**												
242		Customer		$ 359,608,349	$ 331,528,205	$ 22,725,719	$ 68,191	$ 2,512,262	$ 58,119	$ 26,291	$ 62,608	$ 29,208	$ 5,479	$ 2,592,266
243		Demand		$ 147,306,159	$ 90,670,547	$ 28,084,323	$ 539,883	$ 11,410,582	$ 490,645	$ 3,069,839	$ 1,642,472	$ 1,241,278	$ 1,054,246	$ 9,102,344
244		Commodity		$ 1,103,574	$ 648,871	$ 220,461	$ 6,391	$ 49,720	$ 8,387	$ 46,451	$ 37,016	$ 12,372	$ 29,114	$ 44,791
245		Total Rate Base		$ 508,018,082	$ 422,847,623	$ 51,030,503	$ 614,464	$ 13,972,565	$ 557,150	$ 3,142,581	$ 1,742,096	$ 1,282,858	$ 1,088,839	$ 11,739,401

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1		**Transmission and Distribution Op. Exp.**												
2	814-866	**Transmission Expenses**												
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 1,383,447	$ 959,140	$ 221,211	$ 4,252	$ 89,878	$ 3,865	$ 24,180	$ 12,937	$ 9,777	$ 8,494	$ 49,713
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 1,383,447	$ 959,140	$ 221,211	$ 4,252	$ 89,878	$ 3,865	$ 24,180	$ 12,937	$ 9,777	$ 8,494	$ 49,713
7	8700	**Operation Supervision & Engineering**												
8		Customer	871-879CUS	$ 683,850	$ 612,862	$ 60,293	$ 414	$ 9,132	$ 258	$ 404	$ 276	$ 129	$ 74	$ 10
9		Demand	DEM	$ 120,969	$ 83,867	$ 19,343	$ 372	$ 7,859	$ 338	$ 2,114	$ 1,131	$ 855	$ 743	$ 4,347
10		Commodity	COM	$ 22,365	$ 13,150	$ 4,468	$ 130	$ 1,008	$ 170	$ 941	$ 750	$ 251	$ 590	$ 908
11		Total Supervision & Engineering		$ 827,183	$ 709,879	$ 84,104	$ 915	$ 17,998	$ 765	$ 3,459	$ 2,157	$ 1,234	$ 1,406	$ 5,264
12	8710	**Distribution Load Dispatch**												
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 211,750	$ 124,503	$ 42,301	$ 1,226	$ 9,540	$ 1,609	$ 8,913	$ 7,103	$ 2,374	$ 5,586	$ 8,594
16		Total Distribution Load Dispatch		$ 211,750	$ 124,503	$ 42,301	$ 1,226	$ 9,540	$ 1,609	$ 8,913	$ 7,103	$ 2,374	$ 5,586	$ 8,594
17	8740	**Mains & Services - Allocated**												
18		Customer	MSCUS-ALL	$ 2,760,090	$ 2,570,994	$ 175,018	$ 486	$ 12,550	$ 235	$ 328	$ 224	$ 104	$ 60	$ 91
19		Demand	DEM	$ 721,596	$ 500,280	$ 115,382	$ 2,218	$ 46,879	$ 2,016	$ 12,612	$ 6,748	$ 5,100	$ 4,431	$ 25,930
20		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Total Mains & Services - Allocated		$ 3,481,686	$ 3,071,274	$ 290,400	$ 2,704	$ 59,429	$ 2,251	$ 12,940	$ 6,972	$ 5,204	$ 4,490	$ 26,021
22	8740	**Mains & Services - Dir. Assn.**												
23		Customer	MSCUS-DA	$ 28,971	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,971
24		Demand	DEM-DA	$ 22,844	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,844
25		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Total Mains & Services - Dir. Assn.		$ 51,815	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51,815
27	8750	**Meas. & Reg. Station - Gen. - Allocated**												
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ 291,973	$ 202,424	$ 46,686	$ 897	$ 18,968	$ 816	$ 5,103	$ 2,730	$ 2,063	$ 1,793	$ 10,492
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31		Total Meas. & Reg. Station - Gen. - Allocated		$ 291,973	$ 202,424	$ 46,686	$ 897	$ 18,968	$ 816	$ 5,103	$ 2,730	$ 2,063	$ 1,793	$ 10,492
32		**Meas. & Reg. Station - Gen. - DA**												
33	8750	Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM-DA	$ 19,601	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,601
35		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Meas. & Reg. Station - Gen. - DA		$ 19,601	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,601
37	8750	**Odorization**												
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ 58,181	$ 34,209	$ 11,623	$ 337	$ 2,621	$ 442	$ 2,449	$ 1,952	$ 652	$ 1,535	$ 2,361
41		Total Odorization		$ 58,181	$ 34,209	$ 11,623	$ 337	$ 2,621	$ 442	$ 2,449	$ 1,952	$ 652	$ 1,535	$ 2,361
42	8760	**Meas. & Reg. Stat. - Ind. - Allocated**												
43		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	NRDEM	$ 25,471	$ -	$ 13,279	$ 255	$ 5,395	$ 232	$ 1,452	$ 777	$ 587	$ 510	$ 2,984
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Stat. - Ind. - Allocated		$ 25,471	$ -	$ 13,279	$ 255	$ 5,395	$ 232	$ 1,452	$ 777	$ 587	$ 510	$ 2,984
47	8760	**Meas. & Reg. Stat. - Ind. - DA**												
48		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM-DA	$ 529	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 529
50		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Stat. - Ind. - DA		$ 529	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 529

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
52		**Transmission and Distribution Op. Exp. (Cont'd)**												
53	8770	**Meas. & Reg. Stat.- City Gate**												
54		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	DEM	$ 63,314	$ 43,895	$ 10,124	$ 195	$ 4,113	$ 177	$ 1,107	$ 592	$ 447	$ 389	$ 2,275
56		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57		Total Meas. & Reg. Stat. - City Gate		$ 63,314	$ 43,895	$ 10,124	$ 195	$ 4,113	$ 177	$ 1,107	$ 592	$ 447	$ 389	$ 2,275
58	8780	**Meter & House Reg. Exp. - Alloc.**												
59		Customer	MTRGCUS-ALL	$ 3,537,652	$ 3,076,015	$ 378,215	$ 3,282	$ 70,730	$ 2,108	$ 3,343	$ 2,284	$ 1,066	$ 609	$ -
60		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62		Total Meter & House Reg. Exp. - Alloc.		$ 3,537,652	$ 3,076,015	$ 378,215	$ 3,282	$ 70,730	$ 2,108	$ 3,343	$ 2,284	$ 1,066	$ 609	$ -
63	8780	**Meter & House Reg. Exp - Dir. Assn.**												
64		Customer	CUS-DA	$ 12,329	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,329
65		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67		Total Meter & House Reg. Exp. - DA		$ 12,329	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,329
68	8780	**Odorization**												
69		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71		Commodity	COM	$ 56	$ 33	$ 11	$ 0	$ 3	$ 0	$ 2	$ 2	$ 1	$ 1	$ 2
72		Total Odorization		$ 56	$ 33	$ 11	$ 0	$ 3	$ 0	$ 2	$ 2	$ 1	$ 1	$ 2
73	8790	**Customer Installation Expense**												
74		Customer	METCUS-ALL	$ 135,636	$ 118,545	$ 13,979	$ 125	$ 2,629	$ 80	$ 127	$ 87	$ 41	$ 23	$ -
75		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77		Total Customer Install. Expense		$ 135,636	$ 118,545	$ 13,979	$ 125	$ 2,629	$ 80	$ 127	$ 87	$ 41	$ 23	$ -
78	8800	**Other Expenses**												
79		Customer	871-879CUS	$ 630,954	$ 565,457	$ 55,629	$ 382	$ 8,426	$ 238	$ 372	$ 254	$ 119	$ 68	$ 9
80		Demand	DEM	$ 111,612	$ 77,380	$ 17,847	$ 343	$ 7,251	$ 312	$ 1,951	$ 1,044	$ 789	$ 685	$ 4,011
81		Commodity	COM	$ 20,635	$ 12,133	$ 4,122	$ 120	$ 930	$ 157	$ 869	$ 692	$ 231	$ 544	$ 838
82		Total Other Expenses		$ 763,201	$ 654,970	$ 77,598	$ 844	$ 16,606	$ 706	$ 3,192	$ 1,990	$ 1,139	$ 1,298	$ 4,857
83	8810	**Rents**												
84		Customer	871-879CUS	$ 37,975	$ 34,033	$ 3,348	$ 23	$ 507	$ 14	$ 22	$ 15	$ 7	$ 4	$ 1
85		Demand	DEM	$ 6,717	$ 4,657	$ 1,074	$ 21	$ 436	$ 19	$ 117	$ 63	$ 47	$ 41	$ 241
86		Commodity	COM	$ 1,242	$ 730	$ 248	$ 7	$ 56	$ 9	$ 52	$ 42	$ 14	$ 33	$ 50
87		Total Rents		$ 45,934	$ 39,420	$ 4,670	$ 51	$ 999	$ 43	$ 192	$ 120	$ 69	$ 78	$ 292
88	8820	**Corporate & Div. Exp.**												
89		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92		Total Corporate & Div. Exp.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93		**Total Distr. & Trans. Op. Expense**												
94		Customer		$ 7,827,456	$ 6,977,905	$ 686,482	$ 4,712	$ 103,974	$ 2,932	$ 4,597	$ 3,140	$ 1,465	$ 837	$ 41,411
95		Demand		$ 2,768,073	$ 1,871,644	$ 444,946	$ 8,553	$ 180,780	$ 7,773	$ 48,636	$ 26,022	$ 19,666	$ 17,086	$ 142,966
96		Commodity		$ 314,228	$ 184,757	$ 62,773	$ 1,820	$ 14,157	$ 2,388	$ 13,226	$ 10,540	$ 3,523	$ 8,290	$ 12,754
97		Total Distr. & Trans. Operations Exp.		$ 10,909,757	$ 9,034,306	$ 1,194,202	$ 15,085	$ 298,912	$ 13,094	$ 66,459	$ 39,702	$ 24,654	$ 26,213	$ 197,130

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
98		**Distribution Maintenance Expenses**												
99	8850	**Maintenance Supervision and Engineering**												
100		Customer	887-893CUS	$ 14,931	$ 13,975	$ 885	$ 2	$ 63	$ 1	$ 2	$ 1	$ 0	$ 0	$ 1
101		Demand	887-893DEM	$ 9,804	$ 5,626	$ 2,178	$ 42	$ 885	$ 38	$ 238	$ 127	$ 96	$ 84	$ 489
102		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103		Total Supervision and Engineering		$ 24,735	$ 19,601	$ 3,063	$ 44	$ 948	$ 39	$ 240	$ 128	$ 97	$ 84	$ 490
104	8860	**Structures and Improvements**												
105		Customer	887-893CUS	$ 203,734	$ 190,691	$ 12,082	$ 31	$ 860	$ 16	$ 21	$ 14	$ 7	$ 4	$ 10
106		Demand	887-893DEM	$ 133,771	$ 76,770	$ 29,717	$ 571	$ 12,074	$ 519	$ 3,248	$ 1,738	$ 1,313	$ 1,141	$ 6,678
107		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
108		Total Structures and Improvements		$ 337,505	$ 267,461	$ 41,800	$ 602	$ 12,934	$ 535	$ 3,269	$ 1,752	$ 1,320	$ 1,145	$ 6,688
109	8870	**Maintenance of Mains-Allocated**												
110		Customer	CUS	$ 1,595,147	$ 1,503,649	$ 84,742	$ 185	$ 6,076	$ 114	$ 125	$ 85	$ 40	$ 23	$ 108
111		Demand	DEM	$ 858,593	$ 595,260	$ 137,288	$ 2,639	$ 55,780	$ 2,398	$ 15,007	$ 8,029	$ 6,068	$ 5,272	$ 30,852
112		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113		Total Mains - Allocated		$ 2,453,740	$ 2,098,908	$ 222,029	$ 2,824	$ 61,856	$ 2,512	$ 15,132	$ 8,114	$ 6,108	$ 5,295	$ 30,961
114	8870	**Maintenance of Mains - Directly Assigned**												
115		Customer	CUS-DA	$ 25,489	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,489
116		Demand	DEM-DA	$ 27,181	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,181
117		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118		Total Mains - Directly Assigned		$ 52,669	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 52,669
119	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**												
120		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Demand	DEM	$ 367,583	$ 254,844	$ 58,776	$ 1,130	$ 23,881	$ 1,027	$ 6,425	$ 3,437	$ 2,598	$ 2,257	$ 13,209
122		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 367,583	$ 254,844	$ 58,776	$ 1,130	$ 23,881	$ 1,027	$ 6,425	$ 3,437	$ 2,598	$ 2,257	$ 13,209
124	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**												
125		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126		Demand	DEM-DA	$ 25,490	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,490
127		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
128		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 25,490	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,490
129	8890	**Odorization**												
130		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132		Commodity	COM	$ 87,787	$ 51,616	$ 17,537	$ 508	$ 3,955	$ 667	$ 3,695	$ 2,945	$ 984	$ 2,316	$ 3,563
133		Total Odorization		$ 87,787	$ 51,616	$ 17,537	$ 508	$ 3,955	$ 667	$ 3,695	$ 2,945	$ 984	$ 2,316	$ 3,563
134	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**												
135		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136		Demand	NRDEM	$ 256,051	$ -	$ 133,491	$ 2,566	$ 54,237	$ 2,332	$ 14,592	$ 7,807	$ 5,900	$ 5,126	$ 29,999
137		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 256,051	$ -	$ 133,491	$ 2,566	$ 54,237	$ 2,332	$ 14,592	$ 7,807	$ 5,900	$ 5,126	$ 29,999
139	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**												
140		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
141		Demand	DEM-DA	$ 5,321	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,321
142		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ 5,321	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,321
144	8910	**Meas. & Reg. Sta. Eq.- City Gate**												
145		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
146		Demand	DEM	$ 4,437	$ 3,076	$ 709	$ 14	$ 288	$ 12	$ 78	$ 41	$ 31	$ 27	$ 159
147		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148		Total Meas. & Reg. Sta. Eq.- City Gate		$ 4,437	$ 3,076	$ 709	$ 14	$ 288	$ 12	$ 78	$ 41	$ 31	$ 27	$ 159
149	8920	**Services - Allocated**												
150		Customer	SERCUS-ALL	$ 734,099	$ 676,075	$ 53,681	$ 171	$ 3,849	$ 72	$ 115	$ 79	$ 37	$ 21	$ -
151		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153		Total Services - Allocated		$ 734,099	$ 676,075	$ 53,681	$ 171	$ 3,849	$ 72	$ 115	$ 79	$ 37	$ 21	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
154		**Distribution Maintenance Expenses (Cont'd)**												
155	8920	**Services - Directly Assigned**												
156		Customer	CUS-DA	$ 3,904	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,904
157		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
159		Total Services - Directly Assigned		$ 3,904	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,904
160	8930	**Meters & House Regulators - Alloc.**												
161		Customer	MTRGCUS-ALL	$ (6,092)	$ (5,297)	$ (651)	$ (6)	$ (122)	$ (4)	$ (6)	$ (4)	$ (2)	$ (1)	$ -
162		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
164		Total Meters & House Regulators - Alloc.		$ (6,092)	$ (5,297)	$ (651)	$ (6)	$ (122)	$ (4)	$ (6)	$ (4)	$ (2)	$ (1)	$ -
165	8930	**Meters & House Regulators - DA**												
166		Customer	CUS-DA	$ (21)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (21)
167		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169		Total Meters & House Regulators - DA		$ (21)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (21)
170	8940	**Maintenance of Other Equipment**												
171		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
174		Total Maintenance of Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	8950	**Clearing - Meter Shop - Small Meters**												
176		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179		Total Clearing-Meter-Shop-Small Meters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
180	8960	**Clearing - Meter Shop - Large Meters**												
181		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
182		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
184		Total Clearing-Meter Shop-Large Meters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
185		**Total Distr. Maintenance Expense**												
186		Customer		$ 2,571,191	$ 2,379,093	$ 150,739	$ 383	$ 10,727	$ 199	$ 257	$ 175	$ 82	$ 47	$ 29,490
187		Demand		$ 1,688,230	$ 935,576	$ 362,160	$ 6,962	$ 147,145	$ 6,327	$ 39,587	$ 21,180	$ 16,007	$ 13,907	$ 139,380
188		Commodity		$ 87,787	$ 51,616	$ 17,537	$ 508	$ 3,955	$ 667	$ 3,695	$ 2,945	$ 984	$ 2,316	$ 3,563
189		Total Distr. Maintenance Expense		$ 4,347,209	$ 3,366,285	$ 530,436	$ 7,854	$ 161,826	$ 7,193	$ 43,539	$ 24,300	$ 17,073	$ 16,269	$ 172,433
190		**Total Oper. & Maint. Expense**												
191		Customer		$ 10,398,648	$ 9,356,998	$ 837,221	$ 5,095	$ 114,701	$ 3,131	$ 4,853	$ 3,315	$ 1,547	$ 884	$ 70,901
192		Demand		$ 4,456,303	$ 2,807,219	$ 807,106	$ 15,516	$ 327,925	$ 14,100	$ 88,223	$ 47,202	$ 35,673	$ 30,993	$ 282,345
193		Commodity		$ 402,015	$ 236,374	$ 80,310	$ 2,328	$ 18,112	$ 3,055	$ 16,921	$ 13,485	$ 4,507	$ 10,606	$ 16,317
194		Total Operations & Maint. Expense		$ 15,256,965	$ 12,400,591	$ 1,724,638	$ 22,939	$ 460,738	$ 20,287	$ 109,998	$ 64,002	$ 41,727	$ 42,482	$ 369,563
195		**Customer Accounts Expense**												
196	901	Supervision												
197		Customer	902-904CUS	$ 107,476	$ 99,381	$ 7,537	$ 34	$ 465	$ 15	$ 15	$ 11	$ 4	$ 3	$ 11
198		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200		Total Supervision		$ 107,476	$ 99,381	$ 7,537	$ 34	$ 465	$ 15	$ 15	$ 11	$ 4	$ 3	$ 11

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
201		**Customer Accounts Expense (Cont'd)**												
202	902	**Meter Reading Expense**												
203		Customer	METCUS-TOT	$ 581,671	$ 508,050	$ 59,911	$ 534	$ 11,269	$ 344	$ 545	$ 373	$ 174	$ 99	$ 371
204		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
206		Total Meter Reading Expense		$ 581,671	$ 508,050	$ 59,911	$ 534	$ 11,269	$ 344	$ 545	$ 373	$ 174	$ 99	$ 371
207	903	**Customer Accounting**												
208		Customer	903CUS	$ 2,894,519	$ 2,754,966	$ 133,668	$ 205	$ 5,365	$ 100	$ 76	$ 52	$ 7	$ 14	$ 66
209		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
210		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
211		Total Customer Accounting		$ 2,894,519	$ 2,754,966	$ 133,668	$ 205	$ 5,365	$ 100	$ 76	$ 52	$ 7	$ 14	$ 66
212	904	**Bad Debt Expense**												
213		Customer	904CUS	$ 854,390	$ 741,375	$ 110,125	$ 631	$ 2,095	$ 164	$ -	$ -	$ -	$ -	$ -
214		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216		Total Bad Debt Expense		$ 854,390	$ 741,375	$ 110,125	$ 631	$ 2,095	$ 164	$ -	$ -	$ -	$ -	$ -
217	905	**Miscellaneous Customer Accounts**												
218		Customer	902-904CUS	$ 388,943	$ 359,647	$ 27,277	$ 123	$ 1,682	$ 55	$ 56	$ 38	$ 16	$ 10	$ 39
219		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
220		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221		Total Misc. Customer Accounts		$ 388,943	$ 359,647	$ 27,277	$ 123	$ 1,682	$ 55	$ 56	$ 38	$ 16	$ 10	$ 39
222	907-910	**Customer Information Expense**												
223		Customer	CUS	$ 567,855	$ 535,283	$ 30,167	$ 66	$ 2,163	$ 40	$ 45	$ 30	$ 14	$ 8	$ 39
224		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
225		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
226		Total Customer Information Expense		$ 567,855	$ 535,283	$ 30,167	$ 66	$ 2,163	$ 40	$ 45	$ 30	$ 14	$ 8	$ 39
227		**Sales and Advertising Expense**												
228	911	**Supervision**												
229		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
230		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
231		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232		Total Supervision Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
233	912	**Demonstrating and Selling**												
234		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
235		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
237		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
238	913	**Advertising**												
239		Customer	CUS	$ 4,444	$ 4,189	$ 236	$ 1	$ 17	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
240		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
242		Total Advertising		$ 4,444	$ 4,189	$ 236	$ 1	$ 17	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
243	914	**Employee Sales Referrals**												
244		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
245		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
247		Total Employee Sales Referrals		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
248	916	**Misc. Gas Sales Expense**												
249		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
251		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252		Total Misc. Gas Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
253		**Administrative & General Exp.**												
254	920-940	**Administrative & General Expenses**												
255		Customer	OPEXPCUS	$ 20,563,766	$ 18,757,561	$ 1,497,726	$ 7,413	$ 162,655	$ 4,263	$ 6,283	$ 4,292	$ 1,991	$ 1,144	$ 120,438
256		Demand	OPEXPDEM	$ 2,526,196	$ 1,572,642	$ 468,627	$ 9,009	$ 190,402	$ 8,187	$ 51,225	$ 27,407	$ 20,712	$ 18,167	$ 159,818
257		Commodity	COM	$ 230,567	$ 135,567	$ 46,060	$ 1,335	$ 10,388	$ 1,752	$ 9,705	$ 7,734	$ 2,585	$ 6,083	$ 9,358
258		Total Administrative & General Exp.		$ 23,320,529	$ 20,465,770	$ 2,012,413	$ 17,757	$ 363,445	$ 14,203	$ 67,213	$ 39,432	$ 25,288	$ 25,394	$ 289,614
259		**Depreciation & Amortization Expense**												
260	301-03	**Intangible Plant**												
261		Customer	CUS	$ 7,387	$ 6,964	$ 392	$ 1	$ 28	$ 1	$ 1	$ 0	$ 0	$ 0	$ 1
262		Demand	DEM	$ 2,802	$ 1,942	$ 448	$ 9	$ 182	$ 8	$ 49	$ 26	$ 20	$ 17	$ 101
263		Commodity	COM	$ 17	$ 10	$ 3	$ 0	$ 1	$ 0	$ 1	$ 1	$ 0	$ 0	$ 1
264		Total Intangible Plant		$ 10,206	$ 8,916	$ 844	$ 10	$ 211	$ 8	$ 50	$ 27	$ 20	$ 18	$ 102
265	365	**Land and Land Rights**												
266		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
267		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
268		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
269		Total Land and Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270	366	**Meas. and Reg. Station Structures**												
271		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
272		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
273		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274		Total Measuring and Reg. Stat. Struct.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
275	367	**Transmission Mains**												
276		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
277		Demand	DEM	$ 1,099,234	$ 762,096	$ 175,766	$ 3,379	$ 71,413	$ 3,071	$ 19,213	$ 10,279	$ 7,769	$ 6,749	$ 39,500
278		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
279		Total Transmission Mains		$ 1,099,234	$ 762,096	$ 175,766	$ 3,379	$ 71,413	$ 3,071	$ 19,213	$ 10,279	$ 7,769	$ 6,749	$ 39,500
280	368	**Compression Station Equipment**												
281		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
282		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
283		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
284		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
285	369	**Meas. & Reg. Station Equipment**												
286		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
287		Demand	DEM	$ 80,123	$ 55,549	$ 12,812	$ 246	$ 5,205	$ 224	$ 1,400	$ 749	$ 566	$ 492	$ 2,879
288		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
289		Total Meas. & Reg. Stat. Equipment		$ 80,123	$ 55,549	$ 12,812	$ 246	$ 5,205	$ 224	$ 1,400	$ 749	$ 566	$ 492	$ 2,879
290	371	**Other Equipment**												
291		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
292		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
293		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
294		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
295	375	**Structures and Improvements**												
296		Customer	376-379CUS	$ 5,400	$ 5,090	$ 287	$ 1	$ 21	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
297		Demand	DEM	$ 3,446	$ 2,389	$ 551	$ 11	$ 224	$ 10	$ 60	$ 32	$ 24	$ 21	$ 124
298		Commodity	COM	$ 24	$ 14	$ 5	$ 0	$ 1	$ 0	$ 1	$ 1	$ 0	$ 1	$ 1
299		Total Structures and Improvements		$ 8,870	$ 7,494	$ 843	$ 11	$ 246	$ 10	$ 62	$ 33	$ 25	$ 22	$ 125
300	376	**Distribution Mains - Allocated**												
301		Customer	CUS	$ 4,339,888	$ 4,090,950	$ 230,555	$ 504	$ 16,532	$ 309	$ 340	$ 232	$ 108	$ 62	$ 295
302		Demand	DEM	$ 2,335,958	$ 1,619,512	$ 373,517	$ 7,180	$ 151,759	$ 6,525	$ 40,828	$ 21,845	$ 16,509	$ 14,343	$ 83,940
303		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
304		Total Distribution Mains - Allocated		$ 6,675,845	$ 5,710,462	$ 604,072	$ 7,684	$ 168,291	$ 6,835	$ 41,169	$ 22,077	$ 16,617	$ 14,405	$ 84,235

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
305		**Depreciation & Amortization Expense (Cont'd)**												
306	376	**Distribution Mains - Directly Assigned**												
307		Customer	CUS-DA	$ 59,567	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,567
308		Demand	DEM-DA	$ 63,521	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,521
309		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
310		Distribution Mains - Directly Assigned		$ 123,088	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,088
311	377	**Compressor Station Equipment**												
312		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
313		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
314		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
315		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
316	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**												
317		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
318		Demand	DEM	$ 254,098	$ 176,165	$ 40,630	$ 781	$ 16,508	$ 710	$ 4,441	$ 2,376	$ 1,796	$ 1,560	$ 9,131
319		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
320		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		$ 254,098	$ 176,165	$ 40,630	$ 781	$ 16,508	$ 710	$ 4,441	$ 2,376	$ 1,796	$ 1,560	$ 9,131
321	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**												
322		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
323		Demand	DEM-DA	$ 13,337	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,337
324		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
325		Total Meas. & Reg. Sta. Eq. - Gen. - DA		$ 13,337	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,337
326	378	**Odorization Tank**												
327		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
328		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
329		Commodity	COM	$ 4,127	$ 2,426	$ 824	$ 24	$ 186	$ 31	$ 174	$ 138	$ 46	$ 109	$ 167
330		Total Odorization Tank		$ 4,127	$ 2,426	$ 824	$ 24	$ 186	$ 31	$ 174	$ 138	$ 46	$ 109	$ 167
331	379	**Meas.& Reg. Sta. Equip.- City Gate**												
332		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
333		Demand	DEM	$ 101,651	$ 70,474	$ 16,254	$ 312	$ 6,604	$ 284	$ 1,777	$ 951	$ 718	$ 624	$ 3,653
334		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
335		Total Meas. & Reg. Sta. Eq.- City Gate		$ 101,651	$ 70,474	$ 16,254	$ 312	$ 6,604	$ 284	$ 1,777	$ 951	$ 718	$ 624	$ 3,653
336	379	**Odorization Tank**												
337		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
338		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
339		Commodity	COM	$ 14,900	$ 8,761	$ 2,976	$ 86	$ 671	$ 113	$ 627	$ 500	$ 167	$ 393	$ 605
340		Total Odorization Tank		$ 14,900	$ 8,761	$ 2,976	$ 86	$ 671	$ 113	$ 627	$ 500	$ 167	$ 393	$ 605
341	380	**Services - Allocated**												
342		Customer	SERCUS-ALL	$ 5,546,433	$ 5,108,033	$ 405,581	$ 1,291	$ 29,082	$ 544	$ 872	$ 594	$ 277	$ 158	$ -
343		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
344		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
345		Total Services - Allocated		$ 5,546,433	$ 5,108,033	$ 405,581	$ 1,291	$ 29,082	$ 544	$ 872	$ 594	$ 277	$ 158	$ -
346	380	**Services - Directly Assigned**												
347		Customer	CUS-DA	$ 28,042	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,042
348		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
349		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
350		Total Services - Directly Assigned		$ 28,042	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,042
351	381	**Meters - Allocated**												
352		Customer	METCUS-ALL	$ 2,208,080	$ 1,929,841	$ 227,573	$ 2,027	$ 42,804	$ 1,308	$ 2,071	$ 1,416	$ 661	$ 378	$ -
353		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
354		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
355		Total Meters - Allocated		$ 2,208,080	$ 1,929,841	$ 227,573	$ 2,027	$ 42,804	$ 1,308	$ 2,071	$ 1,416	$ 661	$ 378	$ -
356	381	**Meters - Directly Assigned**												
357		Customer	CUS-DA	$ 6,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,340
358		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
359		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
360		Total Meters - Directly Assigned		$ 6,340	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,340

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
361		**Depreciation & Amortization Expense (Cont'd)**												
362	382	**Meter Installations**												
363		Customer	METCUS-TOT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
364		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
365		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
366		Total Meter Installations		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
367	383	**House Regulators - Allocated**												
368		Customer	REGCUS-ALL	$ 500,597	$ 429,453	$ 58,514	$ 477	$ 10,799	$ 303	$ 482	$ 329	$ 153	$ 88	$ -
369		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
370		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
371		Total House Regulators - Allocated		$ 500,597	$ 429,453	$ 58,514	$ 477	$ 10,799	$ 303	$ 482	$ 329	$ 153	$ 88	$ -
372	383	**House Regulators - Directly Assn.**												
373		Customer	CUS-DA	$ 3,203	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,203
374		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
375		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
376		House Regulators - Directly Assn.		$ 3,203	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,203
377	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**												
378		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
379		Demand	NRDEM	$ 378,344	$ -	$ 197,248	$ 3,792	$ 80,141	$ 3,446	$ 21,561	$ 11,536	$ 8,718	$ 7,574	$ 44,327
380		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
381		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		$ 378,344	$ -	$ 197,248	$ 3,792	$ 80,141	$ 3,446	$ 21,561	$ 11,536	$ 8,718	$ 7,574	$ 44,327
382	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**												
383		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
384		Demand	DEM-DA	$ 7,658	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,658
385		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
386		Total Meas. & Reg. Sta. Equip. - Ind.- DA		$ 7,658	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,658
387	386	**Other Prop.- Customer Premises**												
388		Customer	CUS	$ 86,693	$ 81,720	$ 4,606	$ 10	$ 330	$ 6	$ 7	$ 5	$ 2	$ 1	$ 6
389		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
390		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
391		Total Other Prop. - Customer Premises		$ 86,693	$ 81,720	$ 4,606	$ 10	$ 330	$ 6	$ 7	$ 5	$ 2	$ 1	$ 6
392	387	**Other Equipment**												
393		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
394		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
395		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
396		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
397	389-98	**General Plant - Allocated**												
398		Customer	GENPTCUS	$ 4,420,330	$ 4,095,840	$ 274,707	$ 950	$ 24,584	$ 549	$ 769	$ 525	$ 245	$ 140	$ 22,021
399		Demand	DISPLTDEM	$ 548,387	$ 319,749	$ 110,255	$ 2,120	$ 44,796	$ 1,926	$ 12,052	$ 6,448	$ 4,873	$ 4,873	$ 41,295
400		Commodity	COM	$ 4,624	$ 2,719	$ 924	$ 27	$ 208	$ 35	$ 195	$ 155	$ 52	$ 122	$ 188
401		Total General Plant - Allocated		$ 4,973,341	$ 4,418,308	$ 385,886	$ 3,096	$ 69,589	$ 2,511	$ 13,015	$ 7,128	$ 5,170	$ 5,135	$ 63,504
402	389-98	**General Plant - Directly Assigned**												
403		Customer	CUS-DA	$ 3,590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,590
404		Demand	DEM-DA	$ 445	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 445
405		Commodity	COM-DA	$ 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4
406		Total General Plant - Directly Assn.		$ 4,039	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,039

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
407		**Depreciation & Amortization Expense (Cont'd)**												
408	389-98	**General Plant - Odorization**												
409		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
410		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
411		Commodity	COM	$ 582	$ 342	$ 116	$ 3	$ 26	$ 4	$ 25	$ 20	$ 7	$ 15	$ 24
412		Total General Plant - Odorization		$ 582	$ 342	$ 116	$ 3	$ 26	$ 4	$ 25	$ 20	$ 7	$ 15	$ 24
413	40730	**Pension & FAS 106 Amort. Expense**												
414		Customer	CUS	$ 196,716	$ 185,432	$ 10,450	$ 23	$ 749	$ 14	$ 15	$ 11	$ 5	$ 3	$ 13
415		Demand	DEM	$ 37,775	$ 26,189	$ 6,040	$ 116	$ 2,454	$ 106	$ 660	$ 353	$ 267	$ 232	$ 1,357
416		Commodity	COM	$ 3,422	$ 2,012	$ 684	$ 20	$ 154	$ 26	$ 144	$ 115	$ 38	$ 90	$ 139
417		Total Pension & FAS 106 Amort. Exp.		$ 237,913	$ 213,634	$ 17,174	$ 159	$ 3,358	$ 146	$ 820	$ 479	$ 310	$ 325	$ 1,510
418		**Total Depreciation & Amort. Exp.**												
419		Customer		$ 17,412,264	$ 15,933,323	$ 1,212,665	$ 5,284	$ 124,930	$ 3,034	$ 4,557	$ 3,112	$ 1,452	$ 830	$ 123,078
420		Demand		$ 4,926,780	$ 3,034,066	$ 933,521	$ 17,946	$ 379,287	$ 16,309	$ 102,041	$ 54,596	$ 41,260	$ 36,486	$ 311,268
421		Commodity		$ 27,700	$ 16,285	$ 5,533	$ 160	$ 1,248	$ 210	$ 1,166	$ 929	$ 310	$ 731	$ 1,128
422		Total Depreciation & Amort. Expense		$ 22,366,744	$ 18,983,673	$ 2,151,719	$ 23,390	$ 505,464	$ 19,554	$ 107,764	$ 58,636	$ 43,023	$ 38,047	$ 435,474
423		**Taxes Other Than Income**												
424	4081	**Payroll and Other Taxes**												
425		Customer	OPEXPCUS	$ 1,964,187	$ 1,791,664	$ 143,058	$ 708	$ 15,536	$ 407	$ 600	$ 410	$ 190	$ 109	$ 11,504
426		Demand	OPEXPDEM	$ 377,181	$ 234,808	$ 69,970	$ 1,345	$ 28,428	$ 1,222	$ 7,648	$ 4,092	$ 3,093	$ 2,713	$ 23,862
427		Commodity	COM	$ 34,171	$ 20,092	$ 6,826	$ 198	$ 1,540	$ 260	$ 1,438	$ 1,146	$ 383	$ 901	$ 1,387
428		Total Payroll and Other Taxes		$ 2,375,539	$ 2,046,563	$ 219,854	$ 2,251	$ 45,504	$ 1,889	$ 9,687	$ 5,648	$ 3,666	$ 3,723	$ 36,753
429	4081	**Ad Valorem Taxes - Allocated**												
430		Customer	CUS	$ 4,662,217	$ 4,394,790	$ 247,679	$ 541	$ 17,760	$ 332	$ 365	$ 249	$ 116	$ 66	$ 317
431		Demand	DEM	$ 1,745,130	$ 1,209,893	$ 279,044	$ 5,364	$ 113,375	$ 4,875	$ 30,502	$ 16,319	$ 12,333	$ 10,715	$ 62,709
432		Commodity	COM	$ 10,947	$ 6,437	$ 2,187	$ 63	$ 493	$ 83	$ 461	$ 367	$ 123	$ 289	$ 444
433		Total Ad Valorem Taxes - Allocated		$ 6,418,294	$ 5,611,120	$ 528,910	$ 5,969	$ 131,628	$ 5,290	$ 31,328	$ 16,936	$ 12,572	$ 11,070	$ 63,470
434	4081	**Ad Valorem Taxes - Directly Assn.**												
435		Customer	CUS-DA	$ 37,380	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,380
436		Demand	DEM-DA	$ 37,194	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 37,194
437		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
438		Total Ad Valorem Taxes - Directly Assn.		$ 74,573	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74,573
439		**Revenue Related Taxes**												
440		Customer	TOTREVCUS	$ 82,844	$ 61,280	$ 13,928	$ 424	$ 3,231	$ 403	$ 277	$ 409	$ 116	$ 217	$ 2,558
441		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
442		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
443		Total Revenue Related Taxes		$ 82,844	$ 61,280	$ 13,928	$ 424	$ 3,231	$ 403	$ 277	$ 409	$ 116	$ 217	$ 2,558
444		**Total Taxes Other Than Income**												
445		Customer		$ 6,746,627	$ 6,247,735	$ 404,664	$ 1,674	$ 36,527	$ 1,142	$ 1,242	$ 1,068	$ 423	$ 393	$ 51,759
446		Demand		$ 2,159,504	$ 1,444,701	$ 349,014	$ 6,709	$ 141,803	$ 6,097	$ 38,150	$ 20,412	$ 15,426	$ 13,428	$ 123,765
447		Commodity		$ 45,118	$ 26,528	$ 9,013	$ 261	$ 2,033	$ 343	$ 1,899	$ 1,513	$ 506	$ 1,190	$ 1,831
448		Total Taxes Other Than Income		$ 8,951,249	$ 7,718,964	$ 762,691	$ 8,644	$ 180,363	$ 7,582	$ 41,291	$ 22,993	$ 16,354	$ 15,011	$ 177,355
449		**Excess Def. Income Tax Amort. - Directly Assn.**												
450		Customer	CUS-DA	$ (6,563)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,563)
451		Demand	DEM-DA	$ (6,780)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,780)
452		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
453		**Total Excess Def. Income Tax Amort. - DA**		$ (13,343)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,343)
454		**Excess Def. Income Tax Amort. - Alloc.**												
455		Customer	CUS	$ (786,835)	$ (741,702)	$ (41,800)	$ (91)	$ (2,997)	$ (56)	$ (62)	$ (42)	$ (20)	$ (11)	$ (54)
456		Demand	DEM	$ (317,417)	$ (220,064)	$ (50,755)	$ (976)	$ (20,621)	$ (887)	$ (5,548)	$ (2,968)	$ (2,243)	$ (1,949)	$ (11,406)
457		Commodity	COM	$ (1,804)	$ (1,061)	$ (360)	$ (10)	$ (81)	$ (14)	$ (76)	$ (61)	$ (20)	$ (48)	$ (73)
458		**Total Excess Def. Income Tax Amort. - Alloc.**		$ (1,106,056)	$ (962,827)	$ (92,915)	$ (1,077)	$ (23,700)	$ (956)	$ (5,685)	$ (3,071)	$ (2,283)	$ (2,008)	$ (11,533)

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH. TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
459		**Interest on Customer Deposits**												
460		Customer	DEPCUS	$ 4,216	$ 2,510	$ 1,610	$ 24	$ 24	$ 2	$ 39	$ -	$ -	$ 7	$ -
461		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
462		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
463		Total Interest on Cust. Deposits		$ 4,216	$ 2,510	$ 1,610	$ 24	$ 24	$ 2	$ 39	$ -	$ -	$ 7	$ -
464		**Req. Return - Other Than Directly Assn.**												
465		Customer	CUS	$ 27,743,058	$ 26,151,706	$ 1,473,840	$ 3,221	$ 105,682	$ 1,977	$ 2,175	$ 1,483	$ 692	$ 395	$ 1,886
466		Demand	DEM	$ 11,191,828	$ 7,759,259	$ 1,789,559	$ 34,402	$ 727,093	$ 31,264	$ 195,613	$ 104,660	$ 79,095	$ 68,718	$ 402,165
467		Commodity	COM	$ 63,602	$ 37,396	$ 12,706	$ 368	$ 2,866	$ 483	$ 2,677	$ 2,133	$ 713	$ 1,678	$ 2,581
468		Tot. Req. Return - Other Than Dir. Assn.		$ 38,998,488	$ 33,948,361	$ 3,276,105	$ 37,991	$ 835,641	$ 33,725	$ 200,465	$ 108,276	$ 80,500	$ 70,792	$ 406,633
469		**Req. Return - Directly Assigned**												
470		Customer	CUS-DA	$ 231,400	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 231,400
471		Demand	DEM-DA	$ 239,044	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 239,044
472		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
473		Tot. Req. Return - Directly Assigned		$ 470,444	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 470,444
474		**Income Taxes - Other Than DA**												
475		Customer	CUS	$ 5,835,969	$ 5,501,215	$ 310,034	$ 678	$ 22,231	$ 416	$ 457	$ 312	$ 146	$ 83	$ 397
476		Demand	DEM	$ 2,354,288	$ 1,632,221	$ 376,448	$ 7,237	$ 152,950	$ 6,577	$ 41,149	$ 22,016	$ 16,638	$ 14,455	$ 84,599
477		Commodity	COM	$ 13,379	$ 7,867	$ 2,673	$ 77	$ 603	$ 102	$ 563	$ 449	$ 150	$ 353	$ 543
478		Total Income Taxes - Other Than DA		$ 8,203,636	$ 7,141,303	$ 689,154	$ 7,992	$ 175,784	$ 7,094	$ 42,169	$ 22,777	$ 16,934	$ 14,892	$ 85,538
479		**Income Taxes - Directly Assigned**												
480		Customer	CUS-DA	$ 48,677	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,677
481		Demand	DEM-DA	$ 50,285	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50,285
482		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
483		Total Income Taxes - Dir. Assigned		$ 98,962	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 98,962
484		**Total Cost of Service Before Revenue Credits**												
485		Customer		$ 93,590,524	$ 86,212,237	$ 6,064,882	$ 24,889	$ 586,808	$ 14,630	$ 20,283	$ 14,043	$ 6,447	$ 3,860	$ 642,445
486		Demand		$ 27,580,032	$ 18,030,044	$ 4,673,520	$ 89,842	$ 1,898,838	$ 81,648	$ 510,853	$ 273,324	$ 206,561	$ 180,298	$ 1,635,103
487		Commodity		$ 780,578	$ 458,956	$ 155,935	$ 4,521	$ 35,168	$ 5,932	$ 32,856	$ 26,182	$ 8,751	$ 20,592	$ 31,685
488		**Total Cost of Service Before Revenue Credits**		$ 121,951,134	$ 104,701,238	$ 10,894,337	$ 119,252	$ 2,520,814	$ 102,210	$ 563,991	$ 313,549	$ 221,759	$ 204,751	$ 2,309,233

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Customer Cost Allocation Factors												
2													
3	Total Customers		280,650	264,551	14,909	33	1,069	20	22	15	7	4	19
4	Total Customers Factor (CUS)	CUS	1.00000	0.94264	0.05312	0.00012	0.00381	0.00007	0.00008	0.00005	0.00002	0.00001	0.00007
5													
6	Customers - Directly Assigned		19	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	1.00000
8													
9	Services - Allocated Weighting			1.00000	1.40888	2.05186	1.40888	1.40888	2.05186	2.05186	2.05186	2.05186	0.00000
10	Weighted Customers		287,257	264,551	21,006	67	1,506	28	45	31	14	8	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.92096	0.07312	0.00023	0.00524	0.00010	0.00016	0.00011	0.00005	0.00003	0.00000
12													
13	Meters - Allocated Weighting			1.00000	2.09242	8.52874	5.48861	8.96348	12.90694	12.94521	12.94521	12.94521	0.00000
14	Weighted Customers		302,694	264,551	31,197	278	5,868	179	284	194	91	52	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.87399	0.10306	0.00092	0.01939	0.00059	0.00094	0.00064	0.00030	0.00017	0.00000
16													
17	Meters - Total Weighting			1.00000	2.09242	8.52874	5.48861	8.96348	12.90694	12.94521	12.94521	12.94521	10.13457
18	Weighted Customers		302,887	264,551	31,197	278	5,868	179	284	194	91	52	193
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.87343	0.10300	0.00092	0.01937	0.00059	0.00094	0.00064	0.00030	0.00017	0.00064
20													
21	Regulators - Allocated Weighting			1.00000	2.41765	9.02145	6.22224	9.32803	13.49204	13.49204	13.49204	13.49204	0.00000
22	Weighted Customers		308,377	264,551	36,046	294	6,652	187	297	202	94	54	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.85788	0.11689	0.00095	0.02157	0.00060	0.00096	0.00066	0.00031	0.00018	0.00000
24													
25	Meters and Regulators - Allocated Weighting			1.00000	2.18172	8.66403	5.69005	9.06357	13.06760	13.09536	13.09536	13.09536	0.00000
26	Weighted Customers		304,254	264,551	32,528	282	6,083	181	287	196	92	52	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.86951	0.10691	0.00093	0.01999	0.00060	0.00094	0.00065	0.00030	0.00017	0.00000
28													
29	Non-Residential Customers		16,098	0	14,909	33	1,069	20	22	15	7	4	19
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.92616	0.00202	0.06641	0.00124	0.00137	0.00093	0.00043	0.00025	0.00119
31													
32	Customer Cost Allocation Factors												
33													
34	Distribution Plant Customer Costs		$ 409,452,764	$ 373,725,099	$ 28,633,606	$ 122,939	$ 2,896,365	$ 69,602	$ 104,938	$ 71,652	$ 33,438	$ 19,107	$ 3,776,019
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.91274	0.06993	0.00030	0.00707	0.00017	0.00026	0.00017	0.00008	0.00005	0.00922
36													
37	Account 376-379 Customer Costs		$ 162,729,662	$ 153,395,429	$ 8,644,956	$ 18,893	$ 619,890	$ 11,597	$ 12,756	$ 8,697	$ 4,059	$ 2,319	$ 11,065
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.94264	0.05312	0.00012	0.00381	0.00007	0.00008	0.00005	0.00002	0.00001	0.00007
39													
40	Total Revenue (inc. cost of gas)		$ 178,214,831	$ 131,827,414	$ 29,961,297	$ 912,947	$ 6,951,034	$ 866,272	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 5,503,422
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.73971	0.16812	0.00512	0.03900	0.00486	0.00334	0.00493	0.00140	0.00262	0.03088
42													
43	Mains - Allocated Customer Cost Factor		0.48572	0.45786	0.02580	0.00006	0.00185	0.00003	0.00004	0.00003	0.00001	0.00001	0.00003
44	Services - Allocated Customer Cost Factor		0.51428	0.47363	0.03761	0.00012	0.00270	0.00005	0.00008	0.00006	0.00003	0.00001	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.93149	0.06341	0.00018	0.00455	0.00009	0.00012	0.00008	0.00004	0.00002	0.00003
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	1.00000
48													
49	Total Plant Customer		$ 477,155,470	$ 436,438,715	$ 32,834,129	$ 137,429	$ 3,271,750	$ 77,981	$ 116,651	$ 79,648	$ 37,169	$ 21,239	$ 4,140,759
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.91467	0.06881	0.00029	0.00686	0.00016	0.00024	0.00017	0.00008	0.00004	0.00868
51													
52	Non-Intangible Plant Customer												
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 476,594,908	$ 449,257,251	$ 25,318,936	$ 55,333	$ 1,815,506	$ 33,964	$ 37,360	$ 25,473	$ 11,887	$ 6,793	$ 32,407
54		NONINCUS	1.00000	0.94264	0.05312	0.00012	0.00381	0.00007	0.00008	0.00005	0.00002	0.00001	0.00007
55													
56	Account 871-879 Customer Costs		$ 6,433,377	$ 5,765,553	$ 567,212	$ 3,893	$ 85,910	$ 2,423	$ 3,798	$ 2,595	$ 1,211	$ 692	$ 91
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.89619	0.08817	0.00061	0.01335	0.00038	0.00059	0.00040	0.00019	0.00011	0.00001
58													
59	Account 887-893 Customer Costs		2323154.56431	$ 2,174,427	$ 137,771	$ 350	$ 9,804	$ 182	$ 235	$ 160	$ 75	$ 43	$ 108
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.93598	0.05930	0.00015	0.00422	0.00008	0.00010	0.00007	0.00003	0.00002	0.00005
61													
62	Account 903 Customer		$ 2,894,519	$ 2,754,966	$ 133,668	$ 205	$ 5,365	$ 100	$ 76	$ 52	$ 7	$ 14	$ 66
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000000	0.95179	0.04618	0.00007	0.00185	0.00003	0.00003	0.00002	0.00000	0.00000	0.00002

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
64													
65	Customer Cost Allocation Factors												
66													
67	Account 904 Customer		$ 854,390	$ 741,375	$ 110,125	$ 631	$ 2,095	$ 164	$ -	$ -	$ -	$ -	$ -
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.86772	0.12889	0.00074	0.00245	0.00019	0.00000	0.00000	0.00000	0.00000	0.00000
69													
70	Accounts 902-904 Customer		$ 4,330,579	$ 4,004,391	$ 303,704	$ 1,370	$ 18,728	$ 609	$ 621	$ 424	$ 181	$ 113	$ 437
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	$ 1	0.92468	0.07013	0.00032	0.00432	0.00014	0.00014	0.00010	0.00004	0.00003	0.00010
72													
73	Operating Expense Customer		$ 33,210,210	$ 30,293,213	$ 2,418,808	$ 11,972	$ 262,686	$ 6,885	$ 10,147	$ 6,931	$ 3,215	$ 1,848	$ 194,505
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.91217	0.07283	0.00036	0.00791	0.00021	0.00031	0.00021	0.00010	0.00006	0.00586
75													
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 36,040,736	$ 32,895,926	$ 2,520,379	$ 10,821	$ 254,943	$ 6,126	$ 9,237	$ 6,307	$ 2,943	$ 1,682	$ 332,372
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 31,101,408	$ 29,317,420	$ 1,652,251	$ 3,611	$ 118,475	$ 2,216	$ 2,438	$ 1,662	$ 776	$ 443	$ 2,115
78	Total General Plant Customer Costs		$ 67,142,144	$ 62,213,346	$ 4,172,631	$ 14,432	$ 373,418	$ 8,343	$ 11,675	$ 7,969	$ 3,719	$ 2,125	$ 334,486
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.92659	0.06215	0.00021	0.00556	0.00012	0.00017	0.00012	0.00006	0.00003	0.00498
80													
81	Customer Deposits		$ (7,026,858)	$ (4,183,526)	$ (2,684,022)	$ (39,658)	$ (39,904)	$ (3,131)	$ (65,401)	$ -	$ -	$ (11,216)	$ -
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.59536	0.38197	0.00564	0.00568	0.00045	0.00931	0.00000	0.00000	0.00160	0.00000
83													
84	Demand Cost Allocation Factors												
85													
86	System Demand												
87	**System Demand Factor (DEM)**	DEM	1.00000	0.69330	0.15990	0.00307	0.06497	0.00279	0.01748	0.00935	0.00707	0.00614	0.03593
88													
89	Non-Residential Demand												
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.52135	0.01002	0.21182	0.00911	0.05699	0.03049	0.02304	0.02002	0.11716
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	1.00000
94													
95	Distribution Plant Demand		$ 124,371,026	$ 72,517,131	$ 25,005,254	$ 480,692	$ 10,159,565	$ 436,852	$ 2,733,272	$ 1,462,397	$ 1,105,189	$ 1,105,189	$ 9,365,486
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.58307	0.20105	0.00386	0.08169	0.00351	0.02198	0.01176	0.00889	0.00889	0.07530
97													
98	Demand Cost Allocation Factors												
99													
100	Non-Intangible Plant Demand		$ 180,748,757	$ 125,312,541	$ 28,901,494	$ 555,592	$ 11,742,596	$ 504,921	$ 3,159,162	$ 1,690,263	$ 1,277,395	$ 1,109,804	$ 6,494,988
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.69330	0.15990	0.00307	0.06497	0.00279	0.01748	0.00935	0.00707	0.00614	0.03593
102													
103	Total Plant Demand		$ 181,148,795	$ 110,626,343	$ 34,521,961	$ 663,637	$ 14,026,177	$ 603,113	$ 3,773,523	$ 2,018,968	$ 1,525,810	$ 1,525,810	$ 11,863,452
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.61069	0.19057	0.00366	0.07743	0.00333	0.02083	0.01115	0.00842	0.00842	0.06549
105													
106	Operating Expense Demand		$ 9,383,083	$ 5,841,286	$ 1,740,627	$ 33,461	$ 707,212	$ 30,409	$ 190,264	$ 101,798	$ 76,933	$ 67,479	$ 593,614
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.62253	0.18551	0.00357	0.07537	0.00324	0.02028	0.01085	0.00820	0.00719	0.06326
108													
109	Acct. 887-893 Demand		$ 1,486,664	$ 853,180	$ 330,265	$ 6,349	$ 134,186	$ 5,770	$ 36,101	$ 19,315	$ 14,597	$ 12,682	$ 74,220
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.57389	0.22215	0.00427	0.09026	0.00388	0.02428	0.01299	0.00982	0.00853	0.04992
111													
112	Rate Base Demand		$ 147,493,190	$ 90,670,547	$ 28,084,323	$ 539,883	$ 11,410,582	$ 490,645	$ 3,069,839	$ 1,642,472	$ 1,241,278	$ 1,241,278	$ 9,102,344
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.61474	0.19041	0.00366	0.07736	0.00333	0.02081	0.01114	0.00842	0.00842	0.06171
114													
115	Commodity Cost Allocation Factors												
116													
117	Annual Distribution Volumes (Ccf)		195,605,480	115,010,655	39,076,075	1,132,809	8,812,764	1,486,506	8,233,369	6,561,058	2,192,902	5,160,298	7,939,044
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.58797	0.19977	0.00579	0.04505	0.00760	0.04209	0.03354	0.01121	0.02638	0.04059
119													
120	Commodity - Direct Assignment		7,939,044	0	0	0	0	0	0	0	0	0	7,939,044
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	1.00000

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Current Revenue-to-Cost Ratio (1)	0.9094	0.8388	1.3093	3.0953	1.3856	2.2941	1.0061
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	1.0000
5	Rate Design Revenue Increase	$ 11,045,802	$ 16,872,998	$ (3,544,377)	$ (906,840)	$ (1,097,026)	$ (264,971)	$ (13,982)
6	% Increase - Non-Gas Revenue (2)	9.96%	19.21%	-23.62%	-67.69%	-27.83%	-56.41%	-0.60%
7	% Increase - Total Revenue (3)	6.11%	12.57%	-11.52%	-50.47%	-13.55%	-56.41%	-0.25%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)							
9	Revenue-to-Cost Ratio	1.0000	0.9556	1.2475	2.6762	1.3085	2.0353	1.0000
10	Rate Design Revenue Increase	$ 11,045,802	$ 12,222,427	$ (708,875)	$ (181,368)	$ (219,405)	$ (52,994)	$ (13,982)
11	% Increase - Non-Gas Revenue (2)	9.96%	13.92%	-4.72%	-13.54%	-5.57%	-11.28%	-0.60%
12	% Increase - Total Revenue (3)	6.11%	9.10%	-2.30%	-10.09%	-2.71%	-11.28%	-0.25%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)							
14	Revenue-to-Cost Ratio	1.0000	0.9445	1.3093	3.0953	1.3856	2.2941	1.0000
15	Rate Design Revenue Increase	$ 11,045,802	$ 11,059,784	$ -	$ -	$ -	$ -	$ (13,982)
16	% Increase - Non-Gas Revenue (2)	9.96%	12.59%	0.00%	0.00%	0.00%	0.00%	-0.60%
17	% Increase - Total Revenue (3)	6.11%	8.24%	0.00%	0.00%	0.00%	0.00%	-0.25%

(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, excluding Fort Bliss, 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	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Costs	$ 10,901,149	$ 9,287,485	$ 1,411,544	$ 10,256	$ 191,863
2	Demand Costs	$ 4,362,257	$ 2,365,583	$ 1,420,696	$ 35,901	$ 540,078
3	Commodity Costs	$ 50,902	$ 22,591	$ 22,299	$ 854	$ 5,158
4	Cost of Service Before Revenue Credits	$ 15,314,307	$ 11,675,659	$ 2,854,539	$ 47,010	$ 737,099
5	Revenues Credited to Cost of Service (1)	$ 340,907	$ 274,125	$ 54,282	$ 746	$ 11,755
6	Total Cost of Service	$ 14,973,400	$ 11,401,534	$ 2,800,257	$ 46,265	$ 725,344
7	Revenue at Current Rates	$ 13,619,898	$ 6,920,061	$ 5,380,093	$ 178,814	$ 1,140,930
8	Revenue Deficiency	$ 1,353,502	$ 4,481,473	$ (2,579,836)	$ (132,549)	$ (415,586)
9	Revenue-to-Cost Ratios:					
10	Current Revenue	0.9116	0.6162	1.9038	3.8196	1.5638
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge including Company recommended changes and special contract 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	$ 97,935
Special Contract	$ 242,972
Other Revenue	$ -
	$ 340,907

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Intangible Plant					
1	301	Organization	NONINTPLT	$ 89,582	$ 61,825	$ 27,698	$ 59
2	302	Franchises and Consents	NONINTPLT	$ 118	$ 81	$ 36	$ 0
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 131,851	$ 90,997	$ 40,767	$ 87
4		Total Intangible Plant		$ 221,551	$ 152,904	$ 68,501	$ 146
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ 113,362	$ -	$ 113,362	$ -
8	366	Meas. and Reg. Station Structures	DEM	$ -	$ -	$ -	$ -
9	367	Transmission Mains	DEM	$ 1,722,091	$ -	$ 1,722,091	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 750,393	$ -	$ 750,393	$ -
12	371	Other Equipment	DEM	$ -	$ -	$ -	$ -
13		Total Transmission Plant		$ 2,585,846	$ -	$ 2,585,846	$ -
14							
15		**Distribution Plant**					
16	374	Land & Land Rights	DIS376-379	$ 63,659	$ 39,380	$ 24,256	$ 23
17	375	Structures and Improvements	DIS376-379	$ 28,085	$ 17,374	$ 10,701	$ 10
18	376	Distribution Mains	MAINS	$ 54,514,610	$ 36,873,454	$ 17,641,156	$ -
19	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
20	378	Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 3,519,477	$ -	$ 3,519,477	$ -
21	378	Odorization Tank	COM	$ 22,098	$ -	$ -	$ 22,098
22	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 1,551,543	$ -	$ 1,551,543	$ -
23	379	Odorization Tank	COM	$ 21,519	$ -	$ -	$ 21,519
24	380	Services	CUS	$ 16,345,104	$ 16,345,104	$ -	$ -
25	381	Meters	CUS	$ 2,708,292	$ 2,708,292	$ -	$ -
26	382	Meter Installations	CUS	$ 1,996	$ 1,996	$ -	$ -
27	383	House Regulators	CUS	$ 753,647	$ 753,647	$ -	$ -
28	385	Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 1,033,655	$ -	$ 1,033,655	$ -
29	386	Other Property - Customer Premises	CUS	$ 9,515	$ 9,515	$ -	$ -
30	387	Other Equipment	DIS376-379	$ -	$ -	$ -	$ -
31		Total Distribution Plant		$ 80,573,199	$ 56,748,760	$ 23,780,789	$ 43,650

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
32							
33		**General Plant**					
34	389	Land & Land Rights	GENPLT	$ 88,161	$ 65,218	$ 22,901	$ 42
35	390	Structures & Improvements	GENPLT	$ 1,165,327	$ 873,544	$ 291,248	$ 535
36	391	Office Furniture and Equipment	GENPLT	$ 1,738,884	$ 1,690,575	$ 48,221	$ 89
37	392	Transportation Equipment	GENPLT	$ 2,263,461	$ 1,594,185	$ 668,050	$ 1,226
38	393	Stores Equipment	GENPLT	$ 3,856	$ 2,716	$ 1,138	$ 2
39	394	Tools, Shop & Garage	GENPLT	$ 1,092,023	$ 769,219	$ 322,213	$ 591
40	394	Odorization Tank	COM	$ 13,097	$ -	$ -	$ 13,097
41	396	Major Work Equipment	GENPLT	$ 479,691	$ 337,853	$ 141,579	$ 260
42	397	Communication Equipment	GENPLT	$ 1,799,692	$ 1,276,082	$ 522,651	$ 959
43	398	Miscellaneous General Plant	GENPLT	$ -	$ -	$ -	$ -
44		Total General Plant		$ 8,644,192	$ 6,609,391	$ 2,018,000	$ 16,801
45							
46		Total Plant in Service		$ 92,024,789	$ 63,511,055	$ 28,453,137	$ 60,597
47							
48		**Depreciation & Amortization Reserve**					
49	301-303	Intangible Plant	DISPLTRES	$ (88,274)	$ (64,228)	$ (24,061)	$ 14
50	325-371	Transmission Plant	DEM	$ (333,409)	$ -	$ (333,409)	$ -
51	374-387	Distribution Plant	DISPLTRES	$ (5,803,211)	$ (4,222,369)	$ (1,581,770)	$ 929
52	389-398	General Plant	GENPLTRES	$ (3,590,915)	$ (2,741,888)	$ (841,255)	$ (7,772)
53		Total Depreciation & Amortization Reserve		$ (9,815,810)	$ (7,028,485)	$ (2,780,496)	$ (6,829)
54							
55		Net Plant in Service		$ 82,208,980	$ 56,482,571	$ 25,672,641	$ 53,768
56							
57		Customer Deposits	CUS	$ (644,834)	$ (644,834)	$ -	$ -
58							
59		Customer Advances	MAINS/SVCS	$ (169,477)	$ (127,284)	$ (42,193)	$ -
60							
61		Accumulated Deferred Income Taxes	TOTPLT	$ (9,958,250)	$ (6,872,702)	$ (3,078,990)	$ (6,557)
62							
63		Excess Deferred Income Tax	TOTPLT	$ (2,701,021)	$ (1,864,114)	$ (835,128)	$ (1,779)
64							
65		Materials and Supplies	TOTPLT	$ 760,974	$ 525,188	$ 235,286	$ 501

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
66							
67		Prepayments	OPEXP	$ 176,227	$ 129,527	$ 45,387	$ 1,313
68							
69		Pension & FAS 106 Regulatory Asset	OPEXP	$ 1,023,144	$ 752,012	$ 263,508	$ 7,623
70							
71		DIMP Deferrals	OPEXP	$ 377,873	$ 277,737	$ 97,320	$ 2,815
72							
73		Regulatory Assets	OPEXP	$ 129,990	$ 95,543	$ 33,479	$ 969
74							
75		Cash Working Capital	OPEXP	$ (64,813)	$ (47,638)	$ (16,692)	$ (483)
76							
77		Total Rate Base		$ 71,138,793	$ 48,706,006	$ 22,374,616	$ 58,170

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Transmission & Distribution Operations Exp.**					
2	814-866	Transmission Expenses	DEM	$ 321,559	$ -	$ 321,559	$ -
3	8700	Operation Supervision & Engineering	DIS871-879	$ 52,938	$ 44,629	$ 7,845	$ 464
4	8710	Distribution Load Dispatch	COM	$ 12,213	$ -	$ -	$ 12,213
5	8740	Mains and Services Expenses	MAINS/SVCS	$ 704,127	$ 528,828	$ 175,299	$ -
6	8740	Odorization	COM	$ 1,103	$ -	$ -	$ 1,103
7	8750	Measuring & Reg. Stat. Exp.-Gen.	DEM	$ 29,550	$ -	$ 29,550	$ -
8	8750	Odorization	COM	$ 100	$ -	$ -	$ 100
9	8760	Meas. & Reg. Stat. Exp.- Ind.	DEM	$ 1,500	$ -	$ 1,500	$ -
10	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 272	$ -	$ 272	$ -
11	8780	Meter and House Regulator Exp.	CUS	$ 646,605	$ 646,605	$ -	$ -
12	8790	Customer Installation Expenses	CUS	$ -	$ -	$ -	$ -
13	8800	Other Expenses	DIS871-879	$ 70,559	$ 59,484	$ 10,456	$ 618
14	8810	Rents	DIS871-879	$ 14,828	$ 12,501	$ 2,197	$ 130
15	8820	Corporate & Div. Exp.	DEM	$ -	$ -	$ -	$ -
16		Total Transmission & Distribution Oper. Exp.		$ 1,855,353	$ 1,292,047	$ 548,678	$ 14,628
17							
18		**Distribution Maintenance Expenses**					
19	8850	Maintenance Supervision and Engineering	DIS887-893	$ -	$ -	$ -	$ -
20	8860	Structures and Improvements	DIS887-893	$ 129,161	$ 76,910	$ 52,251	$ -
21	8870	Maintenance of Mains	MAINS	$ 588,939	$ 398,356	$ 190,583	$ -
22	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 137,349	$ -	$ 137,349	$ -
23	8890	Odorization	COM	$ 16,059	$ -	$ -	$ 16,059
24	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 129,878	$ -	$ 129,878	$ -
25	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 1,999	$ -	$ 1,999	$ -
26	8920	Maintenance of Services	CUS	$ 278,451	$ 278,451	$ -	$ -
27	8930	Main. of Meters & House Reg.	CUS	$ -	$ -	$ -	$ -
28	8940	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
29	8950	Clearing - Meter Shop - Small Meters	DEM	$ -	$ -	$ -	$ -
30	8960	Clearing - Meter Shop - Large Meters	DEM	$ -	$ -	$ -	$ -
31		Total Distribution Maintenance Expenses		$ 1,281,836	$ 753,717	$ 512,060	$ 16,059
32							
33		Total Operations & Maintenance Expenses		$ 3,137,189	$ 2,045,764	$ 1,060,738	$ 30,687
34							

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
35		**Customer Accounts Expenses**					
36	9010	Supervision	CUS	$ 6,199	$ 6,199	$ -	$ -
37	9020	Meter Reading Expense	CUS	$ 35,072	$ 35,072	$ -	$ -
38	9030	Customer Accounting	CUS	$ 166,507	$ 166,507	$ -	$ -
39	9040	Bad Debts (includes gross up)	CUS	$ 97,843	$ 97,843	$ -	$ -
40	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 20,973	$ 20,973	$ -	$ -
41		Total Customer Accounts Expenses		$ 326,593	$ 326,593	$ -	$ -
42							
43		**Customer Information Expenses**					
44	9070	Supervision	CUS	$ -	$ -	$ -	$ -
45	9080	Customer Assistance	CUS	$ 144,299	$ 144,299	$ -	$ -
46	9090	Informational and Instructional Advertising	CUS	$ 2,548	$ 2,548	$ -	$ -
47	9100	Customer Service & Informational Svc.	CUS	$ -	$ -	$ -	$ -
48		Total Customer Information Expenses		$ 146,847	$ 146,847	$ -	$ -
49							
50		**Sales and Advertising Expenses**					
51	9110	Supervision	CUS	$ -	$ -	$ -	$ -
52	9120	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
53	9130	Advertising	CUS	$ 42	$ 42	$ -	$ -
54	9140	Employee Sales Referrals	CUS	$ -	$ -	$ -	$ -
55	9163	Misc. Gas Sales Expense	CUS	$ -	$ -	$ -	$ -
56		Total Sales and Advertising Expenses		$ 42	$ 42	$ -	$ -
57							
58		**Administrative & General Expenses**					
59	920-940	Administrative & General Expenses	ADMINGEN	$ 1,817,991	$ 1,470,830	$ 337,400	$ 9,761
60		Total Administrative & General Expenses		$ 1,817,991	$ 1,470,830	$ 337,400	$ 9,761
61							
62		**Depreciation and Amortization Expense**					
63	301-303	Intangible Plant	PLT301-03	$ 5,731	$ 3,955	$ 1,772	$ 4
64	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -
65	366	Meas. and Reg. Station Structures	PLT366	$ -	$ -	$ -	$ -
66	367	Transmission Mains	PLT367	$ 44,743	$ -	$ 44,743	$ -
67	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
68	369	Measuring and Reg. Station Equipment	PLT369	$ 26,789	$ -	$ 26,789	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
69	371	Other Equipment	PLT371	$ -	$ -	$ -	$ -
70	375	Structures and Improvements	PLT375	$ 1,533	$ 949	$ 584	$ 1
71	376	Mains	MAINS	$ 1,393,153	$ 942,323	$ 450,830	$ -
72		**Depreciation and Amortization Expense (Cont'd)**					
73	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
74	378	Meas. & Reg. Sta. Equip. - General	PLT378	$ 77,162	$ -	$ 77,162	$ -
75	378	Odorization Tank	COM	$ 484	$ -	$ -	$ 484
76	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 31,651	$ -	$ 31,651	$ -
77	379	Odorization Tank	COM	$ 439	$ -	$ -	$ 439
78	380	Services	PLT380	$ 551,006	$ 551,006	$ -	$ -
79	381	Meters	PLT381	$ 127,844	$ 127,844	$ -	$ -
80	382	Meter Installations	PLT382	$ (17)	$ (17)	$ -	$ -
81	383	House Regulators	PLT383	$ 28,707	$ 28,707	$ -	$ -
82	385	Meas. & Reg. Sta. Equip. - Ind.	PLT385	$ 25,135	$ -	$ 25,135	$ -
83	386	Other Property - Customer Premises	PLT386	$ 3,376	$ 3,376	$ -	$ -
84	387	Other Equipment	PLT387	$ -	$ -	$ -	$ -
85	389-980	General Plant	GENDEP	$ 386,057	$ 316,462	$ 68,598	$ 997
86	389-980	General Plant - Odorization	COM	$ 873	$ -	$ -	$ 873
87	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ -	$ -	$ -	$ -
88		Total Depreciation and Amortization Expense		$ 2,704,667	$ 1,974,604	$ 727,265	$ 2,797
89							
90		**Taxes Other Than Income**					
91	4080	Payroll and Other	OPEXP	$ 281,055	$ 206,576	$ 72,385	$ 2,094
92	4080	Ad Valorem - Allocated	TOTPLT	$ 447,453	$ 308,810	$ 138,348	$ 295
93	4080	Revenue Related (includes gross up)	CUS	$ 10,151	$ 10,151	$ -	$ -
94		Total Taxes Other Than Income		$ 738,659	$ 525,537	$ 210,733	$ 2,389
95							
96	4101	Excess Deferred Income Tax Amortization	RB	$ (244,859)	$ (167,646)	$ (77,013)	$ (200)
97							
98	4310	Interest on Customer Deposits	CUS	$ 387	$ 387	$ -	$ -
99							
100		Required Return	RB	$ 5,526,914	$ 3,784,066	$ 1,738,328	$ 4,519
101		Income Taxes	RB	$ 1,159,877	$ 794,124	$ 364,805	$ 948
102		Total Cost of Service Before Revenue Credits		$ 15,314,307	$ 10,901,149	$ 4,362,257	$ 50,902

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7		DEM-COM	Demand and Commodity Factor		0.00000	0.50000	0.50000
8							
9			Total Transmission Plant	$ 2,585,846	$ -	$ 2,585,846	$ -
10			Total Distribution Plant	$ 80,573,199	$ 56,748,760	$ 23,780,789	$ 43,650
11			Total General Plant	$ 8,644,192	$ 6,609,391	$ 2,018,000	$ 16,801
12			Total Non-Intangible Plant	$ 91,803,238	$ 63,358,151	$ 28,384,635	$ 60,451
13		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.69015	0.30919	0.00066
14							
15	376		Distribution Mains	$ 54,514,610	$ 36,873,454	$ 17,641,156	$ -
16	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
17	378		Meas. & Reg. Sta. Equip.- Gen.	$ 3,519,477	$ -	$ 3,519,477	$ -
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 1,573,062	$ -	$ 1,551,543	$ 21,519
19			Total Accounts 376-379	$ 59,607,149	$ 36,873,454	$ 22,712,176	$ 21,519
20		DIS376-379	Accounts 376-379 Factor	1.00000	0.61861	0.38103	0.00036
21							
22	376		Mains	$ 54,514,610	$ 36,873,454	$ 17,641,156	$ -
23		MAINS	Distribution Mains Allocated Factor	1.00000	0.67640	0.32360	0.00000
24							
25	376/380		Mains and Services-Allocated	$ 70,859,713	$ 53,218,557	$ 17,641,156	$ -
26		MAINS/SVCS	Mains and Services Allocated Factor	1.00000	0.75104	0.24896	0.00000
27							
28	374-87		Total Distribution Plant	$ 80,573,199	$ 56,748,760	$ 23,780,789	$ 43,650
29		DISPLT	Distribution Plant Factor	1.00000	0.70431	0.29515	0.00054
30							
31							
32	374		Land & Land Rights	$ (32)	$ (20)	$ (12)	$ (0)
33	375		Structures and Improvements	$ (9,170)	$ (5,672)	$ (3,494)	$ (3)
34	376		Distribution Mains	$ (4,314,395)	$ (2,918,238)	$ (1,396,156)	$ -

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
35	378		Meas. & Reg. Sta. Equip.-Gen.	$ (70,977)	$ -	$ (70,977)	$ -
36	379		Meas. & Reg. Sta. Equip.-City Gate	$ (56,605)	$ -	$ (56,605)	$ -
37	378-379		Odorization Tank	$ 933	$ -	$ -	$ 933
38	380		Services	$ (909,215)	$ (909,215)	$ -	$ -
39	381		Meters	$ (306,869)	$ (306,869)	$ -	$ -
40	382		Meter Installations	$ (5,893)	$ (5,893)	$ -	$ -
41	383		House Regulators	$ (74,232)	$ (74,232)	$ -	$ -
42	385		Meas. & Reg. Sta. Equip.-Ind.	$ (53,152)	$ -	$ (53,152)	$ -
43	386		Other Property-Customer Premises	$ (3,607)	$ (2,231)	$ (1,374)	$ (1)
44	378		Other Equipment	$ -	$ -	$ -	$ -
45			Total Distribution Plant Reserve	$ (5,803,211)	$ (4,222,369)	$ (1,581,770)	$ 929
46		DISPLTRES	Distribution Plant Reserve Factor	$ 1.00000	0.72759	0.27257	-0.00016
47							
48			General Plant Reserve	$ (3,590,915)	$ (2,741,888)	$ (841,255)	$ (7,772)
49		GENPLTRES	General Plant Reserve Factor	1.00000	0.76356	0.23427	0.00216
50							
51			Total Plant	$ 92,024,789	$ 63,511,055	$ 28,453,137	$ 60,597
52		TOTPLT	Total Plant Factor	1.00000	0.69015	0.30919	0.00066
53							
54	374		Land & Land Rights	$ (32)	$ (20)	$ (12)	$ (0)
55	375		Structures and Improvements	$ (9,170)	$ (5,672)	$ (3,494)	$ (3)
56	376		Distribution Mains	$ (4,314,395)	$ (2,918,238)	$ (1,396,156)	$ -
57	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
58	378		Meas. & Reg. Station Equip.- Gen.	$ (70,977)	$ -	$ (70,977)	$ -
59	378		Odorization Tank	$ 195	$ -	$ -	$ 195
60	379		Meas. & Reg. Station Equip.- City Gate	$ (56,605)	$ -	$ (56,605)	$ -
61	379		Odorization Tank	$ 738	$ -	$ -	$ 738
62	380		Services	$ (909,215)	$ (909,215)	$ -	$ -
63	381		Meters	$ (306,869)	$ (306,869)	$ -	$ -
64	382		Meter Installations	$ (5,893)	$ (5,893)	$ -	$ -
65	383		House Regulators	$ (74,232)	$ (74,232)	$ -	$ -
66	385		Meas. & Reg. Sta. Equip. -Ind.	$ (53,152)	$ -	$ (53,152)	$ -
67	386		Other Property - Customer Premises	$ (3,607)	$ (2,231)	$ (1,374)	$ (1)
68	387		Other Equipment	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
69			Total Distribution Plant Reserve	$ (5,803,211)	$ (4,222,369)	$ (1,581,770)	$ 929
70		DISPLTRES	Distribution Plant Reserve	1.00000	0.72759	0.27257	(0.00016)
71							
72			Total Operations and Maintenance Expenses	$ 3,137,189	$ 2,045,764	$ 1,060,738	$ 30,687
73			Total Customer Accounts Expenses	$ 326,593	$ 326,593	$ -	$ -
74			Total Customer Service Expenses	$ 146,847	$ 146,847	$ -	$ -
75			Total Sales and Advertising Expenses	$ 42	$ 42	$ -	$ -
76			Administrative and General Expenses	$ 1,817,991	$ 1,470,830	$ 337,400	$ 9,761
77			Total Operating Expenses	$ 5,428,662	$ 3,990,076	$ 1,398,138	$ 40,448
78		OPEXP	Operating Expense Factor	1.00000	0.73500	0.25755	0.00745
79							
80	8710		Distribution Load Dispatch	$ 12,213	$ -	$ -	$ 12,213
81	8740		Mains and Services Expenses	$ 704,127	$ 528,828	$ 175,299	$ -
82	8750		Measuring & Reg. Stat. Exp.-Gen.	$ 29,550	$ -	$ 29,550	$ -
83	8760		Meas. & Reg. Stat. Exp.- Ind.	$ 1,500	$ -	$ 1,500	$ -
84	8770		Meas. & Regulating Station Exp.- City Gate	$ 272	$ -	$ 272	$ -
85	8780		Meter and House Regulator Exp.	$ 646,605	$ 646,605	$ -	$ -
86	8790		Customer Installation Expenses	$ -	$ -	$ -	$ -
87			Total Accounts 871-879	$ 1,394,266	$ 1,175,433	$ 206,620	$ 12,213
88		DIS871-879	Accounts 871-879 Factor	1.00000	0.84305	0.14819	0.00876
89							
90	8870		Maintenance of Mains	$ 588,939	$ 398,356	$ 190,583	$ -
91	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen.	$ 137,349	$ -	$ 137,349	$ -
92	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind.	$ 129,878	$ -	$ 129,878	$ -
93	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 1,999	$ -	$ 1,999	$ -
94	8920		Maintenance of Services	$ 278,451	$ 278,451	$ -	$ -
95	8930		Main. of Meters & House Reg.	$ -	$ -	$ -	$ -
96			Total Accounts 887-893	$ 1,136,616	$ 676,807	$ 459,809	$ -
97		DIS887-893	Accounts 887-893 Factor	1.00000	0.59546	0.40454	0.00000
98							
99			Total Operations and Maintenance Expenses	$ 3,137,189	$ 2,045,764	$ 1,060,738	$ 30,687
100			Total Customer Accounts Expenses	$ 326,593	$ 326,593	$ -	$ -
101			Total Customer Service Expenses	$ 146,847	$ 146,847	$ -	$ -
102			Total Sales and Advertising Expenses	$ 42	$ 42	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
103			Total Operating Exp. Without A&G Expenses	$ 3,610,671	$ 2,519,246	$ 1,060,738	$ 30,687
104		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.69772	0.29378	0.00850
105							
106	920-932		Administrative and General Expenses	$ 1,817,991	$ 1,470,830	$ 337,400	$ 9,761
107		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.80904	0.18559	0.00537
108							
109	366		Meas. and Reg. Station Structures	$ -	$ -	$ -	$ -
110		PLT366	Measuring and Reg. Station Structures Factor	0.00000	0.00000	0.00000	0.00000
111							
112	367		Transmission Mains	$ 1,722,091	$ -	$ 1,722,091	$ -
113		PLT367	Transmission Mains	1.00000	0.00000	1.00000	0.00000
114							
115	368		Compression Station Equipment	$ -	$ -	$ -	$ -
116		PLT368	Compression Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
117							
118	369		Measuring and Reg. Station Equipment	$ 750,393	$ -	$ 750,393	$ -
119		PLT369	Measuring & Reg, Station Equipment Factor	1.00000	0.00000	1.00000	0.00000
120							
121	371		Other Equipment	$ -	$ -	$ -	$ -
122		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
123							
124	375		Structures and Improvements	$ 28,085	$ 17,374	$ 10,701	$ 10
125		PLT375	Structures and Improvements Factor	1.00000	0.61861	0.38103	0.00036
126							
127	376		Distribution Mains	$ 54,514,610	$ 36,873,454	$ 17,641,156	$ -
128		PLT376	Distribution Mains Factor	1.00000	0.67640	0.32360	0.00000
129							
130	378		Meas. & Reg. Sta. Equip.- Gen.	$ 3,519,477	$ -	$ 3,519,477	$ -
131		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
132							
133	379		Meas. & Reg. Sta. Equip.- City Gate	$ 1,551,543	$ -	$ 1,551,543	$ -
134		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
135							
136	380		Services	$ 16,345,104	$ 16,345,104	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
137		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
138							
139	381		Meters	$ 2,708,292	$ 2,708,292	$ -	$ -
140		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
141							
142	382		Meter Installations	$ 1,996	$ 1,996	$ -	$ -
143		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000
144							
145	383		House Regulators	$ 753,647	$ 753,647	$ -	$ -
146		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
147							
148	385		Meas. & Reg. Sta. Equip. - Ind.	$ 1,033,655	$ -	$ 1,033,655	$ -
149		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
150							
151	386		Other Property - Customer Premises	$ 9,515	$ 9,515	$ -	$ -
152		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
153							
154	387		Other Equipment	$ -	$ -	$ -	$ -
155		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
156							
157	301-03		Intangible Plant	$ 221,551	$ 152,904	$ 68,501	$ 146
158		PLT301-03	Intangible Plant	1.00000	0.69015	0.30919	0.00066
159							
160	389-98		General Plant Depreciation Expense	$ 386,930	$ 317,178	$ 68,753	$ 999
161		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.81973	0.17769	0.00258
162							
163			Rate Base	$ 71,138,793	$ 48,706,006	$ 22,374,616	$ 58,170
164		RB	Rate Base Factor	1.00000	0.68466	0.31452	0.00082

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	301-303	**Intangible Plant**						
2		Customer	NONINCUS	$ 152,904	$ 132,460	$ 18,383	$ 75	$ 1,985
3		Demand	NONINDEM	$ 68,501	$ 39,065	$ 20,945	$ 529	$ 7,962
4		Commodity	COM	$ 146	$ 65	$ 64	$ 2	$ 15
5		Total Intangible Plant		$ 221,551	$ 171,590	$ 39,392	$ 607	$ 9,962
6	365-371	**Transmission Plant**						
7		Customer	CUS	$ -	$ -	$ -	$ -	$ -
8		Demand	DEM	$ 2,585,846	$ 1,474,671	$ 790,636	$ 19,979	$ 300,560
9		Commodity	COM	$ -	$ -	$ -	$ -	$ -
10		Total Transmission Plant		$ 2,585,846	$ 1,474,671	$ 790,636	$ 19,979	$ 300,560
11		**Distribution Plant**						
12	374	**Land & Land Rights**						
13		Customer	CUS	$ 39,380	$ 34,115	$ 4,735	$ 19	$ 511
14		Demand	DEM	$ 24,256	$ 13,833	$ 7,416	$ 187	$ 2,819
15		Commodity	COM	$ 23	$ 10	$ 10	$ 0	$ 2
16		Total Land & Land Rights		$ 63,659	$ 47,958	$ 12,161	$ 207	$ 3,333
17	375	**Structures and Improvements**						
18		Customer	376-379CUS	$ 17,374	$ 15,051	$ 2,089	$ 9	$ 226
19		Demand	DEM	$ 10,701	$ 6,103	$ 3,272	$ 83	$ 1,244
20		Commodity	COM	$ 10	$ 4	$ 4	$ 0	$ 1
21		Total Structures and Improvements		$ 28,085	$ 21,158	$ 5,365	$ 91	$ 1,470
22	376	**Distribution Mains**						
23		Customer	CUS	$ 36,873,454	$ 31,943,367	$ 4,433,210	$ 18,150	$ 478,727
24		Demand	DEM	$ 17,641,156	$ 10,060,498	$ 5,393,875	$ 136,301	$ 2,050,482
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -
26		Total Distribution Mains		$ 54,514,610	$ 42,003,865	$ 9,827,085	$ 154,451	$ 2,529,209
27	377	**Compressor Station Equipment**						
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ -	$ -	$ -	$ -	$ -
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -
31		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
32		**Distribution Plant (Cont'd)**						
33	378	**Meas. & Reg. Sta. Equip.- Gen.**						
34		Customer	CUS	$ -	$ -	$ -	$ -	$ -
35		Demand	DEM	$ 3,519,477	$ 2,007,107	$ 1,076,098	$ 27,193	$ 409,079
36		Commodity	COM	$ -	$ -	$ -	$ -	$ -
37		Total Meas. & Reg. Sta. Equip.- Gen.		$ 3,519,477	$ 2,007,107	$ 1,076,098	$ 27,193	$ 409,079
38	378	**Odorization Tank**						
39		Customer	CUS	$ -	$ -	$ -	$ -	$ -
40		Demand	DEM	$ -	$ -	$ -	$ -	$ -
41		Commodity	COM	$ 22,098	$ 9,808	$ 9,681	$ 371	$ 2,239
42		Total Odorization Tank		$ 22,098	$ 9,808	$ 9,681	$ 371	$ 2,239
43	379	**Meas. & Reg. Station - City Gate**						
44		Customer	CUS	$ -	$ -	$ -	$ -	$ -
45		Demand	DEM	$ 1,551,543	$ 884,823	$ 474,392	$ 11,988	$ 180,340
46		Commodity	COM	$ -	$ -	$ -	$ -	$ -
47		Total Meas. & Reg. Equip.-City Gate		$ 1,551,543	$ 884,823	$ 474,392	$ 11,988	$ 180,340
48	379	**Odorization Tank**						
49		Customer	CUS	$ -	$ -	$ -	$ -	$ -
50		Demand	DEM	$ -	$ -	$ -	$ -	$ -
51		Commodity	COM	$ 21,519	$ 9,551	$ 9,427	$ 361	$ 2,181
52		Total Odorization Tank		$ 21,519	$ 9,551	$ 9,427	$ 361	$ 2,181
53	380	**Services**						
54		Customer	SERCUS	$ 16,345,104	$ 13,989,771	$ 2,110,914	$ 16,468	$ 227,950
55		Demand	DEM	$ -	$ -	$ -	$ -	$ -
56		Commodity	COM	$ -	$ -	$ -	$ -	$ -
57		Total Services		$ 16,345,104	$ 13,989,771	$ 2,110,914	$ 16,468	$ 227,950
58	381	**Meters**						
59		Customer	METCUS	$ 2,708,292	$ 2,023,761	$ 532,259	$ 10,010	$ 142,261
60		Demand	DEM	$ -	$ -	$ -	$ -	$ -
61		Commodity	COM	$ -	$ -	$ -	$ -	$ -
62		Total Meters		$ 2,708,292	$ 2,023,761	$ 532,259	$ 10,010	$ 142,261

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
63		**Distribution Plant (Cont'd)**						
64	382	**Meter Installations**						
65		Customer	METCUS	$ 1,996	$ 1,491	$ 392	$ 7	$ 105
66		Demand	DEM	$ -	$ -	$ -	$ -	$ -
67		Commodity	COM	$ -	$ -	$ -	$ -	$ -
68		Total Meter Installations		$ 1,996	$ 1,491	$ 392	$ 7	$ 105
69	383	**House Regulators**						
70		Customer	REGCUS	$ 753,647	$ 539,690	$ 166,455	$ 2,814	$ 44,689
71		Demand	DEM	$ -	$ -	$ -	$ -	$ -
72		Commodity	COM	$ -	$ -	$ -	$ -	$ -
73		Total House Regulators		$ 753,647	$ 539,690	$ 166,455	$ 2,814	$ 44,689
74	385	**Meas. & Reg. Sta. Equip. - Ind.**						
75		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
76		Demand	NRDEM	$ 1,033,655	$ -	$ 735,478	$ 18,585	$ 279,592
77		Commodity	COM	$ -	$ -	$ -	$ -	$ -
78		Total Meas. & Reg. Sta. Equip.- Ind.		$ 1,033,655	$ -	$ 735,478	$ 18,585	$ 279,592
79	386	**Other Prop.-Customer Premises**						
80		Customer	CUS	$ 9,515	$ 8,243	$ 1,144	$ 5	$ 124
81		Demand	DEM	$ -	$ -	$ -	$ -	$ -
82		Commodity	COM	$ -	$ -	$ -	$ -	$ -
83		Total Other Prop.- Cust. Premises		$ 9,515	$ 8,243	$ 1,144	$ 5	$ 124
84	387	**Other Equipment**						
85		Customer	CUS	$ -	$ -	$ -	$ -	$ -
86		Demand	DEM	$ -	$ -	$ -	$ -	$ -
87		Commodity	COM	$ -	$ -	$ -	$ -	$ -
88		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
89		**Total Distribution Plant**						
90		Customer		$ 56,748,760	$ 48,555,489	$ 7,251,197	$ 47,482	$ 894,592
91		Demand		$ 23,780,789	$ 12,972,363	$ 7,690,532	$ 194,337	$ 2,923,556
92		Commodity		$ 43,650	$ 19,373	$ 19,122	$ 732	$ 4,423
93		Total Distribution Plant		$ 80,573,199	$ 61,547,225	$ 14,960,851	$ 242,552	$ 3,822,571

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
94		**Total General Plant**						
95		Customer	CUS	$ 6,609,391	$ 5,725,697	$ 794,632	$ 3,253	$ 85,809
96		Demand	DEM	$ 2,018,000	$ 1,150,836	$ 617,014	$ 15,592	$ 234,558
97		Commodity	COM	$ 16,801	$ 7,457	$ 7,360	$ 282	$ 1,702
98		Total General Plant		$ 8,644,192	$ 6,883,990	$ 1,419,006	$ 19,127	$ 322,070
99		**Total Plant in Service**						
100		Customer		$ 63,511,055	$ 54,413,646	$ 8,064,212	$ 50,811	$ 982,387
101		Demand		$ 28,453,137	$ 15,636,936	$ 9,119,127	$ 230,437	$ 3,466,637
102		Commodity		$ 60,597	$ 26,894	$ 26,546	$ 1,016	$ 6,140
103		Total Plant in Service		$ 92,024,789	$ 70,077,476	$ 17,209,885	$ 282,265	$ 4,455,164
104		**Depreciation & Amort. Reserve**						
105		**Intangible Plant**						
106		Customer	CUS	$ (64,228)	$ (55,640)	$ (7,722)	$ (32)	$ (834)
107		Demand	DEM	$ (24,061)	$ (13,722)	$ (7,357)	$ (186)	$ (2,797)
108		Commodity	COM	$ 14	$ 6	$ 6	$ 0	$ 1
109		Total Intangible Plant		$ (88,274)	$ (69,356)	$ (15,072)	$ (217)	$ (3,629)
110		**Transmission Plant**						
111		Customer	CUS	$ -	$ -	$ -	$ -	$ -
112		Demand	DEM	$ (333,409)	$ (190,138)	$ (101,942)	$ (2,576)	$ (38,753)
113		Commodity	COM	$ -	$ -	$ -	$ -	$ -
114		Total Transmission Plant		$ (333,409)	$ (190,138)	$ (101,942)	$ (2,576)	$ (38,753)
115		**Distribution Plant**						
116		Customer	DISPLTCUS	$ (4,222,369)	$ (3,612,752)	$ (539,522)	$ (3,533)	$ (66,562)
117		Demand	DISPLTDEM	$ (1,581,770)	$ (862,852)	$ (511,533)	$ (12,926)	$ (194,459)
118		Commodity	COM	$ 929	$ 412	$ 407	$ 16	$ 94
119		Total Distribution Plant		$ (5,803,211)	$ (4,475,192)	$ (1,050,648)	$ (16,444)	$ (260,927)
120		**General Plant**						
121		Customer	GENPTCUS	$ (2,741,888)	$ (2,353,963)	$ (344,733)	$ (2,038)	$ (41,154)
122		Demand	DISPLTDEM	$ (841,255)	$ (458,903)	$ (272,056)	$ (6,875)	$ (103,422)
123		Commodity	COM	$ (7,772)	$ (3,449)	$ (3,405)	$ (130)	$ (788)
124		Total General Plant		$ (3,590,915)	$ (2,816,316)	$ (620,193)	$ (9,043)	$ (145,363)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
125		**Total Depr. & Amort. Reserve**						
126		Customer		$ (7,028,485)	$ (6,022,356)	$ (891,977)	$ (5,602)	$ (108,549)
127		Demand		$ (2,780,496)	$ (1,525,615)	$ (892,887)	$ (22,563)	$ (339,431)
128		Commodity		$ (6,829)	$ (3,031)	$ (2,992)	$ (115)	$ (692)
129		Total Depr. & Amortization Reserve		$ (9,815,810)	$ (7,551,001)	$ (1,787,856)	$ (28,280)	$ (448,672)
130		**Net Plant in Service**						
131		Customer		$ 56,482,571	$ 48,391,290	$ 7,172,235	$ 45,209	$ 873,837
132		Demand		$ 25,672,641	$ 14,111,321	$ 8,226,240	$ 207,874	$ 3,127,206
133		Commodity		$ 53,768	$ 23,863	$ 23,554	$ 902	$ 5,448
134		Total Net Plant in Service		$ 82,208,980	$ 62,526,475	$ 15,422,029	$ 253,985	$ 4,006,491
135		**Customer Deposits**						
136		Customer	DEPCUS	$ (644,834)	$ (279,344)	$ (364,855)	$ (100)	$ (535)
137		Demand	DEM	$ -	$ -	$ -	$ -	$ -
138		Commodity	CUS	$ -	$ -	$ -	$ -	$ -
139		Total Customer Deposits		$ (644,834)	$ (279,344)	$ (364,855)	$ (100)	$ (535)
140		**Customer Advances**						
141		Customer	MSCUS	$ (127,284)	$ (109,859)	$ (15,652)	$ (83)	$ (1,690)
142		Demand	DEM	$ (42,193)	$ (24,062)	$ (12,901)	$ (326)	$ (4,904)
143		Commodity	COM	$ -	$ -	$ -	$ -	$ -
144		Total Customer Advances		$ (169,477)	$ (133,921)	$ (28,552)	$ (409)	$ (6,594)
145		**Accum. Deferred Income Taxes**						
146		Customer	TPLTCUS	$ (6,872,702)	$ (5,888,247)	$ (872,650)	$ (5,498)	$ (106,307)
147		Demand	TPLTDEM	$ (3,078,990)	$ (1,692,115)	$ (986,805)	$ (24,936)	$ (375,134)
148		Commodity	COM	$ (6,557)	$ (2,910)	$ (2,873)	$ (110)	$ (664)
149		Total Accum. Deferred Inc. Taxes		$ (9,958,250)	$ (7,583,272)	$ (1,862,328)	$ (30,545)	$ (482,105)
150		**Excess Deferred Income Taxes**						
151		Customer	TPLTCUS	$ (1,864,114)	$ (1,597,095)	$ (236,693)	$ (1,491)	$ (28,834)
152		Demand	TPLTDEM	$ (835,128)	$ (458,960)	$ (267,656)	$ (6,764)	$ (101,749)
153		Commodity	COM	$ (1,779)	$ (789)	$ (779)	$ (30)	$ (180)
154		**Total Excess Deferred Income Taxes**		$ (2,701,021)	$ (2,056,845)	$ (505,127)	$ (8,285)	$ (130,764)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
155		**Materials and Supplies**						
156		Customer	TPLTCUS	$ 525,188	$ 449,959	$ 66,685	$ 420	$ 8,124
157		Demand	TPLTDEM	$ 235,286	$ 129,305	$ 75,408	$ 1,906	$ 28,666
158		Commodity	COM	$ 501	$ 222	$ 220	$ 8	$ 51
159		Total Materials and Supplies		$ 760,974	$ 579,487	$ 142,313	$ 2,334	$ 36,841
160		**Prepayments**						
161		Customer	OPEXPCUS	$ 129,527	$ 109,016	$ 17,626	$ 163	$ 2,722
162		Demand	OPEXPDEM	$ 45,387	$ 23,361	$ 15,672	$ 396	$ 5,958
163		Commodity	COM	$ 1,313	$ 583	$ 575	$ 22	$ 133
164		Total Prepayments		$ 176,227	$ 132,960	$ 33,873	$ 581	$ 8,813
165		**Pension & FAS 106 Reg. Asset**						
166		Customer	OPEXPCUS	$ 752,012	$ 632,930	$ 102,331	$ 949	$ 15,802
167		Demand	OPEXPDEM	$ 263,508	$ 135,630	$ 90,990	$ 2,299	$ 34,590
168		Commodity	COM	$ 7,623	$ 3,383	$ 3,340	$ 128	$ 772
169		Total Pen. & FAS 106 Reg. Asset		$ 1,023,144	$ 771,943	$ 196,660	$ 3,376	$ 51,164
170		**DIMP Deferrals**						
171		Customer	TPLTCUS	$ 277,737	$ 237,954	$ 35,265	$ 222	$ 4,296
172		Demand	TPLTDEM	$ 97,320	$ 53,484	$ 31,191	$ 788	$ 11,857
173		Commodity	COM	$ 2,815	$ 1,250	$ 1,233	$ 47	$ 285
174		Total DIMP Deferrals		$ 377,873	$ 292,687	$ 67,689	$ 1,058	$ 16,438
175		**Regulatory Assets**						
176		Customer	TPLTCUS	$ 95,543	$ 81,857	$ 12,131	$ 76	$ 1,478
177		Demand	TPLTDEM	$ 33,479	$ 18,399	$ 10,730	$ 271	$ 4,079
178		Commodity	COM	$ 969	$ 430	$ 424	$ 16	$ 98
179		**Total Regulatory Assets**		$ 129,990	$ 100,686	$ 23,286	$ 364	$ 5,655
180		**Cash Working Capital**						
181		Customer	OPEXPCUS	$ (47,638)	$ (40,094)	$ (6,482)	$ (60)	$ (1,001)
182		Demand	OPEXPDEM	$ (16,692)	$ (8,592)	$ (5,764)	$ (146)	$ (2,191)
183		Commodity	COM	$ (483)	$ (214)	$ (212)	$ (8)	$ (49)
184		Total Cash Working Capital		$ (64,813)	$ (48,900)	$ (12,458)	$ (214)	$ (3,241)
185		**Total Rate Base**						
186		Customer		$ 48,706,006	$ 41,988,366	$ 5,909,941	$ 39,807	$ 767,892
187		Demand		$ 22,374,616	$ 12,287,772	$ 7,177,105	$ 181,363	$ 2,728,377
188		Commodity		$ 58,170	$ 25,817	$ 25,483	$ 976	$ 5,894

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
189		Total Rate Base		$ 71,138,793	$ 54,301,955	$ 13,112,529	$ 222,146	$ 3,502,163

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		**Transmission and Distribution Operating Expense**						
2	814-866	**Transmission Expenses**						
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 321,559	$ 183,380	$ 98,318	$ 2,484	$ 37,376
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 321,559	$ 183,380	$ 98,318	$ 2,484	$ 37,376
7	8700	**Operation Supervision & Engineering**						
8		Customer	871-879CUS	$ 44,629	$ 35,459	$ 7,463	$ 104	$ 1,603
9		Demand	DEM	$ 7,845	$ 4,474	$ 2,399	$ 61	$ 912
10		Commodity	COM	$ 464	$ 206	$ 203	$ 8	$ 47
11		Total Supervision & Engineering		$ 52,938	$ 40,139	$ 10,065	$ 172	$ 2,562
12	8710	**Distribution Load Dispatch**						
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 12,213	$ 5,420	$ 5,350	$ 205	$ 1,238
16		Total Distribution Load Dispatch		$ 12,213	$ 5,420	$ 5,350	$ 205	$ 1,238
17	8740	**Mains and Services Expenses**						
18		Customer	MSCUS	$ 528,828	$ 456,434	$ 65,028	$ 344	$ 7,022
19		Demand	DEM	$ 175,299	$ 99,970	$ 53,598	$ 1,354	$ 20,375
20		Commodity	COM	$ -	$ -	$ -	$ -	$ -
21		Total Mains & Services		$ 704,127	$ 556,404	$ 118,627	$ 1,698	$ 27,398
22	8740	**Odorization**						
23		Customer	CUS	$ -	$ -	$ -	$ -	$ -
24		Demand	DEM	$ -	$ -	$ -	$ -	$ -
25		Commodity	COM	$ 1,103	$ 490	$ 483	$ 19	$ 112
26		Total Odorization		$ 1,103	$ 490	$ 483	$ 19	$ 112
27	8750	**Meas. & Reg. Station - Gen.**						
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ 29,550	$ 16,852	$ 9,035	$ 228	$ 3,435
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -
31		Total Meas. & Reg. Station - Gen.		$ 29,550	$ 16,852	$ 9,035	$ 228	$ 3,435
32	8750	**Odorization**						
33		Customer	CUS	$ -	$ -	$ -	$ -	$ -
34		Demand	DEM	$ -	$ -	$ -	$ -	$ -
35		Commodity	COM	$ 100	$ 44	$ 44	$ 2	$ 10
36		Total Odorization		$ 100	$ 44	$ 44	$ 2	$ 10

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
37		**Transmission and Distribution Operating Expense (Cont'd)**						
38	8760	**Meas. & Reg. Stat. - Ind.**						
39		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
40		Demand	NRDEM	$ 1,500	$ -	$ 1,067	$ 27	$ 406
41		Commodity	COM	$ -	$ -	$ -	$ -	$ -
42		Total Meas. & Reg. Stat. - Ind.		$ 1,500	$ -	$ 1,067	$ 27	$ 406
43	8770	**Meas. & Reg. Stat.- City Gate**						
44		Customer	CUS	$ -	$ -	$ -	$ -	$ -
45		Demand	DEM	$ 272	$ 155	$ 83	$ 2	$ 32
46		Commodity	COM	$ -	$ -	$ -	$ -	$ -
47		Total Meas. & Reg. Stat. - City Gate		$ 272	$ 155	$ 83	$ 2	$ 32
48	8780	**Meter & House Reg. Exp.**						
49		Customer	MTRGCUS	$ 646,605	$ 477,478	$ 131,528	$ 2,397	$ 35,203
50		Demand	DEM	$ -	$ -	$ -	$ -	$ -
51		Commodity	COM	$ -	$ -	$ -	$ -	$ -
52		Total Meter & House Reg. Exp.		$ 646,605	$ 477,478	$ 131,528	$ 2,397	$ 35,203
53	8790	**Customer Installation Expense**						
54		Customer	METCUS	$ -	$ -	$ -	$ -	$ -
55		Demand	DEM	$ -	$ -	$ -	$ -	$ -
56		Commodity	COM	$ -	$ -	$ -	$ -	$ -
57		Total Customer Install. Expense		$ -	$ -	$ -	$ -	$ -
58	8800	**Other Expenses**						
59		Customer	871-879CUS	$ 59,484	$ 47,262	$ 9,947	$ 139	$ 2,137
60		Demand	DEM	$ 10,456	$ 5,963	$ 3,197	$ 81	$ 1,215
61		Commodity	COM	$ 618	$ 274	$ 271	$ 10	$ 63
62		Total Other Expenses		$ 70,559	$ 53,499	$ 13,415	$ 230	$ 3,415
63	8810	**Rents**						
64		Customer	871-879CUS	$ 12,501	$ 9,932	$ 2,090	$ 29	$ 449
65		Demand	DEM	$ 2,197	$ 1,253	$ 672	$ 17	$ 255
66		Commodity	COM	$ 130	$ 58	$ 57	$ 2	$ 13
67		Total Rents		$ 14,828	$ 11,243	$ 2,819	$ 48	$ 718
68	8820	Corporate & Div. Exp.						
69		Customer	CUS	$ -	$ -	$ -	$ -	$ -
70		Demand	DEM	$ -	$ -	$ -	$ -	$ -
71		Commodity	COM	$ -	$ -	$ -	$ -	$ -
72		Total Corporate & Div. Exp.		$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
73		**Transmission and Distribution Operating Expense (Cont'd)**						
74		**Total Distr. & Trans. Op. Expense**						
75		Customer		$ 1,292,047	$ 1,026,564	$ 216,056	$ 3,013	$ 46,414
76		Demand		$ 548,678	$ 312,048	$ 168,370	$ 4,255	$ 64,006
77		Commodity		$ 14,628	$ 6,492	$ 6,408	$ 245	$ 1,482
78		Total Distr. & Trans. Operations Exp.		$ 1,855,353	$ 1,345,104	$ 390,834	$ 7,513	$ 111,902
79		**Distribution Maintenance Expenses**						
80	8850	**Maintenance Supervision and Engineering**						
81		Customer	887-893CUS	$ -	$ -	$ -	$ -	$ -
82		Demand	887-893DEM	$ -	$ -	$ -	$ -	$ -
83		Commodity	COM	$ -	$ -	$ -	$ -	$ -
84		Total Supervision and Engineering		$ -	$ -	$ -	$ -	$ -
85	8860	**Structures and Improvements**						
86		Customer	887-893CUS	$ 76,910	$ 66,298	$ 9,529	$ 54	$ 1,029
87		Demand	887-893DEM	$ 52,251	$ 21,381	$ 21,965	$ 555	$ 8,350
88		Commodity	COM	$ -	$ -	$ -	$ -	$ -
89		Total Structures and Improvements		$ 129,161	$ 87,679	$ 31,494	$ 609	$ 9,379
90	8870	**Maintenance of Mains**						
91		Customer	CUS	$ 398,356	$ 345,094	$ 47,893	$ 196	$ 5,172
92		Demand	DEM	$ 190,583	$ 108,687	$ 58,272	$ 1,473	$ 22,152
93		Commodity	COM	$ -	$ -	$ -	$ -	$ -
94		Total Mains		$ 588,939	$ 453,781	$ 106,165	$ 1,669	$ 27,324
95	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen.**						
96		Customer	CUS	$ -	$ -	$ -	$ -	$ -
97		Demand	DEM	$ 137,349	$ 78,328	$ 41,995	$ 1,061	$ 15,964
98		Commodity	COM	$ -	$ -	$ -	$ -	$ -
99		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		$ 137,349	$ 78,328	$ 41,995	$ 1,061	$ 15,964
100	8890	**Odorization**						
101		Customer	CUS	$ -	$ -	$ -	$ -	$ -
102		Demand	DEM	$ -	$ -	$ -	$ -	$ -
103		Commodity	COM	$ 16,059	$ 7,128	$ 7,035	$ 269	$ 1,627
104		Total Odorization		$ 16,059	$ 7,128	$ 7,035	$ 269	$ 1,627
105	8900	**Meas. & Reg. Sta. Equip. - Ind.**						
106		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
107		Demand	NRDEM	$ 129,878	$ -	$ 92,412	$ 2,335	$ 35,131
108		Commodity	COM	$ -	$ -	$ -	$ -	$ -
109		Total Meas. & Reg. Sta. Eq.- Ind.		$ 129,878	$ -	$ 92,412	$ 2,335	$ 35,131

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
110		**Distribution Maintenance Expense (Cont'd)**						
111	8910	**Meas. & Reg. Sta. Eq.- City Gate**						
112		Customer	CUS	$ -	$ -	$ -	$ -	$ -
113		Demand	DEM	$ 1,999	$ 1,140	$ 611	$ 15	$ 232
114		Commodity	COM	$ -	$ -	$ -	$ -	$ -
115		Total Meas. & Reg. Sta. Eq.- City Gate		$ 1,999	$ 1,140	$ 611	$ 15	$ 232
116	8920	**Services**						
117		Customer	SERCUS	$ 278,451	$ 238,326	$ 35,961	$ 281	$ 3,883
118		Demand	DEM	$ -	$ -	$ -	$ -	$ -
119		Commodity	COM	$ -	$ -	$ -	$ -	$ -
120		Total Services		$ 278,451	$ 238,326	$ 35,961	$ 281	$ 3,883
121	8930	**Meters & House Regulators**						
122		Customer	MTRGCUS	$ -	$ -	$ -	$ -	$ -
123		Demand	DEM	$ -	$ -	$ -	$ -	$ -
124		Commodity	COM	$ -	$ -	$ -	$ -	$ -
125		Total Meters & House Regulators		$ -	$ -	$ -	$ -	$ -
126	8940	**Maintenance of Other Equipment**						
127		Customer	CUS	$ -	$ -	$ -	$ -	$ -
128		Demand	DEM	$ -	$ -	$ -	$ -	$ -
129		Commodity	COM	$ -	$ -	$ -	$ -	$ -
130		Total Maintenance of Other Equipment		$ -	$ -	$ -	$ -	$ -
131	8950	Clearing - Meter Shop - Small Meters						
132		Customer	CUS	$ -	$ -	$ -	$ -	$ -
133		Demand	DEM	$ -	$ -	$ -	$ -	$ -
134		Commodity	COM	$ -	$ -	$ -	$ -	$ -
135		**Total Clearing-Meter-Shop-Small Meters**		$ -	$ -	$ -	$ -	$ -
136	8960	Clearing - Meter Shop - Large Meters						
137		Customer	CUS	$ -	$ -	$ -	$ -	$ -
138		Demand	DEM	$ -	$ -	$ -	$ -	$ -
139		Commodity	COM	$ -	$ -	$ -	$ -	$ -
140		**Total Clearing-Meter Shop-Large Meters**		$ -	$ -	$ -	$ -	$ -
141		**Total Distr. Maintenance Expense**						
142		Customer		$ 753,717	$ 649,719	$ 93,383	$ 531	$ 10,084
143		Demand		$ 512,060	$ 209,536	$ 215,255	$ 5,439	$ 81,829
144		Commodity		$ 16,059	$ 7,128	$ 7,035	$ 269	$ 1,627
145		Total Distr. Maintenance Expense		$ 1,281,836	$ 866,382	$ 315,674	$ 6,240	$ 93,541

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
146		**Total Oper. & Maint. Expense**						
147		Customer		$ 2,045,764	$ 1,676,283	$ 309,440	$ 3,544	$ 56,498
148		Demand		$ 1,060,738	$ 521,584	$ 383,625	$ 9,694	$ 145,835
149		Commodity		$ 30,687	$ 13,620	$ 13,443	$ 515	$ 3,110
150		Total Operations & Maint. Expense		$ 3,137,189	$ 2,211,486	$ 706,508	$ 13,752	$ 205,443
151		**Customer Accounts Expense**		$ 3,137,189				
152	901	Supervision						
153		Customer	902-904CUS	$ 6,199	$ 5,615	$ 526	$ 4	$ 54
154		Demand	DEM	$ -	$ -	$ -	$ -	$ -
155		Commodity	COM	$ -	$ -	$ -	$ -	$ -
156		Total Supervision		$ 6,199	$ 5,615	$ 526	$ 4	$ 54
157	902	**Meter Reading Expense**						
158		Customer	METCUS	$ 35,072	$ 26,207	$ 6,893	$ 130	$ 1,842
159		Demand	DEM	$ -	$ -	$ -	$ -	$ -
160		Commodity	COM	$ -	$ -	$ -	$ -	$ -
161		Total Meter Reading Expense		$ 35,072	$ 26,207	$ 6,893	$ 130	$ 1,842
162	903	**Customer Accounting**						
163		Customer	903CUS	$ 166,507	$ 153,018	$ 12,666	$ 69	$ 754
164		Demand	DEM	$ -	$ -	$ -	$ -	$ -
165		Commodity	COM	$ -	$ -	$ -	$ -	$ -
166		Total Customer Accounting		$ 166,507	$ 153,018	$ 12,666	$ 69	$ 754
167	904	**Bad Debt Expense**						
168		Customer	904CUS	$ 97,843	$ 92,000	$ 5,844	$ -	$ -
169		Demand	DEM	$ -	$ -	$ -	$ -	$ -
170		Commodity	COM	$ -	$ -	$ -	$ -	$ -
171		Total Bad Debt Expense		$ 97,843	$ 92,000	$ 5,844	$ -	$ -
172	905	**Miscellaneous Customer Accounts**						
173		Customer	902-904CUS	$ 20,973	$ 18,998	$ 1,779	$ 14	$ 182
174		Demand	DEM	$ -	$ -	$ -	$ -	$ -
175		Commodity	COM	$ -	$ -	$ -	$ -	$ -
176		Total Misc. Customer Accounts		$ 20,973	$ 18,998	$ 1,779	$ 14	$ 182

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
177		**Customer Accounts Expense (Cont'd)**						
178	907-910	**Customer Information Expense**						
179		Customer	CUS	$ 146,847	$ 127,213	$ 17,655	$ 72	$ 1,907
180		Demand	DEM	$ -	$ -	$ -	$ -	$ -
181		Commodity	COM	$ -	$ -	$ -	$ -	$ -
182		Total Customer Information Expense		$ 146,847	$ 127,213	$ 17,655	$ 72	$ 1,907
183		**Sales and Advertising Expense**						
184	911	Supervision						
185		Customer	CUS	$ -	$ -	$ -	$ -	$ -
186		Demand	DEM	$ -	$ -	$ -	$ -	$ -
187		Commodity	COM	$ -	$ -	$ -	$ -	$ -
188		**Total Supervision Expense**		$ -	$ -	$ -	$ -	$ -
189	912	**Demonstrating and Selling**						
190		Customer	CUS	$ -	$ -	$ -	$ -	$ -
191		Demand	DEM	$ -	$ -	$ -	$ -	$ -
192		Commodity	COM	$ -	$ -	$ -	$ -	$ -
193		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -
194	913	**Advertising**						
195		Customer	CUS	$ 42	$ 36	$ 5	$ 0	$ 1
196		Demand	DEM	$ -	$ -	$ -	$ -	$ -
197		Commodity	COM	$ -	$ -	$ -	$ -	$ -
198		Total Advertising		$ 42	$ 36	$ 5	$ 0	$ 1
199	914	Employee Sales Referrals						
200		Customer	CUS	$ -	$ -	$ -	$ -	$ -
201		Demand	DEM	$ -	$ -	$ -	$ -	$ -
202		Commodity	COM	$ -	$ -	$ -	$ -	$ -
203		Total Employee Sales Referrals		$ -	$ -	$ -	$ -	$ -
204		Misc. Gas Sales Expense						
205	916	Customer	CUS	$ -	$ -	$ -	$ -	$ -
206		Demand	DEM	$ -	$ -	$ -	$ -	$ -
207		Commodity	COM	$ -	$ -	$ -	$ -	$ -
208		Total Misc. Gas Sales Expense		$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
209		**Administrative & General Exp.**						
210	920-940	**Administrative & General Expenses**						
211		Customer	OPEXPCUS	$ 1,470,830	$ 1,237,922	$ 200,145	$ 1,856	$ 30,907
212		Demand	OPEXPDEM	$ 337,400	$ 173,662	$ 116,505	$ 2,944	$ 44,289
213		Commodity	COM	$ 9,761	$ 4,332	$ 4,276	$ 164	$ 989
214		Total Administrative & General Exp.		$ 1,817,991	$ 1,415,916	$ 320,926	$ 4,964	$ 76,185
215		**Depreciation & Amortization Expense**						
216	301-03	**Intangible Plant**						
217		Customer	CUS	$ 3,955	$ 3,427	$ 476	$ 2	$ 51
218		Demand	DEM	$ 1,772	$ 1,011	$ 542	$ 14	$ 206
219		Commodity	COM	$ 4	$ 2	$ 2	$ 0	$ 0
220		Total Intangible Plant		$ 5,731	$ 4,439	$ 1,019	$ 16	$ 258
221	365	**Land and Land Rights**						
222		Customer	CUS	$ -	$ -	$ -	$ -	$ -
223		Demand	DEM	$ -	$ -	$ -	$ -	$ -
224		Commodity	COM	$ -	$ -	$ -	$ -	$ -
225		Total Land and Land Rights		$ -	$ -	$ -	$ -	$ -
226	366	**Meas. and Reg. Station Structures**						
227		Customer	CUS	$ -	$ -	$ -	$ -	$ -
228		Demand	DEM	$ -	$ -	$ -	$ -	$ -
229		Commodity	COM	$ -	$ -	$ -	$ -	$ -
230		Total Measuring and Reg. Stat. Struct.		$ -	$ -	$ -	$ -	$ -
231	367	**Transmission Mains**						
232		Customer	CUS	$ -	$ -	$ -	$ -	$ -
233		Demand	DEM	$ 44,743	$ 25,516	$ 13,680	$ 346	$ 5,201
234		Commodity	COM	$ -	$ -	$ -	$ -	$ -
235		Total Transmission Mains		$ 44,743	$ 25,516	$ 13,680	$ 346	$ 5,201
236	368	**Compression Station Equipment**						
237		Customer	CUS	$ -	$ -	$ -	$ -	$ -
238		Demand	DEM	$ -	$ -	$ -	$ -	$ -
239		Commodity	COM	$ -	$ -	$ -	$ -	$ -
240		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -
241	369	**Meas. & Reg. Station Equipment**						
242		Customer	CUS	$ -	$ -	$ -	$ -	$ -
243		Demand	DEM	$ 26,789	$ 15,277	$ 8,191	$ 207	$ 3,114
244		Commodity	COM	$ -	$ -	$ -	$ -	$ -
245		Total Meas. & Reg. Stat. Equipment		$ 26,789	$ 15,277	$ 8,191	$ 207	$ 3,114

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
246		**Depreciation & Amortization Expense (Cont'd)**						
247	371	**Other Equipment**						
248		Customer	CUS	$ -	$ -	$ -	$ -	$ -
249		Demand	DEM	$ -	$ -	$ -	$ -	$ -
250		Commodity	COM	$ -	$ -	$ -	$ -	$ -
251		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
252	375	**Structures and Improvements**						
253		Customer	376-379CUS	$ 949	$ 822	$ 114	$ 0	$ 12
254		Demand	DEM	$ 584	$ 333	$ 179	$ 5	$ 68
255		Commodity	COM	$ 1	$ 0	$ 0	$ 0	$ 0
256		Total Structures and Improvements		$ 1,533	$ 1,155	$ 293	$ 5	$ 80
257	376	**Distribution Mains**						
258		Customer	CUS	$ 942,323	$ 816,332	$ 113,293	$ 464	$ 12,234
259		Demand	DEM	$ 450,830	$ 257,102	$ 137,844	$ 3,483	$ 52,401
260		Commodity	COM	$ -	$ -	$ -	$ -	$ -
261		Total Distribution Mains		$ 1,393,153	$ 1,073,434	$ 251,137	$ 3,947	$ 64,635
262	377	**Compressor Station Equipment**						
263		Customer	CUS	$ -	$ -	$ -	$ -	$ -
264		Demand	DEM	$ -	$ -	$ -	$ -	$ -
265		Commodity	COM	$ -	$ -	$ -	$ -	$ -
266		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -
267	378	**Meas. & Reg. Sta. Equip. - Gen.**						
268		Customer	CUS	$ -	$ -	$ -	$ -	$ -
269		Demand	DEM	$ 77,162	$ 44,004	$ 23,593	$ 596	$ 8,969
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -
271		Total Meas. & Reg. Sta. Eq.- Gen.		$ 77,162	$ 44,004	$ 23,593	$ 596	$ 8,969
272	378	**Odorization Tank**						
273		Customer	CUS	$ -	$ -	$ -	$ -	$ -
274		Demand	DEM	$ -	$ -	$ -	$ -	$ -
275		Commodity	COM	$ 484	$ 215	$ 212	$ 8	$ 49
276		Total Odorization Tank		$ 484	$ 215	$ 212	$ 8	$ 49
277	379	**Meas.& Reg. Sta. Equip.- City Gate**						
278		Customer	CUS	$ -	$ -	$ -	$ -	$ -
279		Demand	DEM	$ 31,651	$ 18,050	$ 9,678	$ 245	$ 3,679
280		Commodity	COM	$ -	$ -	$ -	$ -	$ -
281		Total Meas. & Reg. Sta. Eq.- City Gate		$ 31,651	$ 18,050	$ 9,678	$ 245	$ 3,679

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
282		**Depreciation & Amortization Expense (Cont'd)**						
283	379	**Odorization Tank**						
284		Customer	CUS	$ -	$ -	$ -	$ -	$ -
285		Demand	DEM	$ -	$ -	$ -	$ -	$ -
286		Commodity	COM	$ 439	$ 195	$ 192	$ 7	$ 44
287		Total Odorization Tank		$ 439	$ 195	$ 192	$ 7	$ 44
288	380	**Services**						
289		Customer	SERCUS	$ 551,006	$ 471,606	$ 71,160	$ 555	$ 7,684
290		Demand	DEM	$ -	$ -	$ -	$ -	$ -
291		Commodity	COM	$ -	$ -	$ -	$ -	$ -
292		Total Services		$ 551,006	$ 471,606	$ 71,160	$ 555	$ 7,684
293	381	**Meters**						
294		Customer	METCUS	$ 127,844	$ 95,531	$ 25,125	$ 473	$ 6,715
295		Demand	DEM	$ -	$ -	$ -	$ -	$ -
296		Commodity	COM	$ -	$ -	$ -	$ -	$ -
297		Total Meters		$ 127,844	$ 95,531	$ 25,125	$ 473	$ 6,715
298	382	**Meter Installations**						
299		Customer	METCUS	$ (17)	$ (13)	$ (3)	$ (0)	$ (1)
300		Demand	DEM	$ -	$ -	$ -	$ -	$ -
301		Commodity	COM	$ -	$ -	$ -	$ -	$ -
302		Total Meter Installations		$ (17)	$ (13)	$ (3)	$ (0)	$ (1)
303	383	**House Regulators**						
304		Customer	REGCUS	$ 28,707	$ 20,557	$ 6,340	$ 107	$ 1,702
305		Demand	DEM	$ -	$ -	$ -	$ -	$ -
306		Commodity	COM	$ -	$ -	$ -	$ -	$ -
307		Total House Regulators		$ 28,707	$ 20,557	$ 6,340	$ 107	$ 1,702
308	385	**Meas. & Reg. Sta. Equip. - Ind.**						
309		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
310		Demand	NRDEM	$ 25,135	$ -	$ 17,884	$ 452	$ 6,799
311		Commodity	COM	$ -	$ -	$ -	$ -	$ -
312		Total Meas. & Reg. Stat. Eq.- Ind.		$ 25,135	$ -	$ 17,884	$ 452	$ 6,799
313	386	**Other Prop.- Customer Premises**						
314		Customer	CUS	$ 3,376	$ 2,924	$ 406	$ 2	$ 44
315		Demand	DEM	$ -	$ -	$ -	$ -	$ -
316		Commodity	COM	$ -	$ -	$ -	$ -	$ -
317		Total Other Prop. - Customer Premises		$ 3,376	$ 2,924	$ 406	$ 2	$ 44

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
318		**Depreciation & Amortization Expense (Cont'd)**						
319	387	**Other Equipment**						
320		Customer	CUS	$ -	$ -	$ -	$ -	$ -
321		Demand	DEM	$ -	$ -	$ -	$ -	$ -
322		Commodity	COM	$ -	$ -	$ -	$ -	$ -
323		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
324	389-98	**General Plant**						
325		Customer	GENPTCUS	$ 316,462	$ 271,689	$ 39,788	$ 235	$ 4,750
326		Demand	DISPLTDEM	$ 68,598	$ 37,420	$ 22,184	$ 561	$ 8,433
327		Commodity	COM	$ 997	$ 443	$ 437	$ 17	$ 101
328		Total General Plant		$ 386,057	$ 309,551	$ 62,409	$ 813	$ 13,284
329	389-98	**General Plant - Odorization**						
330		Customer	CUS	$ -	$ -	$ -	$ -	$ -
331		Demand	DEM	$ -	$ -	$ -	$ -	$ -
332		Commodity	COM	$ 873	$ 388	$ 382	$ 15	$ 88
333		Total General Plant - Odorization		$ 873	$ 388	$ 382	$ 15	$ 88
334	40730	**Pension & FAS 106 Amort. Expense**						
335		Customer	CUS	$ -	$ -	$ -	$ -	$ -
336		Demand	DEM	$ -	$ -	$ -	$ -	$ -
337		Commodity	COM	$ -	$ -	$ -	$ -	$ -
338		Total Pension & FAS 106 Amort. Exp.		$ -	$ -	$ -	$ -	$ -
339		**Total Depreciation & Amort. Exp.**						
340		Customer		$ 1,974,604	$ 1,682,874	$ 256,700	$ 1,838	$ 33,193
341		Demand		$ 727,265	$ 398,714	$ 233,774	$ 5,907	$ 88,869
342		Commodity		$ 2,797	$ 1,242	$ 1,226	$ 47	$ 283
343		Total Depreciation & Amort. Expense		$ 2,704,667	$ 2,082,830	$ 491,699	$ 7,792	$ 122,345
344		**Taxes Other Than Income**						
345	4081	**Payroll and Other Taxes**						
346		Customer	OPEXPCUS	$ 206,576	$ 173,864	$ 28,110	$ 261	$ 4,341
347		Demand	OPEXPDEM	$ 72,385	$ 37,257	$ 24,995	$ 632	$ 9,502
348		Commodity	COM	$ 2,094	$ 929	$ 917	$ 35	$ 212
349		Total Payroll and Other Taxes		$ 281,055	$ 212,051	$ 54,022	$ 927	$ 14,055

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
350		**Taxes Other Than Income (Cont'd)**						
351	4081	**Ad Valorem Taxes**						
352		Customer	CUS	$ 308,810	$ 267,522	$ 37,128	$ 152	$ 4,009
353		Demand	DEM	$ 138,348	$ 78,898	$ 42,301	$ 1,069	$ 16,081
354		Commodity	COM	$ 295	$ 131	$ 129	$ 5	$ 30
355		Total Ad Valorem Taxes		$ 447,453	$ 346,550	$ 79,557	$ 1,226	$ 20,120
356		**Revenue Related Taxes**						
357		Customer	TOTREVCUS	$ 10,151	$ 4,924	$ 4,167	$ 147	$ 914
358		Demand	DEM	$ -	$ -	$ -	$ -	$ -
359		Commodity	COM	$ -	$ -	$ -	$ -	$ -
360		Total Revenue Related Taxes		$ 10,151	$ 4,924	$ 4,167	$ 147	$ 914
361		**Total Taxes Other Than Income**						
362		Customer		$ 525,537	$ 446,309	$ 69,404	$ 559	$ 9,264
363		Demand		$ 210,733	$ 116,155	$ 67,295	$ 1,701	$ 25,582
364		Commodity		$ 2,389	$ 1,060	$ 1,046	$ 40	$ 242
365		Total Taxes Other Than Income		$ 738,659	$ 563,525	$ 137,746	$ 2,300	$ 35,089
366		**Excess Deferred Income Tax Amortization**						
367		Customer	CUS	$ (167,646)	$ (145,231)	$ (20,156)	$ (83)	$ (2,177)
368		Demand	DEM	$ (77,013)	$ (43,920)	$ (23,547)	$ (595)	$ (8,951)
369		Commodity	COM	$ (200)	$ (89)	$ (88)	$ (3)	$ (20)
370		**Total Excess Def. Income Tax Amortization**		$ (244,859)	$ (189,239)	$ (43,791)	$ (681)	$ (11,148)
371		**Interest on Customer Deposits**						
372		Customer	DEPCUS	$ 387	$ 168	$ 219	$ 0	$ 0
373		Demand	DEM	$ -	$ -	$ -	$ -	$ -
374		Commodity	COM	$ -	$ -	$ -	$ -	$ -
375		Total Interest on Cust. Deposits		$ 387	$ 168	$ 219	$ 0	$ 0
376		**Required Return**						
377		Customer	CUS	$ 3,784,066	$ 3,278,126	$ 454,950	$ 1,863	$ 49,128
378		Demand	DEM	$ 1,738,328	$ 991,344	$ 531,503	$ 13,431	$ 202,051
379		Commodity	COM	$ 4,519	$ 2,006	$ 1,980	$ 76	$ 458
380		Tot. Req. Return		$ 5,526,914	$ 4,271,475	$ 988,432	$ 15,369	$ 251,637
381		**Income Taxes**						
382		Customer	CUS	$ 794,124	$ 687,947	$ 95,476	$ 391	$ 10,310
383		Demand	DEM	$ 364,805	$ 208,043	$ 111,541	$ 2,819	$ 42,402
384		Commodity	COM	$ 948	$ 421	$ 415	$ 16	$ 96
385		Total Income Taxes		$ 1,159,877	$ 896,411	$ 207,432	$ 3,225	$ 52,809

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
386		**Total Cost of Service Before**						
387		**Revenue Credits**						
388		Customer		$ 10,901,149	$ 9,287,485	$ 1,411,544	$ 10,256	$ 191,863
389		Demand		$ 4,362,257	$ 2,365,583	$ 1,420,696	$ 35,901	$ 540,078
390		Commodity		$ 50,902	$ 22,591	$ 22,299	$ 854	$ 5,158
391		**Total Cost of Service Before Revenue Credits**		$ 15,314,307	$ 11,675,659	$ 2,854,539	$ 47,010	$ 737,099

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Cost Allocation Factors						
2							
3	Total Customers		16,253	14,080	1,954	8	211
4	**Total Customers Factor (CUS)**	CUS	1.00000	0.86630	0.12023	0.00049	0.01298
5							
6	Services - Allocated Weighting			1.00000	1.08723	2.07175	1.08723
7	Weighted Customers		16,450	14,080	2,124	17	229
8	**Weighted Services Customer Factor (SERCUS)**	SERCUS	1.00000	0.85590	0.12915	0.00101	0.01395
9							
10	Meters - Allocated Weighting			1.00000	1.89507	8.70536	4.69051
11	Weighted Customers		18,842	14,080	3,703	70	990
12	**Weighted Meters Customer Factor (METCUS)**	METCUS	1.00000	0.74725	0.19653	0.00370	0.05253
13							
14	Regulators - Allocated Weighting			1.00000	2.22236	9.17742	5.52520
15	Weighted Customers		19,662	14,080	4,343	73	1,166
16	**Weighted Regulators Customer Factor (REGCUS)**	REGCUS	1.00000	0.71610	0.22087	0.00373	0.05930
17							
18	Meters and Regulators - Allocated Weighting			1.00000	1.98484	8.83484	4.91946
19	Weighted Customers		19,067	14,080	3,878	71	1,038
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	MTRGCUS	1.00000	0.73844	0.20341	0.00371	0.05444
21							
22	Non-Residential Customers		2,173	0	1,954	8	211
23	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.89922	0.00368	0.09710
24							
25	Customer Cost Allocation Factors						
26							
27	Distribution Plant Customer Costs		$ 56,748,760	$ 48,555,489	$ 7,251,197	$ 47,482	$ 894,592
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.85562	0.12778	0.00084	0.01576
29							
30	Account 376-379 Customer Costs		$ 36,873,454	$ 31,943,367	$ 4,433,210	$ 18,150	$ 478,727
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.86630	0.12023	0.00049	0.01298
32							
33	Total Revenue (inc. cost of gas)		$ 21,235,309	$ 10,299,962	$ 8,716,208	$ 306,531	$ 1,912,607

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
34	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.48504	0.41046	0.01443	0.09007
35							
36	Mains - Customer Cost Factor		0.69287	0.60023	0.08330	0.00034	0.00900
37	Services - Customer Cost Factor		0.30713	0.26287	0.03966	0.00031	0.00428
38	**Mains & Svcs. Cust. Factor (MSCUS)**	MSCUS	1.00000	0.86310	0.12297	0.00065	0.01328
39							
40	Total Plant Customer		$ 63,511,055	$ 54,413,646	$ 8,064,212	$ 50,811	$ 982,387
41	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.85676	0.12697	0.00080	0.01547
42							
43	Non-Intangible Plant Customer						
44	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 63,358,151	$ 54,886,985	$ 7,617,404	$ 31,186	$ 822,577
45		NONINCUS	1.00000	0.86630	0.12023	0.00049	0.01298
46							
47	Account 871-879 Customer Costs		$ 1,175,433	$ 933,911	$ 196,556	$ 2,741	$ 42,225
48	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.79453	0.16722	0.00233	0.03592
49							
50	Account 887-893 Customer Costs		$ 676,807	$ 583,421	$ 83,854	$ 477	$ 9,055
51	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.86202	0.12390	0.00070	0.01338
52							
53	Account 903 Customer		$ 166,507	$ 153,018	$ 12,666	$ 69	$ 754
54	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.91899	0.07607	0.00041	0.00453
55							
56	Customer Cost Allocation Factors						
57							
58	Account 904 Customer		$ 97,843	$ 92,000	$ 5,844	$ -	$ -
59	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.94028	0.05972	0.00000	0.00000
60							
61	Accounts 902-904 Customer		$ 299,422	$ 271,225	$ 25,402	$ 198	$ 2,596
62	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.90583	0.08484	0.00066	0.00867
63							
64	Operating Expense Customer		$ 4,493,851	$ 3,782,244	$ 611,507	$ 5,670	$ 94,430
65	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.84165	0.13608	0.00126	0.02101
66							
67	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 4,815,610	$ 4,120,342	$ 615,325	$ 4,029	$ 75,914

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
68	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 1,793,782	$ 1,553,948	$ 215,662	$ 883	$ 23,289
69	Total General Plant Customer Costs		$ 6,609,391	$ 5,674,290	$ 830,987	$ 4,912	$ 99,202
70	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.85852	0.12573	0.00074	0.01501
71							
72	Customer Deposits		$ (644,834)	$ (279,344)	$ (364,855)	$ (100)	$ (535)
73	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.43320	0.56581	0.00016	0.00083
74							
75	Demand Cost Allocation Factors						
76							
77	System Demand						
78	**System Demand Factor (DEM)**	DEM	1.00000	0.57029	0.30576	0.00773	0.11623
79							
80	Non-Residential Demand						
81	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.71153	0.01798	0.27049
82							
83	Distribution Plant Demand		$ 23,780,789	$ 12,972,363	$ 7,690,532	$ 194,337	$ 2,923,556
84	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.54550	0.32339	0.00817	0.12294
85							
86	Demand Cost Allocation Factors						
87							
88	Non-Intangible Plant Demand		$ 28,384,635	$ 16,187,349	$ 8,678,750	$ 219,309	$ 3,299,227
89	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.57029	0.30576	0.00773	0.11623
90							
91	Total Plant Demand		$ 28,453,137	$ 15,636,936	$ 9,119,127	$ 230,437	$ 3,466,637
92	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.54957	0.32050	0.00810	0.12184
93							
94	Operating Expense Demand		$ 1,788,003	$ 920,298	$ 617,399	$ 15,601	$ 234,704
95	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.51471	0.34530	0.00873	0.13127
96							
97	Acct. 887-893 Demand		$ 459,809	$ 188,155	$ 193,291	$ 4,884	$ 73,479
98	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.40920	0.42037	0.01062	0.15980
99							
100	Rate Base Demand		$ 22,374,616	$ 12,287,772	$ 7,177,105	$ 181,363	$ 2,728,377
101	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.54918	0.32077	0.00811	0.12194

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
102							
103	Commodity Cost Allocation Factors						
104							
105	Annual Distribution Volumes (Ccf)		14,148,464	6,279,427	6,198,077	237,283	1,433,677
106	**Distribution Commodity Factor (COM)**	COM	1.00000	0.44382	0.43807	0.01677	0.10133

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION		TOTAL		RESIDENTIAL		COMMERCIAL		INDUSTRIAL		PUBLIC AUTHORITY
	(a)		(b)		(c)		(d)		(e)		(f)
1	Current Revenue-to-Cost Ratio (1)		0.9116		0.6162		1.9038		3.8196		1.5638
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
5	Rate Design Revenue Increase	$	1,353,502	$	4,481,473	$	(2,579,836)	$	(132,549)	$	(415,586)
6	% Increase - Non-Gas Revenue (2)		9.70%		62.29%		-47.47%		-73.82%		-36.05%
7	% Increase - Total Revenue (3)		6.27%		42.38%		-29.41%		-43.14%		-21.60%
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)										
9	Revenue-to-Cost Ratio		1.0000		0.7857		1.7230		3.2557		1.4511
10	Rate Design Revenue Increase	$	1,353,502	$	1,979,096	$	(515,967)	$	(26,510)	$	(83,117)
11	% Increase - Non-Gas Revenue (2)		9.70%		27.51%		-9.49%		-14.76%		-7.21%
12	% Increase - Total Revenue (3)		6.27%		18.72%		-5.88%		-8.63%		-4.32%
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)										
14	Revenue-to-Cost Ratio		1.0000		0.7321		1.9038		3.8196		1.5638
15	Rate Design Revenue Increase	$	1,353,502	$	1,353,502	$	-	$	-	$	-
16	% Increase - Non-Gas Revenue (2)		9.70%		18.81%		0.00%		0.00%		0.00%
17	% Increase - Total Revenue (3)		6.27%		12.80%		0.00%		0.00%		0.00%

(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	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer Costs	$ 2,632,278	$ 2,306,129	$ 280,134	$ 9,521	$ 36,494
2	Demand Costs	$ 520,717	$ 331,629	$ 146,236	$ 10,422	$ 32,430
3	Commodity Costs	$ 12,052	$ 7,826	$ 3,374	$ 97	$ 754
4	Cost of Service Before Revenue Credits	$ 3,165,046	$ 2,645,584	$ 429,744	$ 20,040	$ 69,678
5	Revenues Credited to Cost of Service (1)	$ 33,323	$ 31,288	$ 2,026	$ 1	$ 9
6	Total Cost of Service	$ 3,131,723	$ 2,614,296	$ 427,718	$ 20,039	$ 69,669
7	Revenue at Current Rates	$ 2,566,315	$ 1,735,268	$ 661,454	$ 16,373	$ 153,220
8	Revenue Deficiency	$ 565,408	$ 879,028	$ (233,735)	$ 3,666	$ (83,551)
9	Revenue-to-Cost Ratios:					
10	Current Revenue	0.8214	0.6677	1.5439	0.8171	2.1991
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge including Company recommended changes, 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. The components of the total revenue credit are as follows:

Service Charges	$	33,323
Other Revenue	$	-
	$	33,323

CLASS COST OF SERVICE STUDY: SUMMARY FOR RATE DESIGN

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)
1	Customer Costs	$ 2,632,278	$ 2,306,129	$ 280,134	$ 46,015
2	Demand Costs	$ 520,717	$ 331,629	$ 146,236	$ 42,852
3	Commodity Costs	$ 12,052	$ 7,826	$ 3,374	$ 851
4	Cost of Service Before Revenue Credits	$ 3,165,046	$ 2,645,584	$ 429,744	$ 89,718
5	Revenues Credited to Cost of Service	$ 33,323	$ 31,288	$ 2,026	$ 10
6	Total Cost of Service	$ 3,131,723	$ 2,614,296	$ 427,718	$ 89,708
7	Revenue at Current Rates	$ 2,566,315	$ 1,735,268	$ 661,454	$ 169,593
8	Revenue Deficiency	$ 565,408	$ 879,028	$ (233,735)	$ (79,884)
9	Revenue-to-Cost Ratios				
10	Current Revenue	0.8214	0.6677	1.5439	1.8904
11	Required Revenue	1.0000	1.0000	1.0000	1.0000
12	Customer and Demand Costs Per Bill		$ 43.72	$ 73.60	$ 139.73
13	Commodity Cost Per Ccf	$ 0.0023			

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	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	$ 2,170	$ 1,745	$ 422	$ 3
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 34,801	$ 27,986	$ 6,768	$ 48
4		Total Intangible Plant		$ 36,971	$ 29,731	$ 7,190	$ 51
5							
6		**Transmission Plant**					
7	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -
8	366	Meas. and Reg. Station Structures	DEM	$ -	$ -	$ -	$ -
9	367	Transmission Mains	DEM	$ -	$ -	$ -	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ -	$ -	$ -	$ -
12	371	Other Equipment	DEM	$ -	$ -	$ -	$ -
13		Total Transmission Plant		$ -	$ -	$ -	$ -
14							
15		**Distribution Plant**					
16	374	Land & Land Rights	DIS376-379	$ 444	$ 304	$ 139	$ 1
17	375	Structures and Improvements	DIS376-379	$ 7,451	$ 5,102	$ 2,336	$ 13
18	376	Distribution Mains	MAINS	$ 7,736,916	$ 5,441,947	$ 2,294,969	$ -
19	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
20	378	Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 68,791	$ -	$ 68,791	$ -
21	378	Odorization Tank	COM	$ 1,682	$ -	$ -	$ 1,682
22	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 127,363	$ -	$ 127,363	$ -
23	379	Odorization Tank	COM	$ 13,726	$ -	$ -	$ 13,726
24	380	Services	CUS	$ 3,295,576	$ 3,295,576	$ -	$ -
25	381	Meters	CUS	$ 1,308,571	$ 1,308,571	$ -	$ -
26	382	Meter Installations	CUS	$ 647	$ 647	$ -	$ -
27	383	House Regulators	CUS	$ 423,925	$ 423,925	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
28		**Distribution Plant (Cont'd)**					
29	385	Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 168,231	$ -	$ 168,231	$ -
30	386	Other Property - Customer Premises	CUS	$ 4,576	$ 4,576	$ -	$ -
31	387	Other Equipment	DIS376-379	$ -			
32		Total Distribution Plant		$ 13,157,899	$ 10,480,648	$ 2,661,830	$ 15,421
33							
34		**General Plant**					
35	389	Land & Land Rights	GENPLT	$ 43,948	$ 35,743	$ 8,158	$ 47
36	390	Structures & Improvements	GENPLT	$ 776,896	$ 631,273	$ 144,784	$ 839
37	391	Office Furniture and Equipment	GENPLT	$ 611,875	$ 597,275	$ 14,516	$ 84
38	392	Transportation Equipment	GENPLT	$ 532,904	$ 424,474	$ 107,806	$ 625
39	393	Stores Equipment	GENPLT	$ -	$ -	$ -	$ -
40	394	Tools, Shop & Garage	GENPLT	$ 404,490	$ 322,210	$ 81,806	$ 474
41	394	Odorization Tank	COM	$ 3,935	$ -	$ -	$ 3,935
42	395	CNG Equipment	GENPLT	$ -	$ -	$ -	$ -
43	396	Major Work Equipment	GENPLT	$ 160,515	$ 127,855	$ 32,472	$ 188
44	397	Communication Equipment	GENPLT	$ 291,267	$ 234,016	$ 56,921	$ 330
45	398	Miscellaneous General Plant	GENPLT	$ -	$ -	$ -	$ -
46		Total General Plant		$ 2,825,830	$ 2,372,845	$ 446,463	$ 6,521
47							
48		Total Plant in Service		$ 16,020,700	$ 12,883,224	$ 3,115,483	$ 21,993
49							
50		**Depreciation & Amortization Reserve**					
51	301-303	Intangible Plant	DISPLTRES	$ (39,378)	$ (30,600)	$ (8,733)	$ (46)
52	325-371	Transmission Plant	DEM	$ -	$ -	$ -	$ -
53	374-387	Distribution Plant	DISPLTRES	$ (3,253,114)	$ (2,527,921)	$ (721,424)	$ (3,768)
54	389-398	General Plant	GENPLTRES	$ (997,799)	$ (845,151)	$ (150,707)	$ (1,942)
55		Total Depreciation & Amortization Reserve		$ (4,290,291)	$ (3,403,672)	$ (880,863)	$ (5,756)
56							
57		Net Plant in Service		$ 11,730,410	$ 9,479,553	$ 2,234,619	$ 16,237
58							

CLASS COST OF SERVICE STUDY: CLASSIFIED RATE BASE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
59		Customer Deposits	CUS	$ (166,631)	$ (166,631)	$ -	$ -
60							
61		Customer Advances	MAINS/SVCS	$ 10,113	$ 8,009	$ 2,104	$ -
62							
63		Accumulated Deferred Income Taxes	TOTPLT	$ (1,577,763)	$ (1,268,776)	$ (306,821)	$ (2,166)
64							
65		Excess Deferred Income Taxes	TOTPLT	$ (379,918)	$ (305,515)	$ (73,881)	$ (522)
66							
67		Materials and Supplies	TOTPLT	$ 179,353	$ 144,228	$ 34,878	$ 246
68							
69		Prepayments	OPEXP	$ 60,414	$ 51,414	$ 8,613	$ 387
70							
71		Pension & FAS 106 Regulatory Asset	OPEXP	$ 350,756	$ 298,504	$ 50,004	$ 2,248
72							
73		DIMP Deferrals	OPEXP	$ 88,673	$ 75,464	$ 12,641	$ 568
74							
75		Regulatory Assets	OPEXP	$ 35,028	$ 29,810	$ 4,994	$ 224
76							
77		Cash Working Capital	OPEXP	$ (82,115)	$ (69,882)	$ (11,706)	$ (526)
78							
79		Total Rate Base		$ 10,248,319	$ 8,276,177	$ 1,955,444	$ 16,698

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Transmission & Distribution Operations Exp.**					
2	814-866	Transmission Expenses	DEM	$ 6,202	$ -	$ 6,202	$ -
3	8700	Operation Supervision & Engineering	DIS871-879	$ 41,929	$ 34,433	$ 6,903	$ 592
4	8710	Distribution Load Dispatch	COM	$ 4,187	$ -	$ -	$ 4,187
5	8740	Mains and Services Expenses	MAINS/SVCS	$ 111,659	$ 88,432	$ 23,227	$ -
6	8740	Odorization	COM	$ 442	$ -	$ -	$ 442
7	8750	Measuring & Reg. Stat. Exp.-Gen.	DEM	$ 24,964	$ -	$ 24,964	$ -
8	8760	Meas. & Reg. Stat. Exp.- Ind.	DEM	$ 514	$ -	$ 514	$ -
9	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 93	$ -	$ 93	$ -
10	8780	Meter and House Regulator Exp.	CUS	$ 154,971	$ 154,971	$ -	$ -
11	8790	Customer Installation Expenses	CUS	$ 2	$ 2	$ -	$ -
12	8800	Other Expenses	DIS871-879	$ 30,452	$ 25,009	$ 5,014	$ 430
13	8810	Rents	DIS871-879	$ 312	$ 257	$ 51	$ 4
14	8820	Corporate & Div. Exp.	DEM	$ -	$ -	$ -	$ -
15		Total Transmission & Distribution Oper. Exp.		$ 375,726	$ 303,102	$ 66,968	$ 5,655
16							
17		**Distribution Maintenance Expenses**					
18	8850	Maintenance Supervision and Engineering	DIS887-893	$ -	$ -	$ -	$ -
19	8860	Structures and Improvements	DIS887-893	$ 37,517	$ 28,840	$ 8,677	$ -
20	8870	Maintenance of Mains	MAINS	$ 137,368	$ 96,621	$ 40,747	$ -
21	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen.	DEM	$ 4,336	$ -	$ 4,336	$ -
22	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind.	DEM	$ 5,063	$ -	$ 5,063	$ -
23	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 0	$ -	$ 0	$ -
24	8920	Maintenance of Services	CUS	$ 70,051	$ 70,051	$ -	$ -
25	8930	Main. of Meters & House Reg.	CUS	$ -	$ -	$ -	$ -
26	8940	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -
27	8950	Clearing - Meter Shop - Small Meters	DEM	$ -	$ -	$ -	$ -
28	8960	Clearing - Meter Shop - Large Meters	DEM	$ -	$ -	$ -	$ -
29		Total Distribution Maintenance Expenses		$ 254,336	$ 195,513	$ 58,824	$ -
30							
31		Total Operations & Maintenance Expenses		$ 630,062	$ 498,615	$ 125,792	$ 5,655
32							
33		**Customer Accounts Expenses**					
34	9010	Supervision	CUS	$ 2,125	$ 2,125	$ -	$ -
35	9020	Meter Reading Expense	CUS	$ 10,040	$ 10,040	$ -	$ -
36	9030	Customer Accounting	CUS	$ 62,117	$ 62,117	$ -	$ -
37	9040	Bad Debts (includes gross up)	CUS	$ 20,794	$ 20,794	$ -	$ -
38	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 7,190	$ 7,190	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
39		**Customer Accounts Expenses (Cont'd)**					
40		Total Customer Accounts Expenses		$ 102,266	$ 102,266	$ -	$ -
41							
42		**Customer Information Expenses**					
43	9070	Supervision	CUS	$ -	$ -	$ -	$ -
44	9080	Customer Assistance	CUS	$ 3,528	$ 3,528	$ -	$ -
45	9090	Informational and Instructional Advertising	CUS	$ 873	$ 873	$ -	$ -
46	9100	Customer Informational Expenses	CUS	$ -	$ -	$ -	$ -
47		Total Customer Information Expenses		$ 4,401	$ 4,401	$ -	$ -
48							
49		**Sales and Advertising Expenses**					
50	9110	Supervision	CUS	$ -	$ -	$ -	$ -
51	9120	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -
52	9130	Advertising	CUS	$ 14	$ 14	$ -	$ -
53	9140	Employee Sales Referrals	CUS	$ -	$ -	$ -	$ -
54	9163	Misc. Gas Sales Expense	CUS	$ -	$ -	$ -	$ -
55		Total Sales and Advertising Expenses		$ 14	$ 14	$ -	$ -
56							
57		Administrative & General Expenses					
58	920-940	Administrative & General Expenses	ADMINGEN	$ 653,956	$ 578,230	$ 72,468	$ 3,258
59		Total Administrative & General Expenses		$ 653,956	$ 578,230	$ 72,468	$ 3,258
60							
61		**Depreciation and Amortization Expense**					
62	301-303	Intangible Plant	PLT301-03	$ -	$ -	$ -	$ -
63	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -
64	366	Meas. and Reg. Station Structures	PLT366	$ -	$ -	$ -	$ -
65	367	Transmission Mains	PLT367	$ -	$ -	$ -	$ -
66	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -
67	369	Measuring and Reg. Station Equipment	PLT369	$ -	$ -	$ -	$ -
68	371	Other Equipment	PLT371	$ -	$ -	$ -	$ -
69	375	Structures and Improvements	PLT375	$ -	$ -	$ -	$ -
70	376	Mains	MAINS	$ 250,756	$ 176,375	$ 74,381	$ -
71	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
72	378	Meas. & Reg. Sta. Equip. - General	PLT378	$ 1,598	$ -	$ 1,598	$ -
73	378	Odorization Tank	COM	$ 39	$ -	$ -	$ 39
74	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 2,433	$ -	$ 2,433	$ -
75	379	Odorization Tank	COM	$ 262	$ -	$ -	$ 262
76	380	Services	PLT380	$ 121,239	$ 121,239	$ -	$ -

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
77		**Depreciation and Amortization Expense (Cont'd)**					
78	381	Meters	PLT381	$ 54,597	$ 54,597	$ -	$ -
79	382	Meter Installations	PLT382	$ 5	$ 5	$ -	$ -
80	383	House Regulators	PLT383	$ 13,710	$ 13,710	$ -	$ -
81	385	Meas. & Reg. Sta. Equip. - Ind.	PLT385	$ 4,192	$ -	$ 4,192	$ -
82	386	Other Property - Customer Premises	PLT386	$ 852	$ 852	$ -	$ -
83	387	Other Equipment	PLT387	$ -	$ -	$ -	$ -
84	389-980	General Plant - Allocated	GENDEP	$ 125,081	$ 110,278	$ 14,458	$ 346
85	389-980	General Plant - Odorization	COM	$ 262	$ -	$ -	$ 262
86	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ -	$ -	$ -	$ -
87		Total Depreciation and Amortization Expense		$ 575,025	$ 477,055	$ 97,061	$ 909
88							
89		**Taxes Other Than Income**					
90	4080	Payroll and Other	OPEXP	$ 70,778	$ 60,234	$ 10,090	$ 454
91	4080	Ad Valorem	TOTPLT	$ 218,922	$ 176,049	$ 42,573	$ 301
92	4080	Revenue Related (includes gross up)	CUS	$ 4,241	$ 4,241	$ -	$ -
93		Total Taxes Other Than Income		$ 293,940	$ 240,523	$ 52,663	$ 754
94							
95	4101	Excess Deferred Income Tax Amortization	RB	$ (58,408)	$ (47,168)	$ (11,145)	$ (95)
96							
97	4310	Interest on Customer Deposits	CUS	$ 100	$ 100	$ -	$ -
98							
99		Required Return	RB	$ 796,213	$ 642,993	$ 151,922	$ 1,297
100		Income Taxes	RB	$ 167,476	$ 135,248	$ 31,955	$ 273
101		Total Cost of Service Before Revenue Credits		$ 3,165,046	$ 2,632,278	$ 520,717	$ 12,052

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7		DEM-COM	Demand and Commodity Factor		0.00000	0.50000	0.50000
8							
9			Total Transmission Plant	$ -	$ -	$ -	$ -
10			Total Distribution Plant	$ 13,157,899	$ 10,480,648	$ 2,661,830	$ 15,421
11			Total General Plant	$ 2,825,830	$ 2,372,845	$ 446,463	$ 6,521
12			Total Non-Intangible Plant	$ 15,983,729	$ 12,853,494	$ 3,108,293	$ 21,943
13		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.80416	0.19447	0.00137
14							
15	376		Distribution Mains	$ 7,736,916	$ 5,441,947	$ 2,294,969	$ -
16	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
17	378		Meas. & Reg. Sta. Equip.- Gen.	$ 68,791	$ -	$ 68,791	$ -
18	379		Meas. & Reg. Sta. Equip.- City Gate	$ 141,089	$ -	$ 127,363	$ 13,726
19			Total Accounts 376-379	$ 7,946,796	$ 5,441,947	$ 2,491,124	$ 13,726
20		DIS376-379	Accounts 376-379 Factor	1.00000	0.68480	0.31348	0.00173
21							
22	376		Mains	$ 7,736,916	$ 5,441,947	$ 2,294,969	$ -
23		MAINS	Distribution Mains Factor	1.00000	0.70337	0.29663	0.00000
24							
25	376/380		Mains and Services	$ 11,032,492	$ 8,737,523	$ 2,294,969	$ -
26		MAINS/SVCS	Mains and Services Factor	1.00000	0.79198	0.20802	0.00000
27							
28	374-87		Total Distribution Plant	$ 13,157,899	$ 10,480,648	$ 2,661,830	$ 15,421
29		DISPLT	Distribution Plant Factor	1.00000	0.79653	0.20230	0.00117
30							
31							
32	374		Land & Land Rights	$ (18)	$ (13)	$ (6)	$ (0)
33	375		Structures and Improvements	$ (9,707)	$ (6,647)	$ (3,043)	$ (17)
34	376		Distribution Mains	$ (2,033,589)	$ (1,430,374)	$ (603,215)	$ -
35	378		Meas. & Reg. Sta. Equip.-Gen.	$ (22,305)	$ -	$ (22,305)	$ -
36	379		Meas. & Reg. Sta. Equip.-City Gate	$ (30,584)	$ -	$ (30,584)	$ -
37	378-379		Odorization Tank	$ (3,746)	$ -	$ -	$ (3,746)

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
38	380		Services	$ (600,105)	$ (600,105)	$ -	$ -
39	381		Meters	$ (317,312)	$ (317,312)	$ -	$ -
40	382		Meter Installations	$ (939)	$ (939)	$ -	$ -
41	383		House Regulators	$ (170,385)	$ (170,385)	$ -	$ -
42	385		Meas. & Reg. Sta. Equip.-Ind.	$ (61,289)	$ -	$ (61,289)	$ -
43	386		Other Property-Customer Premises	$ (3,135)	$ (2,147)	$ (983)	$ (5)
44	378		Other Equipment	$ -	$ -	$ -	$ -
45			Total Distribution Plant - Reserve	$ (3,253,114)	$ (2,527,921)	$ (721,424)	$ (3,768)
46		DISPLTRES	Distribution Plant Reserve Factor	$ 1.00000	0.77708	0.22176	0.00116
47							
48			General Plant - Reserve	$ (997,799)	$ (845,151)	$ (150,707)	$ (1,942)
49		GENPLTRES	General Plant Reserve Factor	1.00000	0.84701	0.15104	0.00195
50							
51			Total Plant	$ 16,020,700	$ 12,883,224	$ 3,115,483	$ 21,993
52		TOTPLT	Total Plant Factor	1.00000	0.80416	0.19447	0.00137
53							
54	374		Land & Land Rights	$ (18)	$ (13)	$ (6)	$ (0)
55	375		Structures and Improvements	$ (9,707)	$ (6,647)	$ (3,043)	$ (17)
56	376		Distribution Mains	$ (2,033,589)	$ (1,430,374)	$ (603,215)	$ -
57	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
58	378		Meas. & Reg. Station Equip.- Gen.	$ (22,305)	$ -	$ (22,305)	$ -
59	378		Odorization Tank	$ (909)	$ -	$ -	$ (909)
60	379		Meas. & Reg. Station Equip.- City Gate	$ (30,584)	$ -	$ (30,584)	$ -
61	379		Odorization Tank	$ (2,837)	$ -	$ -	$ (2,837)
62	380		Services	$ (600,105)	$ (600,105)	$ -	$ -
63	381		Meters	$ (317,312)	$ (317,312)	$ -	$ -
64	382		Meter Installations	$ (939)	$ (939)	$ -	$ -
65	383		House Regulators	$ (170,385)	$ (170,385)	$ -	$ -
66	385		Meas. & Reg. Sta. Equip. -Ind.	$ (61,289)	$ -	$ (61,289)	$ -
67	386		Other Property - Customer Premises	$ (3,135)	$ (2,147)	$ (983)	$ (5)

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
68	387		Other Equipment	$ -	$ -	$ -	$ -
69			Total Distribution Plant Reserve	$ (3,253,114)	$ (2,527,921)	$ (721,424)	$ (3,768)
70		DISPLTRES	Distribution Plant Reserve	1.00000	0.77708	0.22176	0.00116
71							
72			Total Operations and Maintenance Expenses	$ 630,062	$ 498,615	$ 125,792	$ 5,655
73			Total Customer Accounts Expenses	$ 102,266	$ 102,266	$ -	$ -
74			Total Customer Service Expenses	$ 4,401	$ 4,401	$ -	$ -
75			Total Sales and Advertising Expenses	$ 14	$ 14	$ -	$ -
76			Administrative and General Expenses	$ 653,956	$ 578,230	$ 72,468	$ 3,258
77			Total Operating Expenses	$ 1,390,700	$ 1,183,527	$ 198,260	$ 8,913
78		OPEXP	Operating Expense Factor	1.00000	0.85103	0.14256	0.00641
79							
80	8710		Distribution Load Dispatch	$ 4,187	$ -	$ -	$ 4,187
81	8740		Mains and Services Expenses	$ 111,659	$ 88,432	$ 23,227	$ -
82	8750		Measuring & Reg. Stat. Exp.-Gen.	$ 24,964	$ -	$ 24,964	$ -
83	8760		Meas. & Reg. Stat. Exp.- Ind.	$ 514	$ -	$ 514	$ -
84	8770		Meas. & Regulating Station Exp.- City Gate	$ 93	$ -	$ 93	$ -
85	8780		Meter and House Regulator Exp.	$ 154,971	$ 154,971	$ -	$ -
86	8790		Customer Installation Expenses	$ 2	$ 2	$ -	$ -
87			Total Accounts 871-879	$ 296,389	$ 243,404	$ 48,798	$ 4,187
88		DIS871-879	Accounts 871-879 Factor	1.00000	0.82123	0.16464	0.01413
89							
90	8870		Maintenance of Mains	$ 137,368	$ 96,621	$ 40,747	$ -
91	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen.	$ 4,336	$ -	$ 4,336	$ -
92	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind.	$ 5,063	$ -	$ 5,063	$ -
93	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 0	$ -	$ 0	$ -
94	8920		Maintenance of Services	$ 70,051	$ 70,051	$ -	$ -
95	8930		Main. of Meters & House Reg.	$ -	$ -	$ -	$ -
96			Total Accounts 887-893	$ 216,819	$ 166,673	$ 50,147	$ -
97		DIS887-893	Accounts 887-893 Factor	1.00000	0.76872	0.23128	0.00000
98							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
99			Total Operations and Maintenance Expenses	$ 630,062	$ 498,615	$ 125,792	$ 5,655
100			Total Customer Accounts Expenses	$ 102,266	$ 102,266	$ -	$ -
101			Total Customer Service Expenses	$ 4,401	$ 4,401	$ -	$ -
102			Total Sales and Advertising Expenses	$ 14	$ 14	$ -	$ -
103			Total Operating Exp. Without A&G Expenses	$ 736,744	$ 605,297	$ 125,792	$ 5,655
104		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.82158	0.17074	0.00768
105							
106	920-932		Administrative and General Expenses	$ 653,956	$ 578,230	$ 72,468	$ 3,258
107		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.88420	0.11081	0.00498
108							
109	366		Meas. and Reg. Station Structures	$ -	$ -	$ -	$ -
110		PLT366	Measuring and Reg. Station Structures Factor	0.00000	0.00000	0.00000	0.00000
111							
112	367		Transmission Mains	$ -	$ -	$ -	$ -
113		PLT367	Transmission Mains	0.00000	0.00000	0.00000	0.00000
114							
115	368		Compression Station Equipment	$ -	$ -	$ -	$ -
116		PLT368	Compression Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
117							
118	369		Measuring and Reg. Station Equipment	$ -	$ -	$ -	$ -
119		PLT369	Measuring & Reg, Station Equipment Factor	0.00000	0.00000	0.00000	0.00000
120							
121	371		Other Equipment	$ -	$ -	$ -	$ -
122		PLT371	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
123							
124	375		Structures and Improvements	$ 7,451	$ 5,102	$ 2,336	$ 13
125		PLT375	Structures and Improvements Factor	1.00000	0.68480	0.31348	0.00173
126							
127	376		Distribution Mains	$ 7,736,916	$ 5,441,947	$ 2,294,969	$ -
128		PLT376	Distribution Mains Factor	1.00000	0.70337	0.29663	0.00000
129							

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
130	378		Meas. & Reg. Sta. Equip.- Gen.	$ 68,791	$ -	$ 68,791	$ -
131		PLT378	Meas. & Reg. Station Equip. - General Factor	1.00000	0.00000	1.00000	0.00000
132							
133	379		Meas. & Reg. Sta. Equip.- City Gate	$ 127,363	$ -	$ 127,363	$ -
134		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000
135							
136	380		Services	$ 3,295,576	$ 3,295,576	$ -	$ -
137		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000
138							
139	381		Meters	$ 1,308,571	$ 1,308,571	$ -	$ -
140		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000
141							
142	382		Meter Installations	$ 647	$ 647	$ -	$ -
143		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000
144							
145	383		House Regulators	$ 423,925	$ 423,925	$ -	$ -
146		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000
147							
148	385		Meas. & Reg. Sta. Equip. - Ind.	$ 168,231	$ -	$ 168,231	$ -
149		PLT385	Meas. & Reg. Sta. Equip.-Industrial Factor	1.00000	0.00000	1.00000	0.00000
150							
151	386		Other Property - Customer Premises	$ 4,576	$ 4,576	$ -	$ -
152		PLT386	Other Property-Customer Premises Factor	1.00000	1.00000	0.00000	0.00000
153							
154	387		Other Equipment	$ -	$ -	$ -	$ -
155		PLT387	Other Equipment Factor	0.00000	0.00000	0.00000	0.00000
156							
157	301-03		Intangible Plant	$ 36,971	$ 29,731	$ 7,190	$ 51
158		PLT301-03	Intangible Plant	1.00000	0.80416	0.19447	0.00137
159							
160	389-98		General Plant Depreciation Expense	$ 125,343	$ 110,509	$ 14,488	$ 346
161		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.88165	0.11559	0.00276
162							
163			Rate Base	$ 10,248,319	$ 8,276,177	$ 1,955,444	$ 16,698
164		RB	Rate Base Factor	1.00000	0.80756	0.19081	0.00163

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	301-303	**Intangible Plant**						
2		Customer	NONINCUS	$ 29,731	$ 26,867	$ 2,580	$ 59	$ 224
3		Demand	NONINDEM	$ 7,190	$ 4,723	$ 1,908	$ 136	$ 423
4		Commodity	COM	$ 51	$ 33	$ 14	$ 0	$ 3
5		Total Intangible Plant		$ 36,971	$ 31,623	$ 4,502	$ 195	$ 651
6	365-371	**Transmission Plant**						
7		Customer	CUS	$ -	$ -	$ -	$ -	$ -
8		Demand	DEM	$ -	$ -	$ -	$ -	$ -
9		Commodity	COM	$ -	$ -	$ -	$ -	$ -
10		Total Transmission Plant		$ -	$ -	$ -	$ -	$ -
11		**Distribution Plant**						
12	374	Land & Land Rights						
13		Customer	CUS	$ 304	$ 275	$ 26	$ 1	$ 2
14		Demand	DEM	$ 139	$ 92	$ 37	$ 3	$ 8
15		Commodity	COM	$ 1	$ 0	$ 0	$ 0	$ 0
16		Total Land & Land Rights		$ 444	$ 367	$ 64	$ 3	$ 11
17	375	**Structures and Improvements**						
18		Customer	376-379CUS	$ 5,102	$ 4,611	$ 443	$ 10	$ 39
19		Demand	DEM	$ 2,336	$ 1,534	$ 620	$ 44	$ 137
20		Commodity	COM	$ 13	$ 8	$ 4	$ 0	$ 1
21		Total Structures and Improvements		$ 7,451	$ 6,153	$ 1,066	$ 54	$ 177
22	376	**Distribution Mains**						
23		Customer	CUS	$ 5,441,947	$ 4,917,844	$ 472,257	$ 10,761	$ 41,086
24		Demand	DEM	$ 2,294,969	$ 1,507,457	$ 609,042	$ 43,406	$ 135,065
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -
26		Total Distribution Mains		$ 7,736,916	$ 6,425,301	$ 1,081,299	$ 54,166	$ 176,150
27	377	**Compressor Station Equipment**						
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ -	$ -	$ -	$ -	$ -
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -
31		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
32		**Distribution Plant (Cont'd)**						
33	378	**Meas. & Reg. Sta. Equip.- Gen.**						
34		Customer	CUS	$ -	$ -	$ -	$ -	$ -
35		Demand	DEM	$ 68,791	$ 45,186	$ 18,256	$ 1,301	$ 4,049
36		Commodity	COM	$ -	$ -	$ -	$ -	$ -
37		Total Meas. & Reg. Sta. Equip.- Gen.		$ 68,791	$ 45,186	$ 18,256	$ 1,301	$ 4,049
38	378	**Odorization Tank**						
39		Customer	CUS	$ -	$ -	$ -	$ -	$ -
40		Demand	DEM	$ -	$ -	$ -	$ -	$ -
41		Commodity	COM	$ 1,682	$ 1,092	$ 471	$ 14	$ 105
42		Total Odorization Tank		$ 1,682	$ 1,092	$ 471	$ 14	$ 105
43	379	**Meas. & Reg. Station - City Gate**						
44		Customer	CUS	$ -	$ -	$ -	$ -	$ -
45		Demand	DEM	$ 127,363	$ 83,659	$ 33,800	$ 2,409	$ 7,496
46		Commodity	COM	$ -	$ -	$ -	$ -	$ -
47		Total Meas. & Reg. Equip.-City Gate		$ 127,363	$ 83,659	$ 33,800	$ 2,409	$ 7,496
48	379	**Odorization Tank**						
49		Customer	CUS	$ -	$ -	$ -	$ -	$ -
50		Demand	DEM	$ -	$ -	$ -	$ -	$ -
51		Commodity	COM	$ 13,726	$ 8,913	$ 3,843	$ 111	$ 858
52		Total Odorization Tank		$ 13,726	$ 8,913	$ 3,843	$ 111	$ 858
53	380	**Services**						
54		Customer	SERCUS	$ 3,295,576	$ 2,956,205	$ 305,799	$ 6,968	$ 26,604
55		Demand	DEM	$ -	$ -	$ -	$ -	$ -
56		Commodity	COM	$ -	$ -	$ -	$ -	$ -
57		Total Services		$ 3,295,576	$ 2,956,205	$ 305,799	$ 6,968	$ 26,604
58	381	**Meters**						
59		Customer	METCUS	$ 1,308,571	$ 993,295	$ 244,034	$ 14,786	$ 56,456
60		Demand	DEM	$ -	$ -	$ -	$ -	$ -
61		Commodity	COM	$ -	$ -	$ -	$ -	$ -
62		Total Meters - Allocated		$ 1,308,571	$ 993,295	$ 244,034	$ 14,786	$ 56,456
63	382	**Meter Installations**						
64		Customer	METCUS	$ 647	$ 491	$ 121	$ 7	$ 28
65		Demand	DEM	$ -	$ -	$ -	$ -	$ -
66		Commodity	COM	$ -	$ -	$ -	$ -	$ -
67		Total Meter Installations		$ 647	$ 491	$ 121	$ 7	$ 28

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
68		**Distribution Plant (Cont'd)**						
69	383	**House Regulators**						
70		Customer	REGCUS	$ 423,925	$ 307,744	$ 89,918	$ 5,451	$ 20,813
71		Demand	DEM	$ -	$ -	$ -	$ -	$ -
72		Commodity	COM	$ -	$ -	$ -	$ -	$ -
73		Total House Regulators		$ 423,925	$ 307,744	$ 89,918	$ 5,451	$ 20,813
74	385	**Meas. & Reg. Sta. Equip. - Ind.**						
75		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
76		Demand	NRDEM	$ 168,231	$ -	$ 130,106	$ 9,272	$ 28,853
77		Commodity	COM	$ -	$ -	$ -	$ -	$ -
78		Total Meas. & Reg. Sta. Equip.- Ind.		$ 168,231	$ -	$ 130,106	$ 9,272	$ 28,853
79	386	**Other Prop.-Customer Premises**						
80		Customer	CUS	$ 4,576	$ 4,135	$ 397	$ 9	$ 35
81		Demand	DEM	$ -	$ -	$ -	$ -	$ -
82		Commodity	COM	$ -	$ -	$ -	$ -	$ -
83		Total Other Prop.- Cust. Premises		$ 4,576	$ 4,135	$ 397	$ 9	$ 35
84	387	**Other Equipment**						
85		Customer	CUS	$ -	$ -	$ -	$ -	$ -
86		Demand	DEM	$ -	$ -	$ -	$ -	$ -
87		Commodity	COM	$ -	$ -	$ -	$ -	$ -
88		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
89		**Total Distribution Plant**						
90		Customer		$ 10,480,648	$ 9,184,600	$ 1,112,995	$ 37,992	$ 145,062
91		Demand		$ 2,661,830	$ 1,637,928	$ 791,860	$ 56,435	$ 175,607
92		Commodity		$ 15,421	$ 10,014	$ 4,318	$ 125	$ 964
93		Total Distribution Plant		$ 13,157,899	$ 10,832,542	$ 1,909,173	$ 94,552	$ 321,634
94		**Total General Plant**						
95		Customer	CUS	$ 2,372,845	$ 2,144,321	$ 205,918	$ 4,692	$ 17,915
96		Demand	DEM	$ 446,463	$ 293,261	$ 118,483	$ 8,444	$ 26,275
97		Commodity	COM	$ 6,521	$ 4,235	$ 1,826	$ 53	$ 408
98		Total General Plant		$ 2,825,830	$ 2,441,817	$ 326,227	$ 13,189	$ 44,598
99		**Total Plant in Service**						
100		Customer		$ 12,883,224	$ 11,355,788	$ 1,321,492	$ 42,743	$ 163,201
101		Demand		$ 3,115,483	$ 1,935,911	$ 912,251	$ 65,015	$ 202,306
102		Commodity		$ 21,993	$ 14,282	$ 6,158	$ 178	$ 1,375
103		Total Plant in Service		$ 16,020,700	$ 13,305,981	$ 2,239,901	$ 107,936	$ 366,882

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
104		**Depreciation & Amort. Reserve**						
105		**Intangible Plant**						
106		Customer	CUS	$ (30,600)	$ (27,653)	$ (2,655)	$ (61)	$ (231)
107		Demand	DEM	$ (8,733)	$ (5,736)	$ (2,317)	$ (165)	$ (514)
108		Commodity	COM	$ (46)	$ (30)	$ (13)	$ (0)	$ (3)
109		Total Intangible Plant		$ (39,378)	$ (33,418)	$ (4,986)	$ (226)	$ (748)
110		**Transmission Plant**						
111		Customer	CUS	$ -	$ -	$ -	$ -	$ -
112		Demand	DEM	$ -	$ -	$ -	$ -	$ -
113		Commodity	COM	$ -	$ -	$ -	$ -	$ -
114		Total Transmission Plant		$ -	$ -	$ -	$ -	$ -
115		**Distribution Plant**						
116		Customer	DISPLTCUS	$ (2,527,921)	$ (2,215,316)	$ (268,453)	$ (9,164)	$ (34,989)
117		Demand	DISPLTDEM	$ (721,424)	$ (443,920)	$ (214,614)	$ (15,295)	$ (47,594)
118		Commodity	COM	$ (3,768)	$ (2,447)	$ (1,055)	$ (30)	$ (236)
119		Total Distribution Plant		$ (3,253,114)	$ (2,661,683)	$ (484,123)	$ (24,489)	$ (82,818)
120		**General Plant**						
121		Customer	GENPTCUS	$ (845,151)	$ (746,629)	$ (85,499)	$ (2,703)	$ (10,320)
122		Demand	DISPLTDEM	$ (150,707)	$ (92,736)	$ (44,833)	$ (3,195)	$ (9,942)
123		Commodity	COM	$ (1,942)	$ (1,261)	$ (544)	$ (16)	$ (121)
124		Total General Plant		$ (997,799)	$ (840,626)	$ (130,876)	$ (5,914)	$ (20,384)
125		**Total Depr. & Amort. Reserve**						
126		Customer		$ (3,403,672)	$ (2,989,598)	$ (356,607)	$ (11,927)	$ (45,539)
127		Demand		$ (880,863)	$ (542,392)	$ (261,765)	$ (18,656)	$ (58,051)
128		Commodity		$ (5,756)	$ (3,738)	$ (1,612)	$ (46)	$ (360)
129		Total Depr. & Amortization Reserve		$ (4,290,291)	$ (3,535,728)	$ (619,984)	$ (30,629)	$ (103,950)
130		**Net Plant in Service**						
131		Customer		$ 9,479,553	$ 8,366,190	$ 964,885	$ 30,816	$ 117,661
132		Demand		$ 2,234,619	$ 1,393,519	$ 650,486	$ 46,359	$ 144,255
133		Commodity		$ 16,237	$ 10,544	$ 4,546	$ 131	$ 1,015
134		Total Net Plant in Service		$ 11,730,410	$ 9,770,254	$ 1,619,917	$ 77,306	$ 262,932
135		**Customer Deposits**						
136		Customer	DEPCUS	$ (166,631)	$ (88,787)	$ (77,444)	$ (39)	$ (361)
137		Demand	DEM	$ -	$ -	$ -	$ -	$ -
138		Commodity	CUS	$ -	$ -	$ -	$ -	$ -
139		Total Customer Deposits		$ (166,631)	$ (88,787)	$ (77,444)	$ (39)	$ (361)

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
140		**Customer Advances**						
141		Customer	MSCUS	$ 8,009	$ 7,218	$ 713	$ 16	$ 62
142		Demand	DEM	$ 2,104	$ 1,382	$ 558	$ 40	$ 124
143		Commodity	COM	$ -	$ -	$ -	$ -	$ -
144		Total Customer Advances		$ 10,113	$ 8,600	$ 1,271	$ 56	$ 186
145		**Accum. Deferred Income Taxes**						
146		Customer	TPLTCUS	$ (1,268,776)	$ (1,118,350)	$ (130,144)	$ (4,209)	$ (16,072)
147		Demand	TPLTDEM	$ (306,821)	$ (190,654)	$ (89,841)	$ (6,403)	$ (19,924)
148		Commodity	COM	$ (2,166)	$ (1,407)	$ (606)	$ (17)	$ (135)
149		Total Accum. Deferred Inc. Taxes		$ (1,577,763)	$ (1,310,410)	$ (220,592)	$ (10,630)	$ (36,132)
150		**Excess Deferred Income Taxes**						
151		Customer	TPLTCUS	$ (305,515)	$ (269,293)	$ (31,338)	$ (1,014)	$ (3,870)
152		Demand	TPLTDEM	$ (73,881)	$ (45,909)	$ (21,633)	$ (1,542)	$ (4,798)
153		Commodity	COM	$ (522)	$ (339)	$ (146)	$ (4)	$ (33)
154		**Total Excess Deferred Income Taxes**		$ (379,918)	$ (315,541)	$ (53,117)	$ (2,560)	$ (8,700)
155		**Materials and Supplies**						
156		Customer	TPLTCUS	$ 144,228	$ 127,129	$ 14,794	$ 479	$ 1,827
157		Demand	TPLTDEM	$ 34,878	$ 21,673	$ 10,213	$ 728	$ 2,265
158		Commodity	COM	$ 246	$ 160	$ 69	$ 2	$ 15
159		Total Materials and Supplies		$ 179,353	$ 148,961	$ 25,076	$ 1,208	$ 4,107
160		**Prepayments**						
161		Customer	OPEXPCUS	$ 51,414	$ 44,324	$ 5,982	$ 230	$ 878
162		Demand	OPEXPDEM	$ 8,613	$ 5,364	$ 2,513	$ 179	$ 557
163		Commodity	COM	$ 387	$ 251	$ 108	$ 3	$ 24
164		Total Prepayments		$ 60,414	$ 49,939	$ 8,603	$ 412	$ 1,459
165		**Pension & FAS 106 Reg. Asset**						
166		Customer	OPEXPCUS	$ 298,504	$ 257,338	$ 34,733	$ 1,335	$ 5,098
167		Demand	OPEXPDEM	$ 50,004	$ 31,142	$ 14,588	$ 1,040	$ 3,235
168		Commodity	COM	$ 2,248	$ 1,460	$ 629	$ 18	$ 141
169		Total Pen. & FAS 106 Reg. Asset		$ 350,756	$ 289,940	$ 49,950	$ 2,393	$ 8,473
170		**DIMP Deferrals**						
171		Customer	TPLTCUS	$ 75,464	$ 66,517	$ 7,741	$ 250	$ 956
172		Demand	TPLTDEM	$ 12,641	$ 7,855	$ 3,702	$ 264	$ 821
173		Commodity	COM	$ 568	$ 369	$ 159	$ 5	$ 36
174		Total DIMP Deferrals		$ 88,673	$ 74,741	$ 11,601	$ 519	$ 1,812

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
175		**Regulatory Assets**						
176		Customer	TPLTCUS	$ 29,810	$ 26,275	$ 3,058	$ 99	$ 378
177		Demand	TPLTDEM	$ 4,994	$ 3,103	$ 1,462	$ 104	$ 324
178		Commodity	COM	$ 224	$ 146	$ 63	$ 2	$ 14
179		**Total Regulatory Assets**		$ 35,028	$ 29,524	$ 4,583	$ 205	$ 716
180		**Cash Working Capital**						
181		Customer	OPEXPCUS	$ (69,882)	$ (60,245)	$ (8,131)	$ (313)	$ (1,193)
182		Demand	OPEXPDEM	$ (11,706)	$ (7,291)	$ (3,415)	$ (243)	$ (757)
183		Commodity	COM	$ (526)	$ (342)	$ (147)	$ (4)	$ (33)
184		Total Cash Working Capital		$ (82,115)	$ (67,877)	$ (11,694)	$ (560)	$ (1,984)
185		**Total Rate Base**						
186		Customer		$ 8,276,177	$ 7,358,316	$ 784,848	$ 27,651	$ 105,362
187		Demand		$ 1,955,444	$ 1,220,184	$ 568,632	$ 40,526	$ 126,103
188		Commodity		$ 16,698	$ 10,844	$ 4,675	$ 135	$ 1,044
189		Total Rate Base		$ 10,248,319	$ 8,589,343	$ 1,358,155	$ 68,311	$ 232,509

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1		**Transmission and Distribution Operating Expense**						
2	814-866	**Transmission Expenses**						
3		Customer	CUS	$ -	$ -	$ -	$ -	$ -
4		Demand	DEM	$ 6,202	$ 4,073	$ 1,646	$ 117	$ 365
5		Commodity	COM	$ -	$ -	$ -	$ -	$ -
6		Total Transmission Expense		$ 6,202	$ 4,073	$ 1,646	$ 117	$ 365
7	8700	**Operation Supervision & Engineering**						
8		Customer	871-879CUS	$ 34,433	$ 27,708	$ 5,362	$ 283	$ 1,080
9		Demand	DEM	$ 6,903	$ 4,534	$ 1,832	$ 131	$ 406
10		Commodity	COM	$ 592	$ 385	$ 166	$ 5	$ 37
11		Total Supervision & Engineering		$ 41,929	$ 32,627	$ 7,360	$ 418	$ 1,523
12	8710	**Distribution Load Dispatch**						
13		Customer	CUS	$ -	$ -	$ -	$ -	$ -
14		Demand	DEM	$ -	$ -	$ -	$ -	$ -
15		Commodity	COM	$ 4,187	$ 2,719	$ 1,172	$ 34	$ 262
16		Total Distribution Load Dispatch		$ 4,187	$ 2,719	$ 1,172	$ 34	$ 262
17	8740	**Mains and Services Expenses**						
18		Customer	MSCUS	$ 88,432	$ 79,693	$ 7,875	$ 179	$ 685
19		Demand	DEM	$ 23,227	$ 15,257	$ 6,164	$ 439	$ 1,367
20		Commodity	COM	$ -	$ -	$ -	$ -	$ -
21		Total Mains & Services		$ 111,659	$ 94,950	$ 14,039	$ 619	$ 2,052
22	8740	**Odorization**						
23		Customer	CUS	$ -	$ -	$ -	$ -	$ -
24		Demand	DEM	$ -	$ -	$ -	$ -	$ -
25		Commodity	COM	$ 442	$ 287	$ 124	$ 4	$ 28
26		Total Odorization		$ 442	$ 287	$ 124	$ 4	$ 28
27	8750	**Meas. & Reg. Station - Gen.**						
28		Customer	CUS	$ -	$ -	$ -	$ -	$ -
29		Demand	DEM	$ 24,964	$ 16,397	$ 6,625	$ 472	$ 1,469
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -
31		Total Meas. & Reg. Station - Gen.		$ 24,964	$ 16,397	$ 6,625	$ 472	$ 1,469

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
32		**Transmission and Distribution Operating Expense (Cont'd)**						
33	8760	**Meas. & Reg. Stat. - Ind.**						
34		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
35		Demand	NRDEM	$ 514	$ -	$ 398	$ 28	$ 88
36		Commodity	COM	$ -	$ -	$ -	$ -	$ -
37		Total Meas. & Reg. Stat. - Ind.		$ 514	$ -	$ 398	$ 28	$ 88
38	8770	**Meas. & Reg. Stat.- City Gate**						
39		Customer	CUS	$ -	$ -	$ -	$ -	$ -
40		Demand	DEM	$ 93	$ 61	$ 25	$ 2	$ 5
41		Commodity	COM	$ -	$ -	$ -	$ -	$ -
42		Total Meas. & Reg. Stat. - City Gate		$ 93	$ 61	$ 25	$ 2	$ 5
43	8780	**Meter & House Reg. Exp.**						
44		Customer	MTRGCUS	$ 154,971	$ 116,171	$ 30,031	$ 1,820	$ 6,949
45		Demand	DEM	$ -	$ -	$ -	$ -	$ -
46		Commodity	COM	$ -	$ -	$ -	$ -	$ -
47		Total Meter & House Reg. Exp.		$ 154,971	$ 116,171	$ 30,031	$ 1,820	$ 6,949
48	8790	**Customer Installation Expense**						
49		Customer	METCUS	$ 2	$ 1	$ 0	$ 0	$ 0
50		Demand	DEM	$ -	$ -	$ -	$ -	$ -
51		Commodity	COM	$ -	$ -	$ -	$ -	$ -
52		Total Customer Install. Expense		$ 2	$ 1	$ 0	$ 0	$ 0
53	8800	**Other Expenses**						
54		Customer	871-879CUS	$ 25,009	$ 20,124	$ 3,895	$ 205	$ 784
55		Demand	DEM	$ 5,014	$ 3,293	$ 1,331	$ 95	$ 295
56		Commodity	COM	$ 430	$ 279	$ 120	$ 3	$ 27
57		Total Other Expenses		$ 30,452	$ 23,697	$ 5,346	$ 304	$ 1,106
58	8810	**Rents**						
59		Customer	871-879CUS	$ 257	$ 206	$ 40	$ 2	$ 8
60		Demand	DEM	$ 51	$ 34	$ 14	$ 1	$ 3
61		Commodity	COM	$ 4	$ 3	$ 1	$ 0	$ 0
62		Total Rents		$ 312	$ 243	$ 55	$ 3	$ 11

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
63		**Transmission and Distribution Operating Expense (Cont'd)**						
64	8820	Corporate & Div. Exp.						
65		Customer	CUS	$ -	$ -	$ -	$ -	$ -
66		Demand	DEM	$ -	$ -	$ -	$ -	$ -
67		Commodity	COM	$ -	$ -	$ -	$ -	$ -
68		Total Corporate & Div. Exp.		$ -	$ -	$ -	$ -	$ -
69		**Total Distr. & Trans. Op. Expense**						
70		Customer		$ 303,102	$ 243,904	$ 47,203	$ 2,490	$ 9,506
71		Demand		$ 66,968	$ 43,651	$ 18,033	$ 1,285	$ 3,999
72		Commodity		$ 5,655	$ 3,673	$ 1,583	$ 46	$ 354
73		Total Distr. & Trans. Operations Exp.		$ 375,726	$ 291,227	$ 66,820	$ 3,821	$ 13,859
74		**Distribution Maintenance Expenses**						
75	8850	**Maintenance Supervision and Engineering**						
76		Customer	887-893CUS	$ -	$ -	$ -	$ -	$ -
77		Demand	887-893DEM	$ -	$ -	$ -	$ -	$ -
78		Commodity	COM	$ -	$ -	$ -	$ -	$ -
79		Total Supervision and Engineering		$ -	$ -	$ -	$ -	$ -
80	8860	**Structures and Improvements**						
81		Customer	887-893CUS	$ 28,840	$ 25,982	$ 2,576	$ 59	$ 224
82		Demand	887-893DEM	$ 8,677	$ 5,124	$ 2,748	$ 196	$ 609
83		Commodity	COM	$ -	$ -	$ -	$ -	$ -
84		Total Structures and Improvements		$ 37,517	$ 31,106	$ 5,323	$ 255	$ 833
85	8870	**Maintenance of Mains**						
86		Customer	CUS	$ 96,621	$ 87,316	$ 8,385	$ 191	$ 729
87		Demand	DEM	$ 40,747	$ 26,765	$ 10,813	$ 771	$ 2,398
88		Commodity	COM	$ -	$ -	$ -	$ -	$ -
89		Total Mains - Allocated		$ 137,368	$ 114,081	$ 19,198	$ 962	$ 3,128
90	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen.**						
91		Customer	CUS	$ -	$ -	$ -	$ -	$ -
92		Demand	DEM	$ 4,336	$ 2,848	$ 1,151	$ 82	$ 255
93		Commodity	COM	$ -	$ -	$ -	$ -	$ -
94		Total Meas. & Reg. Sta. Equip. - Gen.		$ 4,336	$ 2,848	$ 1,151	$ 82	$ 255

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
95		**Distribution Maintenance Expenses (Cont'd)**						
96	8900	**Meas. & Reg. Sta. Equip. - Ind.**						
97		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
98		Demand	NRDEM	$ 5,063	$ -	$ 3,916	$ 279	$ 868
99		Commodity	COM	$ -	$ -	$ -	$ -	$ -
100		Total Meas. & Reg. Sta. Eq.- Ind.		$ 5,063	$ -	$ 3,916	$ 279	$ 868
101	8910	**Meas. & Reg. Sta. Eq.- City Gate**						
102		Customer	CUS	$ -	$ -	$ -	$ -	$ -
103		Demand	DEM	$ 0	$ 0	$ 0	$ 0	$ 0
104		Commodity	COM	$ -	$ -	$ -	$ -	$ -
105		Total Meas. & Reg. Sta. Eq.- City Gate		$ 0	$ 0	$ 0	$ 0	$ 0
106	8920	**Services**						
107		Customer	SERCUS	$ 70,051	$ 62,838	$ 6,500	$ 148	$ 566
108		Demand	DEM	$ -	$ -	$ -	$ -	$ -
109		Commodity	COM	$ -	$ -	$ -	$ -	$ -
110		Total Services		$ 70,051	$ 62,838	$ 6,500	$ 148	$ 566
111	8930	**Meters & House Regulators**						
112		Customer	MTRGCUS	$ -	$ -	$ -	$ -	$ -
113		Demand	DEM	$ -	$ -	$ -	$ -	$ -
114		Commodity	COM	$ -	$ -	$ -	$ -	$ -
115		Total Meters & House Regulators		$ -	$ -	$ -	$ -	$ -
116	8940	**Other Equipment**						
117		Customer	CUS	$ -	$ -	$ -	$ -	$ -
118		Demand	DEM	$ -	$ -	$ -	$ -	$ -
119		Commodity	COM	$ -	$ -	$ -	$ -	$ -
120		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
121	8950	Clearing - Meter Shop - Small Meters						
122		Customer	CUS	$ -	$ -	$ -	$ -	$ -
123		Demand	DEM	$ -	$ -	$ -	$ -	$ -
124		Commodity	COM	$ -	$ -	$ -	$ -	$ -
125		Total Clearing-Meter-Shop-Small Meters		$ -	$ -	$ -	$ -	$ -
126	8960	Clearing - Meter Shop - Large Meters						
127		Customer	CUS	$ -	$ -	$ -	$ -	$ -
128		Demand	DEM	$ -	$ -	$ -	$ -	$ -
129		Commodity	COM	$ -	$ -	$ -	$ -	$ -
130		Total Clearing-Meter Shop-Large Meters		$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
131		**Total Distr. Maintenance Expense**						
132		Customer		$ 195,513	$ 176,135	$ 17,461	$ 398	$ 1,519
133		Demand		$ 58,824	$ 34,737	$ 18,628	$ 1,328	$ 4,131
134		Commodity		$ -	$ -	$ -	$ -	$ -
135		Total Distr. Maintenance Expense		$ 254,336	$ 210,872	$ 36,088	$ 1,725	$ 5,650
136		**Total Oper. & Maint. Expense**						
137		Customer		$ 498,615	$ 420,039	$ 64,663	$ 2,888	$ 11,025
138		Demand		$ 125,792	$ 78,388	$ 36,661	$ 2,613	$ 8,130
139		Commodity		$ 5,655	$ 3,673	$ 1,583	$ 46	$ 354
140		Total Operations & Maint. Expense		$ 630,062	$ 502,099	$ 102,908	$ 5,546	$ 19,509
141		**Customer Accounts Expense**						
142	901	Supervision						
143		Customer	902-904CUS	$ 2,125	$ 1,898	$ 208	$ 4	$ 15
144		Demand	DEM	$ -	$ -	$ -	$ -	$ -
145		Commodity	COM	$ -	$ -	$ -	$ -	$ -
146		Total Supervision		$ 2,125	$ 1,898	$ 208	$ 4	$ 15
147	902	**Meter Reading Expense**						
148		Customer	METCUS	$ 10,040	$ 7,621	$ 1,872	$ 113	$ 433
149		Demand	DEM	$ -	$ -	$ -	$ -	$ -
150		Commodity	COM	$ -	$ -	$ -	$ -	$ -
151		Total Meter Reading Expense		$ 10,040	$ 7,621	$ 1,872	$ 113	$ 433
152	903	**Customer Accounting**						
153		Customer	903CUS	$ 62,117	$ 57,639	$ 4,183	$ 61	$ 233
154		Demand	DEM	$ -	$ -	$ -	$ -	$ -
155		Commodity	COM	$ -	$ -	$ -	$ -	$ -
156		Total Customer Accounting		$ 62,117	$ 57,639	$ 4,183	$ 61	$ 233
157	904	**Bad Debt Expense**						
158		Customer	904CUS	$ 20,794	$ 17,745	$ 3,049	$ -	$ -
159		Demand	DEM	$ -	$ -	$ -	$ -	$ -
160		Commodity	COM	$ -	$ -	$ -	$ -	$ -
161		Total Bad Debt Expense		$ 20,794	$ 17,745	$ 3,049	$ -	$ -
162	905	**Miscellaneous Customer Accounts**						
163		Customer	902-904CUS	$ 7,190	$ 6,421	$ 704	$ 13	$ 52
164		Demand	DEM	$ -	$ -	$ -	$ -	$ -
165		Commodity	COM	$ -	$ -	$ -	$ -	$ -
166		Total Misc. Customer Accounts		$ 7,190	$ 6,421	$ 704	$ 13	$ 52

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
167		**Customer Accounts Expense (Cont'd)**						
168	907-910	**Customer information Expense**						
169		Customer	CUS	$ 4,401	$ 3,977	$ 382	$ 9	$ 33
170		Demand	DEM	$ -	$ -	$ -	$ -	$ -
171		Commodity	COM	$ -	$ -	$ -	$ -	$ -
172		Total Customer Information Expense		$ 4,401	$ 3,977	$ 382	$ 9	$ 33
173		**Sales and Advertising Expense**						
174	911	Supervision						
175		Customer	CUS	$ -	$ -	$ -	$ -	$ -
176		Demand	DEM	$ -	$ -	$ -	$ -	$ -
177		Commodity	COM	$ -	$ -	$ -	$ -	$ -
178		Total Supervision Expense		$ -	$ -	$ -	$ -	$ -
179	912	**Demonstrating and Selling**						
180		Customer	CUS	$ -	$ -	$ -	$ -	$ -
181		Demand	DEM	$ -	$ -	$ -	$ -	$ -
182		Commodity	COM	$ -	$ -	$ -	$ -	$ -
183		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -
184	913	**Advertising**						
185		Customer	CUS	$ 14	$ 13	$ 1	$ 0	$ 0
186		Demand	DEM	$ -	$ -	$ -	$ -	$ -
187		Commodity	COM	$ -	$ -	$ -	$ -	$ -
188		Total Advertising		$ 14	$ 13	$ 1	$ 0	$ 0
189	914	Employee Sales Referrals						
190		Customer	CUS	$ -	$ -	$ -	$ -	$ -
191		Demand	DEM	$ -	$ -	$ -	$ -	$ -
192		Commodity	COM	$ -	$ -	$ -	$ -	$ -
193		Total Employee Sales Referrals		$ -	$ -	$ -	$ -	$ -
194	916	Misc. Gas Sales Expense						
195		Customer	CUS	$ -	$ -	$ -	$ -	$ -
196		Demand	DEM	$ -	$ -	$ -	$ -	$ -
197		Commodity	COM	$ -	$ -	$ -	$ -	$ -
198		Total Misc. Gas Sales Expense		$ -	$ -	$ -	$ -	$ -
199		**Administrative & General Exp.**						
200	920-940	**Administrative & General Expenses**						
201		Customer	OPEXPCUS	$ 578,230	$ 498,488	$ 67,282	$ 2,586	$ 9,875
202		Demand	OPEXPDEM	$ 72,468	$ 45,132	$ 21,141	$ 1,507	$ 4,688
203		Commodity	COM	$ 3,258	$ 2,116	$ 912	$ 26	$ 204
204		Total Administrative & General Exp.		$ 653,956	$ 545,735	$ 89,335	$ 4,119	$ 14,767

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
205		**Depreciation & Amortization Expense**						
206	301-03	**Intangible Plant**						
207		Customer	CUS	$ -	$ -	$ -	$ -	$ -
208		Demand	DEM	$ -	$ -	$ -	$ -	$ -
209		Commodity	COM	$ -	$ -	$ -	$ -	$ -
210		Total Intangible Plant		$ -	$ -	$ -	$ -	$ -
211	365	**Land and Land Rights**						
212		Customer	CUS	$ -	$ -	$ -	$ -	$ -
213		Demand	DEM	$ -	$ -	$ -	$ -	$ -
214		Commodity	COM	$ -	$ -	$ -	$ -	$ -
215		Total Land and Land Rights		$ -	$ -	$ -	$ -	$ -
216	366	**Meas. and Reg. Station Structures**						
217		Customer	CUS	$ -	$ -	$ -	$ -	$ -
218		Demand	DEM	$ -	$ -	$ -	$ -	$ -
219		Commodity	COM	$ -	$ -	$ -	$ -	$ -
220		Total Measuring and Reg. Stat. Struct.		$ -	$ -	$ -	$ -	$ -
221	367	**Transmission Mains**						
222		Customer	CUS	$ -	$ -	$ -	$ -	$ -
223		Demand	DEM	$ -	$ -	$ -	$ -	$ -
224		Commodity	COM	$ -	$ -	$ -	$ -	$ -
225		Total Transmission Mains		$ -	$ -	$ -	$ -	$ -
226	368	**Compression Station Equipment**						
227		Customer	CUS	$ -	$ -	$ -	$ -	$ -
228		Demand	DEM	$ -	$ -	$ -	$ -	$ -
229		Commodity	COM	$ -	$ -	$ -	$ -	$ -
230		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -
231	369	**Meas. & Reg. Station Equipment**						
232		Customer	CUS	$ -	$ -	$ -	$ -	$ -
233		Demand	DEM	$ -	$ -	$ -	$ -	$ -
234		Commodity	COM	$ -	$ -	$ -	$ -	$ -
235		Total Meas. & Reg. Stat. Equipment		$ -	$ -	$ -	$ -	$ -
236	371	**Other Equipment**						
237		Customer	CUS	$ -	$ -	$ -	$ -	$ -
238		Demand	DEM	$ -	$ -	$ -	$ -	$ -
239		Commodity	COM	$ -	$ -	$ -	$ -	$ -
240		Total Other Equipment		$ -	$ -	$ -	$ -	$ -

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
241		**Depreciation & Amortization Expense (Cont'd)**						
242	375	**Structures and Improvements**						
243		Customer	376-379CUS	$ -	$ -	$ -	$ -	$ -
244		Demand	DEM	$ -	$ -	$ -	$ -	$ -
245		Commodity	COM	$ -	$ -	$ -	$ -	$ -
246		Total Structures and Improvements		$ -	$ -	$ -	$ -	$ -
247	376	**Distribution Mains**						
248		Customer	CUS	$ 176,375	$ 159,389	$ 15,306	$ 349	$ 1,332
249		Demand	DEM	$ 74,381	$ 48,857	$ 19,739	$ 1,407	$ 4,377
250		Commodity	COM	$ -	$ -	$ -	$ -	$ -
251		Total Distribution Mains		$ 250,756	$ 208,246	$ 35,045	$ 1,756	$ 5,709
252	377	**Compressor Station Equipment**						
253		Customer	CUS	$ -	$ -	$ -	$ -	$ -
254		Demand	DEM	$ -	$ -	$ -	$ -	$ -
255		Commodity	COM	$ -	$ -	$ -	$ -	$ -
256		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -
257	378	**Meas. & Reg. Sta. Equip. - Gen.**						
258		Customer	CUS	$ -	$ -	$ -	$ -	$ -
259		Demand	DEM	$ 1,598	$ 1,050	$ 424	$ 30	$ 94
260		Commodity	COM	$ -	$ -	$ -	$ -	$ -
261		Total Meas. & Reg. Sta. Eq.- Gen.		$ 1,598	$ 1,050	$ 424	$ 30	$ 94
262	378	**Odorization Tank**						
263		Customer	CUS	$ -	$ -	$ -	$ -	$ -
264		Demand	DEM	$ -	$ -	$ -	$ -	$ -
265		Commodity	COM	$ 39	$ 25	$ 11	$ 0	$ 2
266		Total Odorization Tank		$ 39	$ 25	$ 11	$ 0	$ 2
267	379	**Meas.& Reg. Sta. Equip.- City Gate**						
268		Customer	CUS	$ -	$ -	$ -	$ -	$ -
269		Demand	DEM	$ 2,433	$ 1,598	$ 646	$ 46	$ 143
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -
271		Total Meas. & Reg. Sta. Eq.- City Gate		$ 2,433	$ 1,598	$ 646	$ 46	$ 143
272	379	**Odorization Tank**						
273		Customer	CUS	$ -	$ -	$ -	$ -	$ -
274		Demand	DEM	$ -	$ -	$ -	$ -	$ -
275		Commodity	COM	$ 262	$ 170	$ 73	$ 2	$ 16
276		Total Odorization Tank		$ 262	$ 170	$ 73	$ 2	$ 16
277	380	**Services**						
278		Customer	SERCUS	$ 121,239	$ 108,754	$ 11,250	$ 256	$ 979
279		Demand	DEM	$ -	$ -	$ -	$ -	$ -
280		Commodity	COM	$ -	$ -	$ -	$ -	$ -
281		Total Services		$ 121,239	$ 108,754	$ 11,250	$ 256	$ 979

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
282		**Depreciation & Amortization Expense (Cont'd)**						
283	381	**Meters**						
284		Customer	METCUS	$ 54,597	$ 41,443	$ 10,182	$ 617	$ 2,355
285		Demand	DEM	$ -	$ -	$ -	$ -	$ -
286		Commodity	COM	$ -	$ -	$ -	$ -	$ -
287		Total Meters		$ 54,597	$ 41,443	$ 10,182	$ 617	$ 2,355
288	382	**Meter Installations**						
289		Customer	METCUS	$ 5	$ 3	$ 1	$ 0	$ 0
290		Demand	DEM	$ -	$ -	$ -	$ -	$ -
291		Commodity	COM	$ -	$ -	$ -	$ -	$ -
292		Total Meter Installations		$ 5	$ 3	$ 1	$ 0	$ 0
293	383	**House Regulators**						
294		Customer	REGCUS	$ 13,710	$ 9,952	$ 2,908	$ 176	$ 673
295		Demand	DEM	$ -	$ -	$ -	$ -	$ -
296		Commodity	COM	$ -	$ -	$ -	$ -	$ -
297		Total House Regulators		$ 13,710	$ 9,952	$ 2,908	$ 176	$ 673
298	385	**Meas. & Reg. Sta. Equip. - Ind.**						
299		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -
300		Demand	NRDEM	$ 4,192	$ -	$ 3,242	$ 231	$ 719
301		Commodity	COM	$ -	$ -	$ -	$ -	$ -
302		Total Meas. & Reg. Stat. Eq.- Ind.		$ 4,192	$ -	$ 3,242	$ 231	$ 719
303	386	**Other Prop.- Customer Premises**						
304		Customer	CUS	$ 852	$ 770	$ 74	$ 2	$ 6
305		Demand	DEM	$ -	$ -	$ -	$ -	$ -
306		Commodity	COM	$ -	$ -	$ -	$ -	$ -
307		Total Other Prop. - Customer Premises		$ 852	$ 770	$ 74	$ 2	$ 6
308	387	**Other Equipment**						
309		Customer	CUS	$ -	$ -	$ -	$ -	$ -
310		Demand	DEM	$ -	$ -	$ -	$ -	$ -
311		Commodity	COM	$ -	$ -	$ -	$ -	$ -
312		Total Other Equipment		$ -	$ -	$ -	$ -	$ -
313	389-98	**General Plant**						
314		Customer	GENPTCUS	$ 110,278	$ 97,422	$ 11,156	$ 353	$ 1,347
315		Demand	DISPLTDEM	$ 14,458	$ 8,896	$ 4,301	$ 307	$ 954
316		Commodity	COM	$ 346	$ 224	$ 97	$ 3	$ 22
317		Total General Plant		$ 125,081	$ 106,543	$ 15,554	$ 662	$ 2,322
318	389-98	**General Plant - Odorization**						
319		Customer	CUS	$ -	$ -	$ -	$ -	$ -
320		Demand	DEM	$ -	$ -	$ -	$ -	$ -
321		Commodity	COM	$ 262	$ 170	$ 73	$ 2	$ 16
322		Total General Plant - Odorization		$ 262	$ 170	$ 73	$ 2	$ 16

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
323	40730	**Pension & FAS 106 Amort. Expense**						
324		Customer	CUS	$ -	$ -	$ -	$ -	$ -
325		Demand	DEM	$ -	$ -	$ -	$ -	$ -
326		Commodity	COM	$ -	$ -	$ -	$ -	$ -
327		Total Pension & FAS 106 Amort. Exp.		$ -	$ -	$ -	$ -	$ -
328		**Total Depreciation & Amort. Exp.**						
329		Customer		$ 477,055	$ 417,734	$ 50,876	$ 1,753	$ 6,692
330		Demand		$ 97,061	$ 60,401	$ 28,352	$ 2,021	$ 6,287
331		Commodity		$ 909	$ 590	$ 255	$ 7	$ 57
332		Total Depreciation & Amort. Expense		$ 575,025	$ 478,725	$ 79,483	$ 3,781	$ 13,036
333		**Taxes Other Than Income**						
334	4081	**Payroll and Other Taxes**						
335		Customer	OPEXPCUS	$ 60,234	$ 51,927	$ 7,009	$ 269	$ 1,029
336		Demand	OPEXPDEM	$ 10,090	$ 6,284	$ 2,944	$ 210	$ 653
337		Commodity	COM	$ 454	$ 295	$ 127	$ 4	$ 28
338		Total Payroll and Other Taxes		$ 70,778	$ 58,506	$ 10,079	$ 483	$ 1,710
339	4081	**Ad Valorem Taxes**						
340		Customer	CUS	$ 176,049	$ 159,094	$ 15,278	$ 348	$ 1,329
341		Demand	DEM	$ 42,573	$ 27,964	$ 11,298	$ 805	$ 2,506
342		Commodity	COM	$ 301	$ 195	$ 84	$ 2	$ 19
343		Total Ad Valorem Taxes - Allocated		$ 218,922	$ 187,253	$ 26,660	$ 1,156	$ 3,853
344		**Revenue Related Taxes**						
345		Customer	TOTREVCUS	$ 4,241	$ 2,815	$ 1,137	$ 30	$ 259
346		Demand	DEM	$ -	$ -	$ -	$ -	$ -
347		Commodity	COM	$ -	$ -	$ -	$ -	$ -
348		Total Revenue Related Taxes		$ 4,241	$ 2,815	$ 1,137	$ 30	$ 259
349		**Total Taxes Other Than Income**						
350		Customer		$ 240,523	$ 213,836	$ 23,423	$ 648	$ 2,616
351		Demand		$ 52,663	$ 34,248	$ 14,242	$ 1,015	$ 3,158
352		Commodity		$ 754	$ 490	$ 211	$ 6	$ 47
353		Total Taxes Other Than Income		$ 293,940	$ 248,574	$ 37,876	$ 1,669	$ 5,822
354		**Excess Deferred Income Tax Amortization**						
355		Customer	CUS	$ (47,168)	$ (42,626)	$ (4,093)	$ (93)	$ (356)
356		Demand	DEM	$ (11,145)	$ (7,320)	$ (2,958)	$ (211)	$ (656)
357		Commodity	COM	$ (95)	$ (62)	$ (27)	$ (1)	$ (6)
358		**Total Excess Def. Income Tax Amortization**		$ (58,408)	$ (50,008)	$ (7,078)	$ (305)	$ (1,018)
359		**Interest on Customer Deposits**						
360		Customer	DEPCUS	$ 100	$ 53	$ 46	$ 0	$ 0
361		Demand	DEM	$ -	$ -	$ -	$ -	$ -
362		Commodity	COM	$ -	$ -	$ -	$ -	$ -
363		Total Interest on Cust. Deposits		$ 100	$ 53	$ 46	$ 0	$ 0

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
364		**Req. Return**						
365		Customer	CUS	$ 642,993	$ 581,068	$ 55,800	$ 1,271	$ 4,854
366		Demand	DEM	$ 151,922	$ 99,791	$ 40,317	$ 2,873	$ 8,941
367		Commodity	COM	$ 1,297	$ 842	$ 363	$ 10	$ 81
368		Tot. Req. Return		$ 796,213	$ 681,701	$ 96,480	$ 4,155	$ 13,877
369		**Income Taxes**						
370		Customer	CUS	$ 135,248	$ 122,222	$ 11,737	$ 267	$ 1,021
371		Demand	DEM	$ 31,955	$ 20,990	$ 8,480	$ 604	$ 1,881
372		Commodity	COM	$ 273	$ 177	$ 76	$ 2	$ 17
373		Total Income Taxes - Other Than DA		$ 167,476	$ 143,390	$ 20,294	$ 874	$ 2,919
374		**Total Cost of Service Before**						
375		**Revenue Credits**						
376		Customer		$ 2,632,278	$ 2,306,129	$ 280,134	$ 9,521	$ 36,494
377		Demand		$ 520,717	$ 331,629	$ 146,236	$ 10,422	$ 32,430
378		Commodity		$ 12,052	$ 7,826	$ 3,374	$ 97	$ 754
379		**Total Cost of Service Before Revenue Credits**		$ 3,165,046	$ 2,645,584	$ 429,744	$ 20,040	$ 69,678

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer Cost Allocation Factors						
2							
3	Total Customers		5,563	5,027	483	11	42
4	Total Customers Factor (CUS)	CUS	1.00000	0.90369	0.08678	0.00198	0.00755
5							
6	Services - Allocated Weighting			1.00000	1.07720	1.07720	1.07720
7	Weighted Customers		5,604	5,027	520	12	45
8	**Weighted Services Customer Factor (SERCUS)**	SERCUS	1.00000	0.89702	0.09279	0.00211	0.00807
9							
10	Meters - Allocated Weighting			1.00000	2.55840	6.80322	6.80322
11	Weighted Customers		6,623	5,027	1,235	75	286
12	**Weighted Meters Customer Factor (METCUS)**	METCUS	1.00000	0.75907	0.18649	0.01130	0.04314
13							
14	Regulators - Allocated Weighting			1.00000	3.04265	8.09525	8.09525
15	Weighted Customers		6,925	5,027	1,469	89	340
16	**Weighted Regulators Customer Factor (REGCUS)**	REGCUS	1.00000	0.72594	0.21211	0.01286	0.04910
17							
18	Meters and Regulators - Allocated Weighting			1.00000	2.69195	7.15953	7.15953
19	Weighted Customers		6,706	5,027	1,300	79	301
20	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS)**	MTRGCUS	1.00000	0.74963	0.19378	0.01174	0.04484
21							
22	Non-Residential Customers		536	0	483	11	42
23	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.90108	0.02053	0.07839
24							
25	Customer Cost Allocation Factors						
26							
27	Distribution Plant Customer Costs		$ 10,480,648	$ 9,184,600	$ 1,112,995	$ 37,992	$ 145,062
28	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.87634	0.10620	0.00363	0.01384
29							
30	Account 376-379 Customer Costs		$ 5,441,947	$ 4,917,844	$ 472,257	$ 10,761	$ 41,086
31	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.90369	0.08678	0.00198	0.00755
32							
33	Total Revenue (inc. cost of gas)		$ 4,765,053	$ 3,163,112	$ 1,277,098	$ 34,135	$ 290,708
34	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.66381	0.26801	0.00716	0.06101
35							

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
36	Mains - Customer Cost Factor		0.62282	0.56284	0.05405	0.00123	0.00470
37	Services - Customer Cost Factor		0.37718	0.33833	0.03500	0.00080	0.00304
38	**Mains & Svcs. Cust. Factor (MSCUS)**	MSCUS	1.00000	0.90118	0.08905	0.00203	0.00775
39							
40	Total Plant Customer		$ 12,883,224	$ 11,355,788	$ 1,321,492	$ 42,743	$ 163,201
41	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.88144	0.10257	0.00332	0.01267
42							
43	Non-Intangible Plant Customer						
44	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 12,853,494	$ 11,615,599	$ 1,115,437	$ 25,416	$ 97,041
45		NONINCUS	1.00000	0.90369	0.08678	0.00198	0.00755
46							
47	Account 871-879 Customer Costs		$ 243,404	$ 195,865	$ 37,906	$ 1,999	$ 7,634
48	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.80469	0.15573	0.00821	0.03136
49							
50	Account 887-893 Customer Costs		$ 166,673	$ 150,153	$ 14,885	$ 339	$ 1,295
51	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.90089	0.08931	0.00203	0.00777
52							
53	Account 903 Customer		$ 62,117	$ 57,639	$ 4,183	$ 61	$ 233
54	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.92792	0.06735	0.00098	0.00375
55							
56	Customer Cost Allocation Factors						
57							
58	Account 904 Customer		$ 20,794	$ 17,745	$ 3,049	$ -	$ -
59	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.85338	0.14662	0.00000	0.00000
60							
61	Accounts 902-904 Customer		$ 92,951	$ 83,006	$ 9,105	$ 174	$ 666
62	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.89300	0.09795	0.00188	0.00717
63							
64	Operating Expense Customer		$ 1,082,352	$ 933,088	$ 125,940	$ 4,841	$ 18,484
65	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.86209	0.11636	0.00447	0.01708
66							
67	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 1,757,897	$ 1,540,514	$ 186,680	$ 6,372	$ 24,331
68	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 614,948	$ 555,723	$ 53,366	$ 1,216	$ 4,643
69	Total General Plant Customer Costs		$ 2,372,845	$ 2,096,237	$ 240,046	$ 7,588	$ 28,974
70	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.88343	0.10116	0.00320	0.01221
71							

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY	SCHOOL AND MUNICIPAL
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
72	Customer Deposits		$ (166,631)	$ (88,787)	$ (77,444)	$ (39)	$ (361)
73	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.53283	0.46477	0.00023	0.00217
74							
75	Demand Cost Allocation Factors						
76							
77	System Demand						
78	**System Demand Factor (DEM)**	DEM	1.00000	0.65685	0.26538	0.01891	0.05885
79							
80	Non-Residential Demand						
81	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.77337	0.05512	0.17151
82							
83	Distribution Plant Demand		$ 2,661,830	$ 1,637,928	$ 791,860	$ 56,435	$ 175,607
84	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.61534	0.29749	0.02120	0.06597
85							
86	Demand Cost Allocation Factors						
87							
88	Non-Intangible Plant Demand		$ 3,108,293	$ 2,041,691	$ 824,883	$ 58,788	$ 182,931
89	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.65685	0.26538	0.01891	0.05885
90							
91	Total Plant Demand		$ 3,115,483	$ 1,935,911	$ 912,251	$ 65,015	$ 202,306
92	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.62138	0.29281	0.02087	0.06494
93							
94	Operating Expense Demand		$ 222,853	$ 138,789	$ 65,013	$ 4,633	$ 14,418
95	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.62278	0.29173	0.02079	0.06470
96							
97	Acct. 887-893 Demand		$ 50,147	$ 29,613	$ 15,880	$ 1,132	$ 3,522
98	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.59053	0.31667	0.02257	0.07023
99							
100	Rate Base Demand		$ 1,955,444	$ 1,220,184	$ 568,632	$ 40,526	$ 126,103
101	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.62399	0.29079	0.02072	0.06449
102							
103	Commodity Cost Allocation Factors						
104							
105	Annual Distribution Volumes (Ccf)		5,292,042	3,436,612	1,481,765	42,750	330,915
106	**Distribution Commodity Factor (COM)**	COM	1.00000	0.64939	0.28000	0.00808	0.06253

CLASS REVENUE ALLOCATION

LINE	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	PUBLIC AUTHORITY
	(a)	(b)	(c)	(d)	(e)
1	Current Revenue-to-Cost Ratio (1)	0.8214	0.6677	1.5439	1.8904
2	Revenue Allocation One - Cost of Service Study Required Revenue Changes				
3	Revenue-to-Cost Ratio	1.0000	1.0000	1.0000	1.0000
4	Rate Design Revenue Increase	$ 565,408	$ 879,028	$ (233,735)	$ (79,884)
5	% Increase - Non-Gas Revenue (2)	21.75%	49.76%	-35.23%	-47.10%
6	% Increase - Total Revenue (3)	11.78%	27.52%	-18.27%	-24.59%
7	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)				
8	Revenue-to-Cost Ratio	1.0000	0.9052	1.4351	1.7123
9	Rate Design Revenue Increase	$ 565,408	$ 628,132	$ (46,747)	$ (15,977)
10	% Increase - Non-Gas Revenue (2)	21.75%	35.56%	-7.05%	-9.42%
11	% Increase - Total Revenue (3)	11.78%	19.66%	-3.65%	-4.92%
12	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)				
13	Revenue-to-Cost Ratio	1.0000	0.8815	1.5439	1.8904
14	Rate Design Revenue Increase	$ 565,408	$ 565,408	$ -	$ -
15	% Increase - Non-Gas Revenue (2)	21.75%	32.01%	0.00%	0.00%
16	% Increase - Total Revenue (3)	11.78%	17.70%	0.00%	0.00%

(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.

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.

DocuSigned by:
Teresa D. Serna
20FBD40B5A5147D...

Teresa D. Serna

SUBSCRIBED AND SWORN TO BEFORE ME by the said Teresa D. Serna on this 16th day of June 2022.

DocuSigned by:
Christine Marie Bell
1C45AAFD08DC44A...

Notary Public in and for the State of Texas

NOTARY PUBLIC STATE OF TEXAS
CHRISTINE MARIE BELL
Notary ID
130547096
My Commission Expires
2/19/2024

CASE NO. 00009896

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	**§ § § § § § § § §**	**BEFORE THE RAILROAD COMMISSION OF TEXAS**

DIRECT TESTIMONY

OF

PAUL H. RAAB

ON BEHALF OF

TEXAS GAS SERVICE COMPANY

June 30, 2022

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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 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 TESTIFIED PREVIOUSLY BEFORE THE RAILROAD COMMISSION OF TEXAS ("COMMISSION") IN REGULATORY PROCEEDINGS?

A. Yes. I have previously provided expert testimony before this Commission and numerous state regulatory authorities, as well as the Federal Energy Regulatory Commission, the Michigan House Economic Development and Energy Committee, the Pennsylvania House Consumer Affairs Committee, the Province of Saskatchewan, and the United States Tax Court. Details on the subject matter of the testimony presented are provided in Exhibit PHR-1.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I prepared and sponsor the exhibits listed in the table of contents.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents and supports the rate design I developed for the proposed West North Service Area ("WNSA") based on the WNSA class cost of service study ("CCOSS") results sponsored by Company witness Teresa Serna.

Q. DID YOU ALSO DEVELOP SEPARATE RATES FOR THE WEST TEXAS SERVICE AREA ("WTSA"), THE NORTH TEXAS SERVICE AREA ("NTSA"), AND THE BORGER SKELLYTOWN SERVICE AREA ("BSSA")?

A. Yes. I developed rates based on the separate WTSA, NTSA, and BSSA revenue requirements in the event consolidation of these service areas is not approved. Exhibits PHR-2 through PHR-10 support my development of rates for the proposed WNSA service area. Exhibits PHR-11 through PHR-19 support my development of the proposed rates for the WTSA, Exhibits PHR-20 through PHR-24 support my development of the proposed rates for the NTSA, and Exhibits PHR-25 through PHR-29 support my development of the proposed rates for the BSSA. These separate service area rates are based on each area's calculated revenue requirement.

II. <u>RATE DESIGN</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE RATE DESIGN PRESENTATION IN YOUR TESTIMONY.

A. As I have previously indicated, my testimony develops rates for the proposed WNSA as well as rates for the component service areas that comprise the new proposed WNSA: WTSA, NTSA and BSSA. Because there is not a one-to-one correspondence between the rate offerings in the three service areas being proposed for consolidation, certain rates will be eliminated, and others will be modified so that they can be applied in the consolidated service area. In addition, the Company is proposing new sales and transportation tariffs for Compressed Natural Gas ("CNG"). And finally, the Company is proposing rate structure changes within many of the remaining rate offerings.

Accordingly, this section of my testimony begins with the specific rates to be discontinued, modifications to existing rate structures to accommodate the proposed service area consolidation, the new tariffs being proposed, and the rate structure changes being proposed within certain of the existing rate offerings. This is followed by a discussion of how the Company's rate design objectives translate into specific tariffs for the consolidated service area and, in the event the consolidation is not approved, the specific tariffs for the WTSA, NTSA, and BSSA.

Q. WHICH RATE OFFERINGS DOES THE COMPANY PROPOSE TO ELIMINATE?

A. The Company is proposing to eliminate air conditioning rates, such as those that are currently offered to Commercial and Public Authority customers in the WTSA. Customers currently served under these rate offerings are proposed to be served under the Commercial and Public Authority Sales rate offerings, respectively. The bill impact to the affected customers is shown in Exhibits PHR-6 and PHR-8. The Company is also proposing to eliminate the WTSA Municipal Water Pumping rate and the School and Municipal rate offered to customers in its BSSA. Customers currently served on these tariffs will be billed using the appropriate Public Authority Sales or Transport rate, although there are currently no Municipal Water Pumping Transportation customers. The bill impact to the affected customers is shown in Exhibit PHR-8.

Q. PLEASE DISCUSS THE MODIFICATIONS TO EXISTING RATE STRUCTURES THAT ARE BEING MADE TO ACCOMMODATE THE PROPOSED SERVICE AREA CONSOLIDATION.

A. To offer consistent rates across the consolidated service territory, the Company is proposing to eliminate the declining block rates currently in place in its WTSA and replace them with flat rates. Flat rates are more consistent with those in place in all other service areas that the Company serves.

Q. PLEASE DESCRIBE THE NEW TARIFFS BEING PROPOSED.

A. New CNG rates for Sales and Transportation Service are being proposed in this filing. The Company currently provides service to four CNG transport customers, although these customers pay Commercial or Public Authority Transportation rate charges. Given the unique nature of this service and an anticipation that more customers are likely to avail themselves of this service in the future, the Company is proposing to offer CNG customers a dedicated rate with its own cost basis. While it has no current CNG Sales customers, the Company is proposing both a CNG Sales rate and a CNG Transportation rate, in anticipation of potential future need.

Q. PLEASE DESCRIBE THE RATE STRUCTURE CHANGES BEING PROPOSED.

A. To minimize the bill impacts associated with service area consolidations and rate level increases, the Company is proposing to split the existing residential class into two classes: a "large" residential class composed of residential customers who annually consume more than the average amount of the combined class, and a "small" residential class composed of residential customers who annually consume less than the average amount of the combined class. This is analogous to the small commercial/large commercial rate offerings of many local distribution companies ("LDCs") throughout the country.

Q. GIVEN THIS GENERAL OVERVIEW, WHAT SPECIFIC RATE DESIGNS ARE PROPOSED?

A. The Company's request in this case is to consolidate the WTSA, NTSA and BSSA service areas into a new WNSA rate area with consistent rate structures and levels applying to all consumption in the consolidated area and my recommended rate designs are consistent with that request. As a result, the primary focus of my testimony is on the consolidated WNSA service area rate designs. I have developed nine exhibits, Exhibit PHR-2 through Exhibit PHR-10, to assist in the presentation of these rate designs. This presentation focuses on three areas: (1) the rates themselves and how they compare to existing rates; (2) the customer bill impacts when moving from existing rates to the new rates; and (3) how effectively the new rate structures recover Commission-approved levels of revenues in this case.

Exhibit PHR-2 begins with a summary of Current and Recommended Rates. Bill impacts are explored in Exhibits PHR-3 through PHR-9. Seven of these exhibits relate to my evaluation of bill impacts and examine how the proposed rate designs minimize bill impact issues associated with consolidation of service areas and changes in rate structure. Finally, Exhibit PHR-10 contains a proof of revenues that demonstrates that the new rate structures recover Company-proposed levels of revenues in this case.

Q. DOES YOUR TESTIMONY ALSO INCLUDE A DISCUSSION OF RATES BASED ON THE SEPARATE WTSA, NTSA, AND BSSA REVENUE REQUIREMENTS IN THE EVENT THAT THE COMMISSION DOES NOT APPROVE CONSOLIDATION OF THESE SERVICE AREAS?

A. Yes, and my presentation of those rates covers the same three areas as above and generally relies on a similar set of exhibits. This is true for my presentation of the rates proposed for the WTSA. In the case of the NTSA and the BSSA, however, there is no detailed, customer-by-customer bill impact analysis for Commercial, Industrial, and Public Authority rates because customers in those classes and service areas are not currently billed under a declining block rate structure and only the average bill impacts are evaluated and presented.

Q. PLEASE DESCRIBE THE CURRENT RESIDENTIAL RATES IN THE WTSA, THE NTSA, AND THE BSSA.

A. Current residential rate structures consist of a fixed customer charge and usage charges for each service area, as shown in Exhibit PHR-2. The residential customer charge is $23.53/customer/month in the environs and incorporated WTSA, $24.50/customer/month in the NTSA environs, $15.44/customer/month in the incorporated NTSA, and $16.00/customer/month in the environs and incorporated BSSA.

Residential usage is priced at a single per Ccf rate of $0.09317 in the WTSA environs and incorporated areas, $0.59366 in the NTSA environs, $0.67101 in the NTSA incorporated areas, and $0.21548 in the BSSA incorporated areas and environs.

Q. PLEASE DESCRIBE THE CURRENT COMMERCIAL RATES.

A. For commercial sales customers, current customer charges are $63.58/customer/month in the WTSA, $76.33/customer/month in the NTSA environs, $47.80/customer/month in the incorporated NTSA, and $37.08/customer/month in the environs and incorporated BSSA. Commercial usage is priced under a declining block structure in the WTSA incorporated areas and environs. Monthly consumption less than or equal to 500 Ccf is priced at $0.08223/Ccf and monthly consumption greater than 500 Ccf is priced at $0.06223/Ccf. Commercial usage is priced at a single per Ccf rate of $0.60165 in the NTSA environs, $0.68165 in the NTSA incorporated areas and $0.29344 in the BSSA environs and incorporated areas.

The usage of commercial transportation customers is priced at the same volumetric rate as sales customers in the WTSA and BSSA and at a single per Ccf rate of $0.57978 in the NTSA environs and incorporated areas. Customer charges for commercial transportation customers of $424.58/customer/month in the WTSA, $509.26/customer/month in the NTSA environs, $250.00/customer/month in the incorporated NTSA, and $252.08/customer/month in the environs and incorporated BSSA reflect the higher metering and administrative costs associated with providing service to these customers.

Commercial rates in the WTSA also include a seasonally differentiated declining block air conditioning rate with a customer charge of $63.58/customer/month, winter usage rates of $0.08223/Ccf for the first 500 Ccf monthly consumption and $0.06223/Ccf for all monthly consumption above 500

Ccf, and summer usage rates of $0.06223/Ccf for the first 500 Ccf monthly consumption and $0.04223/Ccf for all monthly consumption above 500 Ccf. The Company is proposing to discontinue this rate and existing customers would then be served under the new Commercial sales rate.

Q. PLEASE DESCRIBE THE CURRENT ELECTRICAL COGENERATION RATES.

A. The Company currently offers seasonally differentiated declining block rates for electrical cogeneration customers in its WTSA with a monthly customer charge for sales customers of $321.25/customer/month and for transportation customers of $424.58/customer/month. The current blocking structure for usage for both sales and transportation customers is as follows:

	Usage Rates (October - April)	Usage Rates (May - September)
First 5,000 Ccf	$0.05696	$0.04695
Next 95,000	$0.04696	$0.03694
Next 300,000	$0.03696	$0.02695
All Over 400,000	$0.02696	$0.01694

Q. PLEASE DESCRIBE THE CURRENT INDUSTRIAL RATES.

A. For industrial sales customers, current customer charges are $857.20/customer/month in the WTSA, $509.26/customer/month in the NTSA environs and $308.59/customer/month in the NTSA incorporated areas. The Company does not currently offer an industrial sales rate in the BSSA. Industrial usage is priced at a single per Ccf rate of $0.55395/Ccf in the NTSA environs and $0.62874/Ccf in the NTSA incorporated areas and under a declining block structure in the WTSA incorporated areas and environs. Monthly consumption less than or equal to 500 Ccf is priced at $0.12458 and monthly consumption greater than 500 Ccf is priced at $0.10458 in the WTSA incorporated areas and environs.

The usage of industrial transportation customers is priced at the same volumetric rate as sales customers in the WTSA and in the NTSA environs. In the NTSA incorporated areas, usage is priced at $0.55395/Ccf. Customer charges for industrial transportation customers are $1,057.20/customer/month in the WTSA, $509.26/customer/month in the NTSA environs and $250/customer/month in the NTSA incorporated areas.

Q. PLEASE DESCRIBE THE CURRENT STANDBY SERVICE RATES.

A. These rates are also currently offered to sales customers in the Company's WTSA. Customers served under this two-part tariff pay a customer charge of $666.37/customer/month and a usage rate of $20.00/Mcf/hour.

Q. PLEASE DESCRIBE THE CURRENT PUBLIC AUTHORITY RATES.

A. For public authority sales customers, current customer charges are $195.79/customer/month in the WTSA, $160.93/customer/month in the NTSA environs, $101.32/customer/month in the NTSA incorporated areas, and $47.08/customer/month in the BSSA incorporated areas and environs. Like the commercial and industrial rates described above, public authority usage is priced at a single per Ccf rate of $0.54101 in the NTSA environs, $0.61329 in the NTSA incorporated areas and $0.23148 in the BSSA incorporated areas and environs, and under a declining block structure in the WTSA incorporated areas and environs. Monthly consumption less than or equal to 500 Ccf is priced at $0.11461 and monthly consumption greater than 500 Ccf is priced at $0.09461.

The usage of public authority transportation customers is priced at the same volumetric rate as sales customers in the WTSA, in the NTSA environs, and in the BSSA incorporated areas and environs. In the NTSA incorporated areas, usage is priced at $0.54101/Ccf. Customer charges for public authority transportation customers are $495.79/customer/month in the WTSA, $325.93/customer/month in the NTSA environs, $250/customer/month in the NTSA incorporated areas, and $252.08/customer/month in the BSSA incorporated areas and environs.

Similar to the Commercial rates described above, Public Authority rates in the WTSA also include a seasonally differentiated declining block air conditioning rate with a customer charge of $195.79/customer/month, winter usage rates of $0.11461/Ccf for the first 500 Ccf monthly consumption and $0.09461/Ccf for all monthly consumption above 500 Ccf, and summer usage rates of $0.08461/Ccf for the first 500 Ccf monthly consumption and $0.06461/Ccf for all monthly consumption above 500 Ccf. Also, as above, the Company is proposing to discontinue this rate and existing customers would then be served under the new Public Authority sales rate.

Q. PLEASE DESCRIBE THE CURRENT SCHOOL AND MUNICIPAL RATES.

A. These rates are currently offered to customers in the Company's BSSA. Sales customers served under this two-part rate pay a customer charge of $51.02/customer/month and transportation customers pay a customer charge of $256.02/customer/month. Usage for both sales and transportation customers is billed at a rate of $0.37651/Ccf. As discussed previously, the Company is proposing to discontinue this rate and customers currently served under these rates will migrate to the appropriate Public Authority sales or transportation tariff.

Q. PLEASE DESCRIBE HOW THE COMPANY CURRENTLY CHARGES CNG CUSTOMERS FOR SERVICE.

A. Currently, although there are four CNG customers taking transportation service in the WTSA, the Company does not offer a dedicated CNG rate for this service. These customers are currently classified as either Commercial or Public Authority Transportation customers and billed under the corresponding rate. The Company is proposing new sales and transportation rates for CNG customers, which are described below.

Q. PLEASE DESCRIBE THE CURRENT MUNICIPAL WATER PUMPING RATES.

A. These rates are currently offered to sales customers in the Company's WTSA. Customers served under this declining block rate tariff pay a customer charge of $768.75/customer/month. The first 5,000 Ccfs in any month are billed at a rate of $0.06111/Ccf and all Ccfs above 5,000 Ccfs in that month are billed at a rate of $0.05111/Ccf. As discussed previously, the Company is proposing to discontinue this rate and customers currently served under this rate will migrate to Public Authority sales tariffs.

Q. HOW DID YOU DESIGN THE PROPOSED WNSA RATE RECOMMENDATIONS?

A. I began with class revenue recommendations developed by Ms. Serna. As described more fully by Ms. Serna, those recommendations are the result of applying class Revenue Allocation Two, under which the revenue excess of those classes that are indicated to be contributing revenues in excess of their full cost of service are reduced by 20% and credited to the required revenue of the residential class, which is contributing revenues less than its full cost of service. Furthermore, to ensure rate continuity, I relied on the current WTSA rate structures for each class as the starting point in designing the recommended consolidated rates in this case. The concept of rate continuity suggests that current rate structures form the basis for recommended rates.

I also considered intraclass equity which relates to the fairness in the collection of revenue from customers within a class who use different amounts of gas. For each customer class, rates should be designed so that fixed costs are recovered through the fixed monthly customer charge, and variable costs are recovered through the volumetric charges. If a class's customer charge is too low to fully recover fixed costs, moderate-and high-use customers unfairly pay part of the cost to serve lower use customers. Likewise, if the volumetric charge is too low to fully recover variable costs, relatively low-use customers unfairly pay part of the cost to serve moderate-and high-use customers.

I also assessed average monthly bill impacts for each customer class. Furthermore, because the Company is proposing rate structures for many classes that are different from the rates under which these customers are currently served, I present a more detailed analysis of rate impacts in which the bill impacts by annual consumption level are examined. In considering bill impacts, it is important to recognize that no matter how rates are designed, there will be a disparity in customer bill impacts, some of which could be large.

Finally, when designing rates, it is important that customers can easily determine which rate offering is most appropriate for their usage. This is accomplished by keeping the usage charge the same for the sales and corresponding transportation classes.

Q. HAVE YOU IDENTIFIED ANY CHALLENGES IN DESIGNING RATES FOR THE PROPOSED WNSA?

A. Yes. First, current rates allow residential customers to pay less than the cost to serve them. Therefore, all other classes pay more than their own class cost of service, which creates interclass inequities with the revenue collection across customer classes in these three service areas.

Second, current monthly rate levels differ significantly between the service areas proposed for consolidation into the WNSA. These differences are a result of timing differences in rate adjustments between the service areas and different interim rate adjustment mechanisms employed in the different service areas.

Finally, current residential customer charges are below the fixed cost per bill indicated by the CCOSS. This means that moderate and high-use customers are paying a disproportionate amount of the class costs.

Q. WHAT ARE YOUR RECOMMENDED RESIDENTIAL CUSTOMER AND USAGE CHARGES FOR THE PROPOSED WNSA?

A. For "Small" Residential customers in the proposed WNSA whose weather normalized consumption is less than or equal to 440 Ccf per year, I recommend the following charges:

Customer charge:	$20.00/customer/month
Volumetric Charge:	$0.41173/Ccf

For "Large" Residential customers in the proposed WNSA whose weather normalized consumption is greater than 440 Ccf per year, I recommend the following charges:

Customer charge:	$35.00/customer/month
Volumetric Charge:	$0.00264/Ccf

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THESE CHARGES.

A. As stated above, I began with the Company's CCOSS and developed a benchmark single, two-part (a customer charge and a commodity charge) rate for all affected customers. In all the resulting rates, I determined that a customer charge of $35.01 most accurately captures the customer-related and demand-related costs by class identified in the Company's CCOSS as described by Ms. Serna.

This customer charge results from the development of a so-called "Straight Fixed-Variable" or "SFV" rate. These types of rates are particularly appropriate for natural gas LDCs because they operate in competitive end-use markets for every residential customer that they serve. In other words, there is not one end-use that LDCs provide the energy to serve 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 prices faced by residential customers reflect the costs of providing that service, or customers could make energy-consumption decisions that do not maximize economic welfare. This is particularly true on an intraclass basis, where higher volume residential users of natural gas are predominantly heating customers and lower volume users are non-heating customers. SFV rates help to ensure that the individual end-use markets in which these two types of customers participate are not distorted.

Q. WHY ARE YOU NOT SIMPLY PROPOSING THE RATE DESIGN YOU JUST DESCRIBED FOR ALL CUSTOMERS?

A. Because that rate structure, when applied to typical residential class bills, resulted in significant bill increases for lower usage customers relative to the Company's current rate structures in the WTSA, NTSA, and BSSA. Thus, while the rate structure just described would best match the costs of service identified by the Company, it would not avoid significant rate shocks for those customers. Because of this, I adopted a different approach to developing the proposed rate by determining a rate design that best 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 $20.00/customer/month, a level approximating the lowest customer charge that residential customers are currently charged in the WTSA, NTSA environs, NTSA incorporated or BSSA. I also propose that, since 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 reflect the full cost of service to the extent possible.

Q. WHAT DID YOU DO NEXT?

A. Because the prices 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 OR OUT OF THE ORDINARY?

A. No, not at all. This reality exists in virtually any rate design proposal. The term used to describe this inherent reality is “intra-class subsidy.”

Q. HOW DID YOU ACCOUNT FOR THE INTRA-CLASS SUBSIDY IN YOUR PROPOSED RATE DESIGN?

A. I recover the intraclass subsidy through an equal, additional charge applied to the usage charges of both new residential rate classes so that all residential customers are contributing to make up the shortfall. This not only makes up the revenue shortfall relative to the identified cost of service of the lower usage customers but also minimizes the rate impacts of moving to a new rate design. Thus, the new rate design moves the Company's rates closer to its underlying cost of service and avoids the significant rate shock associated with immediate implementation of a full cost of service-based rate for lower usage customers.

Q. CAN THIS RATE STRUCTURE BE EASILY IMPLEMENTED?

A. Yes. Since both rates contain a two-part structure (customer charges and volumetric charges), they can be implemented very simply and in a way that is transparent to customers.

Q. HOW WILL THE PROPOSED RATE DESIGN AFFECT CUSTOMERS WITH AVERAGE USAGE?

A. It is anticipated that customers with average usage will not be overly affected regardless of the sub-class to which they are assigned, so the Company does not expect significant migration of customers from one sub-class to the other. This can be seen by comparing the annual bills for two customers near the breakpoint between sub-classes. Consider a residential customer who uses exactly 440 Ccfs per year. A Small Residential Customer's annual bill is $421.16, the same amount as a Large Residential Customer. If the customer reduces usage by 10%, to 396 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 ($403.05 versus $421.05, or $1.50 per month). A similar result obtains 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 rate shifts.

Q. HOW WILL THE COMPANY DETERMINE WHICH RATE TO APPLY TO CUSTOMERS INITIALLY?

A. The Company will initially assign each residential customer to the rate schedule that appears to be the most economical based on their historical usage and then allow customers to 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. WHY IS THE COMPANY MAKING THIS RATE DESIGN PROPOSAL FOR RESIDENTIAL CUSTOMERS AND NOT FOR OTHER CUSTOMER CLASSES?

A. The Company's proposal to consolidate three rate areas with different customer and usage charges could result in significant negative bill impacts for residential customers currently billed under low customer charges and higher usage charges, such as those customers who are served in the Company's NTSA incorporated area. This proposal mitigates those impacts, particularly for lower usage customers.

Q. PLEASE EXPLAIN THE RECOMMENDED RATE DESIGN FOR THE NON-RESIDENTIAL PROPOSED WNSA TRANSPORT AND SALES CLASSES.

A. Except for cogeneration, I recommend a two-part, single-block rate structure that is currently in place in the NTSA and BSSA. For the cogeneration class, I have retained the current four block rate structure to ensure rate continuity.

When adjusting the customer charges for the classes, I considered both the fixed costs per bill determined in the WNSA CCOSS and the current wide disparity among customer charges in the service areas. The assigned revenue for the class, less the revenue recovered from the recommended customer charge, is the revenue recovered through usage charges for each non-residential class. The recommended transportation volumetric rates are the same as the corresponding volumetric sales rates for all classes. The customer charge is higher than the corresponding sales service charge for each class.

Current and recommended non-residential rates are shown in Exhibit PHR-2.

Q. ARE YOUR RECOMMENDED NON-RESIDENTIAL RATES FOR THE WTSA, NTSA, AND BSSA DEVELOPED IN THE SAME MANNER IF THE THREE SERVICE AREAS ARE NOT CONSOLIDATED IN THIS SOI?

A. Yes, they are. Current and recommended non-residential rates are shown in Exhibit PHR-11 for the WTSA, Exhibit PHR-20 for the NTSA and in Exhibit PHR-25 for the BSSA. These rates are recommended if the three service areas are not combined in this SOI.

Q. IN YOUR OPINION, IS YOUR RATE DESIGN JUST AND REASONABLE?

A. Yes.

III. <u>CUSTOMER BILL IMPACTS</u>

Q. HAVE YOU CALCULATED CUSTOMER BILL IMPACTS RESULTING FROM YOUR RECOMMENDED WNSA RATES?

A. Yes. Exhibit PHR-3 provides proposed WNSA 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 in the applicable service area.

Q. PLEASE DESCRIBE HOW THE NEW RESIDENTIAL USAGE SUBCLASSES AVOID SIGNIFICANT RATE SHOCK FOR RESIDENTIAL CUSTOMERS.

A. This can be demonstrated in two ways. First, the rate impacts from implementation of this rate design for the range of weather-normalized consumption observed for residential customers in the rate areas to be consolidated can be calculated. These calculations are shown in Exhibit PHR-4.

However, these bill impacts show the combined effect of the consolidation, the required revenue increase, and the change from traditional two-part rates to the proposed Residential rates. A better way to show the impact of the rate design change is to compare the proposed rates to the Company's traditional rates, adjusted to collect the required revenues in this case, thereby developing an "apples-to-apples" comparison. This comparison is provided as Exhibit PHR-5 and shows that the rate design change is mitigating the rate increase by reducing bills below levels that they would be if the traditional rate design were continued for lower usage customers in the WTSA and NTSA. Even in the BSSA Incorporated areas, rate impacts because of the change in rate structure are modest, at most about $3/month rate for all users. As can be seen, the rate structure particularly benefits the lowest usage customers on the system.

Q. HAVE YOU PREPARED A SIMILAR BILLING ANALYSIS FOR THE PROPOSED NON-RESIDENTIAL RATE DESIGNS?

A. The comparisons provided in Exhibit PHR-3 are appropriate when comparing existing rates in the NTSA and BSSA to proposed rates in the WNSA because the comparisons evaluate like rate structures (i.e., simple two-part rates). In the case of the WTSA, however, most of the non-residential rate structures are declining block rate structures. As a result, a simple comparison can mask billing differences between customers whose usage patterns deviate from the average. For this reason, I have also developed a customer-by-customer level comparison of bills under the old declining block structure in WTSA to bills under the new, two-part rate structure.

Exhibit PHR-6 compares annual bills at existing rate levels to annual bills at proposed rate levels for the range of weather-normalized consumption observed for commercial, commercial transport, and commercial air conditioning customers (who will migrate to commercial rates). A similar comparison is developed for industrial and industrial transport customers and provided in Exhibit PHR-7. Exhibit PHR-8 shows the comparison for public authority customers (sales, transport, air conditioning and municipal water pumping). Finally, Exhibit PHR-9 contains the bill comparisons for CNG customers.

An evaluation of these four exhibits generally confirms that rate impacts are modest or apply to few customers and that the rate changes are not disadvantaging customers with a unique load pattern.

Q. DO YOU HAVE ANY COMMENTS ON THE TRANSPORTATION CUSTOMER BILL IMPACTS SHOWN IN THESE EXHIBITS?

A. Yes. Transportation customers secure their own gas supplies rather than relying on TGS to provide the commodity. While the Company has no way of knowing the transportation customer's cost of gas, the transportation bill comparisons assume that transportation customers obtain their gas at a cost that is 5% less than the Company's average gas cost in the test year. These transportation bill comparisons provide illustrative approximations of transportation bills and bill changes and may or may not reflect the actual impacts experienced by any average-use transportation customer.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE CUSTOMER BILL IMPACTS?

A. Yes. In reviewing the bill impacts, attention should be focused on the distribution of customers in each class. For the residential sales class, approximately 93% of the class resides in the WTSA, and the remaining 7% in the NTSA and the BSSA. For the commercial and industrial sales classes, approximately 86% resides in the WTSA and the remaining 14% in the NTSA and the BSSA. For the public authority sales class, approximately 80% resides in WTSA, with the remaining 16% resident in the NTSA and 4% in the BSSA. For all transportation customers, approximately 96% resides in the WTSA.

Furthermore, for most classes in the BSSA, bill impacts may be sizable no matter how rates are designed, although they will be much less for residential customers to the extent that recognition of the small and large residential customer distinction is approved by the Commission.

Q. HAVE YOU CALCULATED CUSTOMER BILL IMPACTS RESULTING FROM YOUR RECOMMENDED SEPARATE WTSA, NTSA, AND BSSA RATES IF THE THREE SERVICE AREAS ARE NOT COMBINED?

A. Yes. Exhibits PHR-12 through PHR-18 provide the billing impact information if rates are to be designed separately for the WTSA, Exhibits PHR-21 through PHR-23 provide the billing impact information if rates are to be designed separately for the NTSA, and Exhibits PHR-26 through PHR-28 provide the billing impact information if rates are to be designed separately for the BSSA based on the separate revenue requirements.

IV. PROOF OF REVENUE

Q. HAVE YOU PREPARED A PROOF OF REVENUE TO SHOW THAT THE PROPOSED WNSA RECOMMENDED RATES PRODUCE THE REVENUE ASSOCIATED WITH MS. SERNA'S PROPOSED CLASS ALLOCATION?

A. Yes. An arithmetical demonstration that the recommended proposed WNSA rates produce the assigned revenue for each class and for the entire service area is provided in Exhibit PHR-10. 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 Exhibit PHR-10.

Q. HAVE YOU PREPARED A PROOF OF REVENUE TO SHOW THAT THE SEPARATE WTSA, NTSA, AND BSSA RECOMMENDED RATES PRODUCE THE REQUIRED REVENUE IN EACH AREA IF THE THREE SERVICE AREAS ARE NOT COMBINED?

A. Yes. The proof that the recommended WTSA, NTSA, and BSSA rates produce the required revenue for each class in each area is provided in Exhibit PHR-19 for the WTSA, Exhibit PHR-24 for the NTSA, and Exhibit PHR-29 for the BSSA. These exhibits are based on separate rates for the WTSA, the NTSA, and the BSSA based on the separate revenue requirements and class revenue allocations if consolidation of the three service areas is not approved.

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
District of Columbia	834	Demand Side Planning
	905	Costing/Rate Design
	917	Costing/Rate Design
	921	Demand Side Planning
	922	Rate Design
	934	Rate Design
	989	Rate Design
	1016	Rate Design
	1053	Costing/Rate Design
	1054	Costing/Rate Design
	1079	Rate Design
	1093	Costing/Rate Design
	1137	Costing/Rate Design
	1162	Costing/Rate Design
Georgia	18300-U	Costing/Rate Design

Jurisdiction	Docket Number	Subject
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

Jurisdiction	Docket Number	Subject
Kentucky	9613	Capacity Planning
	97-083	Management Audit
	2009-00354	Cost of Service
	2013-00148	Cost of Service
	2015-00343	Cost of Service
	2017-00349	Cost of Service
	2018-00281	Cost of Service
	2021-00214	Cost of Service
Louisiana	U-21453	Restructuring/Market Power
Maryland	8251	Costing/Rate Design
	8259	Demand Side Planning
	8315	Costing/Rate Design
	8720	Demand Side Planning
	8791	Costing/Rate Design
	8920	Costing/Rate Design
	8959	Costing/Rate Design
	9092	Costing/Rate Design
	9104	Costing/Rate Design
	9106	Costing/Rate Design
	9180	Capacity Planning
	9267	Costing/Rate Design
	9433	Capacity Planning
	9481	Costing
	9651	Costing/Rate Design
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
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

Jurisdiction	Docket Number	Subject
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
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
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.

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- "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.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CURRENT AND RECOMMENDED RATES

		Current Rates					
Description		WTSA Incorporated and Environs Rates	NTSA Environs Rates	NTSA Incorporated Rates	BSSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)
Residential						Small	Large
Customer Charge		$23.53	$24.50	$15.44	$16.00	$20.00	$35.00
Usage Rates	All Ccf	$0.09317	$0.59366	$0.67101	$0.21548	$0.41173	$0.00264
Commercial							
Customer Charge - Sales		$63.58	$76.33	$47.80	$37.08	$75.00	
Usage Rates	All Ccf		$0.60165	$0.68165	$0.29344	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Customer Charge - Transportation		$424.58	$509.26	$250.00	$252.08	$500.00	
Usage Rates	All Ccf		$0.57978	$0.57978	$0.29344	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Commercial Air Conditioning							
Customer Charge - Sales		$63.58	N/A	N/A	N/A	$75.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Usage Rates - (May - September)	All Ccf		N/A	N/A	N/A		
	First 500	$0.06223					
	All Over 500	$0.04223					
Electrical Cogeneration							
Customer Charge - Sales		$424.58	N/A	N/A	N/A	$700.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.05696				$0.05260	
	Next 95,000	$0.04696				$0.04260	
	Next 300,000	$0.03696				$0.03260	
	All Over 400,000	$0.02696				$0.02260	
Usage Rates - (May-September)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.04695				$0.04259	
	Next 95,000	$0.03694				$0.03258	
	Next 300,000	$0.02695				$0.02259	
	All Over 400,000	$0.01694				$0.01258	
Customer Charge - Transportation		$424.58	N/A	N/A	N/A	$700.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.05696				$0.05260	
	Next 95,000	$0.04696				$0.04260	
	Next 300,000	$0.03696				$0.03260	
	All Over 400,000	$0.02696				$0.02260	
Usage Rates - (May-September)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.04695				$0.04259	
	Next 95,000	$0.03694				$0.03258	
	Next 300,000	$0.02695				$0.02259	
	All Over 400,000	$0.01694				$0.01258	
Industrial							
Customer Charge - Sales		$857.20	$509.26	$308.59	N/A	$850.00	
Usage Rates	All Ccf		$0.55395	$0.62874	N/A	$0.08875	
	First 500	$0.12458					
	All Over 500	$0.10458					
Customer Charge - Transportation		$424.58	$509.26	$250.00	N/A	$1,050.00	
Usage Rates	All Ccf		$0.55395	$0.55395	N/A	$0.08875	
	First 500	$0.12458					
	All Over 500	$0.10458					
Standby Service							
Customer Charge - Sales		$666.37	N/A	N/A	N/A	$666.37	
Usage Rates	Per Mcf/Hour	$20.00	N/A	N/A	N/A	$20.00	

Public Authority						
Public Authority						
Customer Charge - Sales		$195.79	$160.93	$101.32	$47.08	$200.00
Usage Rates	All Ccf		$0.54101	$0.61329	$0.23148	$0.11113
	First 500	$0.11461				
	All Over 500	$0.09461				
Customer Charge - Transportation		$495.79	$325.93	$250.00	$252.08	$500.00
Usage Rates	All Ccf		$0.54101	$0.54101	$0.23148	$0.11113
	First 500	$0.11461				
	All Over 500	$0.09461				
Public Authority Air Conditioning						
Customer Charge - Sales		$195.79	N/A	N/A	N/A	$200.00
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A	$0.11113
	First 500	$0.11461				
	All Over 500	$0.09461				
Usage Rates - (May-September)	All Ccf		N/A	N/A	N/A	
	First 500	$0.08461				
	All Over 500	$0.06461				
School and Municipal						
Customer Charge - Sales		N/A	N/A	N/A	$51.02	$200.00
Usage Rates	All Ccf		N/A	N/A	$0.37651	$0.11113
	First 500	N/A				
	All Over 500	N/A				
Customer Charge - Transportation					$256.02	$500.00
Usage Rates	All Ccf		N/A	N/A	$0.37651	$0.11113
	First 500	N/A				
	All Over 500	N/A				
Municipal Water Pumping						
Customer Charge - Sales		$768.75	N/A	N/A	N/A	$200.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.11113
	First 5000	$0.06111				
	All Over 5000	$0.05111				
CNG						
Customer Charge - Sales		N/A	N/A	N/A	N/A	$150.00
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	$0.07652
Customer Charge - Transportation (reclassed from Commercial)		$424.58	N/A	N/A	N/A	$450.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.07652
	First 500	$0.08223				
	All Over 500	$0.06223				
Customer Charge - Transportation (reclassed from Public Authority)		$495.79	N/A	N/A	N/A	$450.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.07652
	First 500	$0.11461				
	All Over 500	$0.09461				

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
WTSA Incorporated and Environs	$ 35.50	$ 39.89	$ 4.39	12.4%
NTSA Incorporated	$ 44.59	$ 39.89	$ (4.70)	-10.5%
NTSA Environs	$ 51.78	$ 39.89	$ (11.89)	-23.0%
BSSA Incorporated and Environs	$ 31.21	$ 39.89	$ 8.68	27.8%
Residential - Large				
WTSA Incorporated and Environs	$ 51.01	$ 58.02	$ 7.01	13.7%
NTSA Incorporated	$ 82.35	$ 58.02	$ (24.33)	-29.5%
NTSA Environs	$ 87.13	$ 58.02	$ (29.11)	-33.4%
BSSA Incorporated and Environs	$ 50.91	$ 58.02	$ 7.11	14.0%
Commercial				
WTSA Incorporated and Environs	$ 172.93	$ 183.39	$ 10.46	6.0%
NTSA Incorporated	$ 322.38	$ 183.39	$ (138.99)	-43.1%
NTSA Environs	$ 332.91	$ 183.39	$ (149.52)	-44.9%
BSSA Incorporated and Environs	$ 196.65	$ 183.39	$ (13.26)	-6.7%
Commercial Air Conditioning (3)				
WTSA Incorporated and Environs	$ 215.66	227.89	$ 12.23	5.7%
Industrial				
WTSA Incorporated and Environs	$ 2,275.65	$ 2,262.91	$ (12.74)	-0.6%
NTSA Incorporated	$ 3,591.72	$ 2,262.91	$ (1,328.81)	-37.0%
NTSA Environs	$ 3,581.98	$ 2,262.91	$ (1,319.07)	-36.8%
Public Authority				
WTSA Incorporated and Environs	$ 535.41	$ 547.09	$ 11.68	2.2%
NTSA Incorporated	$ 863.21	$ 547.09	$ (316.12)	-36.6%
NTSA Environs	$ 875.00	$ 547.09	$ (327.91)	-37.5%
BSSA Incorporated and Environs	$ 475.13	$ 547.09	$ 71.96	15.1%
Public Authority Air Conditioning (3)				
WTSA Incorporated and Environs	$ 1,206.33	$ 1,258.63	$ 52.30	4.3%
Municipal Water Pumping				
WTSA Incorporated and Environs	$ 1,073.85	$ 544.44	$ (529.41)	-49.3%
School and Municipal				
BSSA Incorporated and Environs	$ 4,956.43	$ 3,449.25	$ (1,507.18)	-30.4%
Transportation Service: (4)				
Commercial Transportation				
WTSA Incorporated and Environs	$ 12,908.33	$ 13,400.49	$ 492.16	3.8%
Industrial Transportation				
WTSA Incorporated and Environs	$ 18,221.64	$ 18,602.53	$ 380.89	2.1%
Public Authority Transportation				
WTSA Incorporated and Environs	$ 30,689.79	$ 32,320.44	$ 1,630.65	5.3%
CNG Transportation				
WTSA Incorporated and Environs (reclassed from Commercial)	$ 50,941.58	$ 53,641.47	$ 2,699.89	5.3%
WTSA Incorporated and Environs (reclassed from Public Authority)	$ 151,885.50	$ 149,076.28	$ (2,809.22)	-1.8%
Cogeneration Transportation (3)				
WTSA Incorporated and Environs	$ 39,065.97	$ 39,899.16	$ 833.19	2.1%

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

	WNSA
	Year-Round
Residential - Small	24
Residential - Large	55
Commercial	225
Industrial	2,813
Public Authority	662
Municipal Water Pumping	657
School and Municipal	6,194

	August	January
Commercial AC	259.27	359.08
Public Authority AC	151.33	3,351.29

(3) Year-round average bill is approximated based on the average August bill assumed to occur in each of the 5 summer months and the average January bill assumed to occur in each of the 7 winter months.

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

	WNSA
	Year-Round
Commercial Transportation	27,991
Industrial Transportation	36,450
Public Authority Transportation	63,145
CNG Transportation	113,338

	August	January
Cogeneration Transportation	106,900	79,655

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

Residential Bill Impacts Existing Rates

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing WTSA Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 23.53	$ 0.49675	$ 0.49675			$ 35.00	$ 0.41611	$ 0.41611	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	28	1,829	$ 282.36	$ -	$ 13.66	$ 282.36	$ 296.02	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ (3.53)	$ (2.78)	-15%	-11%
29	55	1,648	$ 282.36	$ 14.16	$ 27.32	$ 296.52	$ 309.68	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ (2.75)	$ (2.02)	-11%	-8%
56	83	2,377	$ 282.36	$ 27.82	$ 40.98	$ 310.18	$ 323.34	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ (2.00)	$ (1.27)	-8%	-5%
84	110	3,165	$ 282.36	$ 41.48	$ 54.64	$ 323.84	$ 337.00	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ (1.24)	$ (0.52)	-5%	-2%
111	138	4,264	$ 282.36	$ 55.14	$ 68.30	$ 337.50	$ 350.66	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ (0.49)	$ 0.23	-2%	1%
139	165	5,763	$ 282.36	$ 68.80	$ 81.96	$ 351.16	$ 364.32	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.26	$ 0.99	1%	3%
166	193	7,282	$ 282.36	$ 82.46	$ 95.62	$ 364.82	$ 377.98	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.01	$ 1.74	3%	6%
194	220	9,197	$ 282.36	$ 96.12	$ 109.29	$ 378.48	$ 391.65	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.77	$ 2.49	6%	8%
221	248	11,601	$ 282.36	$ 109.78	$ 122.95	$ 392.14	$ 405.31	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 2.52	$ 3.24	8%	10%
249	275	13,856	$ 282.36	$ 123.44	$ 136.61	$ 405.80	$ 418.97	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 3.27	$ 4.00	10%	11%
276	303	15,556	$ 282.36	$ 137.10	$ 150.27	$ 419.46	$ 432.63	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 4.02	$ 4.75	12%	13%
304	330	16,884	$ 282.36	$ 150.76	$ 163.93	$ 433.12	$ 446.29	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 4.78	$ 5.50	13%	15%
331	358	17,462	$ 282.36	$ 164.42	$ 177.59	$ 446.78	$ 459.95	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 5.53	$ 6.26	15%	16%
359	385	17,584	$ 282.36	$ 178.08	$ 191.25	$ 460.44	$ 473.61	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 6.28	$ 7.01	16%	18%
386	413	16,555	$ 282.36	$ 191.75	$ 204.91	$ 474.11	$ 487.27	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 7.04	$ 7.76	18%	19%
414	440	15,188	$ 282.36	$ 205.41	$ 218.57	$ 487.77	$ 500.93	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 7.79	$ 8.51	19%	20%
441	1,240	100,529	$ 282.36	$ 219.07	$ 615.97	$ 501.43	$ 898.33	$ 420.00	$ 183.50	$ 515.98	$ 603.50	$ 935.98	$ 8.51	$ 3.14	20%	4%
1,241	2,040	2,807	$ 282.36	$ 616.47	$ 1,013.37	$ 898.83	$ 1,295.73	$ 420.00	$ 516.39	$ 848.86	$ 936.39	$ 1,268.86	$ 3.13	$ (2.24)	4%	-2%
2,041	2,840	548	$ 282.36	$ 1,013.87	$ 1,410.77	$ 1,296.23	$ 1,693.13	$ 420.00	$ 849.28	$ 1,181.75	$ 1,269.28	$ 1,601.75	$ (2.25)	$ (7.61)	-2%	-5%
2,841	3,640	185	$ 282.36	$ 1,411.27	$ 1,808.17	$ 1,693.63	$ 2,090.53	$ 420.00	$ 1,182.17	$ 1,514.64	$ 1,602.17	$ 1,934.64	$ (7.62)	$ (12.99)	-5%	-7%
3,641	4,440	115	$ 282.36	$ 1,808.67	$ 2,205.57	$ 2,091.03	$ 2,487.93	$ 420.00	$ 1,515.06	$ 1,847.53	$ 1,935.06	$ 2,267.53	$ (13.00)	$ (18.37)	-7%	-9%
4,441	5,240	73	$ 282.36	$ 2,206.07	$ 2,602.97	$ 2,488.43	$ 2,885.33	$ 420.00	$ 1,847.94	$ 2,180.42	$ 2,267.94	$ 2,600.42	$ (18.37)	$ (23.74)	-9%	-10%
5,241	6,040	35	$ 282.36	$ 2,603.47	$ 3,000.37	$ 2,885.83	$ 3,282.73	$ 420.00	$ 2,180.83	$ 2,513.30	$ 2,600.83	$ 2,933.30	$ (23.75)	$ (29.12)	-10%	-11%
6,041	6,840	16	$ 282.36	$ 3,000.87	$ 3,397.77	$ 3,283.23	$ 3,680.13	$ 420.00	$ 2,513.72	$ 2,846.19	$ 2,933.72	$ 3,266.19	$ (29.13)	$ (34.49)	-11%	-11%
6,841	7,640	9	$ 282.36	$ 3,398.27	$ 3,795.17	$ 3,680.63	$ 4,077.53	$ 420.00	$ 2,846.61	$ 3,179.08	$ 3,266.61	$ 3,599.08	$ (34.50)	$ (39.87)	-11%	-12%
7,641	8,440	5	$ 282.36	$ 3,795.67	$ 4,192.57	$ 4,078.03	$ 4,474.93	$ 420.00	$ 3,179.50	$ 3,511.97	$ 3,599.50	$ 3,931.97	$ (39.88)	$ (45.25)	-12%	-12%
8,441	9,240	2	$ 282.36	$ 4,193.07	$ 4,589.97	$ 4,475.43	$ 4,872.33	$ 420.00	$ 3,512.38	$ 3,844.86	$ 3,932.38	$ 4,264.86	$ (45.25)	$ (50.62)	-12%	-12%
9,241	10,040	3	$ 282.36	$ 4,590.47	$ 4,987.37	$ 4,872.83	$ 5,269.73	$ 420.00	$ 3,845.27	$ 4,177.74	$ 4,265.27	$ 4,597.74	$ (50.63)	$ (56.00)	-12%	-13%
10,041	10,840	3	$ 282.36	$ 4,987.87	$ 5,384.77	$ 5,270.23	$ 5,667.13	$ 420.00	$ 4,178.16	$ 4,510.63	$ 4,598.16	$ 4,930.63	$ (56.01)	$ (61.37)	-13%	-13%
10,841	11,640	3	$ 282.36	$ 5,385.27	$ 5,782.17	$ 5,667.63	$ 6,064.53	$ 420.00	$ 4,511.05	$ 4,843.52	$ 4,931.05	$ 5,263.52	$ (61.38)	$ (66.75)	-13%	-13%
11,641	59,201	7	$ 282.36	$ 5,782.67	$ 29,408.27	$ 6,065.03	$ 29,690.63	$ 420.00	$ 4,843.94	$ 24,634.27	$ 5,263.94	$ 25,054.27	$ (66.76)	$ (386.36)	-13%	-16%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing NTSA Environs Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 24.50	$ 1.13191	$ 1.13191		0	$ 35.00	$ 0.41611	$ 0.41611	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	28	62	$ 294.00	$ -	$ 31.13	$ 294.00	$ 325.13	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ (4.50)	$ (5.20)	-18%	-19%
29	55	27	$ 294.00	$ 32.26	$ 62.26	$ 326.26	$ 356.26	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ (5.23)	$ (5.91)	-19%	-20%
56	83	23	$ 294.00	$ 63.39	$ 93.38	$ 357.39	$ 387.38	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ (5.93)	$ (6.61)	-20%	-20%
84	110	28	$ 294.00	$ 94.51	$ 124.51	$ 388.51	$ 418.51	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ (6.63)	$ (7.31)	-20%	-21%
111	138	39	$ 294.00	$ 125.64	$ 155.64	$ 419.64	$ 449.64	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ (7.34)	$ (8.01)	-21%	-21%
139	165	43	$ 294.00	$ 156.77	$ 186.77	$ 450.77	$ 480.77	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ (8.04)	$ (8.72)	-21%	-22%
166	193	42	$ 294.00	$ 187.90	$ 217.89	$ 481.90	$ 511.89	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ (8.74)	$ (9.42)	-22%	-22%
194	220	42	$ 294.00	$ 219.02	$ 249.02	$ 513.02	$ 543.02	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ (9.45)	$ (10.12)	-22%	-22%
221	248	61	$ 294.00	$ 250.15	$ 280.15	$ 544.15	$ 574.15	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ (10.15)	$ (10.83)	-22%	-23%
249	275	52	$ 294.00	$ 281.28	$ 311.28	$ 575.28	$ 605.28	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ (10.85)	$ (11.53)	-23%	-23%
276	303	55	$ 294.00	$ 312.41	$ 342.40	$ 606.41	$ 636.40	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ (11.55)	$ (12.23)	-23%	-23%
304	330	46	$ 294.00	$ 343.53	$ 373.53	$ 637.53	$ 667.53	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ (12.26)	$ (12.93)	-23%	-23%
331	358	63	$ 294.00	$ 374.66	$ 404.66	$ 668.66	$ 698.66	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ (12.96)	$ (13.64)	-23%	-23%
359	385	60	$ 294.00	$ 405.79	$ 435.79	$ 699.79	$ 729.79	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ (13.66)	$ (14.34)	-23%	-24%
386	413	62	$ 294.00	$ 436.92	$ 466.91	$ 730.92	$ 760.91	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ (14.37)	$ (15.04)	-24%	-24%
414	440	63	$ 294.00	$ 468.04	$ 498.04	$ 762.04	$ 792.04	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ (15.07)	$ (15.75)	-24%	-24%
441	621	311	$ 294.00	$ 499.17	$ 703.25	$ 793.17	$ 997.25	$ 420.00	$ 183.50	$ 258.53	$ 603.50	$ 678.53	$ (15.81)	$ (26.56)	-24%	-32%
622	803	166	$ 294.00	$ 704.38	$ 908.45	$ 998.38	$ 1,202.45	$ 420.00	$ 258.94	$ 333.96	$ 678.94	$ 753.96	$ (26.62)	$ (37.37)	-32%	-37%
804	984	94	$ 294.00	$ 909.58	$ 1,113.65	$ 1,203.58	$ 1,407.65	$ 420.00	$ 334.38	$ 409.40	$ 754.38	$ 829.40	$ (37.43)	$ (48.19)	-37%	-41%
985	1165	63	$ 294.00	$ 1,114.79	$ 1,318.86	$ 1,408.79	$ 1,612.86	$ 420.00	$ 409.82	$ 484.84	$ 829.82	$ 904.84	$ (48.25)	$ (59.00)	-41%	-44%
1,166	1346	35	$ 294.00	$ 1,319.99	$ 1,524.06	$ 1,613.99	$ 1,818.06	$ 420.00	$ 485.25	$ 560.27	$ 905.25	$ 980.27	$ (59.06)	$ (69.82)	-44%	-46%
1,347	1528	26	$ 294.00	$ 1,525.20	$ 1,729.27	$ 1,819.20	$ 2,023.27	$ 420.00	$ 560.69	$ 635.71	$ 980.69	$ 1,055.71	$ (69.88)	$ (80.63)	-46%	-48%
1,529	1709	22	$ 294.00	$ 1,730.40	$ 1,934.47	$ 2,024.40	$ 2,228.47	$ 420.00	$ 636.13	$ 711.15	$ 1,056.13	$ 1,131.15	$ (80.69)	$ (91.44)	-48%	-49%
1,710	1890	12	$ 294.00	$ 1,935.61	$ 2,139.68	$ 2,229.61	$ 2,433.68	$ 420.00	$ 711.56	$ 786.58	$ 1,131.56	$ 1,206.58	$ (91.50)	$ (102.26)	-49%	-50%
1,891	2072	7	$ 294.00	$ 2,140.81	$ 2,344.88	$ 2,434.81	$ 2,638.88	$ 420.00	$ 787.00	$ 862.02	$ 1,207.00	$ 1,282.02	$ (102.32)	$ (113.07)	-50%	-51%
2,073	2253	4	$ 294.00	$ 2,346.01	$ 2,550.09	$ 2,640.01	$ 2,844.09	$ 420.00	$ 862.44	$ 937.46	$ 1,282.44	$ 1,357.46	$ (113.13)	$ (123.89)	-51%	-52%
2,254	2434	1	$ 294.00	$ 2,551.22	$ 2,755.29	$ 2,845.22	$ 3,049.29	$ 420.00	$ 937.87	$ 1,012.89	$ 1,357.87	$ 1,432.89	$ (123.95)	$ (134.70)	-52%	-53%
2,435	2615	5	$ 294.00	$ 2,756.42	$ 2,960.50	$ 3,050.42	$ 3,254.50	$ 420.00	$ 1,013.31	$ 1,088.33	$ 1,433.31	$ 1,508.33	$ (134.76)	$ (145.51)	-53%	-54%
2,616	2797	4	$ 294.00	$ 2,961.63	$ 3,165.70	$ 3,255.63	$ 3,459.70	$ 420.00	$ 1,088.75	$ 1,163.77	$ 1,508.75	$ 1,583.77	$ (145.57)	$ (156.33)	-54%	-54%
2,798	2978	2	$ 294.00	$ 3,166.83	$ 3,370.91	$ 3,460.83	$ 3,664.91	$ 420.00	$ 1,164.18	$ 1,239.20	$ 1,584.18	$ 1,659.20	$ (156.39)	$ (167.14)	-54%	-55%
2,979	3159	1	$ 294.00	$ 3,372.04	$ 3,576.11	$ 3,666.04	$ 3,870.11	$ 420.00	$ 1,239.62	$ 1,314.64	$ 1,659.62	$ 1,734.64	$ (167.20)	$ (177.96)	-55%	-55%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing NTSA Incorporated Rates

								$ 20.00	$ 0.82520	$ 0.82520 Small						
			$ 15.44	$ 1.20926	$ 1.20926			$ 35.00	$ 0.41611	$ 0.41611 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	28	261	$ 185.28	$ -	$ 33.25	$ 185.28	$ 218.53	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ 4.56	$ 3.68	30%	20%
29	55	143	$ 185.28	$ 34.46	$ 66.51	$ 219.74	$ 251.79	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 3.65	$ 2.80	20%	13%
56	83	231	$ 185.28	$ 67.72	$ 99.76	$ 253.00	$ 285.04	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 2.77	$ 1.92	13%	8%
84	110	263	$ 185.28	$ 100.97	$ 133.02	$ 286.25	$ 318.30	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 1.89	$ 1.04	8%	4%
111	138	342	$ 185.28	$ 134.23	$ 166.27	$ 319.51	$ 351.55	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 1.01	$ 0.16	4%	1%
139	165	337	$ 185.28	$ 167.48	$ 199.53	$ 352.76	$ 384.81	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.13	$ (0.72)	0%	-2%
166	193	367	$ 185.28	$ 200.74	$ 232.78	$ 386.02	$ 418.06	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ (0.75)	$ (1.60)	-2%	-5%
194	220	419	$ 185.28	$ 233.99	$ 266.04	$ 419.27	$ 451.32	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ (1.63)	$ (2.48)	-5%	-7%
221	248	413	$ 185.28	$ 267.25	$ 299.29	$ 452.53	$ 484.57	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ (2.51)	$ (3.36)	-7%	-8%
249	275	498	$ 185.28	$ 300.50	$ 332.55	$ 485.78	$ 517.83	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ (3.39)	$ (4.24)	-8%	-10%
276	303	515	$ 185.28	$ 333.76	$ 365.80	$ 519.04	$ 551.08	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ (4.27)	$ (5.12)	-10%	-11%
304	330	581	$ 185.28	$ 367.01	$ 399.06	$ 552.29	$ 584.34	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ (5.15)	$ (6.00)	-11%	-12%
331	358	623	$ 185.28	$ 400.27	$ 432.31	$ 585.55	$ 617.59	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ (6.03)	$ (6.88)	-12%	-13%
359	385	637	$ 185.28	$ 433.52	$ 465.57	$ 618.80	$ 650.85	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ (6.91)	$ (7.76)	-13%	-14%
386	413	643	$ 185.28	$ 466.77	$ 498.82	$ 652.05	$ 684.10	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ (7.79)	$ (8.64)	-14%	-15%
414	440	576	$ 185.28	$ 500.03	$ 532.07	$ 685.31	$ 717.35	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ (8.67)	$ (9.52)	-15%	-16%
441	623	3,111	$ 185.28	$ 533.28	$ 753.25	$ 718.56	$ 938.53	$ 420.00	$ 183.50	$ 259.19	$ 603.50	$ 679.19	$ (9.59)	$ (21.61)	-16%	-28%
624	806	1,386	$ 185.28	$ 754.46	$ 974.42	$ 939.74	$ 1,159.70	$ 420.00	$ 259.61	$ 335.30	$ 679.61	$ 755.30	$ (21.68)	$ (33.70)	-28%	-35%
807	989	679	$ 185.28	$ 975.63	$ 1,195.59	$ 1,160.91	$ 1,380.87	$ 420.00	$ 335.72	$ 411.41	$ 755.72	$ 831.41	$ (33.77)	$ (45.79)	-35%	-40%
990	1172	266	$ 185.28	$ 1,196.80	$ 1,416.77	$ 1,382.08	$ 1,602.05	$ 420.00	$ 411.82	$ 487.51	$ 831.82	$ 907.51	$ (45.85)	$ (57.88)	-40%	-43%
1,173	1354	125	$ 185.28	$ 1,417.98	$ 1,637.94	$ 1,603.26	$ 1,823.22	$ 420.00	$ 487.93	$ 563.62	$ 907.93	$ 983.62	$ (57.94)	$ (69.97)	-43%	-46%
1,355	1537	66	$ 185.28	$ 1,639.15	$ 1,859.11	$ 1,824.43	$ 2,044.39	$ 420.00	$ 564.04	$ 639.73	$ 984.04	$ 1,059.73	$ (70.03)	$ (82.06)	-46%	-48%
1,538	1720	30	$ 185.28	$ 1,860.32	$ 2,080.29	$ 2,045.60	$ 2,265.57	$ 420.00	$ 640.14	$ 715.83	$ 1,060.14	$ 1,135.83	$ (82.12)	$ (94.14)	-48%	-50%
1,721	1903	18	$ 185.28	$ 2,081.50	$ 2,301.46	$ 2,266.78	$ 2,486.74	$ 420.00	$ 716.25	$ 791.94	$ 1,136.25	$ 1,211.94	$ (94.21)	$ (106.23)	-50%	-51%
1,904	2086	8	$ 185.28	$ 2,302.67	$ 2,522.63	$ 2,487.95	$ 2,707.91	$ 420.00	$ 792.36	$ 868.05	$ 1,212.36	$ 1,288.05	$ (106.30)	$ (118.32)	-51%	-52%
2,087	2269	8	$ 185.28	$ 2,523.84	$ 2,743.81	$ 2,709.12	$ 2,929.09	$ 420.00	$ 868.46	$ 944.15	$ 1,288.46	$ 1,364.15	$ (118.39)	$ (130.41)	-52%	-53%
2,270	2452	2	$ 185.28	$ 2,745.02	$ 2,964.98	$ 2,930.30	$ 3,150.26	$ 420.00	$ 944.57	$ 1,020.26	$ 1,364.57	$ 1,440.26	$ (130.48)	$ (142.50)	-53%	-54%
2,453	2635	2	$ 185.28	$ 2,966.19	$ 3,186.15	$ 3,151.47	$ 3,371.43	$ 420.00	$ 1,020.67	$ 1,096.37	$ 1,440.67	$ 1,516.37	$ (142.57)	$ (154.59)	-54%	-55%
2,636	2818	1	$ 185.28	$ 3,187.36	$ 3,407.33	$ 3,372.64	$ 3,592.61	$ 420.00	$ 1,096.78	$ 1,172.47	$ 1,516.78	$ 1,592.47	$ (154.66)	$ (166.68)	-55%	-56%
2,819	3001	0	$ 185.28	$ 3,408.54	$ 3,628.50	$ 3,593.82	$ 3,813.78	$ 420.00	$ 1,172.89	$ 1,248.58	$ 1,592.89	$ 1,668.58	$ (166.74)	$ (178.77)	-56%	-56%
3,002	7304	6	$ 185.28	$ 3,629.71	$ 8,832.12	$ 3,814.99	$ 9,017.40	$ 420.00	$ 1,248.99	$ 3,039.16	$ 1,668.99	$ 3,459.16	$ (178.83)	$ (463.19)	-56%	-62%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing BSSA Rates

								$ 20.00	$ 0.82520	$ 0.82520 Small						
			$ 16.00	$ 0.63096	$ 0.63096			$ 35.00	$ 0.41611	$ 0.41611 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	28	43	$ 192.00	$ -	$ 17.35	$ 192.00	$ 209.35	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ 4.00	$ 4.45	25%	25%
29	55	12	$ 192.00	$ 17.98	$ 34.70	$ 209.98	$ 226.70	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 4.46	$ 4.89	25%	26%
56	83	34	$ 192.00	$ 35.33	$ 52.05	$ 227.33	$ 244.05	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 4.91	$ 5.34	26%	26%
84	110	42	$ 192.00	$ 52.69	$ 69.41	$ 244.69	$ 261.41	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 5.35	$ 5.78	26%	27%
111	138	45	$ 192.00	$ 70.04	$ 86.76	$ 262.04	$ 278.76	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 5.80	$ 6.23	27%	27%
139	165	75	$ 192.00	$ 87.39	$ 104.11	$ 279.39	$ 296.11	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 6.24	$ 6.67	27%	27%
166	193	73	$ 192.00	$ 104.74	$ 121.46	$ 296.74	$ 313.46	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 6.69	$ 7.12	27%	27%
194	220	118	$ 192.00	$ 122.09	$ 138.81	$ 314.09	$ 330.81	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 7.13	$ 7.56	27%	27%
221	248	131	$ 192.00	$ 139.44	$ 156.16	$ 331.44	$ 348.16	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 7.58	$ 8.01	27%	28%
249	275	156	$ 192.00	$ 156.79	$ 173.51	$ 348.79	$ 365.51	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 8.02	$ 8.45	28%	28%
276	303	180	$ 192.00	$ 174.14	$ 190.87	$ 366.14	$ 382.87	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 8.47	$ 8.90	28%	28%
304	330	203	$ 192.00	$ 191.50	$ 208.22	$ 383.50	$ 400.22	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 8.91	$ 9.34	28%	28%
331	358	195	$ 192.00	$ 208.85	$ 225.57	$ 400.85	$ 417.57	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 9.36	$ 9.79	28%	28%
359	385	196	$ 192.00	$ 226.20	$ 242.92	$ 418.20	$ 434.92	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 9.80	$ 10.23	28%	28%
386	413	211	$ 192.00	$ 243.55	$ 260.27	$ 435.55	$ 452.27	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 10.25	$ 10.68	28%	28%
414	440	224	$ 192.00	$ 260.90	$ 277.62	$ 452.90	$ 469.62	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 10.69	$ 11.12	28%	28%
441	613	1,195	$ 192.00	$ 278.25	$ 387.02	$ 470.25	$ 579.02	$ 420.00	$ 183.50	$ 255.23	$ 603.50	$ 675.23	$ 11.10	$ 8.02	28%	17%
614	787	821	$ 192.00	$ 387.65	$ 496.42	$ 579.65	$ 688.42	$ 420.00	$ 255.65	$ 327.38	$ 675.65	$ 747.38	$ 8.00	$ 4.91	17%	9%
788	960	505	$ 192.00	$ 497.05	$ 605.81	$ 689.05	$ 797.81	$ 420.00	$ 327.80	$ 399.52	$ 747.80	$ 819.52	$ 4.90	$ 1.81	9%	3%
961	1134	248	$ 192.00	$ 606.44	$ 715.21	$ 798.44	$ 907.21	$ 420.00	$ 399.94	$ 471.67	$ 819.94	$ 891.67	$ 1.79	$ (1.29)	3%	-2%
1,135	1307	145	$ 192.00	$ 715.84	$ 824.60	$ 907.84	$ 1,016.60	$ 420.00	$ 472.09	$ 543.82	$ 892.09	$ 963.82	$ (1.31)	$ (4.40)	-2%	-5%
1,308	1480	76	$ 192.00	$ 825.24	$ 934.00	$ 1,017.24	$ 1,126.00	$ 420.00	$ 544.23	$ 615.96	$ 964.23	$ 1,035.96	$ (4.42)	$ (7.50)	-5%	-8%
1,481	1654	40	$ 192.00	$ 934.63	$ 1,043.40	$ 1,126.63	$ 1,235.40	$ 420.00	$ 616.38	$ 688.11	$ 1,036.38	$ 1,108.11	$ (7.52)	$ (10.61)	-8%	-10%
1,655	1827	21	$ 192.00	$ 1,044.03	$ 1,152.79	$ 1,236.03	$ 1,344.79	$ 420.00	$ 688.52	$ 760.25	$ 1,108.52	$ 1,180.25	$ (10.63)	$ (13.71)	-10%	-12%
1,828	2000	10	$ 192.00	$ 1,153.42	$ 1,262.19	$ 1,345.42	$ 1,454.19	$ 420.00	$ 760.67	$ 832.40	$ 1,180.67	$ 1,252.40	$ (13.73)	$ (16.82)	-12%	-14%
2,001	2174	8	$ 192.00	$ 1,262.82	$ 1,371.59	$ 1,454.82	$ 1,563.59	$ 420.00	$ 832.81	$ 904.54	$ 1,252.81	$ 1,324.54	$ (16.83)	$ (19.92)	-14%	-15%
2,175	2347	4	$ 192.00	$ 1,372.22	$ 1,480.98	$ 1,564.22	$ 1,672.98	$ 420.00	$ 904.96	$ 976.69	$ 1,324.96	$ 1,396.69	$ (19.94)	$ (23.02)	-15%	-17%
2,348	2521	3	$ 192.00	$ 1,481.61	$ 1,590.38	$ 1,673.61	$ 1,782.38	$ 420.00	$ 977.10	$ 1,048.83	$ 1,397.10	$ 1,468.83	$ (23.04)	$ (26.13)	-17%	-18%
2,522	2694	4	$ 192.00	$ 1,591.01	$ 1,699.77	$ 1,783.01	$ 1,891.77	$ 420.00	$ 1,049.25	$ 1,120.98	$ 1,469.25	$ 1,540.98	$ (26.15)	$ (29.23)	-18%	-19%
2,695	2867	3	$ 192.00	$ 1,700.41	$ 1,809.17	$ 1,892.41	$ 2,001.17	$ 420.00	$ 1,121.40	$ 1,193.13	$ 1,541.40	$ 1,613.13	$ (29.25)	$ (32.34)	-19%	-19%
2,868	7187	6	$ 192.00	$ 1,809.80	$ 4,534.57	$ 2,001.80	$ 4,726.57	$ 420.00	$ 1,193.54	$ 2,990.49	$ 1,613.54	$ 3,410.49	$ (32.36)	$ (109.67)	-19%	-28%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

Residential Bill Impacts Existing Rates

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing WTSA Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 23.53	$ 0.49675	$ 0.49675			$ 35.00	$ 0.41611	$ 0.41611	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	28	1,829	$ 282.36	$ -	$ 13.66	$ 282.36	$ 296.02	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ (3.53)	$ (2.78)	-15%	-11%
29	55	1,648	$ 282.36	$ 14.16	$ 27.32	$ 296.52	$ 309.68	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ (2.75)	$ (2.02)	-11%	-8%
56	83	2,377	$ 282.36	$ 27.82	$ 40.98	$ 310.18	$ 323.34	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ (2.00)	$ (1.27)	-8%	-5%
84	110	3,165	$ 282.36	$ 41.48	$ 54.64	$ 323.84	$ 337.00	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ (1.24)	$ (0.52)	-5%	-2%
111	138	4,264	$ 282.36	$ 55.14	$ 68.30	$ 337.50	$ 350.66	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ (0.49)	$ 0.23	-2%	1%
139	165	5,763	$ 282.36	$ 68.80	$ 81.96	$ 351.16	$ 364.32	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.26	$ 0.99	1%	3%
166	193	7,282	$ 282.36	$ 82.46	$ 95.62	$ 364.82	$ 377.98	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.01	$ 1.74	3%	6%
194	220	9,197	$ 282.36	$ 96.12	$ 109.29	$ 378.48	$ 391.65	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.77	$ 2.49	6%	8%
221	248	11,601	$ 282.36	$ 109.78	$ 122.95	$ 392.14	$ 405.31	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 2.52	$ 3.24	8%	10%
249	275	13,856	$ 282.36	$ 123.44	$ 136.61	$ 405.80	$ 418.97	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 3.27	$ 4.00	10%	11%
276	303	15,556	$ 282.36	$ 137.10	$ 150.27	$ 419.46	$ 432.63	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 4.02	$ 4.75	12%	13%
304	330	16,884	$ 282.36	$ 150.76	$ 163.93	$ 433.12	$ 446.29	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 4.78	$ 5.50	13%	15%
331	358	17,462	$ 282.36	$ 164.42	$ 177.59	$ 446.78	$ 459.95	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 5.53	$ 6.26	15%	16%
359	385	17,584	$ 282.36	$ 178.08	$ 191.25	$ 460.44	$ 473.61	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 6.28	$ 7.01	16%	18%
386	413	16,555	$ 282.36	$ 191.75	$ 204.91	$ 474.11	$ 487.27	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 7.04	$ 7.76	18%	19%
414	440	15,188	$ 282.36	$ 205.41	$ 218.57	$ 487.77	$ 500.93	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 7.79	$ 8.51	19%	20%
441	1,240	100,529	$ 282.36	$ 219.07	$ 615.97	$ 501.43	$ 898.33	$ 420.00	$ 183.50	$ 515.98	$ 603.50	$ 935.98	$ 8.51	$ 3.14	20%	4%
1,241	2,040	2,807	$ 282.36	$ 616.47	$ 1,013.37	$ 898.83	$ 1,295.73	$ 420.00	$ 516.39	$ 848.86	$ 936.39	$ 1,268.86	$ 3.13	$ (2.24)	4%	-2%
2,041	2,840	548	$ 282.36	$ 1,013.87	$ 1,410.77	$ 1,296.23	$ 1,693.13	$ 420.00	$ 849.28	$ 1,181.75	$ 1,269.28	$ 1,601.75	$ (2.25)	$ (7.61)	-2%	-5%
2,841	3,640	185	$ 282.36	$ 1,411.27	$ 1,808.17	$ 1,693.63	$ 2,090.53	$ 420.00	$ 1,182.17	$ 1,514.64	$ 1,602.17	$ 1,934.64	$ (7.62)	$ (12.99)	-5%	-7%
3,641	4,440	115	$ 282.36	$ 1,808.67	$ 2,205.57	$ 2,091.03	$ 2,487.93	$ 420.00	$ 1,515.06	$ 1,847.53	$ 1,935.06	$ 2,267.53	$ (13.00)	$ (18.37)	-7%	-9%
4,441	5,240	73	$ 282.36	$ 2,206.07	$ 2,602.97	$ 2,488.43	$ 2,885.33	$ 420.00	$ 1,847.94	$ 2,180.42	$ 2,267.94	$ 2,600.42	$ (18.37)	$ (23.74)	-9%	-10%
5,241	6,040	35	$ 282.36	$ 2,603.47	$ 3,000.37	$ 2,885.83	$ 3,282.73	$ 420.00	$ 2,180.83	$ 2,513.30	$ 2,600.83	$ 2,933.30	$ (23.75)	$ (29.12)	-10%	-11%
6,041	6,840	16	$ 282.36	$ 3,000.87	$ 3,397.77	$ 3,283.23	$ 3,680.13	$ 420.00	$ 2,513.72	$ 2,846.19	$ 2,933.72	$ 3,266.19	$ (29.13)	$ (34.49)	-11%	-11%
6,841	7,640	9	$ 282.36	$ 3,398.27	$ 3,795.17	$ 3,680.63	$ 4,077.53	$ 420.00	$ 2,846.61	$ 3,179.08	$ 3,266.61	$ 3,599.08	$ (34.50)	$ (39.87)	-11%	-12%
7,641	8,440	5	$ 282.36	$ 3,795.67	$ 4,192.57	$ 4,078.03	$ 4,474.93	$ 420.00	$ 3,179.50	$ 3,511.97	$ 3,599.50	$ 3,931.97	$ (39.88)	$ (45.25)	-12%	-12%
8,441	9,240	2	$ 282.36	$ 4,193.07	$ 4,589.97	$ 4,475.43	$ 4,872.33	$ 420.00	$ 3,512.38	$ 3,844.86	$ 3,932.38	$ 4,264.86	$ (45.25)	$ (50.62)	-12%	-12%
9,241	10,040	3	$ 282.36	$ 4,590.47	$ 4,987.37	$ 4,872.83	$ 5,269.73	$ 420.00	$ 3,845.27	$ 4,177.74	$ 4,265.27	$ 4,597.74	$ (50.63)	$ (56.00)	-12%	-13%
10,041	10,840	3	$ 282.36	$ 4,987.87	$ 5,384.77	$ 5,270.23	$ 5,667.13	$ 420.00	$ 4,178.16	$ 4,510.63	$ 4,598.16	$ 4,930.63	$ (56.01)	$ (61.37)	-13%	-13%
10,841	11,640	3	$ 282.36	$ 5,385.27	$ 5,782.17	$ 5,667.63	$ 6,064.53	$ 420.00	$ 4,511.05	$ 4,843.52	$ 4,931.05	$ 5,263.52	$ (61.38)	$ (66.75)	-13%	-13%
11,641	59,201	7	$ 282.36	$ 5,782.67	$ 29,408.27	$ 6,065.03	$ 29,690.63	$ 420.00	$ 4,843.94	$ 24,634.27	$ 5,263.94	$ 25,054.27	$ (66.76)	$ (386.36)	-13%	-16%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing NTSA Environs Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 24.50	$ 1.13191	$ 1.13191		0	$ 35.00	$ 0.41611	$ 0.41611	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	28	62	$ 294.00	$ -	$ 31.13	$ 294.00	$ 325.13	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ (4.50)	$ (5.20)	-18%	-19%
29	55	27	$ 294.00	$ 32.26	$ 62.26	$ 326.26	$ 356.26	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ (5.23)	$ (5.91)	-19%	-20%
56	83	23	$ 294.00	$ 63.39	$ 93.38	$ 357.39	$ 387.38	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ (5.93)	$ (6.61)	-20%	-20%
84	110	28	$ 294.00	$ 94.51	$ 124.51	$ 388.51	$ 418.51	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ (6.63)	$ (7.31)	-20%	-21%
111	138	39	$ 294.00	$ 125.64	$ 155.64	$ 419.64	$ 449.64	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ (7.34)	$ (8.01)	-21%	-21%
139	165	43	$ 294.00	$ 156.77	$ 186.77	$ 450.77	$ 480.77	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ (8.04)	$ (8.72)	-21%	-22%
166	193	42	$ 294.00	$ 187.90	$ 217.89	$ 481.90	$ 511.89	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ (8.74)	$ (9.42)	-22%	-22%
194	220	42	$ 294.00	$ 219.02	$ 249.02	$ 513.02	$ 543.02	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ (9.45)	$ (10.12)	-22%	-22%
221	248	61	$ 294.00	$ 250.15	$ 280.15	$ 544.15	$ 574.15	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ (10.15)	$ (10.83)	-22%	-23%
249	275	52	$ 294.00	$ 281.28	$ 311.28	$ 575.28	$ 605.28	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ (10.85)	$ (11.53)	-23%	-23%
276	303	55	$ 294.00	$ 312.41	$ 342.40	$ 606.41	$ 636.40	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ (11.55)	$ (12.23)	-23%	-23%
304	330	46	$ 294.00	$ 343.53	$ 373.53	$ 637.53	$ 667.53	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ (12.26)	$ (12.93)	-23%	-23%
331	358	63	$ 294.00	$ 374.66	$ 404.66	$ 668.66	$ 698.66	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ (12.96)	$ (13.64)	-23%	-23%
359	385	60	$ 294.00	$ 405.79	$ 435.79	$ 699.79	$ 729.79	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ (13.66)	$ (14.34)	-23%	-24%
386	413	62	$ 294.00	$ 436.92	$ 466.91	$ 730.92	$ 760.91	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ (14.37)	$ (15.04)	-24%	-24%
414	440	63	$ 294.00	$ 468.04	$ 498.04	$ 762.04	$ 792.04	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ (15.07)	$ (15.75)	-24%	-24%
441	621	311	$ 294.00	$ 499.17	$ 703.25	$ 793.17	$ 997.25	$ 420.00	$ 183.50	$ 258.53	$ 603.50	$ 678.53	$ (15.81)	$ (26.56)	-24%	-32%
622	803	166	$ 294.00	$ 704.38	$ 908.45	$ 998.38	$ 1,202.45	$ 420.00	$ 258.94	$ 333.96	$ 678.94	$ 753.96	$ (26.62)	$ (37.37)	-32%	-37%
804	984	94	$ 294.00	$ 909.58	$ 1,113.65	$ 1,203.58	$ 1,407.65	$ 420.00	$ 334.38	$ 409.40	$ 754.38	$ 829.40	$ (37.43)	$ (48.19)	-37%	-41%
985	1165	63	$ 294.00	$ 1,114.79	$ 1,318.86	$ 1,408.79	$ 1,612.86	$ 420.00	$ 409.82	$ 484.84	$ 829.82	$ 904.84	$ (48.25)	$ (59.00)	-41%	-44%
1,166	1346	35	$ 294.00	$ 1,319.99	$ 1,524.06	$ 1,613.99	$ 1,818.06	$ 420.00	$ 485.25	$ 560.27	$ 905.25	$ 980.27	$ (59.06)	$ (69.82)	-44%	-46%
1,347	1528	26	$ 294.00	$ 1,525.20	$ 1,729.27	$ 1,819.20	$ 2,023.27	$ 420.00	$ 560.69	$ 635.71	$ 980.69	$ 1,055.71	$ (69.88)	$ (80.63)	-46%	-48%
1,529	1709	22	$ 294.00	$ 1,730.40	$ 1,934.47	$ 2,024.40	$ 2,228.47	$ 420.00	$ 636.13	$ 711.15	$ 1,056.13	$ 1,131.15	$ (80.69)	$ (91.44)	-48%	-49%
1,710	1890	12	$ 294.00	$ 1,935.61	$ 2,139.68	$ 2,229.61	$ 2,433.68	$ 420.00	$ 711.56	$ 786.58	$ 1,131.56	$ 1,206.58	$ (91.50)	$ (102.26)	-49%	-50%
1,891	2072	7	$ 294.00	$ 2,140.81	$ 2,344.88	$ 2,434.81	$ 2,638.88	$ 420.00	$ 787.00	$ 862.02	$ 1,207.00	$ 1,282.02	$ (102.32)	$ (113.07)	-50%	-51%
2,073	2253	4	$ 294.00	$ 2,346.01	$ 2,550.09	$ 2,640.01	$ 2,844.09	$ 420.00	$ 862.44	$ 937.46	$ 1,282.44	$ 1,357.46	$ (113.13)	$ (123.89)	-51%	-52%
2,254	2434	1	$ 294.00	$ 2,551.22	$ 2,755.29	$ 2,845.22	$ 3,049.29	$ 420.00	$ 937.87	$ 1,012.89	$ 1,357.87	$ 1,432.89	$ (123.95)	$ (134.70)	-52%	-53%
2,435	2615	5	$ 294.00	$ 2,756.42	$ 2,960.50	$ 3,050.42	$ 3,254.50	$ 420.00	$ 1,013.31	$ 1,088.33	$ 1,433.31	$ 1,508.33	$ (134.76)	$ (145.51)	-53%	-54%
2,616	2797	4	$ 294.00	$ 2,961.63	$ 3,165.70	$ 3,255.63	$ 3,459.70	$ 420.00	$ 1,088.75	$ 1,163.77	$ 1,508.75	$ 1,583.77	$ (145.57)	$ (156.33)	-54%	-54%
2,798	2978	2	$ 294.00	$ 3,166.83	$ 3,370.91	$ 3,460.83	$ 3,664.91	$ 420.00	$ 1,164.18	$ 1,239.20	$ 1,584.18	$ 1,659.20	$ (156.39)	$ (167.14)	-54%	-55%
2,979	3159	1	$ 294.00	$ 3,372.04	$ 3,576.11	$ 3,666.04	$ 3,870.11	$ 420.00	$ 1,239.62	$ 1,314.64	$ 1,659.62	$ 1,734.64	$ (167.20)	$ (177.96)	-55%	-55%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing NTSA Incorporated Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 15.44	$ 1.20926	$ 1.20926			$ 35.00	$ 0.41611	$ 0.41611	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	28	261	$ 185.28	$ -	$ 33.25	$ 185.28	$ 218.53	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ 4.56	$ 3.68	30%	20%
29	55	143	$ 185.28	$ 34.46	$ 66.51	$ 219.74	$ 251.79	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 3.65	$ 2.80	20%	13%
56	83	231	$ 185.28	$ 67.72	$ 99.76	$ 253.00	$ 285.04	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 2.77	$ 1.92	13%	8%
84	110	263	$ 185.28	$ 100.97	$ 133.02	$ 286.25	$ 318.30	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 1.89	$ 1.04	8%	4%
111	138	342	$ 185.28	$ 134.23	$ 166.27	$ 319.51	$ 351.55	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 1.01	$ 0.16	4%	1%
139	165	337	$ 185.28	$ 167.48	$ 199.53	$ 352.76	$ 384.81	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.13	$ (0.72)	0%	-2%
166	193	367	$ 185.28	$ 200.74	$ 232.78	$ 386.02	$ 418.06	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ (0.75)	$ (1.60)	-2%	-5%
194	220	419	$ 185.28	$ 233.99	$ 266.04	$ 419.27	$ 451.32	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ (1.63)	$ (2.48)	-5%	-7%
221	248	413	$ 185.28	$ 267.25	$ 299.29	$ 452.53	$ 484.57	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ (2.51)	$ (3.36)	-7%	-8%
249	275	498	$ 185.28	$ 300.50	$ 332.55	$ 485.78	$ 517.83	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ (3.39)	$ (4.24)	-8%	-10%
276	303	515	$ 185.28	$ 333.76	$ 365.80	$ 519.04	$ 551.08	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ (4.27)	$ (5.12)	-10%	-11%
304	330	581	$ 185.28	$ 367.01	$ 399.06	$ 552.29	$ 584.34	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ (5.15)	$ (6.00)	-11%	-12%
331	358	623	$ 185.28	$ 400.27	$ 432.31	$ 585.55	$ 617.59	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ (6.03)	$ (6.88)	-12%	-13%
359	385	637	$ 185.28	$ 433.52	$ 465.57	$ 618.80	$ 650.85	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ (6.91)	$ (7.76)	-13%	-14%
386	413	643	$ 185.28	$ 466.77	$ 498.82	$ 652.05	$ 684.10	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ (7.79)	$ (8.64)	-14%	-15%
414	440	576	$ 185.28	$ 500.03	$ 532.07	$ 685.31	$ 717.35	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ (8.67)	$ (9.52)	-15%	-16%
441	623	3,111	$ 185.28	$ 533.28	$ 753.25	$ 718.56	$ 938.53	$ 420.00	$ 183.50	$ 259.19	$ 603.50	$ 679.19	$ (9.59)	$ (21.61)	-16%	-28%
624	806	1,386	$ 185.28	$ 754.46	$ 974.42	$ 939.74	$ 1,159.70	$ 420.00	$ 259.61	$ 335.30	$ 679.61	$ 755.30	$ (21.68)	$ (33.70)	-28%	-35%
807	989	679	$ 185.28	$ 975.63	$ 1,195.59	$ 1,160.91	$ 1,380.87	$ 420.00	$ 335.72	$ 411.41	$ 755.72	$ 831.41	$ (33.77)	$ (45.79)	-35%	-40%
990	1172	266	$ 185.28	$ 1,196.80	$ 1,416.77	$ 1,382.08	$ 1,602.05	$ 420.00	$ 411.82	$ 487.51	$ 831.82	$ 907.51	$ (45.85)	$ (57.88)	-40%	-43%
1,173	1354	125	$ 185.28	$ 1,417.98	$ 1,637.94	$ 1,603.26	$ 1,823.22	$ 420.00	$ 487.93	$ 563.62	$ 907.93	$ 983.62	$ (57.94)	$ (69.97)	-43%	-46%
1,355	1537	66	$ 185.28	$ 1,639.15	$ 1,859.11	$ 1,824.43	$ 2,044.39	$ 420.00	$ 564.04	$ 639.73	$ 984.04	$ 1,059.73	$ (70.03)	$ (82.06)	-46%	-48%
1,538	1720	30	$ 185.28	$ 1,860.32	$ 2,080.29	$ 2,045.60	$ 2,265.57	$ 420.00	$ 640.14	$ 715.83	$ 1,060.14	$ 1,135.83	$ (82.12)	$ (94.14)	-48%	-50%
1,721	1903	18	$ 185.28	$ 2,081.50	$ 2,301.46	$ 2,266.78	$ 2,486.74	$ 420.00	$ 716.25	$ 791.94	$ 1,136.25	$ 1,211.94	$ (94.21)	$ (106.23)	-50%	-51%
1,904	2086	8	$ 185.28	$ 2,302.67	$ 2,522.63	$ 2,487.95	$ 2,707.91	$ 420.00	$ 792.36	$ 868.05	$ 1,212.36	$ 1,288.05	$ (106.30)	$ (118.32)	-51%	-52%
2,087	2269	8	$ 185.28	$ 2,523.84	$ 2,743.81	$ 2,709.12	$ 2,929.09	$ 420.00	$ 868.46	$ 944.15	$ 1,288.46	$ 1,364.15	$ (118.39)	$ (130.41)	-52%	-53%
2,270	2452	2	$ 185.28	$ 2,745.02	$ 2,964.98	$ 2,930.30	$ 3,150.26	$ 420.00	$ 944.57	$ 1,020.26	$ 1,364.57	$ 1,440.26	$ (130.48)	$ (142.50)	-53%	-54%
2,453	2635	2	$ 185.28	$ 2,966.19	$ 3,186.15	$ 3,151.47	$ 3,371.43	$ 420.00	$ 1,020.67	$ 1,096.37	$ 1,440.67	$ 1,516.37	$ (142.57)	$ (154.59)	-54%	-55%
2,636	2818	1	$ 185.28	$ 3,187.36	$ 3,407.33	$ 3,372.64	$ 3,592.61	$ 420.00	$ 1,096.78	$ 1,172.47	$ 1,516.78	$ 1,592.47	$ (154.66)	$ (166.68)	-55%	-56%
2,819	3001	0	$ 185.28	$ 3,408.54	$ 3,628.50	$ 3,593.82	$ 3,813.78	$ 420.00	$ 1,172.89	$ 1,248.58	$ 1,592.89	$ 1,668.58	$ (166.74)	$ (178.77)	-56%	-56%
3,002	7304	6	$ 185.28	$ 3,629.71	$ 8,832.12	$ 3,814.99	$ 9,017.40	$ 420.00	$ 1,248.99	$ 3,039.16	$ 1,668.99	$ 3,459.16	$ (178.83)	$ (463.19)	-56%	-62%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing BSSA Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 16.00	$ 0.63096	$ 0.63096			$ 35.00	$ 0.41611	$ 0.41611	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	28	43	$ 192.00	$ -	$ 17.35	$ 192.00	$ 209.35	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ 4.00	$ 4.45	25%	25%
29	55	12	$ 192.00	$ 17.98	$ 34.70	$ 209.98	$ 226.70	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 4.46	$ 4.89	25%	26%
56	83	34	$ 192.00	$ 35.33	$ 52.05	$ 227.33	$ 244.05	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 4.91	$ 5.34	26%	26%
84	110	42	$ 192.00	$ 52.69	$ 69.41	$ 244.69	$ 261.41	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 5.35	$ 5.78	26%	27%
111	138	45	$ 192.00	$ 70.04	$ 86.76	$ 262.04	$ 278.76	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 5.80	$ 6.23	27%	27%
139	165	75	$ 192.00	$ 87.39	$ 104.11	$ 279.39	$ 296.11	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 6.24	$ 6.67	27%	27%
166	193	73	$ 192.00	$ 104.74	$ 121.46	$ 296.74	$ 313.46	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 6.69	$ 7.12	27%	27%
194	220	118	$ 192.00	$ 122.09	$ 138.81	$ 314.09	$ 330.81	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 7.13	$ 7.56	27%	27%
221	248	131	$ 192.00	$ 139.44	$ 156.16	$ 331.44	$ 348.16	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 7.58	$ 8.01	27%	28%
249	275	156	$ 192.00	$ 156.79	$ 173.51	$ 348.79	$ 365.51	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 8.02	$ 8.45	28%	28%
276	303	180	$ 192.00	$ 174.14	$ 190.87	$ 366.14	$ 382.87	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 8.47	$ 8.90	28%	28%
304	330	203	$ 192.00	$ 191.50	$ 208.22	$ 383.50	$ 400.22	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 8.91	$ 9.34	28%	28%
331	358	195	$ 192.00	$ 208.85	$ 225.57	$ 400.85	$ 417.57	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 9.36	$ 9.79	28%	28%
359	385	196	$ 192.00	$ 226.20	$ 242.92	$ 418.20	$ 434.92	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 9.80	$ 10.23	28%	28%
386	413	211	$ 192.00	$ 243.55	$ 260.27	$ 435.55	$ 452.27	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 10.25	$ 10.68	28%	28%
414	440	224	$ 192.00	$ 260.90	$ 277.62	$ 452.90	$ 469.62	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 10.69	$ 11.12	28%	28%
441	613	1,195	$ 192.00	$ 278.25	$ 387.02	$ 470.25	$ 579.02	$ 420.00	$ 183.50	$ 255.23	$ 603.50	$ 675.23	$ 11.10	$ 8.02	28%	17%
614	787	821	$ 192.00	$ 387.65	$ 496.42	$ 579.65	$ 688.42	$ 420.00	$ 255.65	$ 327.38	$ 675.65	$ 747.38	$ 8.00	$ 4.91	17%	9%
788	960	505	$ 192.00	$ 497.05	$ 605.81	$ 689.05	$ 797.81	$ 420.00	$ 327.80	$ 399.52	$ 747.80	$ 819.52	$ 4.90	$ 1.81	9%	3%
961	1134	248	$ 192.00	$ 606.44	$ 715.21	$ 798.44	$ 907.21	$ 420.00	$ 399.94	$ 471.67	$ 819.94	$ 891.67	$ 1.79	$ (1.29)	3%	-2%
1,135	1307	145	$ 192.00	$ 715.84	$ 824.60	$ 907.84	$ 1,016.60	$ 420.00	$ 472.09	$ 543.82	$ 892.09	$ 963.82	$ (1.31)	$ (4.40)	-2%	-5%
1,308	1480	76	$ 192.00	$ 825.24	$ 934.00	$ 1,017.24	$ 1,126.00	$ 420.00	$ 544.23	$ 615.96	$ 964.23	$ 1,035.96	$ (4.42)	$ (7.50)	-5%	-8%
1,481	1654	40	$ 192.00	$ 934.63	$ 1,043.40	$ 1,126.63	$ 1,235.40	$ 420.00	$ 616.38	$ 688.11	$ 1,036.38	$ 1,108.11	$ (7.52)	$ (10.61)	-8%	-10%
1,655	1827	21	$ 192.00	$ 1,044.03	$ 1,152.79	$ 1,236.03	$ 1,344.79	$ 420.00	$ 688.52	$ 760.25	$ 1,108.52	$ 1,180.25	$ (10.63)	$ (13.71)	-10%	-12%
1,828	2000	10	$ 192.00	$ 1,153.42	$ 1,262.19	$ 1,345.42	$ 1,454.19	$ 420.00	$ 760.67	$ 832.40	$ 1,180.67	$ 1,252.40	$ (13.73)	$ (16.82)	-12%	-14%
2,001	2174	8	$ 192.00	$ 1,262.82	$ 1,371.59	$ 1,454.82	$ 1,563.59	$ 420.00	$ 832.81	$ 904.54	$ 1,252.81	$ 1,324.54	$ (16.83)	$ (19.92)	-14%	-15%
2,175	2347	4	$ 192.00	$ 1,372.22	$ 1,480.98	$ 1,564.22	$ 1,672.98	$ 420.00	$ 904.96	$ 976.69	$ 1,324.96	$ 1,396.69	$ (19.94)	$ (23.02)	-15%	-17%
2,348	2521	3	$ 192.00	$ 1,481.61	$ 1,590.38	$ 1,673.61	$ 1,782.38	$ 420.00	$ 977.10	$ 1,048.83	$ 1,397.10	$ 1,468.83	$ (23.04)	$ (26.13)	-17%	-18%
2,522	2694	4	$ 192.00	$ 1,591.01	$ 1,699.77	$ 1,783.01	$ 1,891.77	$ 420.00	$ 1,049.25	$ 1,120.98	$ 1,469.25	$ 1,540.98	$ (26.15)	$ (29.23)	-18%	-19%
2,695	2867	3	$ 192.00	$ 1,700.41	$ 1,809.17	$ 1,892.41	$ 2,001.17	$ 420.00	$ 1,121.40	$ 1,193.13	$ 1,541.40	$ 1,613.13	$ (29.25)	$ (32.34)	-19%	-19%
2,868	7187	6	$ 192.00	$ 1,809.80	$ 4,534.57	$ 2,001.80	$ 4,726.57	$ 420.00	$ 1,193.54	$ 2,990.49	$ 1,613.54	$ 3,410.49	$ (32.36)	$ (109.67)	-19%	-28%

Commercial Bill Impacts (Gas Costs at $.41347/$.39280)

Commercial Sales			Commercial Transport			Commercial A/C		
Low	High	% Impact	Low	High	% Impact	Low	High	% Impact
0.00%	1.23%	1	0.00%	1.44%	0	0.00%	2.21%	1
1.23%	1.88%	1224	1.44%	1.55%	2	2.21%	2.85%	8
1.88%	2.52%	318	1.55%	1.67%	7	2.85%	3.48%	6
2.52%	3.17%	282	1.67%	1.78%	3	3.48%	4.12%	3
3.17%	3.81%	250	1.78%	1.89%	0	4.12%	4.76%	3
3.81%	4.46%	244	1.89%	2.01%	1	4.76%	5.40%	1
4.46%	5.10%	254	2.01%	2.12%	0	5.40%	6.04%	2
5.10%	5.75%	248	2.12%	2.23%	0	6.04%	6.68%	0
5.75%	6.39%	267	2.23%	2.35%	0	6.68%	7.32%	1
6.39%	7.04%	259	2.35%	2.46%	1	7.32%	7.95%	7
7.04%	7.68%	309	2.46%	2.58%	0	7.95%	8.59%	1
7.68%	8.33%	256	2.58%	2.69%	1	8.59%	9.23%	2
8.33%	8.97%	253	2.69%	2.80%	1	9.23%	9.87%	3
8.97%	9.62%	302	2.80%	2.92%	0	9.87%	10.51%	1
9.62%	10.26%	320	2.92%	3.03%	0	10.51%	11.15%	1
10.26%	10.91%	377	3.03%	3.14%	0	11.15%	11.78%	5
10.91%	11.38%	296	3.14%	4.12%	1	11.78%	12.20%	0
11.38%	11.85%	317	4.12%	5.09%	1	12.20%	12.61%	2
11.85%	12.32%	367	5.09%	6.07%	0	12.61%	13.02%	1
12.32%	12.79%	423	6.07%	7.04%	0	13.02%	13.43%	4
12.79%	13.26%	434	7.04%	8.02%	1	13.43%	13.84%	1
13.26%	13.73%	463	8.02%	8.99%	0	13.84%	14.26%	7
13.73%	14.20%	542	8.99%	9.97%	0	14.26%	14.67%	4
14.20%	14.67%	566	9.97%	10.94%	0	14.67%	15.08%	6
14.67%	15.14%	634	10.94%	11.92%	0	15.08%	15.49%	5
15.14%	15.61%	627	11.92%	12.89%	0	15.49%	15.90%	9
15.61%	16.08%	574	12.89%	13.87%	0	15.90%	16.31%	2
16.08%	16.55%	598	13.87%	14.84%	0	16.31%	16.73%	6
16.55%	17.02%	527	14.84%	15.81%	0	16.73%	17.14%	6
17.02%	17.49%	441	15.81%	16.79%	0	17.14%	17.55%	6
17.49%	18.96%	623	16.79%	17.76%	1	17.55%	17.96%	7

Source: commercial.xlsx

Source: commercial_xport.xlsx

Source: commercial_ac_hdd.xlsx

Industrial Bill Impacts (Gas Costs at $.41347/$.39280)

Industrial Sales			Industrial Transport		
Low	High	% Impact	Low	High	% Impact
0.00%	-2.92%	1	0.00%	-3.16%	1
-2.92%	-2.87%	4	-3.16%	-3.14%	0
-2.87%	-2.82%	0	-3.14%	-3.12%	2
-2.82%	-2.77%	1	-3.12%	-3.10%	3
-2.77%	-2.72%	1	-3.10%	-3.08%	0
-2.72%	-2.67%	0	-3.08%	-3.06%	1
-2.67%	-2.62%	2	-3.06%	-3.03%	1
-2.62%	-2.57%	1	-3.03%	-3.01%	1
-2.57%	-2.52%	2	-3.01%	-2.99%	1
-2.52%	-2.47%	1	-2.99%	-2.97%	1
-2.47%	-2.42%	0	-2.97%	-2.95%	0
-2.42%	-2.37%	1	-2.95%	-2.93%	0
-2.37%	-2.32%	1	-2.93%	-2.91%	0
-2.32%	-2.27%	0	-2.91%	-2.89%	1
-2.27%	-2.22%	0	-2.89%	-2.86%	0
-2.22%	-2.17%	0	-2.86%	-2.84%	0
-2.17%	-2.09%	1	-2.84%	-2.70%	1
-2.09%	-2.01%	0	-2.70%	-2.55%	0
-2.01%	-1.93%	1	-2.55%	-2.41%	0
-1.93%	-1.85%	1	-2.41%	-2.27%	1
-1.85%	-1.77%	0	-2.27%	-2.12%	0
-1.77%	-1.70%	0	-2.12%	-1.98%	0
-1.70%	-1.62%	1	-1.98%	-1.83%	0
-1.62%	-1.54%	0	-1.83%	-1.69%	0
-1.54%	-1.46%	1	-1.69%	-1.55%	0
-1.46%	-1.38%	0	-1.55%	-1.40%	0
-1.38%	-1.30%	1	-1.40%	-1.26%	0
-1.30%	-1.23%	2	-1.26%	-1.11%	0
-1.23%	-1.15%	0	-1.11%	-0.97%	0
-1.15%	-1.07%	2	-0.97%	-0.83%	0
-1.07%	-0.99%	1	-0.83%	-0.68%	1

Source: industrial_nown.xlsx

Source: industrial_xport_nown.xls

Public Authority Bill Impacts (Gas Costs at $.41347/$.39280)

Public Authority Sales			Public Authority Transport			Public Authority A/C			Municipal Water Pumping		
Low	High	% Impact	Low	High	% Impact	Low	High	% Impact	Low	High	% Impact
0.00%	0.64%	1	0.00%	2.41%	1	0.00%	2.15%	1	0.00%	-73.52%	1
0.64%	0.72%	1	2.41%	2.44%	0	2.15%	2.18%	0	-73.52%	-70.01%	2
0.72%	0.80%	1	2.44%	2.48%	0	2.18%	2.21%	0	-70.01%	-66.49%	0
0.80%	0.88%	4	2.48%	2.52%	0	2.21%	2.24%	0	-66.49%	-62.98%	0
0.88%	0.95%	6	2.52%	2.55%	0	2.24%	2.26%	0	-62.98%	-59.47%	0
0.95%	1.03%	9	2.55%	2.59%	0	2.26%	2.29%	0	-59.47%	-55.95%	0
1.03%	1.11%	14	2.59%	2.63%	0	2.29%	2.32%	1	-55.95%	-52.44%	0
1.11%	1.19%	14	2.63%	2.66%	0	2.32%	2.35%	1	-52.44%	-48.93%	0
1.19%	1.26%	23	2.66%	2.70%	0	2.35%	2.38%	0	-48.93%	-45.41%	0
1.26%	1.34%	53	2.70%	2.74%	0	2.38%	2.41%	0	-45.41%	-41.90%	0
1.34%	1.42%	72	2.74%	2.77%	0	2.41%	2.43%	0	-41.90%	-38.39%	0
1.42%	1.50%	87	2.77%	2.81%	1	2.43%	2.46%	0	-38.39%	-34.88%	1
1.50%	1.57%	57	2.81%	2.84%	1	2.46%	2.49%	0	-34.88%	-31.36%	0
1.57%	1.65%	64	2.84%	2.88%	0	2.49%	2.52%	0	-31.36%	-27.85%	0
1.65%	1.73%	69	2.88%	2.92%	1	2.52%	2.55%	0	-27.85%	-24.34%	0
1.73%	1.81%	63	2.92%	2.95%	0	2.55%	2.58%	0	-24.34%	-20.82%	1
1.81%	2.44%	424	2.95%	2.98%	0	2.58%	2.62%	0	-20.82%	-19.12%	1
2.44%	3.08%	68	2.98%	3.01%	0	2.62%	2.67%	0	-19.12%	-17.42%	1
3.08%	3.72%	5	3.01%	3.03%	0	2.67%	2.72%	0	-17.42%	-15.72%	0
3.72%	4.35%	0	3.03%	3.06%	0	2.72%	2.77%	0	-15.72%	-14.02%	0
4.35%	4.99%	0	3.06%	3.09%	0	2.77%	2.81%	1	-14.02%	-12.32%	0
4.99%	5.63%	1	3.09%	3.11%	0	2.81%	2.86%	0	-12.32%	-10.62%	0
5.63%	6.26%	0	3.11%	3.14%	0	2.86%	2.91%	0	-10.62%	-8.92%	1
6.26%	6.90%	0	3.14%	3.16%	0	2.91%	2.96%	0	-8.92%	-7.22%	0
6.90%	7.54%	0	3.16%	3.19%	1	2.96%	3.01%	0	-7.22%	-5.52%	0
7.54%	8.17%	0	3.19%	3.22%	1	3.01%	3.05%	0	-5.52%	-3.82%	2
8.17%	8.81%	0	3.22%	3.24%	0	3.05%	3.10%	0	-3.82%	-2.12%	1
8.81%	9.45%	0	3.24%	3.27%	0	3.10%	3.15%	0	-2.12%	-0.42%	2
9.45%	10.09%	0	3.27%	3.30%	0	3.15%	3.20%	0	-0.42%	1.28%	0
10.09%	10.72%	0	3.30%	3.32%	0	3.20%	3.24%	0	1.28%	2.98%	2
10.72%	11.36%	1	3.32%	3.35%	1	3.24%	4.29%	1	2.98%	4.68%	1

Source: public authority.xlsx

Source: public authority xport.xlsx

Source: public authority_ac_hdd.xlsx

Source: municipal water pumping.xlsx

CNG Bill Impacts (Gas Costs at $.39280)

CNG Reclassified from Commercial

Low	High	% Impact	
0.00%	-4.30%	1	reclassified from PA
-4.30%	-4.16%	0	
-4.16%	-4.02%	0	
-4.02%	-3.88%	1	
-3.88%	-3.74%	0	
-3.74%	-3.60%	1	
-3.60%	-3.46%	0	
-3.46%	-3.32%	0	
-3.32%	-3.18%	0	
-3.18%	-3.04%	0	
-3.04%	-2.90%	0	
-2.90%	-2.76%	0	
-2.76%	-2.62%	0	
-2.62%	-2.48%	0	
-2.48%	-2.34%	0	
-2.34%	-2.20%	0	
-2.20%	-1.84%	0	
-1.84%	-1.49%	0	
-1.49%	-1.13%	0	
-1.13%	-0.77%	0	
-0.77%	-0.42%	0	
-0.42%	-0.06%	0	
-0.06%	0.29%	0	
0.29%	0.65%	0	
0.65%	1.01%	0	
1.01%	1.36%	0	
1.36%	1.72%	0	
1.72%	2.08%	0	
2.08%	2.43%	0	
2.43%	2.79%	0	
2.79%	3.14%	1	reclassified from Commercial

Source: cng xport_nown.xlsx

Proof of Revenue

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROOF OF REVENUE

					Recommended Rates						
Line No.	Description	Bills	Volumes		Customer Charge	Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.	GRIP Allocation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential - Small	2,037,081			$ 20.00		$ 40,741,620				
2			All Ccf	49,102,655		0.41173	$ 20,217,036				
3	Residential - Large	1,366,821			$ 35.00		$ 47,838,735				
4			All Ccf	75,624,039		0.00264	$ 199,647				
5	Residential Total							$ 108,997,039	$ 108,996,862	$ 177	80.71 %
6											
7	Commercial	208,155			$ 75.00		$ 15,611,593				
8			All Ccf	46,755,918		0.06808	$ 3,183,143	$ 18,794,736			
9											
10											
11	Commercial Transportation	240			$ 500.00		$ 120,000				
12			All Ccf	6,717,889		0.06808	$ 457,354	$ 577,354			
13											
14	Electrical Cogeneration Transportation	24			$ 700.00		$ 16,800				
15			Oct.-Apr								
16			First 5000	35,010		0.05260	$ 1,842				
17			Next 95000	665,000		0.04260	$ 28,329				
18			Next 300000	240,050		0.03260	$ 7,826				
19			Over 400000	0		0.02260	$ -				
20			May-Sep								
21			First 5000	25,000		0.04259	$ 1,065				
22			Next 95000	475,000		0.03258	$ 15,476				
23			Next 300000	75,420		0.02259	$ 1,704				
24			Over 400000	0		0.01258	$ -	$ 73,040			
25											
26	Commercial Total							$ 19,445,130	$ 19,445,088	$ 42	14.40 %
27											
28	Industrial	487			$ 850.00		$ 413,950				
29			All Ccf	1,370,091		0.08875	$ 121,596	$ 535,546			
30											
31	Industrial Transportation	180			$ 1,050.00		$ 189,000				
32			All Ccf	6,561,058		0.08875	$ 582,294	$ 771,294			
33											
34	Industrial Total							$ 1,306,840	$ 1,306,864	$ (25)	0.97 %
35											
36	Public Authority	16,237			$ 200.00		$ 3,247,429				
37			All Ccf	12,106,612		$ 0.11113	$ 1,345,408	$ 4,592,837			
38											
39	Public Authority Transportation	84			$ 500.00		$ 42,000				
40			All Ccf	2,192,902		$ 0.11113	$ 243,697	$ 285,697			
41											
42	Public Authority Total							$ 4,878,534	$ 4,878,521	$ 14	3.61 %
43											
44	CNG Transportation	48			$ 450.00		$ 21,600				
45			All Ccf	5,160,298		$ 0.07652	$ 394,866	$ 416,466			
46											
47	CNG Total							$ 416,466	$ 416,451	$ 15	0.31 %
48											
49	Total Revenue - All Classes										
50											
51	Recommended Rate Revenue							$ 135,044,009	$ 135,043,785		
52	Current Rate Revenue							$ 122,097,541	$ 122,097,541		
53	Revenue Change							$ 12,946,468	$ 12,946,245		
54											
55	Fort Bliss Assigned Rev. Change. (1)								$ 48,883		
56	Total Change - All Classes								$ 12,995,128		
57											
58	Schedule A - Revenue Deficiency								$ 12,995,128		

(1) The amount reflects the revenue change assigned to Fort Bliss shown on the Class Revenue Allocation tab within the model.

(0.00)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CURRENT AND RECOMMENDED RATES

Description		Current Rates WTSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c)	(d)
Residential			Small	Large
Customer Charge		$23.53	$20.00	$32.00
Usage Rates	All Ccf	$0.09317	$0.36112	$0.03385
Commercial				
Customer Charge - Sales		$63.58	$75.00	
Usage Rates	All Ccf		$0.01017	
	First 500	$0.08223		
	All Over 500	$0.06223		
Customer Charge - Transportation		$424.58	$500.00	
Usage Rates	All Ccf		$0.01017	
	First 500	$0.08223		
	All Over 500	$0.06223		
Commercial Air Conditioning				
Customer Charge - Sales		$63.58	$75.00	
Usage Rates - (October - April)	All Ccf		$0.01017	
	First 500	$0.08223		
	All Over 500	$0.06223		
Usage Rates - (May - August)	All Ccf			
	First 500	$0.06223		
	All Over 500	$0.04223		
Electrical Cogeneration				
Customer Charge - Sales		$424.58	$700.00	
Usage Rates - (October - April)	All Ccf			
	First 5,000 Ccf	$0.05696	$0.05260	
	Next 95,000	$0.04696	$0.04260	
	Next 300,000	$0.03696	$0.03260	
	All Over 400,000	$0.02696	$0.02260	
Usage Rates - (May-September)	All Ccf			
	First 5,000 Ccf	$0.04695	$0.04259	
	Next 95,000	$0.03694	$0.03258	
	Next 300,000	$0.02695	$0.02259	
	All Over 400,000	$0.01694	$0.01258	
Customer Charge - Transportation		$424.58	$700.00	
Usage Rates - (October - April)	All Ccf			
	First 5,000 Ccf	$0.05696	$0.05260	
	Next 95,000	$0.04696	$0.04260	
	Next 300,000	$0.03696	$0.03260	
	All Over 400,000	$0.02696	$0.02260	
Usage Rates - (May-September)	All Ccf			
	First 5,000 Ccf	$0.04695	$0.04259	
	Next 95,000	$0.03694	$0.03258	
	Next 300,000	$0.02695	$0.02259	
	All Over 400,000	$0.01694	$0.01258	

Industrial				
Customer Charge - Sales			$857.20	$850.00
Usage Rates	All Ccf			$0.08220
	First 500		$0.12458	
	All Over 500		$0.10458	
Customer Charge - Transportation			$1,057.20	$1,050.00
Usage Rates	All Ccf			$0.08220
	First 500		$0.12458	
	All Over 500		$0.10458	
Standby Service				
Customer Charge - Sales			$666.37	$666.37
Usage Rates	Per Mcf/Hour		$20.00	$20.00
Public Authority				
Customer Charge - Sales			$195.79	$200.00
Usage Rates	All Ccf			$0.08291
	First 500		$0.11461	
	All Over 500		$0.09461	
Customer Charge - Transportation			$495.79	$500.00
Usage Rates	All Ccf			$0.08291
	First 500		$0.11461	
	All Over 500		$0.09461	
Public Authority Air Conditioning				
Customer Charge - Sales			$195.79	$200.00
Usage Rates - (October - April)	All Ccf			$0.08291
	First 500		$0.11461	
	All Over 500		$0.09461	
Usage Rates - (May-September)	All Ccf			
	First 500		$0.08461	
	All Over 500		$0.06461	
Municipal Water Pumping				
Customer Charge - Sales			$768.75	$200.00
Usage Rates	All Ccf			$0.08291
	First 5000		$0.06111	
	All Over 5000		$0.05111	
CNG				
Customer Charge - Sales		N/A		$150.00
Usage Rates	All Ccf	N/A		$0.07616
Customer Charge - Transportation (reclassed from Commercial)			$424.58	$450.00
Usage Rates	All Ccf			$0.07616
	First 500		$0.08223	
	All Over 500		$0.06223	
Customer Charge - Transportation (reclassed from Public Authority)			$495.79	$450.00
Usage Rates	All Ccf			$0.07616
	First 500		$0.11461	
	All Over 500		$0.09461	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST TEXAS SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
WTSA Incorporated and Environs	$ 35.55	$ 38.50	$ 2.95	8.3%
Residential - Large				
WTSA Incorporated and Environs	$ 50.70	$ 55.93	$ 5.23	10.3%
Commercial				
WTSA Incorporated and Environs	$ 169.92	$ 165.57	$ (4.35)	-2.6%
Commercial Air Conditioning (3)				
WTSA Incorporated and Environs	$ 215.66	206.36	$ (9.30)	-4.3%
Industrial				
WTSA Incorporated and Environs	$ 2,318.27	$ 2,257.41	$ (60.86)	-2.6%
Public Authority				
WTSA Incorporated and Environs	$ 546.57	$ 532.78	$ (13.79)	-2.5%
Public Authority Air Conditioning (3)				
WTSA Incorporated and Environs	$ 1,206.33	$ 1,181.72	$ (24.61)	-2.0%
Municipal Water Pumping				
WTSA Incorporated and Environs	$ 3,635.00	$ 3,213.21	$ (421.79)	-11.6%
Transportation Service: (4)				
Commercial Transportation				
WTSA Incorporated and Environs	$ 12,908.33	$ 11,516.53	$ (1,391.80)	-10.8%
Industrial Transportation				
WTSA Incorporated and Environs	$ 18,854.26	$ 18,021.31	$ (832.95)	-4.4%
Public Authority Transportation				
WTSA Incorporated and Environs	$ 12,984.73	$ 12,673.50	$ (311.23)	-2.4%
CNG Transportation				
WTSA Incorporated and Environs (reclassed from Commercial)	$ 50,941.58	$ 52,535.80	$ 1,594.22	3.1%
WTSA Incorporated and Environs (reclassed from Public Authority)	$ 151,885.50	$ 145,986.84	$ (5,898.66)	-3.9%
Cogeneration Transportation (3)				
WTSA Incorporated and Environs	$ 39,065.97	$ 39,044.10	$ (21.87)	-0.1%

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

	WTSA
	Year-Round
Residential - Rate Option A	24
Residential - Rate Option B	55
Commercial	219
Industrial	2,897
Public Authority	684
Municipal Water Pumping	6,194

	August	**January**
Commercial AC	259.27	359.08
Public Authority AC	151.33	3,351.29

(3) Year-round average bill is approximated based on the average August bill assumed to occur in each of the 5 summer months and the average January bill assumed to occur in each of the 7 winter months.

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

	WTSA
	Year-Round
Commercial Transportation	27,991
Industrial Transportation	36,450
Public Authority Transportation	26,106
CNG Transportation	113,338

	August	January
Cogeneration Transportation	106,900	79,655

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

Residential Bill Impacts Existing Rates

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Small/Large Rate Relative to Existing WTSA Rates

								$ 20.00	$ 0.76470	$ 0.76470 Small						
			$ 23.53	$ 0.49675	$ 0.49675			$ 32.00	$ 0.43743	$ 0.43743 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	28	1,829	$ 282.36	$ -	$ 13.66	$ 282.36	$ 296.02	$ 240.00	$ -	$ 21.03	$ 240.00	$ 261.03	$ (3.53)	$ (2.92)	-15%	-12%
29	55	1,648	$ 282.36	$ 14.16	$ 27.32	$ 296.52	$ 309.68	$ 240.00	$ 21.79	$ 42.06	$ 261.79	$ 282.06	$ (2.89)	$ (2.30)	-12%	-9%
56	83	2,377	$ 282.36	$ 27.82	$ 40.98	$ 310.18	$ 323.34	$ 240.00	$ 42.82	$ 63.09	$ 282.82	$ 303.09	$ (2.28)	$ (1.69)	-9%	-6%
84	110	3,165	$ 282.36	$ 41.48	$ 54.64	$ 323.84	$ 337.00	$ 240.00	$ 63.85	$ 84.12	$ 303.85	$ 324.12	$ (1.67)	$ (1.07)	-6%	-4%
111	138	4,264	$ 282.36	$ 55.14	$ 68.30	$ 337.50	$ 350.66	$ 240.00	$ 84.88	$ 105.15	$ 324.88	$ 345.15	$ (1.05)	$ (0.46)	-4%	-2%
139	165	5,763	$ 282.36	$ 68.80	$ 81.96	$ 351.16	$ 364.32	$ 240.00	$ 105.91	$ 126.18	$ 345.91	$ 366.18	$ (0.44)	$ 0.15	-1%	1%
166	193	7,282	$ 282.36	$ 82.46	$ 95.62	$ 364.82	$ 377.98	$ 240.00	$ 126.94	$ 147.20	$ 366.94	$ 387.20	$ 0.18	$ 0.77	1%	2%
194	220	9,197	$ 282.36	$ 96.12	$ 109.29	$ 378.48	$ 391.65	$ 240.00	$ 147.97	$ 168.23	$ 387.97	$ 408.23	$ 0.79	$ 1.38	3%	4%
221	248	11,601	$ 282.36	$ 109.78	$ 122.95	$ 392.14	$ 405.31	$ 240.00	$ 169.00	$ 189.26	$ 409.00	$ 429.26	$ 1.40	$ 2.00	4%	6%
249	275	13,856	$ 282.36	$ 123.44	$ 136.61	$ 405.80	$ 418.97	$ 240.00	$ 190.03	$ 210.29	$ 430.03	$ 450.29	$ 2.02	$ 2.61	6%	7%
276	303	15,556	$ 282.36	$ 137.10	$ 150.27	$ 419.46	$ 432.63	$ 240.00	$ 211.06	$ 231.32	$ 451.06	$ 471.32	$ 2.63	$ 3.22	8%	9%
304	330	16,884	$ 282.36	$ 150.76	$ 163.93	$ 433.12	$ 446.29	$ 240.00	$ 232.09	$ 252.35	$ 472.09	$ 492.35	$ 3.25	$ 3.84	9%	10%
331	358	17,462	$ 282.36	$ 164.42	$ 177.59	$ 446.78	$ 459.95	$ 240.00	$ 253.12	$ 273.38	$ 493.12	$ 513.38	$ 3.86	$ 4.45	10%	12%
359	385	17,584	$ 282.36	$ 178.08	$ 191.25	$ 460.44	$ 473.61	$ 240.00	$ 274.14	$ 294.41	$ 514.14	$ 534.41	$ 4.48	$ 5.07	12%	13%
386	413	16,555	$ 282.36	$ 191.75	$ 204.91	$ 474.11	$ 487.27	$ 240.00	$ 295.17	$ 315.44	$ 535.17	$ 555.44	$ 5.09	$ 5.68	13%	14%
414	440	15,188	$ 282.36	$ 205.41	$ 218.57	$ 487.77	$ 500.93	$ 240.00	$ 316.20	$ 336.47	$ 556.20	$ 576.47	$ 5.70	$ 6.29	14%	15%
441	1,240	100,529	$ 282.36	$ 219.07	$ 615.97	$ 501.43	$ 898.33	$ 384.00	$ 192.91	$ 542.41	$ 576.91	$ 926.41	$ 6.29	$ 2.34	15%	3%
1,241	2,040	2,807	$ 282.36	$ 616.47	$ 1,013.37	$ 898.83	$ 1,295.73	$ 384.00	$ 542.85	$ 892.36	$ 926.85	$ 1,276.36	$ 2.34	$ (1.61)	3%	-1%
2,041	2,840	548	$ 282.36	$ 1,013.87	$ 1,410.77	$ 1,296.23	$ 1,693.13	$ 384.00	$ 892.79	$ 1,242.30	$ 1,276.79	$ 1,626.30	$ (1.62)	$ (5.57)	-1%	-4%
2,841	3,640	185	$ 282.36	$ 1,411.27	$ 1,808.17	$ 1,693.63	$ 2,090.53	$ 384.00	$ 1,242.74	$ 1,592.25	$ 1,626.74	$ 1,976.25	$ (5.57)	$ (9.52)	-4%	-5%
3,641	4,440	115	$ 282.36	$ 1,808.67	$ 2,205.57	$ 2,091.03	$ 2,487.93	$ 384.00	$ 1,592.68	$ 1,942.19	$ 1,976.68	$ 2,326.19	$ (9.53)	$ (13.48)	-5%	-7%
4,441	5,240	73	$ 282.36	$ 2,206.07	$ 2,602.97	$ 2,488.43	$ 2,885.33	$ 384.00	$ 1,942.63	$ 2,292.13	$ 2,326.63	$ 2,676.13	$ (13.48)	$ (17.43)	-7%	-7%
5,241	6,040	35	$ 282.36	$ 2,603.47	$ 3,000.37	$ 2,885.83	$ 3,282.73	$ 384.00	$ 2,292.57	$ 2,642.08	$ 2,676.57	$ 3,026.08	$ (17.44)	$ (21.39)	-7%	-8%
6,041	6,840	16	$ 282.36	$ 3,000.87	$ 3,397.77	$ 3,283.23	$ 3,680.13	$ 384.00	$ 2,642.51	$ 2,992.02	$ 3,026.51	$ 3,376.02	$ (21.39)	$ (25.34)	-8%	-8%
6,841	7,640	9	$ 282.36	$ 3,398.27	$ 3,795.17	$ 3,680.63	$ 4,077.53	$ 384.00	$ 2,992.46	$ 3,341.97	$ 3,376.46	$ 3,725.97	$ (25.35)	$ (29.30)	-8%	-9%
7,641	8,440	5	$ 282.36	$ 3,795.67	$ 4,192.57	$ 4,078.03	$ 4,474.93	$ 384.00	$ 3,342.40	$ 3,691.91	$ 3,726.40	$ 4,075.91	$ (29.30)	$ (33.25)	-9%	-9%
8,441	9,240	2	$ 282.36	$ 4,193.07	$ 4,589.97	$ 4,475.43	$ 4,872.33	$ 384.00	$ 3,692.35	$ 4,041.85	$ 4,076.35	$ 4,425.85	$ (33.26)	$ (37.21)	-9%	-9%
9,241	10,040	3	$ 282.36	$ 4,590.47	$ 4,987.37	$ 4,872.83	$ 5,269.73	$ 384.00	$ 4,042.29	$ 4,391.80	$ 4,426.29	$ 4,775.80	$ (37.21)	$ (41.16)	-9%	-9%
10,041	10,840	3	$ 282.36	$ 4,987.87	$ 5,384.77	$ 5,270.23	$ 5,667.13	$ 384.00	$ 4,392.23	$ 4,741.74	$ 4,776.23	$ 5,125.74	$ (41.17)	$ (45.12)	-9%	-10%
10,841	11,640	3	$ 282.36	$ 5,385.27	$ 5,782.17	$ 5,667.63	$ 6,064.53	$ 384.00	$ 4,742.18	$ 5,091.69	$ 5,126.18	$ 5,475.69	$ (45.12)	$ (49.07)	-10%	-10%
11,641	59,201	7	$ 282.36	$ 5,782.67	$ 29,408.27	$ 6,065.03	$ 29,690.63	$ 384.00	$ 5,092.12	$ 25,896.45	$ 5,476.12	$ 26,280.45	$ (49.08)	$ (284.18)	-10%	-11%

Residential Bill Impacts New Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO NEW RATES

Annual Residential Bill Impacts of Small/Large Rate Structure in WTSA Compared to Traditional Rate Structure

Current	$ 20.00	$ 0.70043	$ 0.70043	
Proposed	$ 20.00	$ 0.76470	$ 0.76470	Small
Proposed	$ 32.00	$ 0.43743	$ 0.43743	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	28	1,829	$ 240.00	$ -	$ 19.26	$ 240.00	$ 259.26	$ 240.00	$ -	$ 21.03	$ 240.00	$ 261.03	$ -	$ 0.15	0%	1%
29	55	1,648	$ 240.00	$ 19.96	$ 38.52	$ 259.96	$ 278.52	$ 240.00	$ 21.79	$ 42.06	$ 261.79	$ 282.06	$ 0.15	$ 0.29	1%	1%
56	83	2,377	$ 240.00	$ 39.22	$ 57.79	$ 279.22	$ 297.79	$ 240.00	$ 42.82	$ 63.09	$ 282.82	$ 303.09	$ 0.30	$ 0.44	1%	2%
84	110	3,165	$ 240.00	$ 58.49	$ 77.05	$ 298.49	$ 317.05	$ 240.00	$ 63.85	$ 84.12	$ 303.85	$ 324.12	$ 0.45	$ 0.59	2%	2%
111	138	4,264	$ 240.00	$ 77.75	$ 96.31	$ 317.75	$ 336.31	$ 240.00	$ 84.88	$ 105.15	$ 324.88	$ 345.15	$ 0.59	$ 0.74	2%	3%
139	165	5,763	$ 240.00	$ 97.01	$ 115.57	$ 337.01	$ 355.57	$ 240.00	$ 105.91	$ 126.18	$ 345.91	$ 366.18	$ 0.74	$ 0.88	3%	3%
166	193	7,282	$ 240.00	$ 116.27	$ 134.83	$ 356.27	$ 374.83	$ 240.00	$ 126.94	$ 147.20	$ 366.94	$ 387.20	$ 0.89	$ 1.03	3%	3%
194	220	9,197	$ 240.00	$ 135.53	$ 154.09	$ 375.53	$ 394.09	$ 240.00	$ 147.97	$ 168.23	$ 387.97	$ 408.23	$ 1.04	$ 1.18	3%	4%
221	248	11,601	$ 240.00	$ 154.80	$ 173.36	$ 394.80	$ 413.36	$ 240.00	$ 169.00	$ 189.26	$ 409.00	$ 429.26	$ 1.18	$ 1.33	4%	4%
249	275	13,856	$ 240.00	$ 174.06	$ 192.62	$ 414.06	$ 432.62	$ 240.00	$ 190.03	$ 210.29	$ 430.03	$ 450.29	$ 1.33	$ 1.47	4%	4%
276	303	15,556	$ 240.00	$ 193.32	$ 211.88	$ 433.32	$ 451.88	$ 240.00	$ 211.06	$ 231.32	$ 451.06	$ 471.32	$ 1.48	$ 1.62	4%	4%
304	330	16,884	$ 240.00	$ 212.58	$ 231.14	$ 452.58	$ 471.14	$ 240.00	$ 232.09	$ 252.35	$ 472.09	$ 492.35	$ 1.63	$ 1.77	4%	5%
331	358	17,462	$ 240.00	$ 231.84	$ 250.40	$ 471.84	$ 490.40	$ 240.00	$ 253.12	$ 273.38	$ 493.12	$ 513.38	$ 1.77	$ 1.91	5%	5%
359	385	17,584	$ 240.00	$ 251.10	$ 269.67	$ 491.10	$ 509.67	$ 240.00	$ 274.14	$ 294.41	$ 514.14	$ 534.41	$ 1.92	$ 2.06	5%	5%
386	413	16,555	$ 240.00	$ 270.37	$ 288.93	$ 510.37	$ 528.93	$ 240.00	$ 295.17	$ 315.44	$ 535.17	$ 555.44	$ 2.07	$ 2.21	5%	5%
414	440	15,188	$ 240.00	$ 289.63	$ 308.19	$ 529.63	$ 548.19	$ 240.00	$ 316.20	$ 336.47	$ 556.20	$ 576.47	$ 2.21	$ 2.36	5%	5%
441	1,240	100,529	$ 240.00	$ 308.89	$ 868.53	$ 548.89	$ 1,108.53	$ 384.00	$ 192.91	$ 542.41	$ 576.91	$ 926.41	$ 2.33	$ (15.18)	5%	-16%
1,241	2,040	2,807	$ 240.00	$ 869.23	$ 1,428.88	$ 1,109.23	$ 1,668.88	$ 384.00	$ 542.85	$ 892.36	$ 926.85	$ 1,276.36	$ (15.20)	$ (32.71)	-16%	-24%
2,041	2,840	548	$ 240.00	$ 1,429.58	$ 1,989.22	$ 1,669.58	$ 2,229.22	$ 384.00	$ 892.79	$ 1,242.30	$ 1,276.79	$ 1,626.30	$ (32.73)	$ (50.24)	-24%	-27%
2,841	3,640	185	$ 240.00	$ 1,989.92	$ 2,549.57	$ 2,229.92	$ 2,789.57	$ 384.00	$ 1,242.74	$ 1,592.25	$ 1,626.74	$ 1,976.25	$ (50.27)	$ (67.78)	-27%	-29%
3,641	4,440	115	$ 240.00	$ 2,550.27	$ 3,109.91	$ 2,790.27	$ 3,349.91	$ 384.00	$ 1,592.68	$ 1,942.19	$ 1,976.68	$ 2,326.19	$ (67.80)	$ (85.31)	-29%	-31%
4,441	5,240	73	$ 240.00	$ 3,110.61	$ 3,670.25	$ 3,350.61	$ 3,910.25	$ 384.00	$ 1,942.63	$ 2,292.13	$ 2,326.63	$ 2,676.13	$ (85.33)	$ (102.84)	-31%	-32%
5,241	6,040	35	$ 240.00	$ 3,670.95	$ 4,230.60	$ 3,910.95	$ 4,470.60	$ 384.00	$ 2,292.57	$ 2,642.08	$ 2,676.57	$ 3,026.08	$ (102.87)	$ (120.38)	-32%	-32%
6,041	6,840	16	$ 240.00	$ 4,231.30	$ 4,790.94	$ 4,471.30	$ 5,030.94	$ 384.00	$ 2,642.51	$ 2,992.02	$ 3,026.51	$ 3,376.02	$ (120.40)	$ (137.91)	-32%	-33%
6,841	7,640	9	$ 240.00	$ 4,791.64	$ 5,351.29	$ 5,031.64	$ 5,591.29	$ 384.00	$ 2,992.46	$ 3,341.97	$ 3,376.46	$ 3,725.97	$ (137.93)	$ (155.44)	-33%	-33%
7,641	8,440	5	$ 240.00	$ 5,351.99	$ 5,911.63	$ 5,591.99	$ 6,151.63	$ 384.00	$ 3,342.40	$ 3,691.91	$ 3,726.40	$ 4,075.91	$ (155.47)	$ (172.98)	-33%	-34%
8,441	9,240	2	$ 240.00	$ 5,912.33	$ 6,471.97	$ 6,152.33	$ 6,711.97	$ 384.00	$ 3,692.35	$ 4,041.85	$ 4,076.35	$ 4,425.85	$ (173.00)	$ (190.51)	-34%	-34%
9,241	10,040	3	$ 240.00	$ 6,472.67	$ 7,032.32	$ 6,712.67	$ 7,272.32	$ 384.00	$ 4,042.29	$ 4,391.80	$ 4,426.29	$ 4,775.80	$ (190.53)	$ (208.04)	-34%	-34%
10,041	10,840	3	$ 240.00	$ 7,033.02	$ 7,592.66	$ 7,273.02	$ 7,832.66	$ 384.00	$ 4,392.23	$ 4,741.74	$ 4,776.23	$ 5,125.74	$ (208.07)	$ (225.58)	-34%	-35%
10,841	11,640	3	$ 240.00	$ 7,593.36	$ 8,153.01	$ 7,833.36	$ 8,393.01	$ 384.00	$ 4,742.18	$ 5,091.69	$ 5,126.18	$ 5,475.69	$ (225.60)	$ (243.11)	-35%	-35%
11,641	59,201	7	$ 240.00	$ 8,153.71	$ 41,466.40	$ 8,393.71	$ 41,706.40	$ 384.00	$ 5,092.12	$ 25,896.45	$ 5,476.12	$ 26,280.45	$ (243.13)	$ (1,285.50)	-35%	-37%

Commercial Bill Impacts (Gas Costs at $.40358/$.38340)

Commercial Sales			Commercial Transport			Commercial A/C		
Low	High	% Impact	Low	High	% Impact	Low	High	% Impact
0.00%	-11.12%	1	0.00%	-11.38%	0	0.00%	-9.10%	1
-11.12%	-9.93%	307	-11.38%	-11.17%	2	-9.10%	-7.96%	6
-9.93%	-8.74%	558	-11.17%	-10.95%	6	-7.96%	-6.82%	3
-8.74%	-7.54%	482	-10.95%	-10.74%	4	-6.82%	-5.69%	5
-7.54%	-6.35%	324	-10.74%	-10.52%	0	-5.69%	-4.55%	3
-6.35%	-5.16%	284	-10.52%	-10.31%	1	-4.55%	-3.41%	3
-5.16%	-3.96%	255	-10.31%	-10.10%	0	-3.41%	-2.27%	2
-3.96%	-2.77%	268	-10.10%	-9.88%	0	-2.27%	-1.13%	1
-2.77%	-1.58%	266	-9.88%	-9.67%	0	-1.13%	0.01%	0
-1.58%	-0.38%	295	-9.67%	-9.46%	1	0.01%	1.15%	1
-0.38%	0.81%	291	-9.46%	-9.24%	0	1.15%	2.29%	7
0.81%	2.00%	350	-9.24%	-9.03%	1	2.29%	3.43%	2
2.00%	3.19%	298	-9.03%	-8.82%	0	3.43%	4.57%	3
3.19%	4.39%	324	-8.82%	-8.60%	1	4.57%	5.71%	2
4.39%	5.58%	349	-8.60%	-8.39%	0	5.71%	6.85%	0
5.58%	6.77%	429	-8.39%	-8.18%	0	6.85%	7.99%	3
6.77%	7.52%	293	-8.18%	-6.45%	0	7.99%	8.65%	3
7.52%	8.27%	326	-6.45%	-4.72%	2	8.65%	9.32%	1
8.27%	9.01%	358	-4.72%	-2.99%	0	9.32%	9.98%	2
9.01%	9.76%	386	-2.99%	-1.26%	0	9.98%	10.65%	3
9.76%	10.50%	460	-1.26%	0.47%	0	10.65%	11.31%	1
10.50%	11.25%	455	0.47%	2.20%	1	11.31%	11.98%	7
11.25%	11.99%	540	2.20%	3.93%	0	11.98%	12.64%	3
11.99%	12.74%	576	3.93%	5.66%	0	12.64%	13.31%	5
12.74%	13.49%	625	5.66%	7.39%	0	13.31%	13.97%	6
13.49%	14.23%	646	7.39%	9.12%	0	13.97%	14.64%	7
14.23%	14.98%	594	9.12%	10.85%	0	14.64%	15.30%	5
14.98%	15.72%	617	10.85%	12.58%	0	15.30%	15.97%	7
15.72%	16.47%	554	12.58%	14.30%	0	15.97%	16.63%	5
16.47%	17.22%	449	14.30%	16.03%	0	16.63%	17.30%	7
17.22%	18.96%	636	16.03%	17.76%	1	17.30%	17.96%	7

Source: commercial.xlsx

Source: commercial_xport.xlsx

Source: commercial_ac_hdd.xlsx

Industrial Bill Impacts (Gas Costs at $.40358/$.38340)

Industrial Sales			Industrial Transport		
Low	High	% Impact	Low	High	% Impact
0.00%	-4.09%	1	0.00%	-3.22%	1
-4.09%	-4.00%	2	-3.22%	-3.20%	0
-4.00%	-3.91%	3	-3.20%	-3.18%	2
-3.91%	-3.83%	0	-3.18%	-3.16%	3
-3.83%	-3.74%	0	-3.16%	-3.13%	0
-3.74%	-3.65%	1	-3.13%	-3.11%	1
-3.65%	-3.56%	0	-3.11%	-3.09%	1
-3.56%	-3.48%	0	-3.09%	-3.07%	1
-3.48%	-3.39%	3	-3.07%	-3.05%	1
-3.39%	-3.30%	1	-3.05%	-3.02%	1
-3.30%	-3.21%	1	-3.02%	-3.00%	0
-3.21%	-3.13%	1	-3.00%	-2.98%	0
-3.13%	-3.04%	2	-2.98%	-2.96%	0
-3.04%	-2.95%	0	-2.96%	-2.93%	0
-2.95%	-2.86%	0	-2.93%	-2.91%	1
-2.86%	-2.77%	0	-2.91%	-2.89%	0
-2.77%	-2.66%	0	-2.89%	-2.74%	1
-2.66%	-2.54%	1	-2.74%	-2.60%	0
-2.54%	-2.42%	0	-2.60%	-2.45%	0
-2.42%	-2.31%	0	-2.45%	-2.30%	1
-2.31%	-2.19%	2	-2.30%	-2.15%	0
-2.19%	-2.07%	0	-2.15%	-2.01%	0
-2.07%	-1.96%	1	-2.01%	-1.86%	0
-1.96%	-1.84%	0	-1.86%	-1.71%	0
-1.84%	-1.72%	0	-1.71%	-1.56%	0
-1.72%	-1.61%	1	-1.56%	-1.42%	0
-1.61%	-1.49%	0	-1.42%	-1.27%	0
-1.49%	-1.37%	2	-1.27%	-1.12%	0
-1.37%	-1.26%	1	-1.12%	-0.98%	0
-1.26%	-1.14%	1	-0.98%	-0.83%	0
-1.14%	-1.02%	2	-0.83%	-0.68%	1

Source: industrial_nown.xlsx

Source: industrial_xport_nown.xlsx

Public Authority Bill Impacts (Gas Costs at $.40358/$.38340)

Public Authority Sales			Public Authority Transport			Public Authority A/C			Municipal Water Pumping		
Low	High	% Impact	Low	High	% Impact	Low	High	% Impact	Low	High	% Impact
0.00%	-2.51%	1	0.00%	-2.44%	1	0.00%	-1.75%	1	0.00%	-73.56%	1
-2.51%	-2.37%	40	-2.44%	-2.43%	0	-1.75%	-1.69%	2	-73.56%	-70.30%	2
-2.37%	-2.23%	51	-2.43%	-2.42%	0	-1.69%	-1.63%	0	-70.30%	-67.05%	0
-2.23%	-2.09%	48	-2.42%	-2.41%	0	-1.63%	-1.57%	0	-67.05%	-63.79%	0
-2.09%	-1.95%	69	-2.41%	-2.40%	0	-1.57%	-1.51%	0	-63.79%	-60.53%	0
-1.95%	-1.81%	51	-2.40%	-2.39%	0	-1.51%	-1.45%	0	-60.53%	-57.28%	0
-1.81%	-1.66%	43	-2.39%	-2.39%	1	-1.45%	-1.40%	0	-57.28%	-54.02%	0
-1.66%	-1.52%	32	-2.39%	-2.38%	1	-1.40%	-1.34%	0	-54.02%	-50.76%	0
-1.52%	-1.38%	28	-2.38%	-2.37%	0	-1.34%	-1.28%	1	-50.76%	-47.50%	0
-1.38%	-1.24%	27	-2.37%	-2.36%	0	-1.28%	-1.22%	0	-47.50%	-44.25%	0
-1.24%	-1.10%	30	-2.36%	-2.35%	0	-1.22%	-1.16%	0	-44.25%	-40.99%	0
-1.10%	-0.96%	34	-2.35%	-2.35%	0	-1.16%	-1.10%	0	-40.99%	-37.73%	1
-0.96%	-0.81%	26	-2.35%	-2.34%	0	-1.10%	-1.04%	0	-37.73%	-34.48%	0
-0.81%	-0.67%	29	-2.34%	-2.33%	0	-1.04%	-0.99%	0	-34.48%	-31.22%	0
-0.67%	-0.53%	21	-2.33%	-2.32%	0	-0.99%	-0.93%	0	-31.22%	-27.96%	0
-0.53%	-0.39%	31	-2.32%	-2.31%	0	-0.93%	-0.87%	0	-27.96%	-24.70%	1
-0.39%	0.38%	132	-2.31%	-2.30%	1	-0.87%	-0.67%	0	-24.70%	-23.11%	1
0.38%	1.15%	112	-2.30%	-2.29%	0	-0.67%	-0.47%	0	-23.11%	-21.52%	1
1.15%	1.92%	151	-2.29%	-2.28%	1	-0.47%	-0.26%	0	-21.52%	-19.93%	0
1.92%	2.69%	79	-2.28%	-2.27%	0	-0.26%	-0.06%	0	-19.93%	-18.34%	0
2.69%	3.46%	0	-2.27%	-2.26%	0	-0.06%	0.14%	0	-18.34%	-16.75%	0
3.46%	4.22%	1	-2.26%	-2.25%	0	0.14%	0.34%	0	-16.75%	-15.16%	0
4.22%	4.99%	0	-2.25%	-2.24%	0	0.34%	0.54%	0	-15.16%	-13.57%	1
4.99%	5.76%	0	-2.24%	-2.23%	0	0.54%	0.74%	0	-13.57%	-11.98%	0
5.76%	6.53%	0	-2.23%	-2.22%	1	0.74%	0.94%	0	-11.98%	-10.39%	0
6.53%	7.30%	0	-2.22%	-2.21%	0	0.94%	1.14%	0	-10.39%	-8.80%	2
7.30%	8.07%	0	-2.21%	-2.20%	0	1.14%	1.35%	0	-8.80%	-7.21%	1
8.07%	8.84%	0	-2.20%	-2.19%	0	1.35%	1.55%	0	-7.21%	-5.62%	2
8.84%	9.61%	0	-2.19%	-2.18%	0	1.55%	1.75%	0	-5.62%	-4.02%	0
9.61%	10.38%	0	-2.18%	-2.17%	0	1.75%	1.95%	0	-4.02%	-2.43%	2
10.38%	11.15%	1	-2.17%	-2.16%	1	1.95%	3.15%	1	-2.43%	-0.84%	1

Source: public authority.xlsx

Source: public authority xport.xlsx

Source: public authority_ac_hdd.xlsx

Source: municipal water pumping.xlsx

CNG Bill Impacts(Gas Costs at $.38340)

CNG Reclassified from Commercial

Low	High	% Impact	
0.00%	-4.45%	1	reclassified from PA
-4.45%	-4.31%	0	
-4.31%	-4.16%	0	
-4.16%	-4.02%	1	
-4.02%	-3.88%	1	
-3.88%	-3.74%	0	
-3.74%	-3.59%	0	
-3.59%	-3.45%	0	
-3.45%	-3.31%	0	
-3.31%	-3.17%	0	
-3.17%	-3.03%	0	
-3.03%	-2.88%	0	
-2.88%	-2.74%	0	
-2.74%	-2.60%	0	
-2.60%	-2.46%	0	
-2.46%	-2.31%	0	
-2.31%	-1.95%	0	
-1.95%	-1.59%	0	
-1.59%	-1.22%	0	
-1.22%	-0.86%	0	
-0.86%	-0.50%	0	
-0.50%	-0.14%	0	
-0.14%	0.23%	0	
0.23%	0.59%	0	
0.59%	0.95%	0	
0.95%	1.32%	0	
1.32%	1.68%	0	
1.68%	2.04%	0	
2.04%	2.40%	0	
2.40%	2.77%	0	
2.77%	3.13%	1	reclassified from Commercial

Source: cng xport_nown.xlsx

Proof of Revenue

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	1,922,416			$ 20.00		$ 38,448,320				
2			All Ccf	46,511,207		0.36112	$ 16,796,127				
3	Residential - Large	1,252,202			$ 32.00		$ 40,070,464				
4			All Ccf	68,499,448		0.03385	$ 2,318,706				
5	Residential Total							$ 97,633,617	$ 97,633,841	$ (224)	83.47 %
6											
7	Commercial	178,913			$ 75.00		$ 13,418,472				
8			All Ccf	39,076,075		0.01017	$ 397,404	$ 13,815,875			
9											
10	Commercial Transportation	240			$ 500.00		$ 120,000				
11			All Ccf	6,717,889		0.01017	$ 68,321	$ 188,321			
12											
13	Electrical Cogeneration Transportation	24			$ 700.00		$ 16,800				
14			Oct.-Apr								
15			First 5000	35,010		0.05260	$ 1,842				
16			Next 95000	665,000		0.04260	$ 28,329				
17			Next 300000	240,050		0.03260	$ 7,826				
18			Over 400000	0		0.02260	$ -				
19			May-Sep								
20			First 5000	25,000		0.04259	$ 1,065				
21			Next 95000	475,000		0.03258	$ 15,476				
22			Next 300000	75,420		0.02259	$ 1,704				
23			Over 400000	0		0.01258	$ -	$ 73,040			
24											
25	Commercial Total							$ 14,077,236	$ 14,077,340	$ (104)	12.03 %
26											
27	Industrial	391			$ 850.00		$ 332,350				
28			All Ccf	1,132,809		0.08220	$ 93,117	$ 425,467			
29											
30	Industrial Transportation	180			$ 1,050.00		$ 189,000				
31			All Ccf	6,561,058		0.08220	$ 539,319	$ 728,319			
32											
33	Industrial Total							$ 1,153,786	$ 1,153,751	$ 34	0.99 %
34											
35	Public Authority	13,069			$ 200.00		$ 2,613,807				
36			All Ccf	10,299,270		$ 0.08291	$ 853,912	$ 3,467,719			
37											
38	Public Authority Transportation	84			$ 500.00		$ 42,000				
39			All Ccf	2,192,902		$ 0.08291	$ 181,814	$ 223,814			
40											
41	Public Authority Total							$ 3,691,533	$ 3,691,574	$ (41)	3.16 %
42											
43	CNG Transportation	48			$ 450.00		$ 21,600				
44			All Ccf	5,160,298		$ 0.07616	$ 393,008	$ 414,608			
45											
46	CNG Total							$ 414,608	$ 414,605	$ 3	0.35 %
47											
48	Total Revenue - All Classes										
49	Recommended Rate Revenue							$ 116,970,780	$ 116,971,112		
50	Current Rate Revenue							$ 105,911,328	$ 105,911,328		
51	Revenue Change							$ 11,059,453	$ 11,059,784		
52											
53	Fort Bliss Assigned Rev. Change. (1)								$ (13,982)		
54	Total Change - All Classes								$ 11,045,802		
55											
56	Schedule A - Revenue Deficiency								$ 11,045,802		

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
NORTH TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CURRENT AND RECOMMENDED RATES

Description		NTSA Environs Rates	NTSA Incorporated Rates	Recommended	
(a)		(b)	(c)	(d)	(e)
Residential				Small	Large
Customer Charge		$24.50	$15.44	$20.00	$35.00
Usage Rates	All Ccf	$0.59366	$0.67101	$0.97752	$0.56843
Commercial					
Customer Charge - Sales		$76.33	$47.80	$75.00	
Usage Rates	All Ccf	$0.60165	$0.68165	$0.50104	
Customer Charge - Transportation		$286.33	$250.00	$500.00	
Usage Rates	All Ccf	$0.57978	$0.57978	$0.50104	
Industrial					
Customer Charge - Sales		$509.26	$308.59	$850.00	
Usage Rates	All Ccf	$0.55395	$0.62874	$0.29797	
Customer Charge - Transportation		$509.26	$250.00	$900.00	
Usage Rates	All Ccf	$0.55395	$0.55395	$0.29797	
Public Authority					
Customer Charge - Sales		$160.93	$101.32	$200.00	
Usage Rates	All Ccf	$0.54101	$0.61329	$0.38460	
Customer Charge - Transportation		$325.93	$250.00	$500.00	
Usage Rates	All Ccf	$0.54101	$0.54101	$0.38460	

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
NORTH TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
NTSA Incorporated	$ 41.20	$ 52.29	$ 11.09	26.9%
NTSA Environs	$ 48.61	$ 52.29	$ 3.68	7.6%
Residential - Large				
NTSA Incorporated	$ 83.80	$ 97.56	$ 13.76	16.4%
NTSA Environs	$ 88.49	$ 97.56	$ 9.07	10.2%
Commercial				
NTSA Incorporated	$ 370.25	$ 349.71	$ (20.54)	-5.5%
NTSA Environs	$ 377.64	$ 349.71	$ (27.93)	-7.4%
Industrial				
NTSA Incorporated	$ 3,193.03	$ 2,916.88	$ (276.15)	-8.6%
NTSA Environs	$ 3,208.84	$ 2,916.88	$ (291.96)	-9.1%
Public Authority				
NTSA Incorporated	$ 753.32	$ 722.52	$ (30.80)	-4.1%
NTSA Environs	$ 772.00	$ 722.52	$ (49.48)	-6.4%

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

	NTSA
	Year-Round
Residential - Small	21
Residential - Large	57
Commercial	264
Industrial	2,472
Public Authority	566

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
NORTH TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

Residential Bill Impacts Existing Rates

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Small/Large Rate Relative to Existing NTSA Incorporated Rates

								$ 20.00	$ 1.51577	$ 1.51577 Small						
			$ 15.44	$ 1.20926	$ 1.20926			$ 35.00	$ 1.10668	$ 1.10668 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	28	261	185.28	-	33.25	185.28	218.53	240.00	-	41.68	240.00	281.68	4.56	5.26	30%	29%
29	55	143	185.28	34.46	66.51	219.74	251.79	240.00	43.20	83.37	283.20	323.37	5.29	5.96	29%	28%
56	83	231	185.28	67.72	99.76	253.00	285.04	240.00	84.88	125.05	324.88	365.05	5.99	6.67	28%	28%
84	110	263	185.28	100.97	133.02	286.25	318.30	240.00	126.57	166.73	366.57	406.73	6.69	7.37	28%	28%
111	138	342	185.28	134.23	166.27	319.51	351.55	240.00	168.25	208.42	408.25	448.42	7.40	8.07	28%	28%
139	165	337	185.28	167.48	199.53	352.76	384.81	240.00	209.93	250.10	449.93	490.10	8.10	8.77	28%	27%
166	193	367	185.28	200.74	232.78	386.02	418.06	240.00	251.62	291.79	491.62	531.79	8.80	9.48	27%	27%
194	220	419	185.28	233.99	266.04	419.27	451.32	240.00	293.30	333.47	533.30	573.47	9.50	10.18	27%	27%
221	248	413	185.28	267.25	299.29	452.53	484.57	240.00	334.99	375.15	574.99	615.15	10.20	10.88	27%	27%
249	275	498	185.28	300.50	332.55	485.78	517.83	240.00	376.67	416.84	616.67	656.84	10.91	11.58	27%	27%
276	303	515	185.28	333.76	365.80	519.04	551.08	240.00	418.35	458.52	658.35	698.52	11.61	12.29	27%	27%
304	330	581	185.28	367.01	399.06	552.29	584.34	240.00	460.04	500.20	700.04	740.20	12.31	12.99	27%	27%
331	358	623	185.28	400.27	432.31	585.55	617.59	240.00	501.72	541.89	741.72	781.89	13.01	13.69	27%	27%
359	385	637	185.28	433.52	465.57	618.80	650.85	240.00	543.40	583.57	783.40	823.57	13.72	14.39	27%	27%
386	413	643	185.28	466.77	498.82	652.05	684.10	240.00	585.09	625.26	825.09	865.26	14.42	15.10	27%	26%
414	440	576	185.28	500.03	532.07	685.31	717.35	240.00	626.77	666.94	866.77	906.94	15.12	15.80	26%	26%
441	623	3,111	185.28	533.28	753.25	718.56	938.53	420.00	488.05	689.35	908.05	1,109.35	15.79	14.24	26%	18%
624	806	1,386	185.28	754.46	974.42	939.74	1,159.70	420.00	690.46	891.76	1,110.46	1,311.76	14.23	12.67	18%	13%
807	989	679	185.28	975.63	1,195.59	1,160.91	1,380.87	420.00	892.87	1,094.17	1,312.87	1,514.17	12.66	11.11	13%	10%
990	1172	266	185.28	1,196.80	1,416.77	1,382.08	1,602.05	420.00	1,095.28	1,296.59	1,515.28	1,716.59	11.10	9.54	10%	7%
1,173	1354	125	185.28	1,417.98	1,637.94	1,603.26	1,823.22	420.00	1,297.69	1,499.00	1,717.69	1,919.00	9.54	7.98	7%	5%
1,355	1537	66	185.28	1,639.15	1,859.11	1,824.43	2,044.39	420.00	1,500.10	1,701.41	1,920.10	2,121.41	7.97	6.42	5%	4%
1,538	1720	30	185.28	1,860.32	2,080.29	2,045.60	2,265.57	420.00	1,702.51	1,903.82	2,122.51	2,323.82	6.41	4.85	4%	3%
1,721	1903	18	185.28	2,081.50	2,301.46	2,266.78	2,486.74	420.00	1,904.93	2,106.23	2,324.93	2,526.23	4.85	3.29	3%	2%
1,904	2086	8	185.28	2,302.67	2,522.63	2,487.95	2,707.91	420.00	2,107.34	2,308.64	2,527.34	2,728.64	3.28	1.73	2%	1%
2,087	2269	8	185.28	2,523.84	2,743.81	2,709.12	2,929.09	420.00	2,309.75	2,511.05	2,729.75	2,931.05	1.72	0.16	1%	0%
2,270	2452	2	185.28	2,745.02	2,964.98	2,930.30	3,150.26	420.00	2,512.16	2,713.47	2,932.16	3,133.47	0.16	(1.40)	0%	-1%
2,453	2635	2	185.28	2,966.19	3,186.15	3,151.47	3,371.43	420.00	2,714.57	2,915.88	3,134.57	3,335.88	(1.41)	(2.96)	-1%	-1%
2,636	2818	1	185.28	3,187.36	3,407.33	3,372.64	3,592.61	420.00	2,916.98	3,118.29	3,336.98	3,538.29	(2.97)	(4.53)	-1%	-2%
2,819	3001	0	185.28	3,408.54	3,628.50	3,593.82	3,813.78	420.00	3,119.40	3,320.70	3,539.40	3,740.70	(4.54)	(6.09)	-2%	-2%
3,002	7304	6	185.28	3,629.71	8,832.12	3,814.99	9,017.40	420.00	3,321.81	8,082.90	3,741.81	8,502.90	(6.10)	(42.87)	-2%	-6%

Annual Residential Bill Impacts of Small/Large Rate Relative to Existing NTSA Environs Rates

								$ 20.00	$ 1.51577	$ 1.51577 Small						
			$ 24.50	$ 1.13191	$ 1.13191			$ 35.00	$ 1.10668	$ 1.10668 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	28	62	294.00	-	31.13	294.00	325.13	240.00	-	41.68	240.00	281.68	(4.50)	(3.62)	-18%	-13%
29	55	27	294.00	32.26	62.26	326.26	356.26	240.00	43.20	83.37	283.20	323.37	(3.59)	(2.74)	-13%	-9%
56	83	23	294.00	63.39	93.38	357.39	387.38	240.00	84.88	125.05	324.88	365.05	(2.71)	(1.86)	-9%	-6%
84	110	28	294.00	94.51	124.51	388.51	418.51	240.00	126.57	166.73	366.57	406.73	(1.83)	(0.98)	-6%	-3%
111	138	39	294.00	125.64	155.64	419.64	449.64	240.00	168.25	208.42	408.25	448.42	(0.95)	(0.10)	-3%	-0%
139	165	43	294.00	156.77	186.77	450.77	480.77	240.00	209.93	250.10	449.93	490.10	(0.07)	0.78	-0%	2%
166	193	42	294.00	187.90	217.89	481.90	511.89	240.00	251.62	291.79	491.62	531.79	0.81	1.66	2%	4%
194	220	42	294.00	219.02	249.02	513.02	543.02	240.00	293.30	333.47	533.30	573.47	1.69	2.54	4%	6%
221	248	61	294.00	250.15	280.15	544.15	574.15	240.00	334.99	375.15	574.99	615.15	2.57	3.42	6%	7%
249	275	52	294.00	281.28	311.28	575.28	605.28	240.00	376.67	416.84	616.67	656.84	3.45	4.30	7%	9%
276	303	55	294.00	312.41	342.40	606.41	636.40	240.00	418.35	458.52	658.35	698.52	4.33	5.18	9%	10%
304	330	46	294.00	343.53	373.53	637.53	667.53	240.00	460.04	500.20	700.04	740.20	5.21	6.06	10%	11%
331	358	63	294.00	374.66	404.66	668.66	698.66	240.00	501.72	541.89	741.72	781.89	6.09	6.94	11%	12%
359	385	60	294.00	405.79	435.79	699.79	729.79	240.00	543.40	583.57	783.40	823.57	6.97	7.82	12%	13%
386	413	62	294.00	436.92	466.91	730.92	760.91	240.00	585.09	625.26	825.09	865.26	7.85	8.70	13%	14%
414	440	63	294.00	468.04	498.04	762.04	792.04	240.00	626.77	666.94	866.77	906.94	8.73	9.57	14%	15%
441	621	311	294.00	499.17	703.25	793.17	997.25	420.00	488.05	687.57	908.05	1,107.57	9.57	9.19	14%	11%
622	803	166	294.00	704.38	908.45	998.38	1,202.45	420.00	688.68	888.20	1,108.68	1,308.20	9.19	8.81	11%	9%
804	984	94	294.00	909.58	1,113.65	1,203.58	1,407.65	420.00	889.31	1,088.83	1,309.31	1,508.83	8.81	8.43	9%	7%
985	1165	63	294.00	1,114.79	1,318.86	1,408.79	1,612.86	420.00	1,089.94	1,289.46	1,509.94	1,709.46	8.43	8.05	7%	6%
1,166	1346	35	294.00	1,319.99	1,524.06	1,613.99	1,818.06	420.00	1,290.57	1,490.09	1,710.57	1,910.09	8.05	7.67	6%	5%
1,347	1528	26	294.00	1,525.20	1,729.27	1,819.20	2,023.27	420.00	1,491.20	1,690.72	1,911.20	2,110.72	7.67	7.29	5%	4%
1,529	1709	22	294.00	1,730.40	1,934.47	2,024.40	2,228.47	420.00	1,691.83	1,891.35	2,111.83	2,311.35	7.29	6.91	4%	4%
1,710	1890	12	294.00	1,935.61	2,139.68	2,229.61	2,433.68	420.00	1,892.46	2,091.99	2,312.46	2,511.99	6.90	6.53	4%	3%
1,891	2072	7	294.00	2,140.81	2,344.88	2,434.81	2,638.88	420.00	2,093.09	2,292.62	2,513.09	2,712.62	6.52	6.14	3%	3%
2,073	2253	4	294.00	2,346.01	2,550.09	2,640.01	2,844.09	420.00	2,293.72	2,493.25	2,713.72	2,913.25	6.14	5.76	3%	2%
2,254	2434	1	294.00	2,551.22	2,755.29	2,845.22	3,049.29	420.00	2,494.35	2,693.88	2,914.35	3,113.88	5.76	5.38	2%	2%
2,435	2615	5	294.00	2,756.42	2,960.50	3,050.42	3,254.50	420.00	2,694.98	2,894.51	3,114.98	3,314.51	5.38	5.00	2%	2%
2,616	2797	4	294.00	2,961.63	3,165.70	3,255.63	3,459.70	420.00	2,895.61	3,095.14	3,315.61	3,515.14	5.00	4.62	2%	2%
2,798	2978	2	294.00	3,166.83	3,370.91	3,460.83	3,664.91	420.00	3,096.25	3,295.77	3,516.25	3,715.77	4.62	4.24	2%	1%
2,979	3159	1	294.00	3,372.04	3,576.11	3,666.04	3,870.11	420.00	3,296.88	3,496.40	3,716.88	3,916.40	4.24	3.86	1%	1%

Residential Bill Impacts New Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
NORTH TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO NEW RATES

Annual Residential Bill Impacts of Small/Large Rate Structure in NTSA Incorporated Compared to Traditional Rate Structure

								$ 20.00	$ 1.51577	$ 1.51577	Small					
			$ 20.00	$ 1.41731	$ 1.41731			$ 35.00	$ 1.10668	$ 1.10668	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	28	261	$ 240.00	$ -	$ 38.98	$ 240.00	$ 278.98	$ 240.00	$ -	$ 41.68	$ 240.00	$ 281.68	$ -	$ 0.23	0%	1%
29	55	143	$ 240.00	$ 40.39	$ 77.95	$ 280.39	$ 317.95	$ 240.00	$ 43.20	$ 83.37	$ 283.20	$ 323.37	$ 0.23	$ 0.45	1%	2%
56	83	231	$ 240.00	$ 79.37	$ 116.93	$ 319.37	$ 356.93	$ 240.00	$ 84.88	$ 125.05	$ 324.88	$ 365.05	$ 0.46	$ 0.68	2%	2%
84	110	263	$ 240.00	$ 118.35	$ 155.90	$ 358.35	$ 395.90	$ 240.00	$ 126.57	$ 166.73	$ 366.57	$ 406.73	$ 0.69	$ 0.90	2%	3%
111	138	342	$ 240.00	$ 157.32	$ 194.88	$ 397.32	$ 434.88	$ 240.00	$ 168.25	$ 208.42	$ 408.25	$ 448.42	$ 0.91	$ 1.13	3%	3%
139	165	337	$ 240.00	$ 196.30	$ 233.86	$ 436.30	$ 473.86	$ 240.00	$ 209.93	$ 250.10	$ 449.93	$ 490.10	$ 1.14	$ 1.35	3%	3%
166	193	367	$ 240.00	$ 235.27	$ 272.83	$ 475.27	$ 512.83	$ 240.00	$ 251.62	$ 291.79	$ 491.62	$ 531.79	$ 1.36	$ 1.58	3%	4%
194	220	419	$ 240.00	$ 274.25	$ 311.81	$ 514.25	$ 551.81	$ 240.00	$ 293.30	$ 333.47	$ 533.30	$ 573.47	$ 1.59	$ 1.81	4%	4%
221	248	413	$ 240.00	$ 313.23	$ 350.78	$ 553.23	$ 590.78	$ 240.00	$ 334.99	$ 375.15	$ 574.99	$ 615.15	$ 1.81	$ 2.03	4%	4%
249	275	498	$ 240.00	$ 352.20	$ 389.76	$ 592.20	$ 629.76	$ 240.00	$ 376.67	$ 416.84	$ 616.67	$ 656.84	$ 2.04	$ 2.26	4%	4%
276	303	515	$ 240.00	$ 391.18	$ 428.74	$ 631.18	$ 668.74	$ 240.00	$ 418.35	$ 458.52	$ 658.35	$ 698.52	$ 2.26	$ 2.48	4%	4%
304	330	581	$ 240.00	$ 430.15	$ 467.71	$ 670.15	$ 707.71	$ 240.00	$ 460.04	$ 500.20	$ 700.04	$ 740.20	$ 2.49	$ 2.71	4%	5%
331	358	623	$ 240.00	$ 469.13	$ 506.69	$ 709.13	$ 746.69	$ 240.00	$ 501.72	$ 541.89	$ 741.72	$ 781.89	$ 2.72	$ 2.93	5%	5%
359	385	637	$ 240.00	$ 508.11	$ 545.66	$ 748.11	$ 785.66	$ 240.00	$ 543.40	$ 583.57	$ 783.40	$ 823.57	$ 2.94	$ 3.16	5%	5%
386	413	643	$ 240.00	$ 547.08	$ 584.64	$ 787.08	$ 824.64	$ 240.00	$ 585.09	$ 625.26	$ 825.09	$ 865.26	$ 3.17	$ 3.38	5%	5%
414	440	576	$ 240.00	$ 586.06	$ 623.62	$ 826.06	$ 863.62	$ 240.00	$ 626.77	$ 666.94	$ 866.77	$ 906.94	$ 3.39	$ 3.61	5%	5%
441	623	3,111	$ 240.00	$ 625.03	$ 882.84	$ 865.03	$ 1,122.84	$ 420.00	$ 488.05	$ 689.35	$ 908.05	$ 1,109.35	$ 3.58	$ (1.12)	5%	-1%
624	806	1,386	$ 240.00	$ 884.26	$ 1,142.07	$ 1,124.26	$ 1,382.07	$ 420.00	$ 690.46	$ 891.76	$ 1,110.46	$ 1,311.76	$ (1.15)	$ (5.86)	-1%	-5%
807	989	679	$ 240.00	$ 1,143.48	$ 1,401.29	$ 1,383.48	$ 1,641.29	$ 420.00	$ 892.87	$ 1,094.17	$ 1,312.87	$ 1,514.17	$ (5.88)	$ (10.59)	-5%	-8%
990	1172	266	$ 240.00	$ 1,402.71	$ 1,660.52	$ 1,642.71	$ 1,900.52	$ 420.00	$ 1,095.28	$ 1,296.59	$ 1,515.28	$ 1,716.59	$ (10.62)	$ (15.33)	-8%	-10%
1,173	1354	125	$ 240.00	$ 1,661.94	$ 1,919.74	$ 1,901.94	$ 2,159.74	$ 420.00	$ 1,297.69	$ 1,499.00	$ 1,717.69	$ 1,919.00	$ (15.35)	$ (20.06)	-10%	-11%
1,355	1537	66	$ 240.00	$ 1,921.16	$ 2,178.97	$ 2,161.16	$ 2,418.97	$ 420.00	$ 1,500.10	$ 1,701.41	$ 1,920.10	$ 2,121.41	$ (20.09)	$ (24.80)	-11%	-12%
1,538	1720	30	$ 240.00	$ 2,180.39	$ 2,438.20	$ 2,420.39	$ 2,678.20	$ 420.00	$ 1,702.51	$ 1,903.82	$ 2,122.51	$ 2,323.82	$ (24.82)	$ (29.53)	-12%	-13%
1,721	1903	18	$ 240.00	$ 2,439.61	$ 2,697.42	$ 2,679.61	$ 2,937.42	$ 420.00	$ 1,904.93	$ 2,106.23	$ 2,324.93	$ 2,526.23	$ (29.56)	$ (34.27)	-13%	-14%
1,904	2086	8	$ 240.00	$ 2,698.84	$ 2,956.65	$ 2,938.84	$ 3,196.65	$ 420.00	$ 2,107.34	$ 2,308.64	$ 2,527.34	$ 2,728.64	$ (34.29)	$ (39.00)	-14%	-15%
2,087	2269	8	$ 240.00	$ 2,958.06	$ 3,215.87	$ 3,198.06	$ 3,455.87	$ 420.00	$ 2,309.75	$ 2,511.05	$ 2,729.75	$ 2,931.05	$ (39.03)	$ (43.73)	-15%	-15%
2,270	2452	2	$ 240.00	$ 3,217.29	$ 3,475.10	$ 3,457.29	$ 3,715.10	$ 420.00	$ 2,512.16	$ 2,713.47	$ 2,932.16	$ 3,133.47	$ (43.76)	$ (48.47)	-15%	-16%
2,453	2635	2	$ 240.00	$ 3,476.52	$ 3,734.32	$ 3,716.52	$ 3,974.32	$ 420.00	$ 2,714.57	$ 2,915.88	$ 3,134.57	$ 3,335.88	$ (48.50)	$ (53.20)	-16%	-16%
2,636	2818	1	$ 240.00	$ 3,735.74	$ 3,993.55	$ 3,975.74	$ 4,233.55	$ 420.00	$ 2,916.98	$ 3,118.29	$ 3,336.98	$ 3,538.29	$ (53.23)	$ (57.94)	-16%	-16%
2,819	3001	0	$ 240.00	$ 3,994.97	$ 4,252.78	$ 4,234.97	$ 4,492.78	$ 420.00	$ 3,119.40	$ 3,320.70	$ 3,539.40	$ 3,740.70	$ (57.96)	$ (62.67)	-16%	-17%
3,002	7304	6	$ 240.00	$ 4,254.19	$ 10,351.66	$ 4,494.19	$ 10,591.66	$ 420.00	$ 3,321.81	$ 8,082.90	$ 3,741.81	$ 8,502.90	$ (62.70)	$ (174.06)	-17%	-20%

Annual Residential Bill Impacts of Small/Large Rate Structure in NTSA Environs Compared to Traditional Rate Structure

								$ 20.00	$ 1.51577	$ 1.51577	Small					
			$ 20.00	$ 1.41731	$ 1.41731			$ 35.00	$ 1.10668	$ 1.10668	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	28	62	$ 240.00	$ -	$ 38.98	$ 240.00	$ 278.98	$ 240.00	$ -	$ 41.68	$ 240.00	$ 281.68	$ -	$ 0.23	0%	1%
29	55	27	$ 240.00	$ 40.39	$ 77.95	$ 280.39	$ 317.95	$ 240.00	$ 43.20	$ 83.37	$ 283.20	$ 323.37	$ 0.23	$ 0.45	1%	2%
56	83	23	$ 240.00	$ 79.37	$ 116.93	$ 319.37	$ 356.93	$ 240.00	$ 84.88	$ 125.05	$ 324.88	$ 365.05	$ 0.46	$ 0.68	2%	2%
84	110	28	$ 240.00	$ 118.35	$ 155.90	$ 358.35	$ 395.90	$ 240.00	$ 126.57	$ 166.73	$ 366.57	$ 406.73	$ 0.69	$ 0.90	2%	3%
111	138	39	$ 240.00	$ 157.32	$ 194.88	$ 397.32	$ 434.88	$ 240.00	$ 168.25	$ 208.42	$ 408.25	$ 448.42	$ 0.91	$ 1.13	3%	3%
139	165	43	$ 240.00	$ 196.30	$ 233.86	$ 436.30	$ 473.86	$ 240.00	$ 209.93	$ 250.10	$ 449.93	$ 490.10	$ 1.14	$ 1.35	3%	3%
166	193	42	$ 240.00	$ 235.27	$ 272.83	$ 475.27	$ 512.83	$ 240.00	$ 251.62	$ 291.79	$ 491.62	$ 531.79	$ 1.36	$ 1.58	3%	4%
194	220	42	$ 240.00	$ 274.25	$ 311.81	$ 514.25	$ 551.81	$ 240.00	$ 293.30	$ 333.47	$ 533.30	$ 573.47	$ 1.59	$ 1.81	4%	4%
221	248	61	$ 240.00	$ 313.23	$ 350.78	$ 553.23	$ 590.78	$ 240.00	$ 334.99	$ 375.15	$ 574.99	$ 615.15	$ 1.81	$ 2.03	4%	4%
249	275	52	$ 240.00	$ 352.20	$ 389.76	$ 592.20	$ 629.76	$ 240.00	$ 376.67	$ 416.84	$ 616.67	$ 656.84	$ 2.04	$ 2.26	4%	4%
276	303	55	$ 240.00	$ 391.18	$ 428.74	$ 631.18	$ 668.74	$ 240.00	$ 418.35	$ 458.52	$ 658.35	$ 698.52	$ 2.26	$ 2.48	4%	4%
304	330	46	$ 240.00	$ 430.15	$ 467.71	$ 670.15	$ 707.71	$ 240.00	$ 460.04	$ 500.20	$ 700.04	$ 740.20	$ 2.49	$ 2.71	4%	5%
331	358	63	$ 240.00	$ 469.13	$ 506.69	$ 709.13	$ 746.69	$ 240.00	$ 501.72	$ 541.89	$ 741.72	$ 781.89	$ 2.72	$ 2.93	5%	5%
359	385	60	$ 240.00	$ 508.11	$ 545.66	$ 748.11	$ 785.66	$ 240.00	$ 543.40	$ 583.57	$ 783.40	$ 823.57	$ 2.94	$ 3.16	5%	5%
386	413	62	$ 240.00	$ 547.08	$ 584.64	$ 787.08	$ 824.64	$ 240.00	$ 585.09	$ 625.26	$ 825.09	$ 865.26	$ 3.17	$ 3.38	5%	5%
414	440	63	$ 240.00	$ 586.06	$ 623.62	$ 826.06	$ 863.62	$ 240.00	$ 626.77	$ 666.94	$ 866.77	$ 906.94	$ 3.39	$ 3.61	5%	5%
441	621	311	$ 240.00	$ 625.03	$ 880.56	$ 865.03	$ 1,120.56	$ 420.00	$ 488.05	$ 687.57	$ 908.05	$ 1,107.57	$ 3.58	$ (1.08)	5%	-1%
622	803	166	$ 240.00	$ 881.98	$ 1,137.51	$ 1,121.98	$ 1,377.51	$ 420.00	$ 688.68	$ 888.20	$ 1,108.68	$ 1,308.20	$ (1.11)	$ (5.78)	-1%	-5%
804	984	94	$ 240.00	$ 1,138.92	$ 1,394.45	$ 1,378.92	$ 1,634.45	$ 420.00	$ 889.31	$ 1,088.83	$ 1,309.31	$ 1,508.83	$ (5.80)	$ (10.47)	-5%	-8%
985	1,165	63	$ 240.00	$ 1,395.87	$ 1,651.40	$ 1,635.87	$ 1,891.40	$ 420.00	$ 1,089.94	$ 1,289.46	$ 1,509.94	$ 1,709.46	$ (10.49)	$ (15.16)	-8%	-10%
1,166	1,346	35	$ 240.00	$ 1,652.81	$ 1,908.34	$ 1,892.81	$ 2,148.34	$ 420.00	$ 1,290.57	$ 1,490.09	$ 1,710.57	$ 1,910.09	$ (15.19)	$ (19.85)	-10%	-11%
1,347	1,528	26	$ 240.00	$ 1,909.76	$ 2,165.29	$ 2,149.76	$ 2,405.29	$ 420.00	$ 1,491.20	$ 1,690.72	$ 1,911.20	$ 2,110.72	$ (19.88)	$ (24.55)	-11%	-12%
1,529	1,709	22	$ 240.00	$ 2,166.70	$ 2,422.23	$ 2,406.70	$ 2,662.23	$ 420.00	$ 1,691.83	$ 1,891.35	$ 2,111.83	$ 2,311.35	$ (24.57)	$ (29.24)	-12%	-13%
1,710	1,890	12	$ 240.00	$ 2,423.65	$ 2,679.18	$ 2,663.65	$ 2,919.18	$ 420.00	$ 1,892.46	$ 2,091.99	$ 2,312.46	$ 2,511.99	$ (29.27)	$ (33.93)	-13%	-14%
1,891	2,072	7	$ 240.00	$ 2,680.59	$ 2,936.12	$ 2,920.59	$ 3,176.12	$ 420.00	$ 2,093.09	$ 2,292.62	$ 2,513.09	$ 2,712.62	$ (33.96)	$ (38.63)	-14%	-15%
2,073	2,253	4	$ 240.00	$ 2,937.54	$ 3,193.07	$ 3,177.54	$ 3,433.07	$ 420.00	$ 2,293.72	$ 2,493.25	$ 2,713.72	$ 2,913.25	$ (38.65)	$ (43.32)	-15%	-15%
2,254	2,434	1	$ 240.00	$ 3,194.48	$ 3,450.01	$ 3,434.48	$ 3,690.01	$ 420.00	$ 2,494.35	$ 2,693.88	$ 2,914.35	$ 3,113.88	$ (43.34)	$ (48.01)	-15%	-16%
2,435	2,615	5	$ 240.00	$ 3,451.43	$ 3,706.96	$ 3,691.43	$ 3,946.96	$ 420.00	$ 2,694.98	$ 2,894.51	$ 3,114.98	$ 3,314.51	$ (48.04)	$ (52.70)	-16%	-16%
2,616	2,797	4	$ 240.00	$ 3,708.37	$ 3,963.90	$ 3,948.37	$ 4,203.90	$ 420.00	$ 2,895.61	$ 3,095.14	$ 3,315.61	$ 3,515.14	$ (52.73)	$ (57.40)	-16%	-16%
2,798	2,978	2	$ 240.00	$ 3,965.32	$ 4,220.85	$ 4,205.32	$ 4,460.85	$ 420.00	$ 3,096.25	$ 3,295.77	$ 3,516.25	$ 3,715.77	$ (57.42)	$ (62.09)	-16%	-17%
2,979	3,159	1	$ 240.00	$ 4,222.26	$ 4,477.79	$ 4,462.26	$ 4,717.79	$ 420.00	$ 3,296.88	$ 3,496.40	$ 3,716.88	$ 3,916.40	$ (62.12)	$ (66.78)	-17%	-17%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
NORTH TEXAS SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	92,867			$ 20.00		$ 1,857,340				
2			All Ccf	1,978,163		0.97752	$ 1,933,694				
3	Residential - Large	76,090			$ 35.00		$ 2,663,150				
4			All Ccf	4,301,264		0.56843	$ 2,444,967				
5	Residential Total							$ 8,899,151	$ 8,899,157	$ (6)	59.43 %
6											
7	Commercial	23,448			$ 75.00		$ 1,758,632				
8			All Ccf	6,198,077		0.50104	$ 3,105,485				
9											
10	Commercial Total							$ 4,864,117	$ 4,864,126	$ (9)	32.49 %
11											
12	Industrial	96			$ 850.00		$ 81,600				
13			All Ccf	237,283		0.29797	$ 70,703				
14	Industrial Total							$ 152,303	$ 152,304	$ (1)	1.02 %
15											
16	Public Authority	2,532			$ 200.00		$ 506,423				
17			All Ccf	1,433,677		$ 0.38460	$ 551,392				
18	Public Authority Total							$ 1,057,815	$ 1,057,813	$ 2	7.06 %
19											
20	<u>Total Revenue - All Classes</u>										
21											
22	Recommended Rate Revenue							$ 14,973,386	$ 14,973,400		
23	Current Rate Revenue							$ 13,619,898	$ 13,619,898		
24	Revenue Change							$ 1,353,488	$ 1,353,502		
25											
26	Schedule A - Revenue Deficiency								$ 1,353,502		
									$ -		

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
BORGER-SKELLYTOWN SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CURRENT AND RECOMMENDED RATES

		Current Rates		
Description		BSSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c)	(d)
Residential			Small	Large
Customer Charge		$16.48	$20.00	$35.00
Usage Rates	All Ccf	$0.21548	$0.39138	$0.12861
Commercial				
Customer Charge - Sales		$39.11	$75.00	
Usage Rates	All Ccf	$0.29344	$0.12162	
Customer Charge - Transportation		$254.11	$500.00	
Usage Rates	All Ccf	$0.29344	$0.29344	
Public Authority				
Customer Charge - Sales		$49.07	$200.00	
Usage Rates	All Ccf	$0.23148	$0.07069	
Customer Charge - Transportation		$254.07	$500.00	
Usage Rates	All Ccf	$0.23148	$0.07069	
School and Municipal				
Customer Charge - Sales		$56.80	$200.00	
Usage Rates	All Ccf	$0.37651	$0.07069	
		$261.80	$500.00	
Customer Charge - Transportation	All Ccf	$0.37651	$0.07069	
Usage Rates				

Customer Bill Impacts

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
BORGER-SKELLYTOWN SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CUSTOMER BILL IMPACTS

	Year-Round Average Bill		Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
BSSA Incorporated and Environs	$ 41.62	$ 52.15	$ 10.53	25.3%
Residential - Large				
BSSA Incorporated and Environs	$ 77.07	$ 87.25	$ 10.18	13.2%
Commercial				
BSSA Incorporated and Environs	$ 220.44	$ 212.38	$ (8.06)	-3.7%
Public Authority				
BSSA Incorporated and Environs	$ 258.60	$ 357.45	$ 98.85	38.2%
School and Municipal				
BSSA Incorporated and Environs	$ 576.80	$ 519.21	$ (57.59)	-10.0%

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

	BSSA
	Year-Round
Residential - Small	40
Residential - Large	96
Commercial	256
Public Authority	324
School and Municipal	657

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
BORGER-SKELLYTOWN SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

Residential Bill Impacts Existing Rates

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of Small/Large Rate Relative to Existing BSSA Rates

								$ 20.00	$ 0.80686	$ 0.80686	Res A					
			$ 16.48	$ 0.63096	$ 0.63096			$ 35.00	$ 0.54409	$ 0.54409	Res B					
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	43	48	$ 197.76	$ -	$ 27.01	$ 197.76	$ 224.77	$ 240.00	$ -	$ 34.54	$ 240.00	$ 274.54	$ 3.52	$ 4.15	21%	22%
44	86	43	$ 197.76	$ 27.64	$ 54.03	$ 225.40	$ 251.79	$ 240.00	$ 35.35	$ 69.09	$ 275.35	$ 309.09	$ 4.16	$ 4.78	22%	23%
87	128	70	$ 197.76	$ 54.66	$ 81.04	$ 252.42	$ 278.80	$ 240.00	$ 69.89	$ 103.63	$ 309.89	$ 343.63	$ 4.79	$ 5.40	23%	23%
129	171	103	$ 197.76	$ 81.67	$ 108.05	$ 279.43	$ 305.81	$ 240.00	$ 104.44	$ 138.17	$ 344.44	$ 378.17	$ 5.42	$ 6.03	23%	24%
172	214	147	$ 197.76	$ 108.68	$ 135.06	$ 306.44	$ 332.82	$ 240.00	$ 138.98	$ 172.72	$ 378.98	$ 412.72	$ 6.04	$ 6.66	24%	24%
215	257	224	$ 197.76	$ 135.70	$ 162.08	$ 333.46	$ 359.84	$ 240.00	$ 173.53	$ 207.26	$ 413.53	$ 447.26	$ 6.67	$ 7.29	24%	24%
258	300	258	$ 197.76	$ 162.71	$ 189.09	$ 360.47	$ 386.85	$ 240.00	$ 208.07	$ 241.81	$ 448.07	$ 481.81	$ 7.30	$ 7.91	24%	25%
301	343	322	$ 197.76	$ 189.72	$ 216.10	$ 387.48	$ 413.86	$ 240.00	$ 242.61	$ 276.35	$ 482.61	$ 516.35	$ 7.93	$ 8.54	25%	25%
344	385	293	$ 197.76	$ 216.73	$ 243.12	$ 414.49	$ 440.88	$ 240.00	$ 277.16	$ 310.89	$ 517.16	$ 550.89	$ 8.56	$ 9.17	25%	25%
386	428	342	$ 197.76	$ 243.75	$ 270.13	$ 441.51	$ 467.89	$ 240.00	$ 311.70	$ 345.44	$ 551.70	$ 585.44	$ 9.18	$ 9.80	25%	25%
429	471	308	$ 197.76	$ 270.76	$ 297.14	$ 468.52	$ 494.90	$ 240.00	$ 346.24	$ 379.98	$ 586.24	$ 619.98	$ 9.81	$ 10.42	25%	25%
472	514	323	$ 197.76	$ 297.77	$ 324.16	$ 495.53	$ 521.92	$ 240.00	$ 380.79	$ 414.52	$ 620.79	$ 654.52	$ 10.44	$ 11.05	25%	25%
515	557	293	$ 197.76	$ 324.79	$ 351.17	$ 522.55	$ 548.93	$ 240.00	$ 415.33	$ 449.07	$ 655.33	$ 689.07	$ 11.07	$ 11.68	25%	26%
558	599	280	$ 197.76	$ 351.80	$ 378.18	$ 549.56	$ 575.94	$ 240.00	$ 449.87	$ 483.61	$ 689.87	$ 723.61	$ 11.69	$ 12.31	26%	26%
600	642	238	$ 197.76	$ 378.81	$ 405.19	$ 576.57	$ 602.95	$ 240.00	$ 484.42	$ 518.16	$ 724.42	$ 758.16	$ 12.32	$ 12.93	26%	26%
643	685	204	$ 197.76	$ 405.83	$ 432.21	$ 603.59	$ 629.97	$ 240.00	$ 518.96	$ 552.70	$ 758.96	$ 792.70	$ 12.95	$ 13.56	26%	26%
686	858	710	$ 197.76	$ 432.84	$ 541.60	$ 630.60	$ 739.36	$ 420.00	$ 373.25	$ 467.04	$ 793.25	$ 887.04	$ 13.55	$ 12.31	26%	20%
859	1,032	367	$ 197.76	$ 542.23	$ 651.00	$ 739.99	$ 848.76	$ 420.00	$ 467.58	$ 561.37	$ 887.58	$ 981.37	$ 12.30	$ 11.05	20%	16%
1,033	1,205	212	$ 197.76	$ 651.63	$ 760.40	$ 849.39	$ 958.16	$ 420.00	$ 561.92	$ 655.71	$ 981.92	$ 1,075.71	$ 11.04	$ 9.80	16%	12%
1,206	1,379	107	$ 197.76	$ 761.03	$ 869.79	$ 958.79	$ 1,067.55	$ 420.00	$ 656.25	$ 750.04	$ 1,076.25	$ 1,170.04	$ 9.79	$ 8.54	12%	10%
1,380	1,552	52	$ 197.76	$ 870.42	$ 979.19	$ 1,068.18	$ 1,176.95	$ 420.00	$ 750.58	$ 844.38	$ 1,170.58	$ 1,264.38	$ 8.53	$ 7.29	10%	7%
1,553	1,725	31	$ 197.76	$ 979.82	$ 1,088.59	$ 1,177.58	$ 1,286.35	$ 420.00	$ 844.92	$ 938.71	$ 1,264.92	$ 1,358.71	$ 7.28	$ 6.03	7%	6%
1,726	1,899	16	$ 197.76	$ 1,089.22	$ 1,197.98	$ 1,286.98	$ 1,395.74	$ 420.00	$ 939.25	$ 1,033.04	$ 1,359.25	$ 1,453.04	$ 6.02	$ 4.78	6%	4%
1,900	2,072	13	$ 197.76	$ 1,198.61	$ 1,307.38	$ 1,396.37	$ 1,505.14	$ 420.00	$ 1,033.59	$ 1,127.38	$ 1,453.59	$ 1,547.38	$ 4.77	$ 3.52	4%	3%
2,073	2,245	5	$ 197.76	$ 1,308.01	$ 1,416.77	$ 1,505.77	$ 1,614.53	$ 420.00	$ 1,127.92	$ 1,221.71	$ 1,547.92	$ 1,641.71	$ 3.51	$ 2.26	3%	2%
2,246	2,419	2	$ 197.76	$ 1,417.41	$ 1,526.17	$ 1,615.17	$ 1,723.93	$ 420.00	$ 1,222.26	$ 1,316.05	$ 1,642.26	$ 1,736.05	$ 2.26	$ 1.01	2%	1%
2,420	2,592	5	$ 197.76	$ 1,526.80	$ 1,635.57	$ 1,724.56	$ 1,833.33	$ 420.00	$ 1,316.59	$ 1,410.38	$ 1,736.59	$ 1,830.38	$ 1.00	$ (0.25)	1%	-0%
2,593	2,766	3	$ 197.76	$ 1,636.20	$ 1,744.96	$ 1,833.96	$ 1,942.72	$ 420.00	$ 1,410.93	$ 1,504.72	$ 1,830.93	$ 1,924.72	$ (0.25)	$ (1.50)	-0%	-1%
2,767	2,939	2	$ 197.76	$ 1,745.59	$ 1,854.36	$ 1,943.35	$ 2,052.12	$ 420.00	$ 1,505.26	$ 1,599.05	$ 1,925.26	$ 2,019.05	$ (1.51)	$ (2.76)	-1%	-2%
2,940	3,112	3	$ 197.76	$ 1,854.99	$ 1,963.76	$ 2,052.75	$ 2,161.52	$ 420.00	$ 1,599.60	$ 1,693.39	$ 2,019.60	$ 2,113.39	$ (2.76)	$ (4.01)	-2%	-2%
3,113	7,187	3	$ 197.76	$ 1,964.39	$ 4,534.57	$ 2,162.15	$ 4,732.33	$ 420.00	$ 1,693.93	$ 3,910.26	$ 2,113.93	$ 4,330.26	$ (4.02)	$ (33.51)	-2%	-8%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
BORGER-SKELLYTOWN SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO NEW RATES

Annual Residential Bill Impacts of Small/Large Rate Structure in BSSA Compared to Traditional Rate Structure

								$20.00	$0.80686	$0.80686 Small						
			$20.00	$0.75211	$0.75211			$35.00	$0.54409	$0.54409 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	43	48	$240.00	$ -	$32.20	$240.00	$272.20	$240.00	$ -	$34.54	$240.00	$274.54	$ -	$0.20	0%	1%
44	86	43	$240.00	$32.95	$64.40	$272.95	$304.40	$240.00	$35.35	$69.09	$275.35	$309.09	$0.20	$0.39	1%	2%
87	128	70	$240.00	$65.15	$96.60	$305.15	$336.60	$240.00	$69.89	$103.63	$309.89	$343.63	$0.40	$0.59	2%	2%
129	171	103	$240.00	$97.35	$128.80	$337.35	$368.80	$240.00	$104.44	$138.17	$344.44	$378.17	$0.59	$0.78	2%	3%
172	214	147	$240.00	$129.55	$161.00	$369.55	$401.00	$240.00	$138.98	$172.72	$378.98	$412.72	$0.79	$0.98	3%	3%
215	257	224	$240.00	$161.75	$193.20	$401.75	$433.20	$240.00	$173.53	$207.26	$413.53	$447.26	$0.98	$1.17	3%	3%
258	300	258	$240.00	$193.95	$225.40	$433.95	$465.40	$240.00	$208.07	$241.81	$448.07	$481.81	$1.18	$1.37	3%	4%
301	343	322	$240.00	$226.15	$257.60	$466.15	$497.60	$240.00	$242.61	$276.35	$482.61	$516.35	$1.37	$1.56	4%	4%
344	385	293	$240.00	$258.35	$289.80	$498.35	$529.80	$240.00	$277.16	$310.89	$517.16	$550.89	$1.57	$1.76	4%	4%
386	428	342	$240.00	$290.55	$322.00	$530.55	$562.00	$240.00	$311.70	$345.44	$551.70	$585.44	$1.76	$1.95	4%	4%
429	471	308	$240.00	$322.75	$354.20	$562.75	$594.20	$240.00	$346.24	$379.98	$586.24	$619.98	$1.96	$2.15	4%	4%
472	514	323	$240.00	$354.95	$386.40	$594.95	$626.40	$240.00	$380.79	$414.52	$620.79	$654.52	$2.15	$2.34	4%	4%
515	557	293	$240.00	$387.15	$418.60	$627.15	$658.60	$240.00	$415.33	$449.07	$655.33	$689.07	$2.35	$2.54	4%	5%
558	599	280	$240.00	$419.35	$450.80	$659.35	$690.80	$240.00	$449.87	$483.61	$689.87	$723.61	$2.54	$2.73	5%	5%
600	642	238	$240.00	$451.55	$483.00	$691.55	$723.00	$240.00	$484.42	$518.16	$724.42	$758.16	$2.74	$2.93	5%	5%
643	685	204	$240.00	$483.75	$515.20	$723.75	$755.20	$240.00	$518.96	$552.70	$758.96	$792.70	$2.93	$3.13	5%	5%
686	858	710	$240.00	$515.95	$645.60	$755.95	$885.60	$420.00	$373.25	$467.04	$793.25	$887.04	$3.11	$0.12	5%	0%
859	1,032	367	$240.00	$646.35	$776.00	$886.35	$1,016.00	$420.00	$467.58	$561.37	$887.58	$981.37	$0.10	$(2.89)	0%	-3%
1,033	1,205	212	$240.00	$776.75	$906.40	$1,016.75	$1,146.40	$420.00	$561.92	$655.71	$981.92	$1,075.71	$(2.90)	$(5.89)	-3%	-6%
1,206	1,379	107	$240.00	$907.15	$1,036.80	$1,147.15	$1,276.80	$420.00	$656.25	$750.04	$1,076.25	$1,170.04	$(5.91)	$(8.90)	-6%	-8%
1,380	1,552	52	$240.00	$1,037.55	$1,167.20	$1,277.55	$1,407.20	$420.00	$750.58	$844.38	$1,170.58	$1,264.38	$(8.91)	$(11.90)	-8%	-10%
1,553	1,725	31	$240.00	$1,167.95	$1,297.60	$1,407.95	$1,537.60	$420.00	$844.92	$938.71	$1,264.92	$1,358.71	$(11.92)	$(14.91)	-10%	-12%
1,726	1,899	16	$240.00	$1,298.36	$1,428.01	$1,538.36	$1,668.01	$420.00	$939.25	$1,033.04	$1,359.25	$1,453.04	$(14.93)	$(17.91)	-12%	-13%
1,900	2,072	13	$240.00	$1,428.76	$1,558.41	$1,668.76	$1,798.41	$420.00	$1,033.59	$1,127.38	$1,453.59	$1,547.38	$(17.93)	$(20.92)	-13%	-14%
2,073	2,245	5	$240.00	$1,559.16	$1,688.81	$1,799.16	$1,928.81	$420.00	$1,127.92	$1,221.71	$1,547.92	$1,641.71	$(20.94)	$(23.92)	-14%	-15%
2,246	2,419	2	$240.00	$1,689.56	$1,819.21	$1,929.56	$2,059.21	$420.00	$1,222.26	$1,316.05	$1,642.26	$1,736.05	$(23.94)	$(26.93)	-15%	-16%
2,420	2,592	5	$240.00	$1,819.96	$1,949.61	$2,059.96	$2,189.61	$420.00	$1,316.59	$1,410.38	$1,736.59	$1,830.38	$(26.95)	$(29.94)	-16%	-16%
2,593	2,766	3	$240.00	$1,950.36	$2,080.01	$2,190.36	$2,320.01	$420.00	$1,410.93	$1,504.72	$1,830.93	$1,924.72	$(29.95)	$(32.94)	-16%	-17%
2,767	2,939	2	$240.00	$2,080.76	$2,210.41	$2,320.76	$2,450.41	$420.00	$1,505.26	$1,599.05	$1,925.26	$2,019.05	$(32.96)	$(35.95)	-17%	-18%
2,940	3,112	3	$240.00	$2,211.17	$2,340.82	$2,451.17	$2,580.82	$420.00	$1,599.60	$1,693.39	$2,019.60	$2,113.39	$(35.96)	$(38.95)	-18%	-18%
3,113	7,187	3	$240.00	$2,341.57	$5,405.25	$2,581.57	$5,645.25	$420.00	$1,693.93	$3,910.26	$2,113.93	$4,330.26	$(38.97)	$(109.58)	-18%	-23%

Proof of Revenue

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
BORGER-SKELLYTOWN SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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 - Rate Option A	41,941			$ 20.00		$ 838,820				
2			All Ccf	1,671,053		0.39138	$ 654,017				
3	Residential - Rate Option B	18,386			$ 35.00		$ 643,510				
4			All Ccf	1,765,559		0.12861	$ 227,069				
5	Residential Total							$ 2,363,415	$ 2,363,400	$ 15	75.47 %
6											
7	Commercial	5,793			$ 75.00		$ 434,490				
8			All Ccf	1,481,765		0.12162	$ 180,212				
9	Commercial Total							$ 614,702	$ 614,707	$ (4)	19.63 %
10											
11	Public Authority	636			$ 200.00		$ 127,200				
12			All Ccf	373,665		$ 0.07069	$ 26,414				
13	Total Public Authority							$ 153,614	$ 153,616	$ (2)	4.91 %
14											
15	<u>Total Revenue - All Classes</u>										
16											
17	Recommended Rate Revenue							$ 3,131,732	$ 3,131,723		
18	Current Rate Revenue							$ 2,566,315	$ 2,566,315		
19	Revenue Change							$ 565,417	$ 565,408		
20											
21	Schedule A - Revenue Deficiency								$ 565,408		
									-		

STATE OF MARYLAND §
§
COUNTY OF MONTGOMERY §

AFFIDAVIT OF PAUL H. RAAB

BEFORE ME, the undersigned authority, on this day personally appeared Paul H. Raab who having been placed under oath by me did depose as follows:

1. "My name is Paul H. Raab. I am over the age of eighteen (18) and fully competent to make this affidavit. I am employed as an Economic Consultant. The facts stated herein are true and correct based upon my personal knowledge.

2. I have prepared the foregoing Direct Testimony and the information contained in that document is true and correct to the best of my knowledge."

Further affiant sayeth not.

Paul H. Raab

SUBSCRIBED AND SWORN TO BEFORE ME by the said Paul H. Raab on this 16 day of June 2022.

DAVID KIM
Notary Public - State of Maryland
Montgomery County
My Commission Expires May 1, 2023

Notary Public in and for the State of Maryland

NOTARY PUBLIC

PUBLIC NOTICE OF PROPOSED RATE CHANGE
NATURAL GAS UTILITY RATES

On June 30, 2022, Texas Gas Service Company, a Division of ONE Gas, Inc. (“TGS” or the “Company”), filed a Statement of Intent to Change Rates (“Statement of Intent”) in the Borger Skellytown Service Area (“BSSA”), the North Texas Service Area (“NTSA”) and the West Texas Service Area ("WTSA") with the Railroad Commission of Texas (“Commission”) and with the Cities of Andrews, Anthony, Barstow, Borger, Clint, Crane, Dell City, El Paso, Horizon City, McCamey, Monahans, Pecos, Pyote, San Elizario, Skellytown, Socorro, Thorntonville, Vinton, Wickett, and Wink, Texas for the gas utility rates charged by the Company to customers. The proposed change in rates will affect all residential, commercial, commercial transportation, commercial air conditioning, industrial, industrial transportation, public authority, public authority transportation, public authority air conditioning, school and municipal, school and municipal transportation, municipal water pumping, compressed natural gas, compressed natural gas transportation, electrical cogeneration, electrical cogeneration transportation, and standby service customers within the cities listed above and unincorporated areas of the BSSA, NTSA, and WTSA. The proposed effective date of the requested rate changes is August 30, 2022.

In addition to changing rates, TGS proposes to consolidate the BSSA, the NTSA and the WTSA into one new service area called the West North Service Area ("WNSA"). Consistent with its request for consolidation, the Company has developed its proposed rates based on the system-wide cost of providing service to the proposed WNSA on a combined basis. With regard to cities within the NTSA, the Company's consolidation request will result in a rate reduction. To facilitate uniform rate implementation within the NTSA and other service areas affected by the consolidation request, the Company will file a request with the cities of Aledo, Breckenridge, Bryson, Graford, Graham, Hudson Oaks, Jacksboro, Mineral Wells, Millsap, Weatherford and Willow Park, Texas to implement the resulting rate reduction upon receiving approval of the requested consolidation and the resulting WNSA rates. The proposed rates and tariffs are expected to increase the Company’s annual system-wide revenues within the proposed WNSA by approximately $13.0 million or 6.27% including gas cost or 10.19% excluding gas cost. The proposed change in rates does constitute a “major change” as that term is defined by Section 104.101 of the Texas Utilities Code because the proposed rates will increase the total aggregate revenues of the Company in the proposed WNSA by more than two and one-half percent. The proposed change in rates will not become effective until similar changes have become effective within the nearest incorporated city.

The Company proposes to implement the rates included in Table 1 below:

TABLE 1 – Proposed Rate Changes for Incorporated and Unincorporated/Environs Customers[1]

Customer Class	BSSA Inc	BSSA Env	NTSA Inc	NTSA Env	WTSA Inc	WTSA Env	Proposed WNSA
	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Residential							
Customers Affected	4,606	421	12,631	1,448	239,815	24,737	
Customer Charge	$16.48	$16.48	$15.44	$24.50	$23.53	$23.53	$20.00 (Small) $35.00 (Large)
Ccf	$0.21548	$0.21548	$0.67101	$0.59366	$0.09317	$0.09317	$0.41173 (Small) $0.00264 (Large)
Commercial							
Customers Affected	447	36	1,793	161	13,870	897	
Customer Charge	$39.11	$39.11	$47.80	$76.33	$63.58	$63.58	$75.00
Ccf	$0.29344	$0.29344	$0.68165	$0.60165	$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.06808
Commercial Transportation							
Customers Affected					20		
Customer Charge	$254.11	$254.11	$250.00	$286.33	$424.58	$424.58	$500.00
Ccf	$0.29344	$0.29344	$0.57978	$0.57978	$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.06808

[1] As indicated previously, the Company is not seeking to change rates within the NTSA Cities at this time. The Company is, nevertheless, providing notice of the rate reduction the NTSA Cities will receive if the Company's proposed rates are approved as filed.

Customer Class	BSSA Inc	BSSA Env	NTSA Inc	NTSA Env	WTSA Inc	WTSA Env	Proposed WNSA
	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Commercial Air Conditioning (Withdrawing)							
Customers Affected					128	14	
Customer Charge					$63.58	$63.58	Reclass to Commercial
Ccf					*October - April* $0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf) *May – September* $0.06223 (First 500 Ccf) $0.04223 (All Over 500 Ccf)	*October - April* $0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf) *May – September* $0.06223 (First 500 Ccf) $0.04223 (All Over 500 Ccf)	
Industrial							
Customers Affected			8		29	3	
Customer Charge			$308.59	$509.26	$857.20	$857.20	$850.00
Ccf			$0.62874	$0.55395	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.08875
Industrial Transportation							
Customers Affected					11	4	
Customer Charge			$250.00	$509.26	$424.58	$424.58	$1,050.00
Ccf			$0.55395	$0.55395	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.12458 (First 500 Ccf) $0.10458 (All Over 500 Ccf)	$0.08875

Customer Class	BSSA Inc	BSSA Env	NTSA Inc	NTSA Env	WTSA Inc	WTSA Env	Proposed WNSA
	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Public Authority							
Customers Affected	9	2	180	31	952	112	
Customer Charge	$49.07	$49.07	$101.32	$160.93	$195.79	$195.79	$200.00
Ccf	$0.23148	$0.23148	$0.61329	$0.54101	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11113
Public Authority Transportation							
Customers Affected					7		
Customer Charge	$254.07	$254.07	$250.00	$325.93	$495.79	$495.79	$500.00
All Ccf	$0.23148	$0.23148	$0.54101	$0.54101	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11113
Public Authority Air Conditioning (Withdrawing)							
Customers Affected					5		
Customer Charge					$195.79	$195.79	Reclass to Public Authority
Ccf					*October – April* $0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf) *May – September* $0.08461 (First 500 Ccf) $0.06461 (All Over 500 Ccf)	*October – April* $0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf) *May – September* $0.08461 (First 500 Ccf) $0.06461 (All Over 500 Ccf)	

Customer Class	BSSA Inc	BSSA Env	NTSA Inc	NTSA Env	WTSA Inc	WTSA Env	Proposed WNSA
	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Electrical Cogeneration							
Customers Affected							
Customer Charge					$424.58	$424.58	$700.00
Ccf					*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05260 (First 5,000 Ccf) $0.04260 (Next 95,000 Ccf) $0.03260 (Next 300,000 Ccf) $0.02260 (All Over 400,000 Ccf) *May – September* $0.04259 (First 5,000 Ccf) $0.03258 (Next 95,000 Ccf) $0.02259 (Next 300,000 Ccf) $0.01258 (All Over 400,000 Ccf)

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Electrical Cogeneration Transportation							
Customers Affected					2		
Customer Charge					$424.58	$424.58	$700.00
Ccf					*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05696 (First 5,000 Ccf) $0.04696 (Next 95,000 Ccf) $0.03696 (Next 300,000 Ccf) $0.02696 (All Over 400,000 Ccf) *May – September* $0.04695 (First 5,000 Ccf) $0.03694 (Next 95,000 Ccf) $0.02695 (Next 300,000 Ccf) $0.01694 (All Over 400,000 Ccf)	*October – April* $0.05260 (First 5,000 Ccf) $0.04260 (Next 95,000 Ccf) $0.03260 (Next 300,000 Ccf) $0.02260 (All Over 400,000 Ccf) *May – September* $0.04259 (First 5,000 Ccf) $0.03258 (Next 95,000 Ccf) $0.02259 (Next 300,000 Ccf) $0.01258 (All Over 400,000 Ccf)
School and Municipal (Withdrawing)							
Customers Affected	41	1					
Customer Charge	$56.80	$56.80					Reclass to Public Authority
Ccf	$0.37651	$0.37651					
School and Municipal Transportation (Withdrawing)							
Customers Affected							
Customer Charge	$261.80	$261.80					Reclass to Public Authority Transportation
Ccf	$0.37651	$0.37651					

Customer Class	BSSA Inc	BSSA Env	NTSA Inc	NTSA Env	WTSA Inc	WTSA Env	Proposed WNSA
	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Municipal Water Pumping (Withdrawing)							
Customers Affected					18	2	
Customer Charge					$768.75	$768.75	Reclass to Public Authority
Ccf					$0.06111 (First 5,000 Ccf) $0.05111 (All Over 5,000 Ccf)		
Compressed Natural Gas (Proposed)							
Customers Affected							
Customer Charge							$150.00
Ccf							$0.07652
Compressed Natural Gas Transportation (Reclassed from Commercial)							
Customers Affected					1		Reclassed from Commercial
Customer Charge					$424.58	$424.58	$450.00
Ccf					$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.08223 (First 500 Ccf) $0.06223 (All Over 500 Ccf)	$0.07652

	Incorporated ("Inc") and Unincorporated/Environs ("Env") Current Rates						
Customer Class	**BSSA Inc**	**BSSA Env**	**NTSA Inc**	**NTSA Env**	**WTSA Inc**	**WTSA Env**	**Proposed WNSA**
Compressed Natural Gas Transportation (Reclassed from Public Authority)							
Customers Affected					3		Reclassed from Public Authority
Customer Charge					$495.79	$495.79	$450.00
Ccf					$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.11461 (First 500 Ccf) $0.09461 (All Over 500 Ccf)	$0.07652

TABLE 2 – Impact on Average Bill[2]

Customer Class (Average Monthly Usage)	Current Average Monthly Bill With Gas Cost	Proposed Average Monthly Bill With Gas Cost	Proposed Monthly Dollar Change	Percentage Change with Gas Cost	Percentage Change without Gas Cost
Residential - Small (24 Ccf)[3]					
WTSA Inc and Env	$35.50	$39.89	$4.39	12.37%	16.06%
NTSA Inc	$44.59	$39.89	$(4.70)	(10.54)%	(5.35)%
NTSA Env	$51.78	$39.89	$(11.89)	(22.96)%	(22.91)%
BSSA Inc and Env	$31.21	$39.89	$8.68	27.81%	41.20%
Residential – Large (55 Ccf)[4]					
WTSA Inc and Env	$51.01	$58.02	$7.01	13.74%	22.56%
NTSA Inc	$82.35	$58.02	$(24.33)	(29.54)%	(33.14)%
NTSA Env	$87.13	$58.02	$(29.11)	(33.41)%	(38.71)%
BSSA Inc and Env	$50.91	$58.02	$7.11	13.97%	25.90%

[2] As indicated previously, the Company is not seeking to change rates within the NTSA Cities at this time. The Company is, nevertheless, providing notice of the rate reduction the NTSA Cities will receive if the Company's proposed rates are approved as filed.

[3] Calculations for current Residential- Small are based on the current rates for the WTSA, NTSA and BSSA for usage at 24 Ccf.

[4] Calculations for current Residential – Large rates are based on the current rates for the WTSA, NTSA and BSSA for usage at 55 Ccf.

Customer Class (Average Monthly Usage)	Current Average Monthly Bill With Gas Cost	Proposed Average Monthly Bill With Gas Cost	Proposed Monthly Dollar Change	Percentage Change with Gas Cost	Percentage Change without Gas Cost
Commercial (225 Ccf)					
WTSA Inc and Env	$172.93	$183.39	$10.46	6.05%	10.03%
NTSA Inc	$322.38	$183.39	$(138.99)	(43.11)%	(55.12)%
NTSA Env	$332.91	$183.39	$(149.52)	(44.91)%	(57.35)%
BSSA Inc and Env	$196.65	$183.39	$(13.26)	(6.74)%	(12.42)%
Commercial Air Conditioning[5] (317 Ccf)					
WTSA Inc and Env	$215.66	$227.89	$12.23	5.67%	10.39%
Industrial (2,813 Ccf)					
WTSA Inc and Env	$2,275.65	$2,262.91	$(12.74)	(0.56)%	(3.56)%
NTSA Inc	$3,591.72	$2,262.91	$(1,328.81)	(37.00)%	(47.07)%
NTSA Env	$3,581.98	$2,262.91	$(1,319.07)	(36.83)%	(46.82)%
Public Authority (662 Ccf)					
WTSA Inc and Env	$535.41	$547.09	$11.68	2.18%	1.92%
NTSA Inc	$863.21	$547.09	$(316.12)	(36.62)%	(46.06)%
NTSA Env	$875.00	$547.09	$(327.91)	(37.48)%	(47.28)%
BSSA Inc and Env	$475.13	$547.09	$71.96	15.15%	36.61%
Public Authority Air Conditioning[6] (2,018 Ccf)					
WTSA Inc and Env	$1,206.33	$1,258.63	$52.30	4.34%	8.25%
Municipal Water Pumping[7] (657 Ccf)					
WTSA Inc and Env	$1,073.85	$544.44	$(529.41)	(49.30)%	(66.25)%
School and Municipal[8] (6,194 Ccf)					
BSSA Inc and Env	$4,956.43	$3,449.25	$(1,507.18)	(30.41)%	(62.72)%
Commercial Transportation (27,991 Ccf)					
WTSA Inc and Env	$12,908.33	$13,400.49	$492.16	3.81%	10.53%
Industrial Transportation (36,450 Ccf)					

[5] Proposed reclass to Commercial rate schedule.
[6] Proposed reclass to Public Authority rate schedule.
[7] Proposed reclass to Public Authority rate schedule.
[8] Proposed reclass to Public Authority rate schedule.

Customer Class (Average Monthly Usage)	Current Average Monthly Bill With Gas Cost	Proposed Average Monthly Bill With Gas Cost	Proposed Monthly Dollar Change	Percentage Change with Gas Cost	Percentage Change without Gas Cost
WTSA Inc and Env	$18,221.64	$18,602.53	$380.89	2.09%	0.90%
Public Authority Transportation (63,145 Ccf)					
WTSA Inc and Env	$30,689.79	$32,320.44	$1,630.65	5.31%	16.01%
CNG Transportation					
WTSA Inc and Env[9] **(113,338 Ccf)**	$50,941.58	$53,641.47	$2,699.89	5.30%	21.84%
WTSA Inc and Env[10] **(316,687 Ccf)**	$151,885.50	$149,076.28	$(2,809.22)	(1.85)%	(18.99)%
Cogeneration Transportation (91,007 Ccf)					
WTSA Inc and Env	$39,065.97	$39,899.16	$833.19	2.13%	(0.52)%

Table 2 calculations are based on a $0.41 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 changes to Miscellaneous Service Charges included in Table 3 below.

Table 3 – Miscellaneous Service Charges[11]

Service Charges	BSSA, NTSA, WTSA	
	Current	Proposed
Read-In Fee	$10.00	$15.00
Special Handling Fee	$6.00	$15.00
Expedited Service Fee and Overtime Rate	$67.50	$65.00
Reconnect Fee Regular Labor Rate	$45.00	$48.00
Reconnect Fee After Hours Rate	$67.50	$65.00
No Access Fee	$10.00	$15.00
Customer Requested Meter Test (Up to 1500 Cubic Feet per Hour)	$80.00	$150.00
Customer Requested Meter Test (Over 1500 Cubic Feet per Hour)	$100.00	$200.00
Customer Requested Meter Test (Orifice Meters)	$100.00	$200.00
Collection Fee	$12.00	$15.00

9 Proposed reclass from Commercial rate schedule.
10 Proposed reclass from Public Authority rate schedule.
11 As indicated previously, the Company is not seeking to change rates within the NTSA Cities at this time. The Company is, nevertheless, providing notice of the rate reduction the NTSA Cities will receive if the Company's proposed rates are approved as filed.

Service Charges	BSSA, NTSA, WTSA	
	Current	Proposed
Special Read Fee	$10.00	$18.00
Customer Requested Meter Exchange without Electronic Radio Transponder	$100.00	Withdrawn
Unauthorized Consumption Fee	$20.00	$30.00 plus expenses
Meter Removal Fee	$50.00	$25.00
Account Research Fee	$25.00/hour	$20.00/hour
Meter Tampering Fee	$100.00	$150.00

The proposed changes in Table 3 reflect a net increase of $376,717 in revenues.

In addition to requesting new rates and consolidation of service areas, TGS is requesting: (1) Commission approval of new depreciation rates for Direct and Division distribution and general plant; (2) the Commission find the approvals of the administrative orders by the Gas Services Department of the Commission based on the Accounting Order in Gas Utilities Docket ("GUD") No. 10695 are reasonable and accurate; (3) the Commission find that expenses for Winter Storm Uri and COVID-19 that are contained in regulatory assets authorized by the Commission are reasonable, necessary and accurate; (4) capital investment made in the proposed WNSA through December 31, 2021, including capital investment in the Company's Interim Rate Adjustment ("IRA") filings made since the last rate cases in the WTSA, NTSA and BSSA pursuant to Texas Utilities Code § 104.301, is deemed prudent; (5) form of notice for the proposed Rate Schedule PIT be approved; (6) approval of including Excess Deferred Income Taxes ("EDIT") in base rates, with discontinuance of the EDIT Rider, to return excess deferred income taxes to customers; and (7) 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 WNSA tariffs are approved, TGS proposes to withdraw the existing BSSA, NTSA and WTSA tariffs to reflect the new WNSA rates in Table 1 and/or related changes necessary to reflect consolidation, including revisions to reflect application of tariffs to the WNSA. For all proposed rate schedules for General Sales and Transportation customers, TGS proposes a revision to the "Other Adjustments" section to remove references to Rate Schedule EDIT-Rider, add references to Rate Schedules URI-Rider, Uncollected GRIP Charges (UGC), Rate Case Expense (RCE), RCE-Env, and Pipeline Safety Fee (PSF), and remove references to standby charges under "Conditions." For Residential Rate Schedules 10, 15, 1Y and 1Z, TGS proposes to add residential builders to the "Applicability" sections, designate Rate Schedules 10 and 1Z as Small Residential and add new 15 and 1Y Large Residential rate schedules. For Commercial Rate Schedules, TGS proposes to withdraw Rate Schedules 21 and 2A (Commercial Air Conditioning) and serve these customers under Rate Schedules 20 and 2Z. For Industrial Rate Schedules 30 and 3Z, TGS proposes revisions to the "Applicability" section to revise the description of industrial customers. For Public Authority Rate Schedules, TGS proposes to withdraw Rate Schedules 41 and 4A (Public Authority Air Conditioning), Rate Schedules 42 and 4B (Municipal Water Pumping), and Rate Schedules 48 and 4H (School and Municipal) and serve these customers under Rate Schedules 40 and 4Z. For Unmetered Gas Light Rate Schedules 70 and 7Z, TGS proposes new rate schedules that provide a mechanism to provide unmetered gas service to customers for gas lighting only. For Rate Schedules CNG-1 and CNG-1-ENV, TGS proposes new rate schedules for compressed natural gas service to be used as motor fuel for non-residential customers. For Transportation Rate Schedules T-1, T-1-ENV and T-TERMS, TGS proposes to add rates for Compressed Natural Gas and Electrical Cogeneration service; include definitions for commercial, electrical cogeneration, and industrial service under "Definitions;" add Section 1.3 to clarify Customer and Company rights and responsibilities; make an administrative correction in section 1.5(d); add clarifying language to section 1.6(d) to address upstream pipeline costs that may be incurred by the Company; and add section 1.8 regarding Liability Limitations. For the Cost of Gas Clauses 1-INC and 1-ENV, TGS proposes to add clarifying language to section B.3 to include other renewable sources of natural gas; add section B.5 for a Customer Rate Relief charge applicable to certain WNSA customers (authorized by the Commission's Financing Order in Case No. OS-21-00007061); add clarifying language to sections B, D, E, F and I to make consistent with approved Cost of Gas clauses in GUD Nos. 10656, 10739, 10766, and 10928; include language for the use of financial instruments in sections B.3, B.6, B.8, H, and I.5 in the incorporated tariff to make consistent with the recently approved cost of gas clause in GUD No. 10928. For Rate Schedule WNA, TGS proposes updated weather factors for each class consistent with weather normalization calculations in this case. Proposed Rate Schedules RCE and RCE-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. Proposed Rate Schedule UGC-Rider provides a new tariff to recover uncollected Gas Reliability Infrastructure Program ("GRIP") charges from certain WNSA customers (to the extent these costs are not recovered through base rates). For the Rules of Service, TGS proposes revisions for consistency with the Commission's Quality of Service Rules; updating § 1.3, Definitions, so all definitions are consistent with definitions in the approved Rules of Service in GUD Nos. 10739, 10766, and 10928 as well as add a definition for "electrical cogeneration service," and removing the definition for "power generation service" to establish consistency with terminology used across all proposed WNSA tariffs; revisions to § 3 to include language for the availability of rate schedules on the Company's website; revisions to § 4.4 to remove a reference to the Company's curtailment plans and § 4.4(iv) to include curtailment language consistent with the new Commission Rule § 7.455; revisions to § 4.9 to add language regarding force majeure situations to the limitation of liability provision; revision to § 4.6, § 7.4, § 7.7, § 9.1 and § 9.6 to provide for electronic billing and notice; revisions to § 9.9 (previously § 20.1) to update the language to reflect the current plan description for Average Payment Plan; revisions to the table in § 13.1 (previously § 11.1) to include all WNSA atmospheric and standard serving pressures; revisions to § 15 (previously § 21), Fees and Deposits, to establish greater consistency for service fees and deposits among the Company's service areas; and to withdraw the rules of service addenda WTSA-Env 7-45; WTSA-Env 7-46; WTSA-EFV; NTSA-Env 7-46 and BSSA-Env 7-46, as these provisions have been included within the proposed WNSA Rules of Service in Sections 7.5, 7.7 and 8.3(f). Finally, TGS proposes to withdraw Standby Service Rate Schedule SS, Dell City Cost of Gas Clauses 1-INC-DC and 1-ENV-DC, and Rate Schedule EDIT-Rider.

Persons with specific questions or desiring additional information about this filing may contact TGS at 1-800-700-2443. Complete copies of the filed Statement of Intent, including all proposed rates and schedule changes, are available for inspection at TGS's offices located at 712 N. Florida, Borger, TX 79008, 4600 Pollard St., El Paso, Texas 79930; 315 E. 4th St., Monahans, Texas 79756, and 1525 Texas Drive, Weatherford, Texas 76086, or 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 __, 2022. Please reference Case No. 00009896. Any affected person within an incorporated area may contact his or her city council.

Este aviso tiene como fin informarle a los clientes de Texas Gas Service Company, una Division de ONE Gas, Inc. ("TGS" o la "Compañía") de el área del Oeste de Texas, Norte de Texas y Borger/Skellytown que la Compañía ha presentado una solicitud para aumentar las tarifas del servicio público de gas. Esta solicitud afecta a todos los clientes residenciales, comerciales, transporte comercial, aire acondicionado comercial, industriales, transporte industrial, de autoridad pública, transporte de autoridad pública, aire acondicionado de autoridad pública, escolar y municipal, transporte escolar y municipal, bombeo de agua municipal, de gas natural comprimido, transporte de gas natural comprimido, cogeneracion electrica, transporte de cogeneracion electrica y standby. Las personas que deseen hacer preguntas específicas o recibir más información sobre esta solicitud pueden comunicarse con la Compañía llamando al 1-800-700-2443 o envié un mensaje de correo electrónico a la dirección ODCInformationCenterWebTeam@onegas.com. Cualquier persona afectada puede presentar por escrito comentarios o una protesta sobre el cambio de tarifas propuesto a la Sección de Servicios de la Oficina de la División de Audiencias, Comisión Ferroviaria de Texas, P.O. Box 12967, Austin, Texas 78711-2967, en cualquier momento dentro de los 30 días siguientes a la fecha en que este cambio entraría en vigencia o el __ de septiembre del 2022. Por favor, haga referencia a Caso No. 00009896. Cualquier persona afectada dentro de un área incorporada puede contactar a su Consejo Municipal.

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC., STATEMENT OF INTENT TO CHANGE GAS UTILITY RATES WITHIN THE INCORPORATED AREAS OF THE BORGER SKELLYTOWN SERVICE AREA AND WEST TEXAS SERVICE AREA

PROTECTIVE AGREEMENT

This Protective Agreement shall govern the use of all information deemed confidential or highly sensitive confidential information by a party providing information to the Cities or responding to discovery requests, including information whose confidentiality may be under dispute in this matter.

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 AGREEMENT"** (hereinafter referred to as "protected materials"). The documents shall be consecutively Bates Stamped when necessary. On or before the date the protected materials or highly sensitive materials (as this term is defined in Paragraph 6 herein) are provided to the Commission or parties, the producing party shall file and deliver to each party to the proceeding a written statement, which may be in the form of an objection, indicating: (1) any and all exemptions to the Public Information Act, TEX. GOV'T CODE ANN. Chapter 552, claimed to be applicable to the alleged protected materials; (2) the reasons supporting the providing party's claim that the responsive information is exempt from the public disclosure under the Public Information Act and subject to treatment as protected materials; and (3) that counsel for the providing party has reviewed the information sufficiently to state in good faith that the information is exempt from public disclosure under the Public Information Act and merits protected materials designation.

2. Materials Excluded from Protected Materials Designation

Protected materials shall not include any information or document contained in the public files of the Railroad Commission of Texas, 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 Agreement 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 Agreement as a party to the city-level Statement of Intent proceeding filed by Texas Gas Service Company, a division of ONE Gas, Inc. ("TGS"), including TGS or a representative for a city within the Borger Skellytown Service Area and the West Texas Service Area, or other party with standing to participate in the proceeding.

4. Definition of "producing party"

A "producing party" is defined for purposes of this Protective Agreement as TGS, a city within the Borger Skellytown Service Area and the West Texas Service Area, or any other party with standing to participate in the proceeding.

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 AGREEMENT."

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 this proceeding 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 Agreement. 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 this proceeding, who have primary responsibility for utility regulation. The authorized representatives for the Cities for the purpose of access to these materials shall consist of its respective counsel of record in this proceeding and associated attorneys, paralegals, economists, statisticians, accountants, consultants, or other persons employed or retained by those agencies and directly engaged in this proceeding. 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 Agreement:

> I certify my understanding that the protected materials are provided to me pursuant to the terms and restrictions of the Protective Agreement in this proceeding, and that I have been given a copy of it and have read the Protective Agreement 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 Agreement and shall be used only for the purpose of this proceeding. If the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this proceeding, 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 Agreement:

> I certify that I am eligible to have access to highly sensitive protected materials under the terms of the Protective Agreement in this proceeding.

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 Agreement, 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 Agreement 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 Agreement, 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 Cities 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 Agreement. 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 Agreement. Cities 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 Cities.

11. Changes to Protective Agreement

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 Agreement 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.

12. 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.

13. 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 Agreement 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.

14. Compliance with Legal Requirements

This Protective Agreement 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.

15. 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.

16. Effect of Violation of Court Order

In the event of a breach of the provisions contained in Paragraph 15, 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.

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 Agreement in this proceeding, and that I have been given a copy of it and have read the Protective Agreement 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 Agreement and shall be used only for the purpose of this proceeding. If the information contained in the protected materials is obtained from independent sources that did not obtain such information from documents obtained in this proceeding, 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 Agreement in this proceeding.

____________________	____________________
Signature	Party Represented
____________________	____________________
Printed Name	Date

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
	(a)	(b)	(c)
1	SCHEDULE A	Summary of Revenue Requirement	McTaggart
2	WKP A.a	Proof of Revenue Requirement	McTaggart
3	WKP A.b	Customer Allocation Factors	McTaggart
4	SCHEDULE B	Rate Base	McTaggart
5	WKP B.a	Summary of Plant Adjustments	McTaggart
6	SCHEDULE B-1	Materials and Supplies	McTaggart
7	SCHEDULE B-2	Prepayments	McTaggart
8	WKP B-2.a.1	Prepayments - TGS Division	Borgstadt
9	WKP B-2.b.1	Prepayments - Corporate Allocated through Distrigas	Borgstadt
10	SCHEDULE B-3	Rule 8.209 Regulatory Asset	McTaggart
11	WKP B-3.a	Rule 8.209 Regulatory Asset	McTaggart
12	SCHEDULE B-4	Pension and OPEB Regulatory Asset	McTaggart
13	WKP B-4.a	Pension and OPEB Regulatory Asset	McTaggart
14	SCHEDULE B-5	Prepaid Pension Asset	McTaggart/Smith
15	SCHEDULE B-6	Cash Working Capital	Lyons
16	SCHEDULE B-7	Customer Deposits	McTaggart
17	SCHEDULE B-8	Customer Advances	McTaggart
18	SCHEDULE B-9	Accumulated Deferred Income Taxes	Simpson
19	SCHEDULE B-10	Unamortized Excess Accumulated Deferred Income Taxes	McTaggart/Husen
20	SCHEDULE B-11	Regulatory Assets	McTaggart
21	SCHEDULE C	Total Plant in Service - Direct and Allocated	McTaggart/Borgstadt
22	WKP C.a	Plant in Service - Service Area Direct	McTaggart
23	WKP Ca.1	Fort Bliss	McTaggart

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
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24	WKP C.b	Plant in Service - TGS Division	Borgstadt
25	WKP C.c	Plant in Service - Corporate	Bortstadt
26	SCHEDULE C-1	Total Completed Construction Not Classified (CCNC) - Direct and Allocated	McTaggart/Borgstadt
27	WKP C-1.a	CCNC - Service Area Direct	McTaggart
28	WKP C-1.a.1	Fort Bliss	McTaggart
29	WKP C-1.b	CCNC - TGS Division	Borgstadt
30	WKP C-1.c	CCNC - Corporate	Borgstadt
31	SCHEDULE D	Total Accumulated Reserves for Depreciation and Amortization - Direct and Allocated	McTaggart/Borgstadt
32	WKP D.a	Total Accumulated Reserves for Depreciation and Amortization - Direct	McTaggart
33	WKP D.a.1	Fort Bliss	McTaggart
34	WKP D.b	Total Accumulated Reserves for Depreciation and Amortization - TGS Division	McTaggart/Borgstadt
35	WKP D.c	Total Accumulated Reserves for Depreciation and Amortization - Corporate	McTaggart/Borgstadt
36	SCHEDULE E	Cost of Capital	Fairchild
37	SCHEDULE F	Federal Income Tax	McTaggart
38	SCHEDULE G	Summary of Operating Revenue and Expense Adjustments	McTaggart/Serna/Borgstadt
39	SCHEDULE G	Summary of Operating Revenue and Expenses	McTaggart/Serna/Borgstadt
40	WKP G.a.1	Operating Revenue and Expense Adjustments	McTaggart/Serna/Borgstadt
41	WKP G.a.2	Operating Revenue and Expense Per Book	McTaggart/Serna/Borgstadt
42	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	Borgstadt
43	SCHEDULE G-1	Remove Gas Revenue, Cost of Gas and Related Taxes	Serna

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
	(a)	(b)	(c)
44	SCHEDULE G-2	Normalize Gas Sales Revenue	Serna
45	SCHEDULE G-3	Normalize Other Utility Revenue	Serna
46	SCHEDULE G-4	Base Payroll Adjustment	Borgstadt
47	WKP G-4.a	Base Payroll Expense	Borgstadt
48	WKP G-4.b	Test Year Payroll	Borgstadt
49	WKP G-4.c	December Base Payroll	Borgstadt
50	SCHEDULE G-5	Overtime Payroll Adjustment	Borgstadt
51	WKP G-5.a	Overtime Payroll Expense	Borgstadt
52	SCHEDULE G-6	Benefits and Payroll Tax Adjustment	Borgstadt
53	WKP G-6.a	Benefits and Payroll Tax Expense	Borgstadt
54	WKP G-6.b	Benefits and Taxes	Borgstadt
55	SCHEDULE G-7	Pension and OPEB	McTaggart
56	SCHEDULE G-8	Incentive Compensation	Borgstadt
57	SCHEDULE G-9	Miscellaneous Adjustments	McTaggart/Borgstadt
58	WKP G-9.a	Miscellaneous Adjustments - Direct Service Area	McTaggart
59	WKP G-9.b	Miscellaneous Adjustments - Shared Services	Borgstadt
60	WKP G-9.c	Miscellaneous Adjustments Meals and Hotels - Shared Services	Borgstadt
61	SCHEDULE G-10	Rents and Leases	McTaggart/Borgstadt
62	WKP G-10.a	Rents and Leases - Direct Service Area	McTaggart
63	WKP G-10.b	Rents and Leases - Shared Services	Borgstadt
64	SCHEDULE G-11	Interest on Customer Deposits	McTaggart
65	SCHEDULE G-12	Uncollectible Expense	McTaggart
66	SCHEDULE G-13	Injuries and Damages	Borgstadt

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
	(a)	(b)	(c)
67	WKP G-13.a	Injuries and Damages Workpaper	Borgstadt
68	SCHEDULE G-14	Advertising Expense	McTaggart/Borgstadt
69	SCHEDULE G-15	Depreciation and Amortization Expense	McTaggart/Borgstadt
70	WKP G-15.a.1	Depreciation and Amortization Expense - Direct Service Area	McTaggart
71	WKP G-15.a.2	Fully Depreciated Plant - Direct Service Area	McTaggart
72	WKP G-15.b.1	Depreciation and Amortization Expense - TGS Division	Borgstadt
73	WKP G-15.b.2	Fully Depreciated Plant - TGS Division	Borgstadt
74	WKP G-15.c.1	Depreciation and Amortization Expense - Corporate	Borgstadt
75	WKP G-15.c.2	Fully Depreciated Plant - Corporate	Borgstadt
76	SCHEDULE G-16	Ad Valorem Tax Expense	McTaggart
77	WKP G-16.a	Plant in Service - Direct, Ad Valorem Tax Workpaper	McTaggart
78	WKP G-16.b	CCNC - Direct, Ad Valorem Tax Workpaper	McTaggart
79	WKP G-16.c	Accumulated Reserves for Depreciation and Amortization - Direct, Ad Valorem Tax Workpaper	McTaggart
80	SCHEDULE G-17	Franchise ("Gross Margin") Tax Expense	McTaggart
81	SCHEDULE G-18	Stores Load Clearing	McTaggart
82	SCHEDULE G-19	Transportation and Work Equipment Clearing	McTaggart
83	SCHEDULE G-20	Regulatory Expense Amortization	McTaggart
84	SCHEDULE G-21	Distrigas Allocation Percentage	Borgstadt
85	WKP G-21.a	Distrigas Allocation Percentage Workpaper	Borgstadt
86	SCHEDULE G-22	Causal Allocation Percentage	Borgstadt
87	WKP G-22.a	Causal Allocation Factor	Borgstadt
88	SCHEDULE G-23	Pipeline Integrity Testing Expense	McTaggart

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
	(a)	(b)	(c)
89	SCHEDULE G-24	Excess Deferred Income Tax Amortization	McTaggart/Husen
89	Study Summary	Class Cost of Service Study Summary	Serna
90	Study Summary for Rate Design	Class Cost of Service Study Summary for Revenue Allocations	Serna
91	Classified Rate Base	Classified Rate Base	Serna
92	Classified Cost of Service	Classified Cost of Service	Serna
93	Classification Factors	Classification Factors	Serna
94	Allocated Rate Base	Allocated Rate Base	Serna
95	Allocated Cost of Service	Allocated Cost of Service	Serna
96	Allocation Factors	Allocation Factors	Serna
97	WKP Plant	Plant and Depreciation Workpaper	Serna
98	WKP Admin&Gen	Administrative & General Workpaper	Serna
99	WKP Selected Data	Selected Data Workpaper - Volumes, Bills, Margin, Odorization, Distrigas, Allocation Factors, Mains (Customer) Percentage	Serna
100	903 Factors	Account 903 Factors Summary for CCOSS	Serna
101	904 Factors	Account 904 Factors Summary for CCOSS	Serna
102	Billing Determinants Summary	Billing Determinants Summary for CCOSS	Serna
103	Customer Deposit Factors	Customer Deposit Factors Summary for CCOSS	Serna
104	Mains Study Summary	Mains Study Summary for CCOSS	Serna
105	Meters & Regulator Factors	Meter & Regulator Factors Summar for COSS	Serna
106	Odorization Summary	Odorization Summary for COSS	Serna
107	Peak Demand	Peak Demand Summary for COSS	Serna
108	Service Charges Summary	Service Charges Summary for COSS	Serna
109	Service Line Factors	Service Line Factors Summary for COSS	Serna
110	As Adj. Revenues Summary	Summary of As Adjusted Revenues for CCOSS	Serna

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

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LINE NO.	SCHEDULE OR WORKPAPER	DESCRIPTION	SPONSOR
	(a)	(b)	(c)
111	Class Revenue Allocation	Class Revenue Allocation	Serna
112	Proof of Revenue	Proof of Revenue	Raab
113	Current & Rec Rates	Current and Recommended Rates	Raab
114	WKP Current & Rec Rates	Current and Recommended Rates Workpaper	Raab
115	Customer Bill Impacts	Customer Bill Impacts	Raab
116	Residential Bill Impacts New Rates	Annual Residential Bill Impacts - Proposed A/B Rate Structure compared to Traditional Rate Structure	Raab
117	Residential Bill Impacts Existing Rates	Annual Residential Bill Impacts - Proposed A/B Rate Structure compared to Existing Rate Structure	Raab
118	Residential	Residential Rate Design	Raab
119	Commercial	Commercial Rate Design	Raab
120	Public Authority	Public Authority Rate Design	Raab
121	Industrial	Industrial Rate Design	Raab

SCHEDULE A

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

SUMMARY OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$607,843,675	$(18,447,720)	$589,395,955
2	Rate of Return	E	7.7692%	7.7692%	7.7692%
3	Required Return		$47,224,579	$(1,433,240)	$45,791,339
4	Cost of Gas	G	82,080,953	(82,080,953)	0
5	Depreciation and Amortization Expense	G	20,550,706	3,663,001	24,213,706
6	Taxes Other Than Income Taxes	G	8,487,702	1,426,896	9,914,598
7	Interest on Customer Deposits	G	47,985	(43,282)	4,703
8	Transmission and High-Pressure Distribution Expense	G	921,889	786,888	1,708,777
9	Distribution Expense	G	17,262,118	61,060	17,323,179
10	Customer Accounts Expense	G	6,457,651	(578,763)	5,878,888
11	Administrative and General Expense	G	29,989,964	(4,181,506)	25,808,458
12	Federal Income Tax	F	9,930,081	(300,280)	9,629,801
13	Revenue Requirement before Gross-up		$222,953,628	$(82,680,180)	$140,273,448
14	Test Year Adjusted Revenue	G	198,052,464	(70,586,689)	127,465,775
15	Revenue Deficiency		$24,901,164	$(12,093,491)	$12,807,673
	Gross-up for Revenue Related Expenses:	Factors:			
16	Uncollectible Expense	0.0069250			
17	Texas Franchise Tax	0.0075000			
18	Gross-Up Percentage	0.0144250	364,457	(177,002)	187,455
19	Total Revenue Deficiency		$25,265,620	$(12,270,493)	$12,995,128
20	Total Revenue Requirement (Line 13 + Line 18)		$223,318,085	$(82,857,182)	$140,460,903

WKP A.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROOF OF REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	AMOUNT	AMOUNT
		(a)	(b)
1	Total Revenue Requirement		$140,460,903
	Less:		
2	Depreciation	$24,213,706	
3	Taxes	9,914,598	
4	Interest on Deposits	4,703	
5	Transmission Expense	1,708,777	
6	Distribution Expense	17,323,179	
7	Customer Accounting	5,878,888	
8	Administrative and General Expense	25,808,458	
9	Gross-Up Expenses	187,455	
10	Total Operating Expense	$85,039,763	85,039,763
11	Less Interest on Long-Term Debt		9,700,385
12	Taxable Income	$45,720,756	$45,720,756
13	Add back disallowed parking expense		135,440
14	Tax Rate	21.%	
15	Income Taxes	$9,629,801	
16	Less Tax Adjustments	0	
17	Net Income Tax	$9,629,801	$9,629,801
18	Net Income		$36,090,955
19	Rate Base	$589,395,955	
20	Wtd Cost of Equity (Common + Preferred)	6.12%	
21	Required Return	$36,090,955	$36,090,955
22	Variance		$(0)

WKP A.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	Borger/Skellytown	5,551	0.809%
3	CTX	318,920	46.493%
4	North Texas	16,193	2.361%
5	RGV	64,518	9.406%
6	WTX	280,764	40.931%
7	Total TGS	685,946	100.000%
8	Service Area Factor for this Filing	302,509	44.101%

Based on Test Year Average Total Billed Customers

SCHEDULE B

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	$706,866,431	$(5,743,784)	$701,122,648
2	Completed Construction Not Classified	C-1	66,158,611	(7,466)	66,151,145
3	Accumulated Reserves for Depreciation and Amortization	D	(137,030,363)	6,352,014	(130,678,349)
4	Net Plant in Service		$635,994,679	$600,764	$636,595,444
	OTHER RATE BASE ITEMS				
5	Materials and Supplies Inventory	B-1	$6,310,496	$(634,921)	$5,675,575
6	Prepayments	B-2	3,298,974	(6,833)	3,292,141
7	Rule 8.209 Regulatory Asset - DIMP Deferrals	B-3	1,843,921	0	1,843,921
8	Regulatory Assets	B-11	$1,788,715	0	1,788,715
9	Pension & OPEB Regulatory Asset	B-4	896,913	0	896,913
10	Prepaid Pension Asset	B-5	19,113,633	0	19,113,633
11	Cash Working Capital	B-6	0	$(3,535,483)	(3,535,483)
	NON-INVESTOR SUPPLIED FUNDS				
12	Customer Deposits	B-7	$(7,838,323)	$0	$(7,838,323)
13	Customer Advances	B-8	(3,132,466)	0	(3,132,466)
14	Accumulated Deferred Taxes	B-9	(50,432,867)	0	(50,432,867)
15	Excess Deferred Income Taxes	B-10	0	(14,871,247)	(14,871,247)
16	Total Rate Base		$607,843,675	$(18,447,720)	$589,395,955

WKP B.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

SUMMARY OF PLANT ADJUSTMENTS

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK	ADJUSTMENTS	ADJUSTED TEST YEAR
			(a)	(b)	(c)
1	PLANT IN SERVICE	Schedule C	$706,866,431		$701,122,648
2	Excludable Meals and Hotel	WKP C.a, C.b and C.c		$(17,481)	
3	Plant Miscoded to Service Area	WKP C.a		(91,267)	
4	Reclassification to Correction Location Adjustment	WKP C.a		1,030,487	
5	TGS Direct Post Test Year Adjustment to include plant	WKP C.a		0	
6	Asset Not Used by TGS Division	WKP C.b		(341)	
7	Asset with Insufficient Documentation	WKP C.b		(179,492)	
8	Remove TGS Direct Costs	WKP C.b		(61,083)	
9	TGS DIV Post Test Year Adjustment to include plant	WKP C.b		0	
10	Remove Duplicate Vertex Sales Tax	WKP C.b		(3,857)	
11	Include Customer Information Center Stackers	WKP C.b		11,825	
12	Vertex Duplicate Sales Tax	WKP C.c		20	
13	Artwork	WKP C.c		(5,937)	
14	ONE Gas Aviation	WKP C.c		(1,638,544)	
15	ONE Gas Aviation Internet	WKP C.c		(9,435)	
16	ONE Gas Aviation Furniture	WKP C.c		(69,659)	
17	ONE Gas Post Test Year Adjustment to include plant	WKP C.c		0	
18	ONE Gas Foundation Software	WKP C.c		(156)	
19	Removal of Retiring Asset	WKP C.a, C.a.1, C.b		(4,653,662)	
20	Remove Miscodeed Charges	WKP C.c		(627)	
21	Remove Drone Training	WKP C.c		(180)	
22	Remove Promotion Items	WKP C.c		(234)	
23	Remove Items related to RTCS TYE 2017	WKP C.c		(33,706)	
24	Remove TGS Specific Project			(20,454)	
25	Total		$706,866,431	$(5,743,784)	$701,122,648

WKP B.a

26	COMPLETED CONSTRUCTION NOT CLASSIFIED	Schedule C-1	$66,158,611		$66,151,145
27	Excludable Meals and Hotel	WKP C-1.a and C-1.c		(3)	
28	TGS Direct Post Test Year Adjustment to include plant	WKP C-1.a and C-1.c		0	
29	Plant Miscoded to Service Area	WKP C-1.a		0	
30	Remove TGS Direct Costs	WKP C-1.b		(1,053)	
	TGS DIV Post Test Year Adjustment to include plant	WKP C-1.b		0	
	Remove ONG Specific Project	WKP C-1.c		(4,492)	
31	Remove Aviation	WKP C-1.c		(1,917)	
32	ONE Gas Post Test Year Adjustment to include plant	WKP C-1.c		0	
33	Total		$66,158,611	$(7,466.00)	$66,151,145
34	ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION	Schedule D	$(137,030,363)		$(130,678,349)
35	Plant Miscoded to Service Area	WKP D.a		$(1,441.47)	
36	Removal of Retiring Asset	WKP D.a, D.a.1, D.b		4,653,662	
37	Pro Forma Adjustment Reserve Rebalancing	WKP D.a, D.a.1		209,176	
38	TGS Direct Post Test Year Adjustment to include reserve	WKP D.a		0	
39	Asset Not Used by TGS Division	WKP D.b		303	
40	Asset with Insufficient Documentation	WKP D.b		179,048	
41	Remove Land Depreciation	WKP D.b		1,910	
42	Remove TGS Direct Project	WKP D.b		2,019	
43	Include Customer Information Center Stackers	WKP D.b		(196)	
44	Pro Forma Adjustment Reserve Rebalancing	WKP D.b		(209,176)	
45	Artwork	WKP D.c		1,940	
46	ONE Gas Aviation	WKP D.c		1,487,994	
47	ONE Gas Foundation Software	WKP D.c		2,184	
48	Remove Lease Incentive	WKP D.c		15,026	
49	Remove Land Depreciation	WKP D.c		1	
50	Remove ONG Specific Asset	WKP D.c		117	
51	Remove KGS Specific Asset	WKP D.c		7	
52	Remove TGS Specific Asset	WKP D.c		9,440	
53	ONE Gas Post Test Year Adjustment to include reserve	WKP D.c		0	
54	Total		$(137,030,363)	$6,352,014	$(130,678,349)

SCHEDULE B-1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

MATERIALS AND SUPPLIES

LINE NO.	DESCRIPTION	DIRECT INVENTORY	DIRECT STORES LOAD	OMA INVENTORY	TOTAL
		(a)	(b)	(c)	(d)
1	December 31, 2020	$3,921,974	$12,805	$1,660,736	$5,595,515
2	January 31, 2021	3,899,846	47,455	1,477,370	$5,424,671
3	February 28, 2021	3,839,372	50,724	1,384,687	$5,274,783
4	March 31, 2021	4,042,601	86,415	1,283,933	$5,412,949
5	April 30, 2021	3,936,710	131,647	1,315,137	$5,383,493
6	May 31, 2021	3,981,967	160,531	1,433,468	$5,575,966
7	June 30, 2021	4,082,598	99,232	1,390,127	$5,571,957
8	July 31, 2021	3,972,720	198,031	1,574,354	$5,745,105
9	August 31, 2021	3,933,142	203,244	1,688,213	$5,824,599
10	September 30, 2021	3,828,815	156,561	1,651,722	$5,637,099
11	October 31, 2021	4,189,014	152,102	1,571,053	$5,912,168
12	November 30, 2021	4,240,641	143,055	1,729,977	$6,113,672
13	December 31, 2021	4,681,386	94,991	1,534,119	$6,310,496
14	Total Balances at Month-End	$52,550,786	$1,536,793	$19,694,895	$73,782,474
15	13 Month Average	$4,042,368	$118,215	$1,514,992	$5,675,575

Source: SCH B-1 TGS Materials and Supplies _WNSA.xlsx
Source: SCH B-1 Stores Balances_WNSA.xlsx
Source: SCH B-1 Corporate Materials and Supplies - WNSA.xlsx

SCHEDULE B-2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PREPAYMENTS

LINE NO.	DESCRIPTION	DIRECT	TGS DIVISION	CORPORATE	TOTAL
		(a)	(b)	(c)	(d)
1	December 31, 2020	$0	$3,221,913	$15,879,956	
2	January 31, 2021	0	2,920,291	18,125,494	
3	February 28, 2021	0	2,593,210	18,656,139	
4	March 31, 2021	0	2,305,365	19,396,202	
5	April 30, 2021	0	2,149,862	18,349,930	
6	May 31, 2021	0	2,466,899	20,841,571	
7	June 30, 2021	0	2,144,497	20,970,015	
8	July 31, 2021	0	2,036,057	20,056,193	
9	August 31, 2021	0	1,715,490	18,096,125	
10	September 30, 2021	0	1,356,041	17,524,276	
11	October 31, 2021	0	1,074,322	17,069,495	
12	November 30, 2021	0	3,948,768	18,126,186	
13	December 31, 2021	0	3,614,350	18,154,083	
14	13 Month Average	$0	$2,426,697	$18,557,359	
15	Allocation Factor to TGS	100.0000%	100.0000%	27.1500%	
16	Allocation Factor to Service Area	100.0000%	44.1009%	44.1009%	
17	Total Allocated Prepayments	$0	$1,070,195	$2,221,946	$3,292,141

WKP B-2.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PREPAYMENTS - TGS DIVISION

LINE NO.	MONTH/YEAR ENDING	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
	(a)	(b)	(c)	(d) = (b)+(c)
1	December 31, 2020	$3,221,913	$0	$3,221,913
2	January 31, 2021	$2,920,291	$0	2,920,291
3	February 28, 2021	$2,593,210	$0	2,593,210
4	March 31, 2021	$2,305,365	$0	2,305,365
5	April 30, 2021	$2,149,862	$0	2,149,862
6	May 31, 2021	$2,466,899	$0	2,466,899
7	June 30, 2021	$2,144,497	$0	2,144,497
8	July 31, 2021	$2,036,057	$0	2,036,057
9	August 31, 2021	$1,715,490	$0	1,715,490
10	September 30, 2021	$1,356,041	$0	1,356,041
11	October 31, 2021	$1,074,322	$0	1,074,322
12	November 30, 2021	$3,948,768	$0	3,948,768
13	December 31, 2021	$3,614,350	$0	3,614,350
14	13-Month Average	$2,426,697	$0	$2,426,697
15	Allocation Factor to TGS	100.0000%	100.0000%	100.0000%
16	Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%
17	Total Allocated Prepayments	$1,070,195	$0	$1,070,195

Source: WKP B-2.a.1 Prepayments - TGS Division Detail (CONFIDENTIAL) - WNSA.xlsx

WKP B-2.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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, 2020	$16,014,035	$(134,079)	$15,879,956
2	January 31, 2021	$18,235,590	$(110,096)	18,125,494
3	February 28, 2021	$18,742,253	$(86,113)	18,656,139
4	March 31, 2021	$19,458,332	$(62,131)	19,396,202
5	April 30, 2021	$18,388,078	$(38,148)	18,349,930
6	May 31, 2021	$20,872,904	$(31,333)	20,841,571
7	June 30, 2021	$20,994,532	$(24,517)	20,970,015
8	July 31, 2021	$20,073,894	$(17,702)	20,056,193
9	August 31, 2021	$18,149,212	$(53,087)	18,096,125
10	September 30, 2021	$17,570,408	$(46,133)	17,524,276
11	October 31, 2021	$17,108,670	$(39,175)	17,069,495
12	November 30, 2021	$18,179,521	$(53,335)	18,126,186
13	December 31, 2021	$18,200,109	$(46,026)	18,154,083
14	13-Month Average	$18,614,426	$(57,067)	$18,557,359
15	Pro Forma, Q1 2022, Allocation Factor to TGS	27.1500%	27.1500%	27.1500%
16	13-Month Average Allocated to TGS	$5,053,817	$(15,494)	$5,038,323
17	Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%
18	Total Allocated Prepayments	$2,228,779	$(6,833)	$2,221,946

Source: WKP B-2.b.1 Prepayments - ONE Gas Corp Prepayments Detail (CONFIDENTIAL) - WNSA.xlsx

SCHEDULE B-3

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

RULE 8.209 REGULATORY ASSET

LINE NO.	FERC ACCOUNT	TEST YEAR ACCRUAL	ADJUSTMENT TO ACCRUAL	TOTAL ACCRUAL
		(a)	(b)	(c)
1	(367) Mains	$114	$0	$114
2	(374.2) Land Rignts	137	0	$137
3	(376) Mains	672,833	0	672,833
4	(376.9) Cathodic Protection Anodes	37,311	0	37,311
5	(378) Meas & Reg Stat Eq-General	4,925	0	4,925
6	(379) Meas & Reg Stat Eq-City	850	0	850
7	(380) Services	1,106,897	0	1,106,897
8	(380.1) Ind Service Line Equip	(97)	0	(97)
9	(380.2) Comm Service Line Equip	(222)	0	(222)
10	(380.4) Yard Lines-Customer Svc	87	0	87
11	(381) Meters	2,991	0	2,991
12	(382) Meter Installations	(169)	0	(169)
13	(383) House Regulators	2,902	0	2,902
14	(385) Ind Meas & Reg Sta Equip	15,233	0	15,233
15	(394.1) Tools	106	0	106
16	(397) Communication Equipment	25	0	25
17	Total	$1,843,921	$0	$1,843,921

Source: SCH B-3 WNSA Rule 8.209 Accrual

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	091.053.7850.005100	Borger/Skellytown	$670	$406	$1,988	$1,499	$4,562
2	091.053.7850.010027	Borger/Skellytown	(2)	38	185	140	360
3	091.053.7850.010028	Borger/Skellytown	107	87	427	322	944
4	091.053.7850.010030	Borger/Skellytown	86	72	351	264	773
5	091.054.7850.005100	Borger/Skellytown	3,642	1,537	7,530	5,677	18,386
6	091.054.7850.010216	Borger/Skellytown	354	215	1,052	793	2,413
7	091.054.7850.010218	Borger/Skellytown	329	160	782	589	1,860
8	091.054.7850.010221	Borger/Skellytown	200	92	453	341	1,087
9	091.054.7850.010223	Borger/Skellytown	153	78	382	288	900
10	091.054.7850.010224	Borger/Skellytown	122	81	395	298	894
11	091.054.7850.010226	Borger/Skellytown	(0)	8	40	30	78
12	091.054.7850.010228	Borger/Skellytown	(2)	21	103	77	199
13	091.054.7850.010229	Borger/Skellytown	(18)	90	440	331	843
14	091.054.7850.010230	Borger/Skellytown	152	96	469	353	1,070
15	091.054.7850.010231	Borger/Skellytown	(4)	21	105	79	201
16	091.054.7850.010232	Borger/Skellytown	(8)	67	330	249	637
17	091.054.7850.010233	Borger/Skellytown	(7)	71	346	261	671
18	091.054.7850.010234	Borger/Skellytown	(493)	44	216	163	(70)
19	091.054.7850.010235	Borger/Skellytown	(13)	78	384	290	739
20	091.054.7850.010236	Borger/Skellytown	(2)	28	135	102	263
21	091.054.7850.010237	Borger/Skellytown	254	155	760	573	1,742
22	091.054.7850.010241	Borger/Skellytown	68	76	374	282	800
23	091.054.7850.010242	Borger/Skellytown	171	120	589	444	1,325
24	091.054.7850.010243	Borger/Skellytown	1,218	499	2,446	1,844	6,008
25	091.054.7850.010244	Borger/Skellytown	90	69	336	253	747
26	091.054.7850.010246	Borger/Skellytown	501	330	1,616	1,218	3,665
27	091.054.7850.010247	Borger/Skellytown	89	102	501	378	1,070
28	091.054.7850.010248	Borger/Skellytown	53	40	194	146	432
29	091.054.7850.010249	Borger/Skellytown	341	231	1,130	852	2,553
30	091.054.7850.010250	Borger/Skellytown	72	46	226	170	515
31	091.054.7850.010251	Borger/Skellytown	114	77	376	283	850
32	091.054.7850.010252	Borger/Skellytown	257	201	985	743	2,186
33	091.054.7850.010253	Borger/Skellytown	44	34	166	125	368
34	091.054.7850.010272	Borger/Skellytown	215	183	894	674	1,966
35	091.054.7850.010273	Borger/Skellytown	138	69	336	254	797
36	091.054.7850.010274	Borger/Skellytown	270	149	732	552	1,703
37	091.054.7850.010275	Borger/Skellytown	89	80	391	295	854
38	091.054.7850.010276	Borger/Skellytown	184	123	603	455	1,366
39	091.054.7850.010277	Borger/Skellytown	710	377	1,846	1,392	4,325

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
40	091.054.7850.010278	Borger/Skellytown	111	82	402	303	899
41	091.054.7850.010280	Borger/Skellytown	405	209	1,024	772	2,411
42	091.054.7850.010281	Borger/Skellytown	570	190	932	703	2,395
43	091.054.7850.010282	Borger/Skellytown	786	298	1,460	1,101	3,644
44	091.054.7850.010283	Borger/Skellytown	46	43	212	160	461
45	091.054.7850.010286	Borger/Skellytown	220	145	711	536	1,612
46	091.054.7850.010288	Borger/Skellytown	46	31	150	113	339
47	091.054.7850.010289	Borger/Skellytown	1,051	554	2,715	2,047	6,367
48	091.054.7850.010291	Borger/Skellytown	88	36	176	132	432
49	091.054.7850.010292	Borger/Skellytown	6	1	5	4	15
50	091.054.7851.005100	Borger/Skellytown	0	0	2	1	3
51	091.054.7852.005100	Borger/Skellytown	2	1	5	4	12
52	091.053.7800.010002	North Texas	$(282)	$51	$510	$399	677
53	091.053.7800.010007	North Texas	(5)	0	0	0	(5)
54	091.053.7800.010028	North Texas	127	27	269	210	633
55	091.053.7800.010030	North Texas	(40)	0	0	0	(40)
56	091.053.7800.010035	North Texas	(1,647)	35	354	277	(981)
57	091.053.7800.010075	North Texas	(184)	(3)	(32)	(25)	(244)
58	091.053.7810.005100	North Texas	1	0	1	0	2
59	091.053.7820.005100	North Texas	0	0	(0)	(0)	0
60	091.053.7825.005100	North Texas	0	0	0	0	0
61	091.053.7835.005100	North Texas	1	0	3	2	5
62	091.054.7800.010005	North Texas	397	97	972	760	2,227
63	091.054.7800.010007	North Texas	(102)	16	160	125	200
64	091.054.7800.010009	North Texas	(143)	0	0	0	(143)
65	091.054.7800.010010	North Texas	64	16	158	123	360
66	091.054.7800.010012	North Texas	119	30	297	232	677
67	091.054.7800.010013	North Texas	215	52	522	408	1,197
68	091.054.7800.010018	North Texas	0	0	0	0	0
69	091.054.7800.010020	North Texas	51	11	110	86	257
70	091.054.7800.010022	North Texas	431	99	990	774	2,295
71	091.054.7800.010028	North Texas	3	1	7	6	17
72	091.054.7800.010031	North Texas	(2)	3	33	26	60
73	091.054.7800.010035	North Texas	(11)	17	167	131	303
74	091.054.7800.010041	North Texas	(5)	9	94	74	172
75	091.054.7800.010042	North Texas	(18)	5	50	39	75
76	091.054.7800.010047	North Texas	266	60	595	466	1,387
77	091.054.7800.010048	North Texas	(2)	14	144	112	269
78	091.054.7800.010050	North Texas	(351)	0	0	0	(351)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
79	091.054.7800.010052	North Texas	(8)	45	445	348	830
80	091.054.7800.010060	North Texas	(679)	0	0	0	(679)
81	091.054.7800.010062	North Texas	(117)	25	248	194	350
82	091.054.7800.010067	North Texas	152	45	447	350	994
83	091.054.7800.010068	North Texas	33	6	58	46	143
84	091.054.7800.010080	North Texas	(720)	29	286	224	(181)
85	091.054.7800.010082	North Texas	(1)	3	29	23	54
86	091.054.7800.010083	North Texas	(4,399)	181	1,810	1,416	(991)
87	091.054.7800.010090	North Texas	(236)	15	148	116	43
88	091.054.7800.010103	North Texas	(1,010)	257	2,572	2,012	3,832
89	091.054.7800.010106	North Texas	87	20	199	155	461
90	091.054.7800.010107	North Texas	233	41	414	324	1,012
91	091.054.7800.010108	North Texas	(210)	18	180	141	129
92	091.054.7800.010116	North Texas	(52)	25	247	193	412
93	091.054.7800.010118	North Texas	(117)	11	109	85	88
94	091.054.7800.010121	North Texas	366	233	2,326	1,820	4,744
95	091.054.7800.010128	North Texas	(29)	269	2,685	2,100	5,025
96	091.054.7800.010129	North Texas	(1)	6	57	45	107
97	091.054.7800.010132	North Texas	(47)	11	112	88	163
98	091.054.7800.010136	North Texas	(21)	171	1,708	1,336	3,194
99	091.054.7800.010138	North Texas	1	1	5	4	11
100	091.054.7800.010139	North Texas	29	12	122	95	258
101	091.054.7800.010141	North Texas	(0)	0	1	1	2
102	091.054.7800.010142	North Texas	4,901	1,176	11,759	9,200	27,037
103	091.054.7800.010145	North Texas	3,717	864	8,640	6,759	19,981
104	091.054.7800.010146	North Texas	(42)	11	111	87	168
105	091.054.7800.010150	North Texas	2,990	693	6,928	5,420	16,031
106	091.054.7800.010152	North Texas	599	125	1,249	977	2,950
107	091.054.7800.010154	North Texas	12,712	2,727	27,266	21,330	64,035
108	091.054.7800.010155	North Texas	(34)	6	61	48	80
109	091.054.7800.010159	North Texas	106	26	258	201	591
110	091.054.7800.010162	North Texas	(0)	14	143	112	269
111	091.054.7800.010164	North Texas	271	79	789	617	1,755
112	091.054.7800.010166	North Texas	6	2	16	12	36
113	091.054.7800.010167	North Texas	8,854	2,114	21,131	16,531	48,630
114	091.054.7800.010168	North Texas	(3)	6	63	49	115
115	091.054.7800.010169	North Texas	(82)	1	7	6	(68)
116	091.054.7800.010171	North Texas	(19)	2	22	17	23
117	091.054.7800.010172	North Texas	3	1	6	5	15

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
118	091.054.7800.010174	North Texas	(1)	1	14	11	26
119	091.054.7800.010176	North Texas	(4)	2	17	14	29
120	091.054.7800.010177	North Texas	(10)	1	8	6	4
121	091.054.7800.010178	North Texas	(14)	3	29	23	41
122	091.054.7800.010179	North Texas	(22)	21	213	167	379
123	091.054.7800.010180	North Texas	903	206	2,064	1,614	4,787
124	091.054.7800.010182	North Texas	2,488	571	5,704	4,462	13,224
125	091.054.7800.010183	North Texas	(16)	4	41	32	62
126	091.054.7800.010184	North Texas	24	7	66	52	148
127	091.054.7800.010185	North Texas	(3)	0	2	1	0
128	091.054.7800.010191	North Texas	243	43	430	337	1,054
129	091.054.7800.010192	North Texas	(0)	2	16	13	31
130	091.054.7800.010193	North Texas	2,098	423	4,225	3,305	10,050
131	091.054.7800.010195	North Texas	0	0	0	0	0
132	091.054.7800.010196	North Texas	(3)	5	50	39	91
133	091.054.7800.010198	North Texas	114	54	537	420	1,126
134	091.054.7800.010200	North Texas	942	211	2,113	1,653	4,920
135	091.054.7800.010201	North Texas	32	5	52	41	130
136	091.054.7800.010202	North Texas	956	220	2,204	1,724	5,106
137	091.054.7800.010203	North Texas	26	13	126	98	263
138	091.054.7800.010204	North Texas	457	82	819	640	1,997
139	091.054.7800.010205	North Texas	118	19	193	151	481
140	091.054.7800.010207	North Texas	71	9	95	74	250
141	091.054.7800.010208	North Texas	3,884	917	9,167	7,172	21,140
142	091.054.7800.010209	North Texas	(4)	2	24	19	41
143	091.054.7800.010211	North Texas	443	129	1,287	1,007	2,866
144	091.054.7800.010212	North Texas	809	142	1,418	1,109	3,478
145	091.054.7800.010213	North Texas	68	58	579	453	1,158
146	091.054.7800.010215	North Texas	(2)	5	47	37	86
147	091.054.7800.010216	North Texas	5	5	54	42	107
148	091.054.7800.010217	North Texas	257	95	950	743	2,046
149	091.054.7800.010218	North Texas	1,907	460	4,598	3,597	10,562
150	091.054.7800.010219	North Texas	(29)	194	1,941	1,518	3,624
151	091.054.7800.010223	North Texas	8	3	35	27	73
152	091.054.7800.010224	North Texas	4,063	1,092	10,913	8,537	24,604
153	091.054.7800.010225	North Texas	70	27	274	215	586
154	091.054.7800.010226	North Texas	27	9	94	74	205
155	091.054.7800.010228	North Texas	102	42	424	331	900
156	091.054.7800.010230	North Texas	44	15	149	116	324

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
157	091.054.7800.010231	North Texas	165	43	426	333	968
158	091.054.7800.010232	North Texas	1,707	433	4,330	3,387	9,857
159	091.054.7800.010233	North Texas	(1)	(0)	(4)	(3)	(8)
160	091.054.7800.010234	North Texas	417	139	1,387	1,085	3,028
161	091.054.7800.010237	North Texas	391	76	759	594	1,819
162	091.054.7800.010240	North Texas	714	160	1,595	1,248	3,716
163	091.054.7800.010241	North Texas	956	302	3,016	2,360	6,634
164	091.054.7800.010242	North Texas	522	134	1,345	1,052	3,053
165	091.054.7800.010243	North Texas	581	152	1,521	1,190	3,445
166	091.054.7800.010244	North Texas	5	2	18	14	40
167	091.054.7800.010246	North Texas	26	8	80	62	175
168	091.054.7800.010248	North Texas	51	13	127	99	289
169	091.054.7800.010249	North Texas	369	96	961	752	2,179
170	091.054.7800.010250	North Texas	288	45	448	350	1,131
171	091.054.7800.010252	North Texas	98	19	188	147	451
172	091.054.7800.010254	North Texas	125	24	244	191	585
173	091.054.7800.010255	North Texas	593	176	1,756	1,374	3,898
174	091.054.7800.010259	North Texas	$682	$192	$1,921	$1,503	4,298
175	091.054.7800.010263	North Texas	$171	$36	$365	$285	857
176	091.054.7800.010264	North Texas	$22	$4	$36	$28	89
177	091.054.7800.010266	North Texas	$128	$30	$304	$238	701
178	091.054.7800.010267	North Texas	$367	$103	$1,033	$808	2,311
179	091.054.7800.010272	North Texas	$88	$18	$183	$143	433
180	091.054.7800.010273	North Texas	$81	$20	$202	$158	461
181	091.054.7800.010280	North Texas	$2	$0	$4	$3	10
182	091.054.7800.010286	North Texas	$0	$0	$2	$2	5
183	091.054.7810.005100	North Texas	$39	$6	$63	$49	158
184	091.054.7812.005100	North Texas	$3	$0	$4	$3	11
185	091.054.7813.005100	North Texas	$2	$0	$3	$2	8
186	091.054.7814.005100	North Texas	$4	$0	$5	$4	13
187	091.054.7815.005100	North Texas	$4	$1	$8	$6	19
188	091.054.7816.005100	North Texas	$3	$0	$4	$3	10
189	091.054.7820.005100	North Texas	$21	$5	$47	$37	110
190	091.054.7825.005100	North Texas	$13	$4	$36	$28	81
191	091.054.7830.005100	North Texas	$10	$3	$25	$20	58
192	091.054.7831.005100	North Texas	$0	$0	$1	$1	2
193	091.054.7832.005100	North Texas	$1	$0	$2	$1	5
194	091.054.7835.005100	North Texas	$73	$10	$101	$79	264
195	091.054.7837.005100	North Texas	$0	$0	$0	$0	1

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
196	091.054.7838.005100	North Texas	$(0)	$0	$1	$1	1
197	091.054.7839.005100	North Texas	$3	$0	$3	$2	7
198	091.054.7840.005100	North Texas	$0	$0	$1	$0	2
199	091.054.7841.005100	North Texas	$2	$0	$2	$2	5
200	091.053.7610.005100	West Texas	$6	$3	$11	$9	28
201	091.053.7615.005100	West Texas	0	0	0	0	0
202	091.053.7630.005100	West Texas	(7)	1	2	2	(3)
203	091.053.7635.010017	West Texas	(1)	14	54	44	112
204	091.053.7635.010018	West Texas	(2)	49	195	158	401
205	091.053.7635.010019	West Texas	(5)	41	163	132	330
206	091.053.7635.010020	West Texas	(1)	(10)	(38)	(31)	(80)
207	091.053.7635.010024	West Texas	(3)	12	47	38	95
208	091.053.7640.005100	West Texas	1	0	1	1	4
209	091.053.7641.005100	West Texas	1	0	1	1	3
210	091.053.7645.005100	West Texas	28	16	65	53	162
211	091.053.7650.005100	West Texas	11,236	9,862	39,020	31,654	91,773
212	091.053.7650.010603	West Texas	(2)	31	123	100	251
213	091.053.7650.010626	West Texas	0	0	0	0	0
214	091.053.7650.010627	West Texas	25	521	2,062	1,673	4,281
215	091.053.7650.010628	West Texas	(7)	37	147	119	296
216	091.053.7650.010633	West Texas	158	51	204	165	579
217	091.053.7650.010636	West Texas	153	125	493	400	1,170
218	091.053.7650.010638	West Texas	(1)	42	167	135	343
219	091.053.7650.010640	West Texas	740	533	2,107	1,710	5,089
220	091.053.7650.010646	West Texas	472	330	1,306	1,059	3,168
221	091.053.7650.010647	West Texas	(1)	12	46	38	94
222	091.053.7650.010648	West Texas	159	127	504	409	1,200
223	091.053.7650.010649	West Texas	180	148	585	475	1,387
224	091.053.7650.010652	West Texas	154	83	327	266	830
225	091.053.7650.010653	West Texas	236	187	742	602	1,767
226	091.053.7650.010656	West Texas	234	203	804	653	1,895
227	091.053.7650.010657	West Texas	445	337	1,335	1,083	3,200
228	091.053.7650.010658	West Texas	1,711	1,425	5,638	4,574	13,347
229	091.053.7650.010666	West Texas	536	448	1,772	1,438	4,194
230	091.053.7650.010669	West Texas	3,073	1,883	7,451	6,044	18,451
231	091.053.7650.010673	West Texas	2,923	1,820	7,200	5,840	17,782
232	091.053.7650.010674	West Texas	57	34	135	110	336
233	091.053.7650.010679	West Texas	744	593	2,347	1,903	5,587
234	091.053.7650.010681	West Texas	786	557	2,206	1,789	5,339

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
235	091.053.7650.010683	West Texas	195	136	538	436	1,304
236	091.053.7650.010702	West Texas	147	85	335	272	839
237	091.053.7650.010703	West Texas	1	1	3	2	6
238	091.053.7650.010712	West Texas	25	13	51	42	131
239	091.053.7650.010716	West Texas	92	83	328	266	769
240	091.053.7650.010717	West Texas	137	121	480	390	1,128
241	091.053.7650.010723	West Texas	14	16	64	52	146
242	091.054.7604.005100	West Texas	27	14	54	44	139
243	091.054.7605.005100	West Texas	6	5	19	15	45
244	091.054.7606.005100	West Texas	0	0	0	0	1
245	091.054.7608.005100	West Texas	16	(1)	(4)	(3)	8
246	091.054.7608.010011	West Texas	(43)	68	270	219	514
247	091.054.7609.005100	West Texas	0	0	0	0	0
248	091.054.7610.005100	West Texas	51	27	105	85	268
249	091.054.7612.005100	West Texas	4	2	8	7	20
250	091.054.7614.005100	West Texas	3	1	5	4	13
251	091.054.7615.005100	West Texas	14	8	30	24	76
252	091.054.7616.005100	West Texas	1	0	2	1	4
253	091.054.7617.005100	West Texas	0	0	1	0	1
254	091.054.7630.005100	West Texas	20	13	50	40	123
255	091.054.7634.010012	West Texas	(10,372)	0	0	0	(10,372)
256	091.054.7635.010003	West Texas	(0)	7	26	21	55
257	091.054.7635.010004	West Texas	(5)	140	555	450	1,140
258	091.054.7635.010006	West Texas	(12)	12	49	40	89
259	091.054.7635.010007	West Texas	6	15	60	48	129
260	091.054.7635.010011	West Texas	(0)	230	909	738	1,877
261	091.054.7635.010012	West Texas	(41)	153	606	492	1,211
262	091.054.7635.010013	West Texas	218	838	3,316	2,690	7,063
263	091.054.7635.010014	West Texas	(0)	61	240	194	494
264	091.054.7635.010017	West Texas	(1)	31	122	99	250
265	091.054.7635.010019	West Texas	(1)	8	32	26	65
266	091.054.7635.010021	West Texas	44	62	247	200	554
267	091.054.7635.010024	West Texas	(6)	116	459	372	940
268	091.054.7635.010025	West Texas	(1)	176	696	565	1,437
269	091.054.7635.010026	West Texas	202	185	734	595	1,716
270	091.054.7635.010028	West Texas	(1)	40	157	127	323
271	091.054.7635.010029	West Texas	181	181	715	580	1,656
272	091.054.7635.010034	West Texas	376	355	1,404	1,139	3,275
273	091.054.7635.010035	West Texas	43	33	130	106	311

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
274	091.054.7635.010036	West Texas	2,565	1,616	6,395	5,188	15,763
275	091.054.7635.010037	West Texas	691	580	2,296	1,863	5,431
276	091.054.7635.010038	West Texas	52	44	172	140	408
277	091.054.7635.010039	West Texas	139	116	461	374	1,090
278	091.054.7635.010042	West Texas	22	13	50	41	125
279	091.054.7635.010045	West Texas	32	24	95	77	228
280	091.054.7635.010046	West Texas	34	27	106	86	253
281	091.054.7640.005100	West Texas	49	16	62	50	176
282	091.054.7641.005100	West Texas	(204)	(88)	(348)	(282)	(922)
283	091.054.7641.010045	West Texas	(0)	8	33	27	68
284	091.054.7645.005100	West Texas	61	35	139	113	348
285	091.054.7650.005100	West Texas	112,118	89,847	355,482	288,380	845,827
286	091.054.7650.010873	West Texas	(0)	251	995	807	2,053
287	091.054.7650.011052	West Texas	(0)	98	387	314	798
288	091.054.7650.011083	West Texas	2,627	1,641	6,494	5,268	16,031
289	091.054.7650.011089	West Texas	1,546	1,064	4,212	3,417	10,239
290	091.054.7650.011099	West Texas	49	42	168	136	396
291	091.054.7650.011104	West Texas	3	2	8	7	20
292	091.054.7650.011105	West Texas	(12)	36	141	115	280
293	091.054.7650.011112	West Texas	(3,364)	266	918	853	(1,327)
294	091.054.7650.011115	West Texas	5	4	14	12	35
295	091.054.7650.011118	West Texas	22	18	71	57	168
296	091.054.7650.011120	West Texas	1,578	982	3,886	3,153	9,598
297	091.054.7650.011122	West Texas	4,020	3,080	12,186	9,886	29,172
298	091.054.7650.011124	West Texas	2,651	1,896	7,502	6,086	18,137
299	091.054.7650.011127	West Texas	1,166	1,275	5,045	4,093	11,579
300	091.054.7650.011134	West Texas	334	276	1,093	887	2,590
301	091.054.7650.011138	West Texas	1,100	951	3,762	3,052	8,865
302	091.054.7650.011141	West Texas	84	65	257	209	615
303	091.054.7650.011142	West Texas	(31)	83	328	266	647
304	091.054.7650.011144	West Texas	(17)	7	28	23	41
305	091.054.7650.011149	West Texas	(18)	0	2	2	(14)
306	091.054.7650.011150	West Texas	(1)	26	101	82	208
307	091.054.7650.011151	West Texas	(18)	22	86	70	160
308	091.054.7650.011156	West Texas	97	58	229	186	570
309	091.054.7650.011157	West Texas	74	47	185	150	456
310	091.054.7650.011161	West Texas	116	1,309	5,180	4,203	10,808
311	091.054.7650.011182	West Texas	(3)	3	12	10	22
312	091.054.7650.011186	West Texas	168	188	746	605	1,707

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
313	091.054.7650.011191	West Texas	129	106	419	340	995
314	091.054.7650.011195	West Texas	503	734	2,904	2,356	6,496
315	091.054.7650.011196	West Texas	848	563	2,229	1,808	5,448
316	091.054.7650.011198	West Texas	186	132	523	424	1,266
317	091.054.7650.011209	West Texas	14	10	39	32	95
318	091.054.7650.011210	West Texas	937	360	1,426	1,157	3,879
319	091.054.7650.011212	West Texas	181	119	472	383	1,155
320	091.054.7650.011216	West Texas	(0)	18	73	59	150
321	091.054.7650.011217	West Texas	201	157	621	504	1,482
322	091.054.7650.011223	West Texas	$302	$216	$855	$693	2,066
323	091.054.7650.011226	West Texas	$1,297	$1,053	$4,166	$3,380	9,895
324	091.054.7650.011227	West Texas	$101	$48	$189	$154	492
325	091.054.7650.011231	West Texas	$1,154	$930	$3,678	$2,984	8,746
326	091.054.7650.011238	West Texas	$52	$32	$127	$103	313
327	091.054.7650.011241	West Texas	$609	$382	$1,511	$1,226	3,728
328	091.054.7650.011244	West Texas	$372	$151	$599	$486	1,608
329	091.054.7650.011245	West Texas	$530	$310	$1,225	$994	3,059
330	091.054.7650.011246	West Texas	$150	$130	$514	$417	1,211
331	091.054.7650.011247	West Texas	$22	$20	$80	$65	187
332	091.054.7650.011248	West Texas	$58	$28	$112	$91	289
333	091.054.7650.011249	West Texas	$3,571	$2,414	$9,552	$7,749	23,287
334	091.054.7650.011250	West Texas	$411	$199	$788	$639	2,038
335	091.054.7650.011251	West Texas	$121	$81	$321	$261	784
336	091.054.7650.011252	West Texas	$34	$25	$100	$81	240
337	091.054.7650.011255	West Texas	$1,533	$1,253	$4,958	$4,022	11,766
338	091.054.7650.011256	West Texas	$228	$156	$618	$502	1,504
339	091.054.7650.011257	West Texas	$931	$661	$2,616	$2,122	6,331
340	091.054.7650.011258	West Texas	$5	$29	$116	$94	245
341	091.054.7650.011260	West Texas	$55	$37	$146	$118	355
342	091.054.7650.011261	West Texas	$66	$40	$158	$128	392
343	091.054.7650.011262	West Texas	$101	$62	$244	$198	605
344	091.054.7650.011269	West Texas	$13	$13	$52	$42	121
345	091.054.7650.011271	West Texas	$61	$29	$113	$92	294
346	091.054.7650.011272	West Texas	$48	$36	$143	$116	344
347	091.054.7650.011274	West Texas	$1,736	$1,118	$4,423	$3,588	10,866
348	091.054.7650.011276	West Texas	$4,297	$3,184	$12,597	$10,219	30,297
349	091.054.7650.011278	West Texas	$13	$8	$31	$25	78
350	091.054.7650.011279	West Texas	$(0)	$10	$38	$31	79
351	091.054.7650.011280	West Texas	$197	$108	$428	$347	1,080

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
352	091.054.7650.011281	West Texas	$(0)	$30	$116	$95	240
353	091.054.7650.011284	West Texas	$25	$9	$34	$28	96
354	091.054.7650.011286	West Texas	$47	$26	$104	$84	262
355	091.054.7650.011287	West Texas	$70	$43	$169	$137	418
356	091.054.7650.011288	West Texas	$13	$12	$49	$40	113
357	091.054.7650.011289	West Texas	$63	$736	$2,911	$2,361	6,071
358	091.054.7650.011290	West Texas	$17	$9	$37	$30	92
359	091.054.7650.011291	West Texas	$183	$160	$635	$515	1,493
360	091.054.7650.011292	West Texas	$586	$297	$1,177	$955	3,015
361	091.054.7650.011293	West Texas	$51	$26	$103	$83	263
362	091.054.7650.011294	West Texas	$366	$313	$1,238	$1,004	2,921
363	091.054.7650.011296	West Texas	$117	$89	$354	$287	847
364	091.054.7650.011298	West Texas	$160	$86	$339	$275	859
365	091.054.7650.011299	West Texas	$40	$32	$127	$103	303
366	091.054.7650.011300	West Texas	$30	$13	$51	$41	135
367	091.054.7650.011302	West Texas	$79	$70	$278	$225	652
368	091.054.7650.011303	West Texas	$323	$167	$662	$537	1,689
369	091.054.7650.011304	West Texas	$50	$35	$140	$114	340
370	091.054.7650.011305	West Texas	$75	$71	$282	$229	657
371	091.054.7650.011306	West Texas	$20	$12	$47	$38	117
372	091.054.7650.011312	West Texas	$14	$7	$27	$22	71
373	091.054.7650.011313	West Texas	$30	$28	$112	$91	261
374	091.054.7650.011314	West Texas	$44	$38	$150	$122	354
375	091.054.7650.011316	West Texas	$144	$85	$336	$273	837
376	091.054.7650.011317	West Texas	$139	$130	$514	$417	1,201
377	091.054.7650.011321	West Texas	$76	$38	$151	$123	388
378	091.054.7650.011322	West Texas	$(103)	$4	$14	$11	(74)
379	091.054.7650.011325	West Texas	$127	$91	$360	$292	869
380	091.054.7650.011328	West Texas	$73	$38	$151	$123	385
381	091.054.7650.011332	West Texas	$(0)	$67	$264	$214	545
382	091.054.7650.011334	West Texas	$75	$59	$235	$190	560
383	091.054.7650.011338	West Texas	$57	$49	$195	$158	460
384	091.054.7650.011339	West Texas	$51	$33	$132	$107	324
385	091.054.7650.011347	West Texas	$(10)	$21	$81	$66	158
386	091.054.7650.011365	West Texas	$28	$38	$149	$121	335
387	091.054.7650.011366	West Texas	$254	$236	$934	$757	2,182
388	091.054.7650.011369	West Texas	$97	$46	$183	$149	475
389	091.054.7650.011370	West Texas	$139	$81	$320	$260	801
390	091.054.7650.011375	West Texas	$460	$313	$1,238	$1,004	3,015

WKP B-3.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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)
391	091.054.7650.011379	West Texas	$103	$78	$309	$250	740
392	091.054.7650.011388	West Texas	$(62)	$5	$20	$16	(21)
393	091.054.7650.011390	West Texas	$196	$133	$527	$428	1,285
394	091.054.7650.011391	West Texas	$(0)	$46	$183	$148	377
395	091.054.7650.011396	West Texas	$17	$14	$54	$44	128
396	091.054.7650.011400	West Texas	$113	$69	$272	$221	675
397	091.054.7650.011405	West Texas	$154	$141	$558	$453	1,307
398	091.054.7650.011406	West Texas	$38	$32	$128	$104	302
399	091.054.7650.011417	West Texas	$1	$1	$2	$2	6
400	091.054.7650.011420	West Texas	$38	$31	$124	$100	293
401	091.054.7650.011424	West Texas	$12	$9	$36	$29	86
402	091.054.7650.011427	West Texas	$111	$72	$283	$230	695
403	091.054.7650.011429	West Texas	$108	$72	$286	$232	697
404	091.054.7651.005100	West Texas	$1	$0	$1	$1	3
		Total	$237,373	$172,991	$795,375	$638,182	$1,843,921

Source: SCH B-3 WNSA Rule 8.209 Accrual.xlsx

SCHEDULE B-4

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	$0
2	Reg Assets Def OPEB Recovery	1823	WKP B-4.a	0
3	Regulatory Assets Proforma Amortization December 2021 Through June 2022	4073		0
4	Deferred Pension and OPEB since last rate cases	1860		896,913
5	Total			$896,913

Source: SCH B-4 Trial Balance Pension OPEB Deferral Dec 31 2021_WNSA.xlsx

WKP B-4.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PENSION AND OTHER POST EMPLOYMENT BENEFITS REGULATORY ASSET

PENSION

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2015	2016	2017	2018	2019	2020	2021	GRAND TOTAL
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	1823	January	Reg Assets Def Pension Recovery	$0	$(13,026)	$(13,026)	$(13,026)	$(13,026)	$(13,026)	$(13,026)	$(78,156)
2	1823	February	Reg Assets Def Pension Recovery	$0	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$(13,026)	$(78,156)
3	1823	March	Reg Assets Def Pension Recovery	$924,845	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$859,715
4	1823	April	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
5	1823	May	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
6	1823	June	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
7	1823	July	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
8	1823	August	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
9	1823	September	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
10	1823	October	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
11	1823	November	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
12	1823	December	Reg Assets Def Pension Recovery	$(13,026)	(13,026)	(13,026)	(13,026)	(13,026)	$(13,026)	$0	$(78,156)
13			Total	$807,611	$(156,312)	$(156,312)	$(156,312)	$(156,312)	$(156,312)	$(26,052)	$0

WKP B-4.a

OPEB

LINE NO.	FERC ACCOUNT	MONTH	DESCRIPTION	2015	2016	2017	2018	2019	2020	2021	GRAND TOTAL
	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)
14	1823	January	Reg Assets Def OPEB Recovery	$0	$(1,132)	$(1,132)	$(1,132)	$(1,132)	$(1,132)	$(1,132)	$(6,789)
15	1823	February	Reg Assets Def OPEB Recovery	$0	(1,132)	(1,132)	(1,132)	(1,132)	$(1,132)	$(1,131)	$(6,789)
16	1823	March	Reg Assets Def OPEB Recovery	$80,336	(1,132)	(1,131)	(1,132)	(1,132)	$(1,132)	$0	$74,679
17	1823	April	Reg Assets Def OPEB Recovery	$(1,132)	(1,131)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
18	1823	May	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
19	1823	June	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,131)	(1,131)	(1,132)	$(1,132)	$0	$(6,789)
20	1823	July	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
21	1823	August	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
22	1823	September	Reg Assets Def OPEB Recovery	$(1,132)	(1,131)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
23	1823	October	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
24	1823	November	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,132)	(1,132)	(1,132)	$(1,132)	$0	$(6,789)
25	1823	December	Reg Assets Def OPEB Recovery	$(1,132)	(1,132)	(1,132)	(1,132)	(1,131)	$(1,132)	$0	$(6,789)
26			Total	$70,153	$(13,578)	$(13,578)	$(13,578)	$(13,578)	$(13,578)	$(2,263)	$0
27			Total Pension and OPEB	$877,764	$(169,890)	$(169,890)	$(169,890)	$(169,890)	$(169,890)	$(28,315)	$0

Source: WKP B-4.a_WNSA (CONFIDENTIAL).xlsx

SCHEDULE B-5

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PREPAID PENSION ASSET

LINE NO.	DESCRIPTION	PREPAID PENSION BALANCE
	(a)	(b)
1	Prepaid Pension Asset - TGS	$43,340,687
2	Allocation to Service Area	44.10%
3	Prepaid Pension Asset - WNSA	$19,113,633

Source: SCH B-5 Prepaid Pension Asset Dec 2021 - WNSA.xlsx

SCHEDULE B-6

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

CASH WORKING CAPITAL

LINE NO.	DESCRIPTION	TEST YEAR AMOUNT	AVERAGE DAILY AMOUNT	REVENUE LAG	REFERENCE	EXPENSE LAG	REFERENCE	NET (LEAD)/LAG DAYS	WORKING CAPITAL REQUIREMENT
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Operations and Maintenance Expenses								
2	Purchased Gas Costs	$82,080,953	$224,879	45.47	A	(40.63)	B	4.84	$1,089,068
3	Labor - Regular Payroll Expense	21,878,096	59,940	45.47	A	(27.70)	C	17.78	1,065,451
4	Labor - Annual Performance Bonus Expense	4,838,841	13,257	45.47	A	(242.92)	C	(197.44)	(2,617,544)
5	Non-Labor - Other O&M Expense	23,520,358	64,439	45.47	A	(39.20)	C	6.28	404,370
6	Total O&M Expenses	$132,318,249	$362,516						$(58,655)
7	Federal Income Taxes								
8	Current Income Taxes	$9,629,801	$26,383	45.47	A	(37.00)	D	8.47	$223,517
9	Deferred Income Taxes	0	0	0.00		0.00		0.00	0
10	Total Federal Income Taxes	$9,629,801	$26,383						$223,517
11	Taxes Other Than Income Taxes								
12	FICA	$1,591,995	$4,362	45.47	A	(12.61)	E	32.87	$143,350
13	Federal Unemployment	13,283	36	45.47	A	(30.01)	E	15.46	563
14	State Unemployment	49,874	137	45.47	A	(113.17)	E	(67.70)	(9,250)
15	State Gross Receipts	3,406,328	9,332	45.47	A	(77.00)	E	(31.53)	(294,265)
16	Local Franchise Tax	8,377,329	22,952	45.47	A	(93.29)	E	(47.82)	(1,097,545)
17	State Franchise Tax	1,745,805	4,783	45.47	A	47.71	E	93.18	445,684
18	Ad Valorem	7,183,100	19,680	45.47	A	(196.17)	E	(150.70)	(2,965,686)
19	Sales Tax	3,060,478	8,385	45.47	A	(35.88)	E	9.59	80,434
20	RRC Gas Utility Tax	18,022	49	45.47	A	(86.81)	E	(41.34)	(2,041)
21	Taxes Other Than Income Taxes	$25,446,214	$69,716		A				$(3,698,756)
22	Interest on Customer Deposits	$4,703	$13	45.47	A	(168.77)	F	(123.30)	$(1,589)
23	Depreciation Expense	$24,213,706	$66,339	0.00		0.00		0.00	$0
24	Return	$45,791,339	$125,456	0.00		0.00		0.00	$0
25	Total	$237,404,013	$650,422						$(3,535,483)

Source: SCH B-6 CWC WNSA Tax.xlsx
SCH B-6 Texas Gas Service Lead-Lag Study WNSA

SCHEDULE B-7

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
1	7850 Borger - Incorporated	$151,178
2	7851 Borger - Environs	11,778
3	7852 Skellytown - Incorporated	3,675
4	7810 Mineral Wells - Incorporated	146,150
5	7811 Mineral Wells - Environs	2,605
6	7812 Palo Pinto - Environs	1,615
7	7813 Whitt - Environs	560
8	7814 Perrin - Environs	2,378
9	7815 Graford - Incorporated	2,785
10	7816 Millsap - Incorporated	1,296
11	7817 Graford - Environs	125
12	7818 Millsap - Environs	50
13	7820 Breckenridge - Incorporated	45,989
14	7821 Breckenridge - Environs	6,998
15	7825 Graham - Incorporated	67,923
16	7826 Graham - Environs	6,504
17	7830 Jacksboro - Incorporated	26,517
18	7831 Jermyn - Environs	200
19	7832 Bryson - Incorporated	3,058
20	7833 Jacksboro - Environs	265
21	7834 Bryson - Environs	150
22	7835 Weatherford - Incorporated	249,092
23	7836 Weatherford - Environs	2,856
24	7837 Punkin Center - Environs	1,575
25	7838 Aledo - Incorporated	22,616
26	7839 Hudson Oaks - Incorporated	14,200
27	7840 Willow Park - Incorporated	25,810
28	7841 Possum Kingdom - Environs	2,915
29	7842 Aledo-Rural - Environs	6,440
30	7843 Hudson Oaks - Environs	4,163

SCHEDULE B-7

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
31	7602 Fabens - Environs	49,599
32	7603 Vinton - Incorporated	17,149
33	7604 Clint - Incorporated	8,997
34	7605 Anthony - Incorporated	38,343
35	7606 Socorro - Incorporated	248,769
36	7607 Horizon City - Incorporated	177,883
37	7608 Dell City - Incorporated	10,575
38	7609 Dell City - Environs	192,225
39	7610 Pecos City - Incorporated	58,788
40	7611 Pecos City - Environs	1,480
41	7612 Barstow - Incorporated	725
42	7613 Andrews - Environs	9,005
43	7614 Wickett - Incorporated	4,817
44	7615 Wink - Incorporated	6,815
45	7616 Thorntonville - Incorporated	1,685
46	7617 Pyote - Incorporated	675
47	7618 Pyote - Environs	0
48	7619 San Elizario - Environs	37,691
49	7620 San Elizario - Incorporated	52,354
50	7623 Vinton - Environs	9,938
51	7624 Clint - Environs	15,408
52	7625 Anthony - Environs	0
53	7626 Socorro - Environs	2,218
54	7627 Horizon City - Environs	38,127
55	7630 Andrews - Incorporated	87,197
56	7639 Crane - Environs	1,010
57	7640 Crane - Incorporated	17,863
58	7641 Mccamey - Incorporated	7,930
59	7642 Mccamey - Environs	1,095
60	7645 Monahans - Incorporated	52,974
61	7646 Monahans - Environs	5,194

SCHEDULE B-7

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

CUSTOMER DEPOSITS

LINE NO.	RATE JURISDICTION	DEPOSIT BALANCE
		(a)
62	7650 El Paso - Incorporated	5,454,986
63	7651 El Paso - Environs	414,717
64	7662 Barstow - Environs	100
65	7665 Wink - Environs	525
66	Total	$7,838,323

Source: SCH B-7 WNSA Customer Deposit Balances @ 12 31 21.xlsx

SCHEDULE B-8

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

CUSTOMER ADVANCES

LINE NO.	FERC ACCOUNT	DESCRIPTION	ENDING BALANCE
			(a)
1	2520	LINE EXT DEPOSITS FORFEITED	$12,439
2	2520	LINE EXT DEPOSITS RECEIVED	(2,326)
3	2520	LINE EXT DEPOSITS FORFEITED	826,128
4	2520	LINE EXT DEPOSITS RECEIVED	(1,599,237)
5	2520	LINE EXT DEPOSITS REIMBURSED	880,268
6	2520	LINE EXT DEPOSITS REIMBURSED	44,576
7	2520	LINE EXT DEPOSITS RECEIVED	(39,328)
8	2520	LINE EXT DEPOSITS FORFEITED	61,585
9	2520	LINE EXT DEPOSITS RECEIVED	(223,516)
10	2520	LINE EXT DEPOSITS REIMBURSED	41,256
11	2520	LINE EXT DEPOSITS RECEIVED	(140,643)
12	2520	LINE EXT DEPOSITS RECEIVED	(20,564)
13	2520	LINE EXT DEPOSITS FORFEITED	1,200
14	2520	LINE EXT DEPOSITS RECEIVED	14,817
15	2520	LINE EXT DEPOSITS RECEIVED	(4,554)
16	2520	LINE EXT DEPOSITS FORFEITED	208,646
17	2520	LINE EXT DEPOSITS RECEIVED	(618,794)
18	2520	LINE EXT DEPOSITS REIMBURSED	51,754
19	2520	LINE EXT DEPOSITS RECEIVED	(8,412)
20	2520	LINE EXT DEPOSITS FORFEITED	5,451,261
21	2520	LINE EXT DEPOSITS RECEIVED	(34,161,184)
22	2520	LINE EXT DEPOSITS REIMBURSED	26,092,165
23		Total	$(3,132,466)

Source: SCH B-8 WNSA Customer Advances Balances @ 12 31 21.xlsx

SCHEDULE B-9

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

AS OF DECEMBER 31, 2021

ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DECSCRIPTION	ADIT AT 21%	TOTAL ALLOCATED ADIT TO SERVICE AREA
		(a)	(b)
1	West North Service Area Plant Assets Depreciation	$(26,939,517)	$(26,939,517)
2	West North Service Area Direct Plant Repairs	(55,443,450)	(55,443,450)
3	Subtotal West North Direct Plant Assets Depreciation	$(82,382,967)	$(82,382,967)
4	West North Service Area Other Rate Base Items	(4,965,068)	(4,965,068)
5	TGS Division Plant Assets Depreciation	(704,098)	(704,098)
6	ONEGAS Plant Assets Depreciation	(2,462,154)	(2,462,154)
7	West North Service Area NOL	40,081,420	40,081,420
8	ADFIT - Accumulated Deferred Federal Income Taxes	$(50,432,867)	$(50,432,867)

Source 1: SCH B-9 WNSA ADIT WPs 12.31.21

Source 2: SCH B-9 WNSA Rate Case 12.31.21 Reg NOL

SCHEDULE B-10

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	West-North Texas Service Area Plant Assets Depreciation	$(45,513,830)		$0	$(45,513,830)		$(45,513,830)
2	West-North Service Area Repairs	0		(11,337,295)	(11,337,295)		(11,337,295)
3	West-North Cost of Removal Asset	0	14,702,934	0	14,702,934		14,702,934
4	West-North Service Area Other Nonprotected plant	0		(1,794,371)	(1,794,371)		(1,794,371)
5	West-North Other Rate Base Items	0		(2,886,504)	(2,886,504)		(2,886,504)
6	TGS Division Plant Assets Depreciation	(248,649)			(248,649)		(248,649)
7	ONEGas Plant Assets Depreciation	(1,476,945)			(1,476,945)		(1,476,945)
8	West-North NOL	27,410,692	0	0	27,410,692		27,410,692
9	Total EDIT at December 31, 2017	$(19,828,732)	$14,702,934	$(16,018,171)	$(21,143,969)	$0	$(21,143,969)
10	Less 2018 Amortization				$1,681,286		$1,681,286
11	Less 2019 Amortization				1,694,650		1,694,650
12	Less 2020 Amortization				1,474,120		1,474,120
13	Less 2021 Amortization				1,422,666		1,422,666
14							0
15	Total EDIT at December 31, 2021				$(14,871,247)		$(14,871,247)

Source: SCH B-10 EDIT WNSA

SCHEDULE B-11

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

REG ASSETS

LINE NO.	DESCRIPTION	TOTAL AMOUNT
		(a)
1	Unamortized balance of Reg Assets from GUD 10506	$66,312
2	Less 12 mos. Amortization (line 20, January 2022 - January 2023) Note 1	(66,312)
3	Overcollection of rate case expense from GUD 10739 and GUD 10766	(140)
4	Deferred Regulatory Expense at December 31, 2021 not included in prior cases	22,250
5	Deferred Winter Storm URI O&M at December 31, 2021	62,540
6	Winter Storm URI related STI	351,330
7	Covid related O&M	608,467
8	Uncollected GRIP charges - City of El Paso - Case No. 00006942	744,266
9	Regulatory Assets - Total	$1,788,715

See data on SCH G-20

SCHEDULE C

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

TOTAL PLANT IN SERVICE - DIRECT AND ALLOCATED

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK ACCT 1010	ADJUSTMENTS ACCT 1010	TEST YEAR ADJUSTED ACCT 1010
			(a)	(b)	(c)
1	Service Area Direct Plant In Service	WKP C.a	$671,761,746	$(3,580,695)	$668,181,052
2	Allocated TGS Division Plant In Service	WKP C.b	4,960,600	(370,541)	4,590,059
3	Allocated Corporate Plant In Service	WKP C.c	30,144,085	(1,792,548)	28,351,537
4	Total Plant In Service		$706,866,431	$(5,743,784)	$701,122,648

WKP C.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	FERC RECLASS	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	REMOVAL OF RETIRING ASSETS	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1010	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		INTANGIBLE PLANT											
1	301	Organization	$130,422	$0	$0	$0	$0	$0	$0	$0	$130,422	$0	$130,422
2	302	Franchises & Consents	9,496	0	0	0	0	0	0	0	9,496	0	9,496
3	303	Misc. Intangible	276,605	0	0	0	0	0	0	0	276,605	0	276,605
4	303.1	Misc. Intangible	616,460	0	0	0	0	0	0	0	616,460	0	616,460
5		Total Intangible Plant	$1,032,983	$0	$0	$0	$0	$0	$0	$0	$1,032,983	$0	$1,032,983
		GATHERING AND TRANSMISSION PLANT											
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
9	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0
10	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
14	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0
16	365.2	Rights-of-Way	190,844	0	0	0	0	0	0	0	190,844	0	190,844
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
18	367	Mains	39,623,199	0	0	(126)	0	0	0	(126)	39,623,073	0	39,623,073
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
20	369	Meas & Reg Stations Equip	2,871,564	0	0	0	0	0	0	0	2,871,564	0	2,871,564
21	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0
22		Total Gathering and Transmission Plant	$42,685,607	$0	$0	$(126)	$0	$0	$0	$(126)	$42,685,481	$0	$42,685,481
		DISTRIBUTION PLANT											
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	374.1	Land	88,912	0	0	0	0	0	0	0	88,912	0	88,912
25	374.2	Land Rights	1,504,868	0	0	(33)	0	0	0	(33)	1,504,834	0	1,504,834
26	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
27	375.1	Structures & Improvements	248,985	0	0	46,727	0	0	0	46,727	295,712	0	295,712
28	375.2	Other System Structures	46,727	0	0	(46,727)	0	0	0	(46,727)	0	0	0
29	376	Mains	256,895,273	0	0	293,558	4,907	0	1,028,732	1,327,198	258,222,471	0	258,222,471
30	376.9	Mains - Cathodic Protection Anodes	26,497,695	0	0	(8,615)	0	(1,538,652)	89	(1,547,177)	24,950,517	0	24,950,517
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
32	378	Meas. & Reg. Station - General	10,999,566	0	0	5,710	0	0	0	5,710	11,005,276	0	11,005,276
33	379	Meas. & Reg. Station - C.G.	4,672,947	0	0	(202)	0	0	0	(202)	4,672,745	0	4,672,745
34	380	Services	185,537,333	0	0	(204,898)	(20)	0	(18)	(204,936)	185,332,397	0	185,332,397
35	380.1	Ind Service Line Equip	1,334	0	0	(23)	0	0	0	(23)	1,311	0	1,311
36	380.2	Comm Service Line Equip	0	0	0	(70)	0	0	0	(70)	(70)	0	(70)
37	380.4	Yard Lines-Customer Svc	0	0	0	(141)	0	0	0	(141)	(141)	0	(141)
38	381	Meters	58,525,534	0	0	(1,262)	0	0	0	(1,262)	58,524,271	0	58,524,271
39	382	Meter Installations	0	0	0	(20)	0	0	0	(20)	(20)	0	(20)
40	383	House Regulators	15,109,024	0	0	(1,099)	313	0	0	(786)	15,108,237	0	15,108,237

WKP C.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	FERC RECLASS	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	REMOVAL OF RETIRING ASSETS	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1010	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
41	385	Indust. Meas. & Reg. Stat. Equipment	16,905,921	0	0	(10,900)	(1,416)	0	1,684	(10,633)	16,895,288	0	16,895,288
42	386	Other Property on Customer Premises	638,227	0	0	0	0	0	0	0	638,227	0	638,227
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
44		Total Distribution Plant	$577,672,345	$0	$0	$72,005	$3,784	$(1,538,652)	$1,030,487	$(432,376)	$577,239,969	$0	$577,239,969
		GENERAL PLANT											
45	389	Land & Land Rights	$320,363	$0	$0	$0	$0	$0	$0	$0	$320,363	$0	$320,363
46	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
47	390.1	Structures & Improvements	7,098,549	0	(231)	(224,237)	0	0	0	(224,469)	6,874,080	0	6,874,080
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
50	390.2	Leasehold Improvement	98,721	0	(26)	0	0	0	0	(26)	98,696	0	98,696
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0
53	391.1	Office Furniture & Equipment	1,363,999	0	0	(26,814)	0	(176,058)	0	(202,872)	1,161,128	0	1,161,128
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0
59	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0
64	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0
73	391.9	Computer & Equipment	3,756,155	0	0	0	0	(2,433,082)	0	(2,433,082)	1,323,072	0	1,323,072
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0
75	392	Transportation Equipment	10,208,259	0	0	0	0	0	0	0	10,208,259	0	10,208,259
76	392.2	Transport Equip Pickup Trucks& Vans	76,807	0	0	0	0	0	0	0	76,807	0	76,807
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0
78	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0
80	393	Stores Equipment	30,808	0	0	0	0	(305)	0	(305)	30,503	0	30,503
81	394	Tools, Shop & Garage	6,100,154	0	0	86,572	0	(274,126)	0	(187,554)	5,912,601	0	5,912,601
82	394.1	Tools	84,811	0	0	131	0	0	0	131	84,941	0	84,941
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0

WKP C.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	FERC RECLASS	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	REMOVAL OF RETIRING ASSETS	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1010	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
84	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0
85	396	Major Work Equipment	2,260,869	0	0	0	0	0	0	0	2,260,869	0	2,260,869
86	397	Communication Equipment	11,615,680	0	0	(2,582)	0	(53,883)	0	(56,465)	11,559,215	0	11,559,215
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0
89		Total General Plant	$43,015,175	$0	$(257)	$(166,931)	$0	$(2,937,453)	$0	$(3,104,640)	$39,910,534	$0	$39,910,534
90		Total Orig Cost Plant in Service	$664,406,111	$0	$(257)	$(95,051)	$3,784	$(4,476,105)	$1,030,487	$(3,537,142)	$660,868,968	$0	$660,868,968

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC-WNSA.xlsx

WKP C.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	ADJUSTMENT	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	REMOVAL OF RETIRING ASSETS ACCT 1010	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1010	DIRECT TEST YEAR ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	0
5		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT								
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0
9	329	Other Structures	0	0	0	0	0	0	0	0
10	332	Field Lines	0	0	0	0	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0
14	337	Other Equip	0	0	0	0	0	0	0	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0
18	367	Mains	0	0	0	0	0	0	0	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0
21	371	Other Equipment	0	0	0	0	0	0	0	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0
		DISTRIBUTION PLANT								
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0
24	374.1	Land	0	0	0	0	0	0	0	0
25	374.2	Land Rights	19,533	0	0	0	0	0	0	19,533
26	375	Structures & Improvements	0	0	0	0	0	0	0	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	0
28	375.2	Other System Structures	0	0	0	0	0	0	0	0
29	376	Mains	5,178,343	0	0	0	0	0	0	5,178,343
30	376.9	Mains - Cathodic Protection Anodes	164,588	0	0	0	0	(43,552)	0	121,036
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0
32	378	Meas. & Reg. Station - General	494,534	0	0	0	0	0	0	494,534
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0
34	380	Services	942,233	0	0	0	0	0	0	942,233

WKP C.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	ADJUSTMENT	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	REMOVAL OF RETIRING ASSETS ACCT 1010	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1010	DIRECT TEST YEAR ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0
38	381	Meters	108,468	0	0	0	0	0	0	108,468
39	382	Meter Installations	0	0	0	0	0	0	0	0
40	383	House Regulators	57,282	0	0	0	0	0	0	57,282
41	385	Indust. Meas. & Reg. Stat. Equipment	330,071	0	0	0	0	0	0	330,071
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0
44		Total Distribution Plant	$7,295,053	$0	$0	$0	$0	$(43,552)	$0	$7,251,501
		GENERAL PLANT								
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0
47	390.1	Structures & Improvements	0	0	0	0	0	0	0	0
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0
50	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0
53	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0
59	391.5	Artwork	0	0	0	0	0	0	0	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0
64	391.6	Maximo	0	0	0	0	0	0	0	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0

WKP C.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1010	ADJUSTMENT	MEALS & HOTEL ADJUSTMENTS ACCT 1010	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1010	MISCODED RETIREMENTS ADJUSTMENT ACCT 1010	REMOVAL OF RETIRING ASSETS ACCT 1010	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1010	DIRECT TEST YEAR ADJUSTED ACCT 1010
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	0	0
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0
75	392	Transportation Equipment	0	0	0	0	0	0	0	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0
78	392.5	Trailers	0	0	0	0	0	0	0	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0
80	393	Stores Equipment	0	0	0	0	0	0	0	0
81	394	Tools, Shop & Garage	11,690	0	0	0	0	0	0	11,690
82	394.1	Tools	0	0	0	0	0	0	0	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	0
86	397	Communication Equipment	48,893	0	0	0	0	0	0	48,893
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0
89		Total General Plant	$60,583	$0	$0	$0	$0	$0	$0	$60,583
90		Total Orig Cost Plant in Service	$7,355,635	$0	$0	$0	$0	$(43,552)	$0	$7,312,083

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - WNSA.xlsx

WKP C.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	REMOVE ASSET NOT USED BY DIVISION	ASSET WITH MISSING BACKUP	REMOVE TGS DIRECT COSTS	REMOVE DUPLICATE VERTEX SALES TAX	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	REMOVE 2015 MEALS & HOTEL	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1010	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)	(j)	(k)	(l)
		INTANGIBLE PLANT													
1	301	Organization	$127,437	$0	$(127,437)	$0	$0	$0	$0	$0	$0	$0	$0	44.1009%	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
4	303.1	Misc. Intangible	278,560	0	(278,560)	0	0	0	0	0	0	0	0	44.1009%	0
5		Total Intangible Plant	$405,997	$0	$(405,997)	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT													
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	44.1009%	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
9	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
10	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
14	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
18	367	Mains	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
21	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT													
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	44.1009%	$0
24	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
25	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
26	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
28	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
29	376	Mains	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
32	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
34	380	Services	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
38	381	Meters	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
39	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
40	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
44		Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT													
45	389	Land & Land Rights	$434,697	$0	$0	$0	$0	$0	$0	$0	$434,697	$0	$434,697	44.1009%	$191,705
46	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
47	390.1	Structures & Improvements	4,357,293	0	0	9	(8,657)	0	(492)	0	4,348,153	0	4,348,153	44.1009%	1,917,575
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0

WKP C.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1010	REMOVE ASSET NOT USED BY DIVISION	ASSET WITH MISSING BACKUP	REMOVE TGS DIRECT COSTS	REMOVE DUPLICATE VERTEX SALES TAX	INCLUDE TGS DIVISION COSTS MISCODED TO DIRECT	REMOVE 2015 MEALS & HOTEL	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1010	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1010	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(h)	(i)	(j)	(k)	(l)
50	390.2	Leasehold Improvement	235,077	(774)	0	0	0	0	0	0	234,303	0	234,303	44.1009%	103,330
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
53	391.1	Office Furniture & Equipment	2,685,976	0	0	0	0	26,814	0	(74,104)	2,638,687	0	2,638,687	44.1009%	1,163,685
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
59	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
64	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
73	391.9	Computer & Equipment	1,762,269	0	(1,006)	0	(89)	0	(7,466)	(209,650)	1,544,059	0	1,544,059	44.1009%	680,944
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
75	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
78	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
80	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
81	394	Tools, Shop & Garage	151,938	0	0	(138,516)	0	0	(180)	0	13,242	0	13,242	44.1009%	5,840
82	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
86	397	Communication Equipment	1,215,049	0	0	0	0	0	0	(20,106)	1,194,943	0	1,194,943	44.1009%	526,981
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
89		Total General Plant	$10,842,300	$(774)	$(1,006)	$(138,507)	$(8,746)	$26,814	$(8,138)	$(303,860)	$10,408,084	$0	$10,408,084		$4,590,059
90		Total Orig Cost Plant in Service	$11,248,297	$(774)	$(407,003)	$(138,507)	$(8,746)	$26,814	$(8,138)	$(303,860)	$10,408,084	$0	$10,408,084		$4,590,059
91		Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%		
92		Total Allocated Plant In Service	$4,960,600	$(341)	$(179,492)	$(61,083)	$(3,857)	$11,825	$(3,589)	$(134,005)	$4,590,059	$0	$4,590,059		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve - WNSA.xlxs

WKP C.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

PLANT IN SERVICE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK Acct 1010 (a)	REMOVE VERTEX DUPLICATE SALES TAX (b)	REMOVE ARTWORK (c)	REMOVE AVIATION (d)	REMOVE ONE GAS FOUNDATION SOFTWARE (e)	REMOVE LEASE INCENTIVE (f)	REMOVE ITEMS WITH INSUFFICIENT SUPPORT (g)	REMOVE MISCODED CHARGES (h)	REMOVE DRONE TRAINING (i)	REMOVE PROMOTIONAL ITEMS (j)	REMOVE TGS SPECIFIC PROJECT (k)	REMOVE ITEMS RELATED TO RTCS TYE 2017 (l)	REMOVE 2012 MEALS & HOTEL (m)	REMOVE 2013 MEALS & HOTEL (n)	REMOVE 2014 MEALS & HOTEL (o)	REMOVE 2015 MEALS & HOTEL (p)	REMOVE 2016 MEALS & HOTEL (q)	REMOVE 2017 MEALS & HOTEL (r)	REMOVE 2018 MEALS & HOTEL (s)	REMOVE 2019 MEALS & HOTEL (t)	REMOVE 2020 MEALS & HOTEL (u)	REMOVE 2021 MEALS & HOTEL (v)	CORPORATE TEST YEAR ADJUSTED ACCT 1010 (w)	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE (x)	CORPORATE ADJUSTED ACCT 1010 (y)	ALLOCATION TO TGS (z)	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED (aa)	ALLOCATION TO SERVICE AREA (ab)	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA (ac)
		INTANGIBLE PLANT																													
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009%	$0
2	302	Franchises & Consents	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
3	303	Misc. Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
4	303.1	Misc. Intangible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
5		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT																													
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009%	$0
7	327	Field Comprss Station Strucutres	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
8	328	Field Meas/Reg Station Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
9	329	Other Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
10	332	Field Lines	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
11	333	Field Compressor Station Equip	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
12	334	Field Meas/Reg Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
13	336	Purification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
14	337	Other Equip	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
15	365	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
16	365.2	Rights-of-Way	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
17	366	Meas/Reg Station Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
18	367	Mains	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
19	368	Compressor Station Equip	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
20	369	Meas & Reg Stations Equip	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
21	371	Other Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT																													
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009%	$0
24	374.1	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
25	374.2	Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
26	375	Structures & Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
27	375.1	Structures & Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
28	375.2	Other System Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
29	376	Mains	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
30	376.9	Mains - Cathodic Protection Anodes	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
31	377	Compressor Station Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
32	378	Meas. & Reg. Station - General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
33	379	Meas. & Reg. Station - C.G.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
34	380	Services	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
35	380.1	Ind Service Line Equip	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
36	380.2	Comm Service Line Equip	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
37	380.4	Yard Lines-Customer Svc	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
38	381	Meters	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
39	382	Meter Installations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
40	383	House Regulators	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
41	385	Indust. Meas. & Reg. Stat. Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
42	386	Other Property on Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
43	387	Meas. & Reg. Stat. Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
44		Total Distribution Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT																													
45	389	Land & Land Rights	$47,854	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,854	$0	$47,854	27.15%	$12,992	44.1009%	$5,730
46	390	Structures & Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
47	390.1	Structures & Improvements	$4,816,651	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	4,816,651	0	4,816,651	27.15%	1,307,721	44.1009%	576,717
48	390.17	Building Improv Plum	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
49	390.19	Airplane Hanger Furniture	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
50	390.2	Leasehold Improvement	$6,231,727	$0	$0	$0	$0	$(579,787)	$(44)	$0	$0	$(1,951)	$0	$(92,327)	$0	$0	$0	$0	$0	$0	$0	$(64)	$(125)	$0	5,557,429	0	5,557,429	27.15%	1,508,842	44.1009%	665,413
51	390.21	Leasehold Equipment EQI	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
52	391	Office Furniture & Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
53	391.1	Office Furniture & Equipment	$4,011,433	$0	$0	$0	$0	$0	$0	$0	$(1,495)	$0	$0	$(57,374)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	3,952,564	0	3,952,564	27.15%	1,073,121	44.1009%	473,256
54	391.19	Airplane Hanger Furniture	$11,870	$0	$0	$(11,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
55	391.2	Data Processing Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
56	391.2	Oracle Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
57	391.3	Office Machines	$316,640	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	316,640	0	316,640	27.15%	85,968	44.1009%	37,913
58	391.4	Audio Visual Equipment	$1,084,093	$0	$0	$0	$0	$0	$(437)	$(60)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	1,083,596	0	1,083,596	27.15%	294,196	44.1009%	129,743
59	391.5	Artwork	$49,414	$0	$(49,414)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
60	391.6	Purchased Software	$110,243,539	$192	$0	$0	$23,107	$0	$(821)	$0	$0	$0	$0	$0	$0	$(59)	$(5,703)	$(38,041)	$(21,323)	$(17,417)	$(8,299)	$(7,953)	$(1,330)	$(79)	110,165,813	0	110,165,813	27.15%	29,910,018	44.1009%	13,190,587
61	391.6	Banner Software	$5,459,616	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(355)	$0	$0	$0	$0	5,459,261	0	5,459,261	30.75%	1,678,461	44.1009%	740,216
62	391.6	PowerPlant System	$2,171,982	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	2,171,982	0	2,171,982	26.08%	566,421	44.1009%	249,797
63	391.6	Riskworks	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
64	391.6	Maximo	$4,573,482	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	4,573,482	0	4,573,482	25.00%	1,143,370	44.1009%	504,237
65	391.6	Foundation Software	$101,638	$0	$0	$0	$(101,638)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0.00%	0	44.1009%	0
66	391.6	Concur Project	$47,648	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	47,648	0	47,648	28.75%	13,700	44.1009%	6,042
67	391.6	Journey-Employee-ODC Distrigas	$69,580,940	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(130,843)	$(4,632)	$(4,830)	$0	$(3,193)	$0	$0	$0	$0	$0	$0	69,437,442	0	69,437,442	27.15%	18,852,265	44.1009%	8,314,019
68	391.6	Journey-Employee Count	$1,848,836	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	1,848,836	0	1,848,836	28.75%	531,589	44.1009%	234,435
69	391.6	Payroll - Time Management	$2,945,016	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	2,945,016	0	2,945,016	28.75%	846,770	44.1009%	373,433
70	391.6	Accounts Payable Software	$1,026,973	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	1,026,973	0	1,026,973	33.81%	347,227	44.1009%	153,130
71	391.8	Micro Computer Software	$21,871,281	$(27)	$0	$0	$0	$0	$0	$(5,155)	$0	$0	$(170,238)	$0	$0	$0	$0	$0	$0	$0	$0	$(73)	$(15)	$0	21,695,773	0	21,695,773	27.15%	5,890,403	44.1009%	2,597,721
72	391.81	Aircraft Computer Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
73	391.9	Computer & Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
74	391.99	Cloud Computing	$725,594	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	725,594	0	725,594	27.15%	196,999	44.1009%	86,878
75	392	Transportation Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
76	392.1	Transport Equip-Autos,Trucks & Vans	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
77	392.2	Transport Equip-Trucks, Trls, 5 Ton	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
78	392.5	Trailers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
79	392.6	Aircraft	$13,608,723	$0	$0	$(13,608,723)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
80	393	Stores Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
81	394	Tools, Shop & Garage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
82	394.1	Tools	$17,309	$0	$0	$(17,309)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
83	394.2	Shop Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
84	395	CNG Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
85	396	Power Work Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
86	397	Communication Equipment	$102,489	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	102,489	0	102,489	27.15%	27,826	44.1009%	12,271
87	397.1	Telephone Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
88	398	Miscellaneous General Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	27.15%	0	44.1009%	0
89		Total General Plant	$250,894,748	$165	$(49,414)	$(13,637,902)	$(78,531)	$(579,787)	$(1,302)	$(5,215)	$(1,495)	$(1,951)	$(170,238)	$(280,544)	$(4,632)	$(4,889)	$(5,703)	$(41,234)	$(21,323)	$(17,772)	$(8,299)	$(8,091)	$(1,470)	$(79)	$235,975,042	$0	$235,975,042	27.24%	$64,287,889		$28,351,537
90		Total One Corp Plant in Service	$250,894,748	$165	$(49,414)	$(13,637,902)	$(78,531)	$(579,787)	$(1,302)	$(5,215)	$(1,495)	$(1,951)	$(170,238)	$(280,544)	$(4,632)	$(4,889)	$(5,703)	$(41,234)	$(21,323)	$(17,772)	$(8,299)	$(8,091)	$(1,470)	$(79)	$235,975,042	$0	$235,975,042				
91		Allocation Factor to TGS	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%	27.2435%				
92		Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%				
93		Total Allocated Plant in Service	$30,144,085	$20	$(5,937)	$(1,638,544)	$(9,435)	$(69,659)	$(156)	$(627)	$(180)	$(234)	$(20,454)	$(33,706)	$(557)	$(587)	$(685)	$(4,954)	$(2,562)	$(2,135)	$(997)	$(972)	$(177)	$(10)	$28,351,537	$0	$28,351,537				

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve - WNSA.xlsx

SCHEDULE C-1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

TOTAL COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT AND ALLOCATED

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK ACCT 1060	ADJUSTMENTS ACCT 1060	TEST YEAR ADJUSTED ACCT 1060
			(a)	(b)	(c)
1	Service Area Direct Completed Construction Not Classified	WKP C-1.a	$65,582,603	$0	$65,582,603
2	Allocated TGS Division Completed Construction Not Classified	WKP C-1.b	64,654	(1,056)	63,598
3	Allocated Corporate Completed Construction Not Classified	WKP C-1.c	511,353	(6,410)	504,943
4	Total Completed Construction Not Classified		$66,158,611	$(7,466)	$66,151,145

WKP C-1.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	MISCODED RETIREMENTS ADJUSTMENT ACCT	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	0
5		Total Intangible CCNC	$0	$0	$0	$0	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT								
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0
9	329	Other Structures	0	0	0	0	0	0	0	0
10	332	Field Lines	0	0	0	0	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0
14	337	Other Equip	0	0	0	0	0	0	0	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0
18	367	Mains	5,374,645	0	0	0	0	5,374,645	0	5,374,645
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0
20	369	Meas & Reg Stations Equip	194,532	0	0	0	0	194,532	0	194,532
21	371	Other Equipment	0	0	0	0	0	0	0	0
22		Total Gathering and Transmission CCNC	$5,569,178	$0	$0	$0	$0	$5,569,178	$0	$5,569,178
		DISTRIBUTION PLANT								
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0
24	374.1	Land	-399	0	0	0	0	(399)	0	(399)
25	374.2	Land Rights	88,958	0	0	0	0	88,958	0	88,958
26	375	Structures & Improvements	0	0	0	0	0	0	0	0
27	375.1	Structures & Improvements	9,439	0	0	0	0	9,439	0	9,439
28	375.2	Other System Structures	293,748	0	-293,748	0	(293,748)	0	0	0
29	376	Mains	29,163,028	0	0	0	0	29,163,028	0	29,163,028
30	376.9	Mains - Cathodic Protection Anodes	234,897	0	0	0	0	234,897	0	234,897
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0
32	378	Meas. & Reg. Station - General	4,082,480	0	0	0	0	4,082,480	0	4,082,480

WKP C-1.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	MISCODED RETIREMENTS ADJUSTMENT ACCT	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
33	379	Meas. & Reg. Station - C.G.	2,753,804	0	0	0	0	2,753,804	0	2,753,804
34	380	Services	6,340,839	0	0	0	0	6,340,839	0	6,340,839
35	380.1	Ind Service Line Equip	61,959	0	0	0	0	61,959	0	61,959
36	380.2	Comm Service Line Equip	107,496	0	0	0	0	107,496	0	107,496
37	380.4	Yard Lines-Customer Svc	96,157	0	0	0	0	96,157	0	96,157
38	381	Meters	146,020	0	0	0	0	146,020	0	146,020
39	382	Meter Installations	93,768	0	0	0	0	93,768	0	93,768
40	383	House Regulators	210,483	0	0	0	0	210,483	0	210,483
41	385	Indust. Meas. & Reg. Stat. Equipment	189,011	0	0	0	0	189,011	0	189,011
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0
44		Total Distribution CCNC	$43,871,689	$0	$(293,748)	$0	$(293,748)	$43,577,941	$0	$43,577,941
		GENERAL PLANT								
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0
47	390.1	Structures & Improvements	774,551	0	293,748	0	293,748	1,068,298	0	1,068,298
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0
50	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0
53	391.1	Office Furniture & Equipment	15,239	0	0	0	0	15,239	0	15,239
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0
59	391.5	Artwork	0	0	0	0	0	0	0	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0
64	391.6	Maximo	0	0	0	0	0	0	0	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0

WKP C-1.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	MEAL & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	MISCODED RETIREMENTS ADJUSTMENT ACCT	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	0	0
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0
75	392	Transportation Equipment	328,143	0	0	0	0	328,143	0	328,143
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0
78	392.5	Trailers	0	0	0	0	0	0	0	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0
80	393	Stores Equipment	0	0	0	0	0	0	0	0
81	394	Tools, Shop & Garage	653,783	0	0	0	0	653,783	0	653,783
82	394.1	Tools	503	0	0	0	0	503	0	503
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0
85	396	Major Work Equipment	119,721	0	0	0	0	119,721	0	119,721
86	397	Communication Equipment	13,990,371	0	0	0	0	13,990,371	0	13,990,371
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0
89		Total General CCNC	$15,882,311	$0	$293,748	$0	$293,748	$16,176,059	$0	$16,176,059
90		Total Orig Cost CCNC	$65,323,177	$0	$0	$0	$0	$65,323,177	$0	$65,323,177
			$65,582,603		$0			$65,323,177	$0	$65,323,177

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - WNSA.xlsx

WKP C-1.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED -FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	ADJUSTMENT	MEALS & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT OR RECLASS TO CORRECT FERC ACCT ACCT 1060	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
		INTANGIBLE PLANT							
1	301	Organization	$0	$0	$0	$0	$0	$0	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0
3	303	Misc. Intangible	0	0	0	0	0	0	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0
5		Total Intangible CCNC	$0	$0	$0	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT							
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0
9	329	Other Structures	0	0	0	0	0	0	0
10	332	Field Lines	0	0	0	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0
13	336	Purification Equipment	0	0	0	0	0	0	0
14	337	Other Equip	0	0	0	0	0	0	0
15	365	Land & Land Rights	0	0	0	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0
18	367	Mains	0	0	0	0	0	0	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0
21	371	Other Equipment	0	0	0	0	0	0	0
22		Total Gathering and Transmission CCNC	$0	$0	$0	$0	$0	$0	$0
		DISTRIBUTION PLANT							
23	374	Land	$0	$0	$0	$0	$0	$0	$0
24	374.1	Land	0	0	0	0	0	0	0
25	374.2	Land Rights	0	0	0	0	0	0	0
26	375	Structures & Improvements	0	0	0	0	0	0	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0
28	375.2	Other System Structures	0	0	0	0	0	0	0
29	376	Mains	73,685	0	0	0	0	0	73,685
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0
31	377	Compressor Station Equipment	0	0	0	0	0	0	0

WKP C-1.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED -FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	ADJUSTMENT	MEALS & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT OR RECLASS TO CORRECT FERC ACCT ACCT 1060	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
32	378	Meas. & Reg. Station - General	137,573	0	0	0	0	0	137,573
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0
34	380	Services	(25,836)	0	0	0	0	0	(25,836)
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0
38	381	Meters	38,984	0	0	0	0	0	38,984
39	382	Meter Installations	0	0	0	0	0	0	0
40	383	House Regulators	35,020	0	0	0	0	0	35,020
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0
44		Total Distribution CCNC	$259,426	$0	$0	$0	$0	$0	$259,426
		GENERAL PLANT							
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0
47	390.1	Structures & Improvements	0	0	0	0	0	0	0
48	390.17	Building Improv Plum	0	0	0	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0
50	390.2	Leasehold Improvement	0	0	0	0	0	0	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0
53	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0
57	391.3	Office Machines	0	0	0	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0
59	391.5	Artwork	0	0	0	0	0	0	0
60	391.6	Purchased Software	0	0	0	0	0	0	0
61	391.6	Banner Software	0	0	0	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0
63	391.6	Riskworks	0	0	0	0	0	0	0
64	391.6	Maximo	0	0	0	0	0	0	0

WKP C-1.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED -FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1060	ADJUSTMENT	MEALS & HOTEL ADJUSTMENTS ACCT 1060	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1060	MISCODED RETIREMENTS ADJUSTMENT ACCT 1060	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT OR RECLASS TO CORRECT FERC ACCT ACCT 1060	DIRECT ADJUSTED ACCT 1060
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
65	391.6	Foundation Software	0	0	0	0	0	0	0
66	391.6	Concur Project	0	0	0	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	0
74	391.99	Cloud Computing	0	0	0	0	0	0	0
75	392	Transportation Equipment	0	0	0	0	0	0	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0
78	392.5	Trailers	0	0	0	0	0	0	0
79	392.6	Aircraft	0	0	0	0	0	0	0
80	393	Stores Equipment	0	0	0	0	0	0	0
81	394	Tools, Shop & Garage	0	0	0	0	0	0	0
82	394.1	Tools	0	0	0	0	0	0	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0
84	395	CNG Equipment	0	0	0	0	0	0	0
85	396	Major Work Equipment	0	0	0	0	0	0	0
86	397	Communication Equipment	0	0	0	0	0	0	0
87	397.2	Telephone Equipment	0	0	0	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0
89		Total General CCNC	$0	$0	$0	$0	$0	$0	$0
90		Total Orig Cost CCNC	$259,426	$0	$0	$0	$0	$0	$259,426

Source: WKP C.a & WKP C-1.a Direct Plant and CCNC - WNSA.xlsx

WKP C-1.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	REMOVE 2021 MEALS & HOTEL	REMOVE TGS DIRECT COSTS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	$0	$0	44.1009%	$0
2	302	Franchises & Consents	0	0	0	0	0	0	44.1009%	0
3	303	Misc. Intangible	0	0	0	0	0	0	44.1009%	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	44.1009%	0
5		Total Intangible Plant	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT								
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	44.1009%	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	44.1009%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	44.1009%	0
9	329	Other Structures	0	0	0	0	0	0	44.1009%	0
10	332	Field Lines	0	0	0	0	0	0	44.1009%	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	44.1009%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	44.1009%	0
13	336	Purification Equipment	0	0	0	0	0	0	44.1009%	0
14	337	Other Equip	0	0	0	0	0	0	44.1009%	0
15	365	Land & Land Rights	0	0	0	0	0	0	44.1009%	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	44.1009%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	44.1009%	0
18	367	Mains	0	0	0	0	0	0	44.1009%	0
19	368	Compressor Station Equip	0	0	0	0	0	0	44.1009%	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	44.1009%	0
21	371	Other Equipment	0	0	0	0	0	0	44.1009%	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT								
23	374	Land	$0	$0	$0	$0	$0	$0	44.1009 %	$0
24	374.1	Land	0	0	0	0	0	0	44.1009 %	0
25	374.2	Land Rights	0	0	0	0	0	0	44.1009 %	0
26	375	Structures & Improvements	0	0	0	0	0	0	44.1009 %	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	44.1009 %	0
28	375.2	Other System Structures	14,331	0	(14,331)	0	0	0	44.1009 %	0
29	376	Mains	0	0	0	0	0	0	44.1009 %	0
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	44.1009 %	0
31	377	Compressor Station Equipment	0	0	0	0	0	0	44.1009 %	0
32	378	Meas. & Reg. Station - General	0	0	0	0	0	0	44.1009 %	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	44.1009 %	0

WKP C-1.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	REMOVE 2021 MEALS & HOTEL	REMOVE TGS DIRECT COSTS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
34	380	Services	0	0	0	0	0	0	44.1009 %	0
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	44.1009 %	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	44.1009 %	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	44.1009 %	0
38	381	Meters	0	0	0	0	0	0	44.1009 %	0
39	382	Meter Installations	0	0	0	0	0	0	44.1009 %	0
40	383	House Regulators	0	0	0	0	0	0	44.1009 %	0
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	44.1009 %	0
42	386	Other Property on Customer Premises	0	0	0	0	0	0	44.1009 %	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	44.1009 %	0
44		Total Distribution CCNC	$14,331	$0	$(14,331)	$0	$0	$0		$0
		GENERAL PLANT								
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	44.1009%	0
46	390	Structures & Improvements	0	0	0	0	0	0	44.1009%	0
47	390.1	Structures & Improvements	111,699	0	14,331	126,029	0	126,029	44.1009%	55,580
48	390.17	Building Improv Plum	0	0	0	0	0	0	44.1009%	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	44.1009%	0
50	390.2	Leasehold Improvement	18,187	(6)	0	18,181	0	18,181	44.1009%	8,018
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	44.1009%	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	44.1009%	0
53	391.1	Office Furniture & Equipment	0	0	0	0	0	0	44.1009%	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	44.1009%	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	44.1009%	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	44.1009%	0
57	391.3	Office Machines	0	0	0	0	0	0	44.1009%	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	44.1009%	0
59	391.5	Artwork	0	0	0	0	0	0	44.1009%	0
60	391.6	Purchased Software	0	0	0	0	0	0	44.1009%	0
61	391.6	Banner Software	0	0	0	0	0	0	44.1009%	0
62	391.6	PowerPlant System	0	0	0	0	0	0	44.1009%	0
63	391.6	Riskworks	0	0	0	0	0	0	44.1009%	0
64	391.6	Maximo	0	0	0	0	0	0	44.1009%	0
65	391.6	Foundation Software	0	0	0	0	0	0	44.1009%	0
66	391.6	Concur Project	0	0	0	0	0	0	44.1009%	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	44.1009%	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	44.1009%	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	44.1009%	0

WKP C-1.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCT 1060	REMOVE 2021 MEALS & HOTEL	REMOVE TGS DIRECT COSTS	TGS DIVISION TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
70	391.6	Accounts Payable Software	0	0	0	0	0	0	44.1009%	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	44.1009%	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	44.1009%	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	44.1009%	0
74	391.99	Cloud Computing	0	0	0	0	0	0	44.1009%	0
75	392	Transportation Equipment	0	0	0	0	0	0	44.1009%	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	44.1009%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	44.1009%	0
78	392.5	Trailers	0	0	0	0	0	0	44.1009%	0
79	392.6	Aircraft	0	0	0	0	0	0	44.1009%	0
80	393	Stores Equipment	0	0	0	0	0	0	44.1009%	0
81	394	Tools, Shop & Garage	2,388	0	(2,388)	0	0	0	44.1009%	0
82	394.1	Tools	0	0	0	0	0	0	44.1009%	0
83	394.2	Shop Equipment	0	0	0	0	0	0	44.1009%	0
84	395	CNG Equipment	0	0	0	0	0	0	44.1009%	0
85	396	Major Work Equipment	0	0	0	0	0	0	44.1009%	0
86	397	Communication Equipment	0	0	0	0	0	0	44.1009%	0
87	397.2	Telephone Equipment	0	0	0	0	0	0	44.1009%	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	44.1009%	0
89		Total General plant	$132,273	$(6)	$11,943	$144,210	$0	$144,210		$63,598
90		Total Orig Cost Plant in Service	$146,604	$(6)	$(2,388)	$144,210	$0	$144,210		$63,598
91		Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%		
92		Total Allocated CCNC	$64,654	$(3)	$(1,053)	$63,598	$0	$63,598		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve - WNSA.xlxs

WKP C-1.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	REMOVE ONG SPECIFIC PROJECT	REMOVE 2020 MEALS & HOTEL	REMOVE AVIATION	CORPORATE TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1060	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(d)	(g)	(h)	(i)	(j)	(k)
		INTANGIBLE PLANT											
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009%	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
5		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT											
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009%	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
9	329	Other Structures	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
10	332	Field Lines	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
14	337	Other Equip	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
18	367	Mains	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
21	371	Other Equipment	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT											
23	374	Land	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009%	$0
24	374.1	Land	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
25	374.2	Land Rights	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
26	375	Structures & Improvements	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
28	375.2	Other System Structures	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
29	376	Mains	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
32	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
34	380	Services	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
38	381	Meters	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
39	382	Meter Installations	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
40	383	House Regulators	0	0	0	0	0	0	0	0.00%	0	44.1009%	0

WKP C-1.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	REMOVE ONG SPECIFIC PROJECT	REMOVE 2020 MEALS & HOTEL	REMOVE AVIATION	CORPORATE TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1060	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(d)	(g)	(h)	(i)	(j)	(k)
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
44		Total Distribution CCNC	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT											
45	389	Land & Land Rights	$116	$(116)	$0	$0	$0	$0	$0	27.15%	$0	44.1009%	0
46	390	Structures & Improvements	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
47	390.1	Structures & Improvements	40,259	(37,404)	0	0	2,855	0	2,855	27.15%	775	44.1009%	342
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
50	390.2	Leasehold Improvement	68,361	0	0	0	68,361	0	68,361	27.15%	18,560	44.1009%	8,185
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
53	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
57	391.3	Office Machines	3,562	0	0	0	3,562	0	3,562	27.15%	967	44.1009%	426
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
59	391.5	Artwork	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
60	391.6	Purchased Software	4,142,438	0	(5)	0	4,142,433	0	4,142,433	27.15%	1,124,671	44.1009%	495,990
61	391.6	Banner Software	0	0	0	0	0	0	0	30.75%	0	44.1009%	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	26.08%	0	44.1009%	0
63	391.6	Riskworks	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
64	391.6	Maximo	0	0	0	0	0	0	0	25.00%	0	44.1009%	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0.00%	0	44.1009%	0
66	391.6	Concur Project	0	0	0	0	0	0	0	28.75%	0	44.1009%	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	28.75%	0	44.1009%	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	28.75%	0	44.1009%	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	33.81%	0	44.1009%	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
74	391.99	Cloud Computing	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
75	392	Transportation Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
78	392.5	Trailers	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
79	392.6	Aircraft	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
80	393	Stores Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
81	394	Tools, Shop & Garage	16,013	0	0	(16,013)	0	0	0	27.15%	0	44.1009%	0
82	394.1	Tools	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0

WKP C-1.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED - CORPORATE

LINE NO.	ACCOUNTS	DESCRIPTION	CORPORATE PER BOOK ACCT 1060	REMOVE ONG SPECIFIC PROJECT	REMOVE 2020 MEALS & HOTEL	REMOVE AVIATION	CORPORATE TEST YEAR ADJUSTED ACCT 1060	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	CORPORATE ADJUSTED ACCT 1060	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(d)	(g)	(h)	(i)	(j)	(k)
84	395	CNG Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
86	397	Communication Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	27.15%	0	44.1009%	0
89		Total General plant	$4,270,748	$(37,520)	$(5)	$(16,013)	$4,217,210	$0	$4,217,210	27.15%	$1,144,973		$504,943
											$1,144,973		
90		Total Orig Cost Plant in Service	$4,270,748	$(37,520)	$(5)	$(16,013)	$4,217,210	$0	$4,217,210		0.00		
91		Allocation Factor to TGS	27.1500%	27.1500%	27.1500%	27.1500%	27.1500%	27.1500%	27.1500%				
92		Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%				
93		Total Allocated CCNC	$511,353	$(4,492)	$(1)	$(1,917)	$504,943	$0	$504,943				

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve - WNSA.xlxs

SCHEDULE D

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

TOTAL ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - DIRECT AND ALLOCATED

LINE NO.	DESCRIPTION	REFERENCE	PER BOOK ACCTS 1080100 & 1110	ADJUSTMENTS ACCTS 1080100 & 1110	TEST YEAR ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)
1	Service Area Direct Accumulated Reserves	WKP D.a	$(121,686,651)	$4,727,391	$(116,959,260)
2	Allocated TGS Division Accumulated Reserves	WKP D.b	(1,177,986)	107,913	(1,070,073)
3	Allocated Corporate Accumulated Reserves	WKP D.c	(14,165,725)	1,516,709	(12,649,016)
4	Total Accumulated Reserves		$(137,030,363)	$6,352,014	$(130,678,349)

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP D.a**
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCTS 1080100 & 1110	MISCODED RETIREMENTS ADJUSTMENT ACCTS 1080100 & 1110	REMOVAL OF RETIRING ASSETS	RESERVE BALANCING	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		INTANGIBLE PLANT											
1	301	Organization	$(114,906)	$0	$(114,906)	$0	$0	$0	$0	$0	$(114,906)	$0	$(114,906)
2	302	Franchises & Consents	629	0	629	0	0	0	0	0	629	0	629
3	303	Misc. Intangible	0	(284,067)	(284,067)	0	0	0	0	0	(284,067)	0	(284,067)
4	303.1	Misc. Intangible	0	(87,939)	(87,939)	0	0	0	0	0	(87,939)	0	(87,939)
5		Total Intangible Plant Reserves	$(114,277)	$(372,006)	$(486,283)	$0	$0	$0	$0	$0	$(486,283)	$0	$(486,283)
		GATHERING AND TRANSMISSION PLANT											
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
9	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0
10	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
14	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0
18	367	Mains	(2,633,169)	0	(2,633,169)	0	0	0	(175,158)	(175,158)	(2,808,326)	0	(2,808,326)
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0
20	369	Meas & Reg Stations Equip	(607,496)	0	(607,496)	0	0	0	175,158	175,158	(432,338)	0	(432,338)
21	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0
22		Total Gathering and Transmission Plant Reserves	$(3,240,665)	$0	$(3,240,665)	$0	$0	$0	$0	$0	$(3,240,665)	$0	$(3,240,665)
		DISTRIBUTION PLANT											
23	374	Land	$(31)	$0	$(31)	$0	$0	$0	$0	$0	$(31)	$0	$(31)
24	374.1	Land	0	0	0	0	0	0	0	0	0	0	0
25	374.2	Land Rights	(46,974)	0	(46,974)	0	0	0	0	0	(46,974)	0	(46,974)
26	375	Structures & Improvements	(152,203)	0	(152,203)	152,203	0	0	0	152,203	0	0	0
27	375.1	Structures & Improvements	0	0	0	(182,514)	0	0	33,469	(149,046)	(149,046)	0	(149,046)
28	375.2	Other System Structures	(30,311)	0	(30,311)	30,311	0	0	0	30,311	0	0	0
29	376	Mains	(49,525,874)	0	(49,525,874)	0	4,870	0	15,791,584	15,796,453	(33,729,420)	0	(33,729,420)
30	376.9	Mains - Cathodic Protection Anodes	(1,914,422)	0	(1,914,422)	0	0	1,538,652	(9,842,778)	(8,304,126)	(10,218,549)	0	(10,218,549)
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0
32	378	Meas. & Reg. Station - General	(2,276,219)	0	(2,276,219)	0	0	0	1,225,956	1,225,957	(1,050,262)	0	(1,050,262)
33	379	Meas. & Reg. Station - C.G.	(1,788,770)	0	(1,788,770)	0	0	0	859,283	859,283	(929,487)	0	(929,487)
34	380	Services	(21,529,632)	0	(21,529,632)	0	(29)	0	(4,768,070)	(4,768,099)	(26,297,732)	0	(26,297,732)
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0
38	381	Meters	(15,238,686)	0	(15,238,686)	0	0	(0)	(1,596,962)	(1,596,962)	(16,835,649)	0	(16,835,649)
39	382	Meter Installations	(8,293)	0	(8,293)	0	0	0	0	0	(8,293)	0	(8,293)
40	383	House Regulators	(4,044,495)	0	(4,044,495)	0	1,023	0	(1,078,674)	(1,077,651)	(5,122,147)	0	(5,122,147)
41	385	Indust. Meas. & Reg. Stat. Equipment	(4,119,456)	0	(4,119,456)	126	(1,624)	0	1,142,111	1,140,614	(2,978,842)	0	(2,978,842)
42	386	Other Property on Customer Premises	(266,324)	0	(266,324)	0	0	0	(174,733)	(174,733)	(441,058)	0	(441,058)
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0
44		Total Distribution Plant Reserves	$(100,941,692)	$0	$(100,941,692)	$126	$4,240	$1,538,652	$1,591,184	$3,134,202	$(97,807,490)	$0	$(97,807,490)
		GENERAL PLANT											
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0
47	390.1	Structures & Improvements	(1,008,199)	0	(1,008,199)	1	(5,808)	0	(604,374)	(610,181)	(1,618,380)	0	(1,618,380)
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
50	390.2	Leasehold Improvement	0	(98,730)	(98,730)	0	0	0	0	0	(98,730)	0	(98,730)
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **WKP D.a**

WEST-NORTH SERVICE AREA

AS OF DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT PER BOOK ACCT 1080100 DEPR	DIRECT PER BOOK ACCT 1110 AMORT	DIRECT PER BOOK ACCTS 1080100 & 1110	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCTS 1080100 & 1110	MISCODED RETIREMENTS ADJUSTMENT ACCTS 1080100 & 1110	REMOVAL OF RETIRING ASSETS	RESERVE BALANCING	TOTAL ADJUSTMENTS	DIRECT TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE ASSETS IN SERVICE	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
53	391.1	Office Furniture & Equipment	(414,512)	0	(414,512)	0	0	176,058	(378,449)	(202,391)	(616,903)	0	(616,903)
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0
59	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0
64	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0
73	391.9	Computer & Equipment	(2,185,186)	0	(2,185,186)	0	0	2,433,082	(729,323)	1,703,759	(481,427)	0	(481,427)
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0
75	392	Transportation Equipment	(5,843,676)	0	(5,843,676)	0	0	0	3,711,662	3,711,662	(2,132,014)	0	(2,132,014)
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0
78	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0
80	393	Stores Equipment	(9,828)	0	(9,828)	0	0	305	(12,503)	(12,198)	(22,026)	0	(22,026)
81	394	Tools, Shop & Garage	(1,311,854)	0	(1,311,854)	0	0	274,126	(1,472,943)	(1,198,817)	(2,510,671)	0	(2,510,671)
82	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0
84	395	CNG Equipment	(47)	0	(47)	0	0	0	0	0	(47)	0	(47)
85	396	Major Work Equipment	(1,460,985)	0	(1,460,985)	0	0	0	873,132	873,132	(587,853)	0	(587,853)
86	397	Communication Equipment	(5,164,308)	0	(5,164,308)	0	0	53,883	(1,172,613)	(1,118,730)	(6,283,039)	0	(6,283,039)
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0
88	398	Miscellaneous General Plant	14,531	0	14,531	0	0	0	0	0	14,531	0	14,531
89		Total General Plant Reserves	$(17,384,064)	$(98,730)	$(17,482,794)	$1	$(5,808)	$2,937,453	$214,589	$3,146,235	$(14,336,560)	$0	$(14,336,560)
90		Total Accumulated Reserves For Depreciation	(121,680,697)	$(470,736)	$(122,151,434)	$127	$(1,568)	$4,476,105	$1,805,773	$6,280,436	$(115,870,997)	$0	$(115,870,997)

Source: WKP C.a and WKP C-1.a_D.a Accum Depr and Amort Adjustment Dec 31 2021_WNSA

Source: WKP D.a WNSA REG BKS_091_PP Rpt_1080100_1080500_Accum Dep Dec 31 2021.xlsx

Source: WKP D.a WNSA REG BKS_091_PP Rpt_1110100_1110500_Accum Amor_Dec 31 2021.xlsx

WKP D.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	TOTAL ADJUSTMENTS	RESERVE BALANCING	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1080100 & 1110 AT 12/31/2021	MISCODED RETIREMENTS ADJUSTMENTACCT 1080100 & 1110	REMOVAL OF RETIRING ASSETS	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1080100 & 1110	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		INTANGIBLE PLANT										
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0
5		Total Intangible Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT										
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0
9	329	Other Structures	0	0	0	0	0	0	0	0	0	0
10	332	Field Lines	0	0	0	0	0	0	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0
14	337	Other Equip	0	0	0	0	0	0	0	0	0	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0
18	367	Mains	0	0	0	0	0	0	0	0	0	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0
21	371	Other Equipment	0	0	0	0	0	0	0	0	0	0
22		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
		DISTRIBUTION PLANT										
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	374.1	Land	0	0	0	0	0	0	0	0	0	0
25	374.2	Land Rights	(6,316)	0	(6,316)	0	0	0	0	0	0	(6,316)
26	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0
28	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0
29	376	Mains	630,323	0	630,323	0	(1,371,831)	0	0	0	0	(741,508)
30	376.9	Mains - Cathodic Protection Anodes	(26,346)	0	(26,346)	0	(60,470)	0	0	43,552	0	(43,264)
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0
32	378	Meas. & Reg. Station - General	(49,979)	0	(49,979)	0	15,594	0	0	0	0	(34,385)
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0
34	380	Services	(6,341)	0	(6,341)	0	(151,908)	0	0	0	0	(158,249)
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0
38	381	Meters	(61,756)	0	(61,756)	0	14,181	0	0	0	0	(47,576)
39	382	Meter Installations	0	0	0	0	0	0	0	0	0	0
40	383	House Regulators	(15,564)	0	(15,564)	0	75	0	0	0	0	(15,489)
41	385	Indust. Meas. & Reg. Stat. Equipment	(105)	0	(105)	0	(36,825)	0	0	0	0	(36,930)
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0

WKP D.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	TOTAL ADJUSTMENTS	RESERVE BALANCING	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1080100 & 1110 AT 12/31/2021	MISCODED RETIREMENTS ADJUSTMENTACCT 1080100 & 1110	REMOVAL OF RETIRING ASSETS	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1080100 & 1110	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0
44		Total Distribution Plant Reserves	$463,916	$0	$463,916	$0	$(1,591,184)	$0	$0	$43,552	$0	$(1,083,716)
		GENERAL PLANT										
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0
47	390.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0
50	390.2	Leasehold Improvement	0	0	0	0	0	0	0	0	0	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0
53	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0
59	391.5	Artwork	0	0	0	0	0	0	0	0	0	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0
64	391.6	Maximo	0	0	0	0	0	0	0	0	0	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0
73	391.9	Computer & Equipment	15,138	0	15,138	0	0	0	0	0	0	15,138
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0
75	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0
78	392.5	Trailers	0	0	0	0	0	0	0	0	0	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0
80	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0
81	394	Tools, Shop & Garage	(953)	0	(953)	0	(216)	0	0	0	0	(1,169)
82	394.1	Tools	0	0	0	0	0	0	0	0	0	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0
86	397	Communication Equipment	(13,319)	0	(13,319)	0	(5,197)	0	0	0	0	(18,516)
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0

WKP D.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

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	TOTAL ADJUSTMENTS	RESERVE BALANCING	MISCODED ADDITIONS AND TRANSFERS ADJUSTMENT ACCT 1080100 & 1110 AT 12/31/2021	MISCODED RETIREMENTS ADJUSTMENTACCT 1080100 & 1110	REMOVAL OF RETIRING ASSETS	RECLASSIFICATION TO CORRECT LOCATION ADJUSTMENT ACCT 1080100 & 1110	DIRECT ADJUSTED ACCTS 1080100 & 1110
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0
89		Total General Plant Reserves	$866	$0	$866	$0	$(5,413)	$0	$0	$0	$0	$(4,547)
90												
91		Total Accumulated Reserves For Depreciation	$464,782	$0	$464,782	$0	$(1,596,597)	$0	$0	$43,552	$0	$(1,088,263)

Source: WKP C.a and WKP C-1.a_D.a Accum Depr and Amort Adjustment Dec 31 2021_WNSA

WKP D.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE TGS DIRECT PROJECT	INCLUDE CUSTOMER INFO CENTER STACKERS	REMOVE LAND DEPRECIATION	PRO FORMA ADJUSTMENT RESERVE BALANCING	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		INTANGIBLE PLANT													
1	301	Organization	$(127,437)	$0	$127,437	$0	$0	$0	$0	$0	$0	$0	$0	44.1009%	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
3	303	Misc. Intangible	(278,560)	0	278,560	0	0	0	0	0	0	0	0	44.1009%	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
5		Total Intangible Plant Reserves	$(405,997)	$0	$405,997	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT													
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	44.1009%	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
9	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
10	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
14	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
18	367	Mains	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
21	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	44.1009%	0
22		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT													
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	44.101 %	$0
24	374.1	Land	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
25	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
26	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
28	375.2	Other System Structures	(719)	0	0	719	0	0	0	0	0	0	0	44.101 %	-
29	376	Mains	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
32	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
34	380	Services	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
38	381	Meters	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
39	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
40	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	-
44		Total Distribution Plant Reserves	$(719)	$0	$0	$719	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT													
45	389	Land & Land Rights	$(4,331)	$0	$0	$0	$0	$4,331	$0	$0	$0	$0	$0	44.101 %	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
47	390.1	Structures & Improvements	(310,174)	0	0	(719)	0	0	55,013	0	(255,880)	0	(255,880)	44.101 %	(112,845)
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
50	390.2	Leasehold Improvement	(168,210)	687	0	0	0	0	0	0	(167,523)	0	(167,523)	44.101 %	(73,879)
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
53	391.1	Office Furniture & Equipment	(321,861)	0	0	0	(445)	0	(201,812)	74,104	(450,013)	0	(450,013)	44.101 %	(198,460)
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0

WKP D.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION PER BOOK ACCTS 1080100 & 1110	REMOVE ASSET NOT USED BY DIVISION	REMOVE ASSET WITH INSUFFICIENT DOCUMENTATION	REMOVE TGS DIRECT PROJECT	INCLUDE CUSTOMER INFO CENTER STACKERS	REMOVE LAND DEPRECIATION	PRO FORMA ADJUSTMENT RESERVE BALANCING	REMOVAL OF RETIRING ASSETS	TGS DIVISION TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	TGS DIVISION ADJUSTED ACCT 1060	ALLOCATION TO SERVICE AREA	TGS DIVISION TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
59	391.5	Artwork	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
64	391.6	Maximo	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
73	391.9	Computer & Equipment	(657,275)	0	0	0	0	0	(326,459)	209,650	(774,085)	0	(774,085)	44.101 %	(341,378)
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
75	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
78	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
80	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
81	394	Tools, Shop & Garage	(9,375)	0	0	4,578	0	0	(243)	0	(5,040)	0	(5,040)	44.101 %	(2,223)
82	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
86	397	Communication Equipment	(793,173)	0	0	0	0	0	(812)	20,106	(773,879)	0	(773,879)	44.101 %	(341,288)
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	44.101 %	0
89		Total General Plant Reserves	$(2,264,399)	$687	$0	$3,859	$(445)	$4,331	$(474,312)	$303,860	$(2,426,419)	$0	$(2,426,419)		$(1,070,073)
90		Total Accumulated Reserves For Depreciation	$(2,671,115)	$687	$405,997	$4,578	$(445)	$4,331	$(474,312)	$303,860	$(2,426,419)	$0	$(2,426,419)		
91		Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%		
92		Total Allocated Accumulated Reserves	$(1,177,986)	$303	$179,048	$2,019	$(196)	$1,910	$(209,176)	$134,005	$(1,070,073)	$0	$(1,070,073)		

Source: WKP C.b C-1.b and D.b TGS Division Assets, CCNC, and Accumulated Reserve - WNSA.xlxs

WKP D.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110	REMOVE ARTWORK	REMOVE AVIATION	REMOVE LEASE INCENTIVE	REMOVE LAND DEPRECIATION	REMOVE ONG SPECIFIC ASSET	REMOVE KGS SPECIFIC ASSET	REMOVE TGS SPECIFIC ASSET	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	CORPORATE ADJUSTED ACCTS 1080100 & 1110	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(f)	(l)	(m)	(n)	(o)	(p)
		INTANGIBLE PLANT																
1	301	Organization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009 %	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
5		Total Intangible Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT																
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009 %	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
9	329	Other Structures	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
10	332	Field Lines	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
14	337	Other Equip	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
18	367	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
21	371	Other Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
22		Total Gathering and Transmission Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT																
23	374	Land	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0.00%	$0	44.1009 %	$0
24	374.1	Land	0	0	0	0	0	0	0	0	0	$0	0	$0	0.00%	0	44.1009 %	0
25	374.2	Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
26	375	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
28	375.2	Other System Structures	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
29	376	Mains	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
32	378	Meas. & Reg. Station - General	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
34	380	Services	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
38	381	Meters	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
39	382	Meter Installations	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
40	383	House Regulators	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0	44.1009 %	0
44		Total Distribution Plant Reserves	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$0
		GENERAL PLANT																
45	389	Land & Land Rights	$(7)	$0	$0	$0	$7	$0	$0	$0	$0	$0	$0	0	27.15%	$0	44.1009 %	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
47	390.1	Structures & Improvements	(128,253)	0	0	0	0	977	0	0	0	(127,276)	0	(127,276)	27.15%	(34,555)	44.1009 %	(15,239)
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
50	390.2	Leasehold Improvement	(3,113,279)	0	0	125,431	0	0	0	0	0	(2,987,848)	0	(2,987,848)	27.15%	(811,201)	44.1009 %	(357,747)
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
53	391.1	Office Furniture & Equipment	(1,411,252)	0	0	0	0	0	0	0	0	(1,411,252)	0	(1,411,252)	27.15%	(383,155)	44.1009 %	(168,975)
54	391.19	Airplane Hanger Furniture	(5,169)	0	5,169	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
57	391.3	Office Machines	(35,309)	0	0	0	0	0	0	0	0	(35,309)	0	(35,309)	27.15%	(9,586)	44.1009 %	(4,228)
58	391.4	Audio Visual Equipment	(298,175)	0	0	0	0	0	0	0	0	(298,175)	0	(298,175)	27.15%	(80,955)	44.1009 %	(35,702)
59	391.5	Artwork	(16,194)	16,194	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
60	391.6	Purchased Software	(44,331,304)	0	0	0	0	0	0	0	5,905	(44,325,399)	0	(44,325,399)	27.15%	(12,034,346)	44.1009 %	(5,307,255)
61	391.6	Banner Software	(1,343,962)	0	0	0	0	0	0	0	0	(1,343,962)	0	(1,343,962)	30.75%	(413,204)	44.1009 %	(182,227)
62	391.6	PowerPlant System	(602,259)	0	0	0	0	0	0	0	0	(602,259)	0	(602,259)	26.08%	(157,060)	44.1009 %	(69,265)
63	391.6	Riskworks	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
64	391.6	Maximo	(3,021,131)	0	0	0	0	0	0	0	0	(3,021,131)	0	(3,021,131)	25.00%	(755,283)	44.1009 %	(333,086)
65	391.6	Foundation Software	(12,330)	0	0	0	0	0	0	0	12,330	0	0	0	0.00%	0	44.1009 %	0
66	391.6	Concur Project	(47,648)	0	0	0	0	0	0	0	0	(47,648)	0	(47,648)	28.75%	(13,700)	44.1009 %	(6,042)
67	391.6	Journey-Employee-ODC Distrigas	(38,312,052)	0	0	0	0	0	0	0	0	(38,312,052)	0	(38,312,052)	27.15%	(10,401,722)	44.1009 %	(4,587,253)
68	391.6	Journey-Employee Count	(1,153,517)	0	0	0	0	0	0	0	0	(1,153,517)	0	(1,153,517)	28.75%	(331,667)	44.1009 %	(146,268)
69	391.6	Payroll - Time Management	(175,382)	0	0	0	0	0	0	0	0	(175,382)	0	(175,382)	28.75%	(50,427)	44.1009 %	(22,239)
70	391.6	Accounts Payable Software	(241,670)	0	0	0	0	0	0	0	0	(241,670)	0	(241,670)	33.81%	(81,711)	44.1009 %	(36,035)
71	391.8	Micro Computer Software	(11,530,242)	0	0	0	0	0	0	78,797	0	(11,451,445)	0	(11,451,445)	27.15%	(3,109,067)	44.1009 %	(1,371,127)
72	391.81	Aircraft Computer Equipment	34,623	0	(34,623)	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
74	391.99	Cloud Computing	(33,008)	0	0	0	0	0	0	0	0	(33,008)	0	(33,008)	27.15%	(8,962)	44.1009 %	(3,952)
75	392	Transportation Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
76	392.2	Transport Equip Pickup Trucks& Vans	(59)	0	0	0	0	0	59	0	0	0	0	0	27.15%	0	44.1009 %	0

WKP D.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
AS OF DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION & AMORTIZATION - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE PER BOOK ACCTS 1080100 & 1110	REMOVE ARTWORK	REMOVE AVIATION	REMOVE LEASE INCENTIVE	REMOVE LAND DEPRECIATION	REMOVE ONG SPECIFIC ASSET	REMOVE KGS SPECIFIC ASSET	REMOVE TGS SPECIFIC ASSET	REMOVE ONE GAS FOUNDATION SOFTWARE	CORPORATE TEST YEAR ADJUSTED ACCTS 1080100 & 1110	KNOWN AND MEASURABLE ADJUSTMENT TO INCLUDE RESERVES	CORPORATE ADJUSTED ACCTS 1080100 & 1110	ALLOCATION TO TGS	CORPORATE TEST YEAR ADJUSTED AS ALLOCATED	ALLOCATION TO SERVICE AREA	CORPORATE TEST YEAR ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(f)	(l)	(m)	(n)	(o)	(p)
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
78	392.5	Trailers	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
79	392.6	Aircraft	(12,447,662)	0	12,447,662	0	0	0	0	0	0	(0)	0	(0)	27.15%	(0)	44.1009 %	(0)
80	393	Stores Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
81	394	Tools, Shop & Garage	(2,765)	0	2,765	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
82	394.1	Tools	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
86	397	Communication Equipment	(19,858)	0	0	0	0	0	0	0	0	(19,858)	0	(19,858)	27.15%	(5,391)	44.1009 %	(2,378)
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0	0	0	0	0	27.15%	0	44.1009 %	0
89		Total General Plant Reserves	$(118,247,863)	$16,194	$12,420,973	$125,431	$7	$977	$59	$78,797	$18,235	$(105,587,189)	$0	$(105,587,189)	27.16%	$(28,681,991)		$(12,649,016)
																$(28,681,991)		
90		Total Accumulated Reserves For Depreciation	$(118,247,863)	$16,194	$12,420,973	$125,431	$7	$977	$59	$78,797	$18,235	$(105,587,189)	$0	$(105,587,189)				
91		Allocation Factor to TGS	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%	27.1643%				
92		Allocation Factor to Service Area	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%	44.1009%				
93		Total Allocated Accumulated Reserves	$(14,165,725)	$1,940	$1,487,994	$15,026	$1	$117	$7	$9,440	$2,184	$(12,649,016)	$0	$(12,649,016)				

Source: WKP C.c C-1.c and D.c Corporate Assets, CCNC, and Accumulated Reserve - WNSA.xlxs

SCHEDULE E

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

COST OF CAPITAL

LINE NO.	DESCRIPTION	RATIO	COST RATE %	COMPOSITE RATE %
		(a)	(b)	(c)
1	Long-Term Debt	40.26%	4.09%	1.65%
2	Common Equity	59.74%	10.25%	6.12%
3	Total	100.000%		7.77%

Source: SCH E Cost of Capital - WNSA.xlsx

SCHEDULE F

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

FEDERAL INCOME TAX

LINE NO.	DESCRIPTION	REFERENCE	PER BOOKS	ADJUSTMENT	TEST YEAR ADJUSTED
			(a)	(b)	(c)
1	Rate Base	B	$607,843,675	$(18,447,720)	$589,395,955
2	Rate of Return	E	7.7692%	7.7692%	7.7692%
3	Required Return		$47,224,579	$(1,433,240)	$45,791,340
4	Less: Interest on Long-Term Debt (1)		10,004,001	(303,616)	9,700,385
5	Net After Tax Income before parking adjustment		$37,220,579	$(1,129,624)	$36,090,955
6	Add: Parking Expense (2)		135,440		135,440
7	Net After Tax Income		$37,356,019	$(1,129,624)	$36,226,395
8	Gross-Up Factor [1 / (1-0.21)]		1.2658228	1.2658228	1.2658228
9	Net Taxable Income		$47,286,100	$(1,429,904)	$45,856,197
10	Tax Rate		21.0000%	21.0000%	21.0000%
11	Federal Income Tax		$9,930,081	$(300,280)	$9,629,801
12	Net Income Tax Expense		$9,930,081	$(300,280)	$9,629,801
	Note (1)				
13	Debt Component of Return	E	1.6458%		1.6458%
14	Total Rate Base	B	$607,843,675		$589,395,955
15	Interest on Long-Term Debt		$10,004,001		$9,700,385

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, the IRS issued final regulations under IRC Sec.274 that provided a new exception to the parking disallowance please see S. McTaggart 's direct testimony for more details.

SCHEDULE G
Page 1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	$198,052,464	$(70,586,689)	$127,465,775
	OPERATING EXPENSES				
2	Cost of Gas	G-1	$82,080,953	$(82,080,953)	$0
3	Base Payroll Expense	G-4	19,769,908	472,427	20,242,335
4	Overtime Payroll Expense	G-5	1,593,477	42,285	1,635,762
5	Employee Benefits and Payroll Taxes	G-6	7,982,658	136,645	8,119,302
6	Pension and Other Post Employment Benefits Regulatory Asset Amortization	G-7	28,315	121,170	149,485
7	Incentive Compensation	G-8	4,838,841	(1,171,956)	3,666,885
8	Miscellaneous Adjustments	G-9	4,386,505	(4,386,505)	0
9	Rents and Leases Adjustment	G-10	705,740	19,623	725,362
10	Interest on Customer Deposits	G-11	47,985	(43,282)	4,703
11	Uncollectible Expense	G-12	1,381,749	(499,049)	882,700
12	Injuries and Damages	G-13	134,825	41,773	176,598
13	Advertising Expense	G-14	25,535	(695)	24,840
14	Depreciation and Amortization Expense	G-15	20,433,963	4,964,496	25,398,459
15	Ad Valorem Tax Expense	G-16	6,609,338	573,762	7,183,100
16	Texas Franchise Tax Expense	G-17	0	949,373	949,373
17	Stores Load Clearing	G-18	119,212	56,735	175,947
18	Transportation & Work Equipment Clearing	G-19	1,888,509	(182,716)	1,705,793
19	Regulatory Expense	G-20	88,428	209,691	298,119
20	Distrigas % Adjustment	G-21	0	451,168	451,168
21	Causal % Adjustment - NOT USED	G-22	0	0	0
22	Pipeline Integrity Testing	G-23	0	802,014	802,014
23	Excess Deferred Income Tax Amortization	G-24	0	(1,422,666)	(1,422,666)
24	Unadjusted Expenses		13,683,027		13,683,027
25	Total Operating Expense Adjustments		$165,798,968	$(80,946,660)	$84,852,308
26					
27	Net Operating Revenue & Expense Adjustments		$32,253,496	$10,359,971	$42,613,467

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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		$191,931,191	$(70,998,482)	$120,932,709
2	Forfeited Discounts	4870		0	0	0
3	Misc Fees	4880		1,190,570	376,717	1,567,287
4	Transportation	4893		4,646,058	319,721	4,965,779
5	Misc. Rent Revenue	4930		0	0	0
6	Other Utility Revenue	4950		284,645	(284,645)	0
7	Total Revenue			$198,052,464	$(70,586,689)	$127,465,775
8	COST OF GAS	805		$82,080,953	$(82,080,953)	$0
	DEPRECIATION & AMORTIZATION					
9	Depreciation and Amortization Expense	4030-4050		$20,433,963	$4,964,496	$25,398,459
10	Pension and OPEB Reg Asset Amortization Expense	4073		116,743	121,170	237,913
11	Total Depr. & Amort.			$20,550,706	$5,085,667	$25,636,372
	TAXES OTHER THAN INCOME					
12	Payroll	4081		$1,269,387	$(96,239)	$1,173,147
13	Ad Valorem	4081	190	6,609,338	573,762	7,183,100
14	Revenue Related	4081	133, 138 & 140	0	0	0
15	Other	4081	233	608,977	949,373	1,558,351
16	Total Taxes Other Than Income			$8,487,702	$1,426,896	$9,914,598
17	Excess Deferred Income Tax Amortization	4101	102	$0	$(1,422,666)	$(1,422,666)
17	INTEREST ON CUSTOMER DEPOSITS	4310		$47,985	$(43,282)	$4,703
	TRANSMISSION AND HIGH PRESSURE DISTRIBUTION					
18	Underground Storage	8140-8360		$0	$0	$0
19	Operation Supervision and Engineering	8500		3,234	0	3,234
20	Transmission Communication Equip	8520		0	0	0
21	Compressor Station Labor and Expenses	8530		0	0	0
22	Mains Expenses	8560		527,905	782,555	1,310,460
23	Measuring and Regulating Station Expenses	8570		283,408	3,677	287,085
24	Trans/Compression of Gas by Others	8580		0	0	0
25	Other Expenses	8590		152	0	152
26	Rent	8600		62,330	0	62,330
27	Maintenance Supervison and Engineering	8610		985	0	985
28	Maintenance of Mains	8630		9,611	(177)	9,433
29	Maintenance of Measuring and Regulating Station Equipment	8650		34,265	832	35,097
30	Maintenance of Communication Equipment	8660		0	0	0
31	Total Transmission			$921,889	$786,888	$1,708,777
	DISTRIBUTION OPERATIONS					
32	Supervision and Engineering	8700		$907,272	$14,480	$921,752
33	Distribution Load Dispatch	8710		226,169	1,980	228,149
34	Mains & Services	8740		4,358,732	(7,636)	4,351,096
35	Meas. Stat. Exp. - General	8750		415,348	7,626	422,974
36	Meter & House Reg. Exp. - Ind.	8760		27,770	244	28,014

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

SUMMARY OF OPERATING REVENUES & EXPENSES

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
				(a)	(b)	(c)
37	Meter & House Reg. Exp.-City Gate	8770		62,145	1,296	63,441
38	Meter & House Reg. Exp.	8780		4,319,991	25,977	4,345,968
39	Customer Installation Exp	8790		131,201	3,787	134,987
40	Other Expense	8800		869,548	(9,164)	860,384
41	Rents	8810		61,075	0	61,075
42	Corporate & Div. Exp.	8820		0	0	0
43	Total Distribution Operations			$11,379,249	$38,591	$11,417,840

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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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					
44	Supervision and Engineering	8850		$23,908	$705	$24,613
45	Struct. & Improv.	8860		504,440	(257)	504,182
46	Mains	8870		3,241,108	6,384	3,247,492
47	Meas. & Reg. Stat. Exp. - Gen	8890		635,887	858	636,744
48	Meas. & Reg. Stat. Exp. - Ind.	8900		393,940	834	394,774
49	Meas. & Reg. Stat. Exp. - City Gate	8910		6,436	0	6,436
50	Maintenance of Services	8920		1,077,151	13,945	1,091,097
51	Meters & House Reg.	8930		0	0	0
52	Other Equipment	8940		0	0	0
53	Clearing - Meter Shop - Small Meters	8950		0	0	0
54	Clearing - Meter Shop - Large Meters	8960		0	0	0
55	Total Distribution Maintenance			$5,882,870	$22,469	$5,905,339
56	Total Distribution Expense			$17,262,118	$61,060	$17,323,179
	CUSTOMER ACCOUNTING					
57	Supervision	9010		$114,817	$983	$115,800
58	Meter Reading	9020		612,274	4,116	616,390
59	Customer Accounting	9030		3,106,876	16,438	3,123,314
60	Bad Debts	9040		1,447,900	(565,200)	882,700
61	Miscellaneous	9050		467,414	(50,315)	417,099
62	Total Customer Accounting			$5,749,282	$(593,978)	$5,155,304
	CUSTOMER INFORMATION					
63	Supervision	9070		$0	$0	$0
64	Customer Assistance Expense	9080		655,833	15,215	671,047
65	Inform. & Instruct. Adver. Exp.	9090		48,036	0	48,036
66	Customer Service & Informational Svc.	9100		0	0	0
67	Total Customer Information			$703,868	$15,215	$719,083
	SALES					

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

SUMMARY OF OPERATING REVENUES & EXPENSES

LINE NO.	DESCRIPTION	ACCOUNT NUMBER	SUB ACCOUNT	PER BOOK	ADJUSTMENTS	TEST YEAR ADJUSTED
				(a)	(b)	(c)
68	Supervision	9110		$0	$0	$0
69	Demonstrating and Selling Expense	9120		0	0	0
70	Advertising	9130		4,501	0	4,501
71	Employee Sales Referrals	9140		0	0	0
72	Misc. Gas Sales Expense	9163		0	0	0
73	Total Sales			$4,501	$0	$4,501
74	Total Customer Accounts Expense			$6,457,651	$(578,763)	$5,878,888
	ADMINISTRATIVE & GENERAL					
75	Salaries	9200		$6,261,046	$(329,228)	$5,931,818
76	Office Supplies & Expenses	9210		1,804,140	(548,737)	1,255,404
77	Transferred Credit	9220		(4,461,726)	0	(4,461,726)
78	Outside Services	9230		430,521	(11,908)	418,613
79	Property Insurance	9240		272,311	8,427	280,738
80	Injuries & Damages	9250		1,446,512	150,681	1,597,193
81	Employee Pensions & Benefits	9260		5,148,771	(274,049)	4,874,721
82	A&G Franchise Elections	9270		150,367	(150,000)	367
83	Regulatory Commission Expense	9280		320,533	209,661	530,194
84	Duplicate Charges- Credit	9290		0	0	0
85	General Advertising Expense	9301		7,402	(695)	6,707
86	Misc. General Expenses	9302		17,641,222	(3,255,286)	14,385,935
87	Rents	9310		705,740	19,623	725,362
88	Maintenance of General Plant	9320		263,127	6	263,133
89	Misc. General Expenses	9400's		0	0	0
90	Total Administrative & General Expense			$29,989,964	$(4,181,506)	$25,808,458
91	Total Operating Expense			$165,798,968	$(80,946,660)	$84,852,308
92	Earnings Before Income Tax & Interest Expense			$32,253,496	$10,359,971	$42,613,467

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	PER BOOKS WKP G.a.2 (Note 1) (a)	REMOVE COST OF GAS RELATED ADJ G-1 (b)	NORMALIZE GAS SALES REVENUE ADJ G-2 (c)	NORMALIZE OTHER UTILITY SALES REVENUE ADJ G-3 (d)	BASE PAYROLL ADJ G-4 (e)	OVERTIME PAYROLL ADJ G-5 (f)	BENEFITS & PAYROLL TAX ADJ G-6 (g)	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ G-7 (h)	INCENTIVE COMPENSATION ADJ G-8 (i)	MISC. ADJ G-9 (j)	RENT ADJ G-10 (k)	CUSTOMER DEPOSITS ADJ G-11 (l)	UNCOLLECTIBLE EXPENSE ADJ G-12 (m)	INJURIES & DAMAGES ADJ G-13 (n)	ADVERTISING ADJ G-14 (o)	DEPRECIATION ADJ G-15 (p)	AD VALOREM TAX ADJ G-16 (q)	TEXAS FRANCHISE TAX ADJ G-17 (r)	STORES LOAD ADJ G-18 (s)	TWE LOAD ADJ G-19 (t)	REGULATORY EXP ADJ G-20 (u)	DISTRIGAS % ADJ G-21 (v)	CAUSAL % ADJ G-22 (w)	PIPELINE INTEGRITY TESTING EXPENSE ADJ G-23 (y)	EXCESS DEFERRED INCOME TAX AMORTIZATION ADJ G-24 (z)	TOTAL ADJUSTMENTS (za)	TEST YEAR ADJUSTED (zb)
	Revenue																													
1	Gas Sales Revenue	480-482		$191,931,190.67	$(82,080,953)	$11,082,471	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(70,998,482)	$120,932,709
2	Forfeited Discounts	4870		0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Misc Fees	4880		1,190,570.00	0	0	376,717	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	376,717	1,567,287
4	Transportation	4893		4,646,058.49	0	0	319,721	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	319,721	4,965,779
5	Misc. Rent Revenue	4930		0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Other Utility Revenue	4950		284,645.32	0	0	(284,645)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(284,645)	0
7	Total Revenue			$198,052,464.48	$(82,080,953)	$11,082,471	$411,793	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(70,586,689)	$127,465,775
8	Cost of Gas	805		$82,080,953	$(82,080,953)																								$(82,080,953)	$0
	Deprec. & Amort. Expense																													
9	Depreciation and Amortization Expense	4030-4050		$20,433,963	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,964,496	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,964,496	$25,398,459
10	Pension and OPEB Reg Asset Amortization Expense (Note 2)	4073		116,743	0	0	0	0	0	0	121,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	121,170	237,913
11	Total Depr. & Amort.			$20,550,706	$0	$0	$0	$0	$0	$0	$121,170	$0	$0	$0	$0	$0	$0	$0	$4,964,496	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,085,667	$25,636,372
	Taxes Other Than Income																													
12	Payroll	4081		$1,269,387	$0	$0	$0	$0	$0	$(3,967)	$0	$(7,090)	$(85,183)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(96,239)	$1,173,147
13	Ad Valorem	4081	190	6,609,338	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	573,762	0	0	0	0	0	0	0	0	573,762	7,183,100
14	Revenue Related	4081	133. 138 & 140	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Other	4081	131. 233 & 995	608,977	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	949,373	0	0	0	0	0	0	0	949,373	1,558,351
16	Total Taxes Other Than Income			$8,487,702	$0	$0	$0	$0	$0	$(3,967)	$0	$(7,090)	$(85,183)	$0	$0	$0	$0	$0	$0	$573,762	$949,373	$0	$0	$0	$0	$0	$0	$0	$1,426,896	$9,914,598
17	Excess Deferred Income Tax Amortization	4101	102	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(1,422,666)	$(1,422,666)	$(1,422,666)
17	Interest on Customer Deposits	4310		$47,985	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(43,282)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(43,282)	$4,703
18	Storage Misc.	8140-8360		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Transmission & High Pressure Distribution																													
19	Operation Supervision and Engineering	8500		$3,234	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,234
20	Transmission Communication Equip	8520		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Compressor Station Labor and Expenses	8530		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Mains Expenses	8560		527,905	0	0	0	4,120	640	0	0	0	(19,638)	0	0	0	0	0	0	0	0	0	(4,580)	0	0	0	802,014	0	782,555	1,310,460
23	Measuring and Regulating Station Expenses	8570		283,408	0	0	0	5,464	999	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,786)	0	0	0	0	0	3,677	287,085
24	Trans/Compression of Gas by Others	8580		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Other Expenses	8590		152	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	152
26	Rent	8600		62,330	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	62,330
27	Maintenance Supervison and Engineering	8610		985	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	985
28	Maintenance of Mains	8630		9,611	0	0	0	52	(1)	0	0	0	0	0	0	0	0	0	0	0	0	0	(229)	0	0	0	0	0	(177)	9,433
29	Maintenance of Measuring and Regulating Station Equipment	8650		34,265	0	0	0	704	129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	832	35,097
30	Maintenance of Communication Equipment	8660		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Total Transmission			$921,889	$0	$0	$0	$10,340	$1,767	$0	$0	$0	$(19,638)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(7,595)	$0	$0	$0	$802,014	$0	$786,888	$1,708,777
	Distribution Operations																													
32	Supervision and Engineering	8700		$907,272	$0	$0	$0	$14,482	$2,084	$0	$0	$0	$(1,940)	$0	$0	$0	$0	$0	$0	$0	$0	1	$(148)	$0	$0	$0	$0	$0	$14,480	$921,752
33	Distribution Load Dispatch	8710		226,169	0	0	0	2,007	(27)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,980	228,149
34	Mains & Services	8740		4,358,732	0	0	0	29,594	5,373	0	0	0	(43,871)	0	0	0	0	0	0	0	0	20,129	(18,861)	0	0	0	0	0	(7,636)	4,351,096
35	Meas & Reg. Stat. Exp. - General	8750		415,348	0	0	0	6,659	1,192	0	0	0	(61)	0	0	0	0	0	0	0	0	16	(179)	0	0	0	0	0	7,626	422,974
36	Meas & Reg. Stat. Exp. - Ind.	8760		27,770	0	0	0	248	(3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	244	28,014
37	Meas & Reg. Stat. Exp. - City Gate	8770		62,145	0	0	0	1,141	200	0	0	0	0	0	0	0	0	0	0	0	0	0	(45)	0	0	0	0	0	1,296	63,441
38	Meter & House Reg. Exp.	8780		4,319,991	0	0	0	78,495	14,345	0	0	0	(4,185)	0	0	0	0	0	0	0	0	2,632	(65,309)	0	0	0	0	0	25,977	4,345,968
39	Customer Installation Exp	8790		131,201	0	0	0	3,202	585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,787	134,987
40	Other Expense	8800		869,548	0	0	0	6,143	826	0	0	0	(28,061)	0	0	0	0	0	0	0	0	11,928	0	0	0	0	0	0	(9,164)	860,384
41	Rents	8810		61,075	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	61,075
42	Corporate & TGS Division Expenses Credit	8820		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
43	Total Distribution Operations			$11,379,249	$0	$0	$0	$141,970	$24,575	$0	$0	$0	$(78,118)	$0	$0	$0	$0	$0	$0	$0	$0	$34,706	$(84,541)	$0	$0	$0	$0	$0	$38,591	$11,417,840
	Distribution Maintenance											0	0																	
44	Supervision and Engineering	8850		$23,908	$0	$0	$0	$596	$109	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$705	$24,613
45	Struct. & Improv.	8860		504,440	0	0	0	0	0	0	0	0	(258)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(257)	504,182
46	Mains	8870		3,241,108	0	0	0	31,735	5,798	0	0	0	(67)	0	0	0	0	0	0	0	0	13,657	(44,739)	0	0	0	0	0	6,384	3,247,492
47	Meas. & Reg. Stat. Exp. - Gen	8890		635,887	0	0	0	8,204	1,499	0	0	0	0	0	0	0	0	0	0	0	0	0	(8,845)	0	0	0	0	0	858	636,744
48	Meas. & Reg. Stat. Exp. - Ind.	8900		393,940	0	0	0	7,594	1,387	0	0	0	0	0	0	0	0	0	0	0	0	0	(8,146)	0	0	0	0	0	834	394,774
49	Meas. & Reg. Stat. Exp. - City Gate	8910		6,436	0	0	0	0	(0)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6,436
50	Maintenance of Services	8920		1,077,151	0	0	0	21,001	3,838	0	0	0	0	0	0	0	0	0	0	0	0	7,261	(18,155)	0	0	0	0	0	13,945	1,091,097
51	Meters & House Reg.	8930		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52	Other Equipment	8940		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53	Clearing - Meter Shop - Small Meters	8950		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54	Clearing - Meter Shop - Large Meters	8960		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55	Total Distribution Maintenance			$5,882,870	$0	$0	$0	$69,131	$12,630	$0	$0	$0	$(325)	$0	$0	$0	$0	$0	$0	$0	$0	$20,918	$(79,885)	$0	$0	$0	$0	$0	$22,469	$5,905,339
56	Total Distribution			$17,262,118	$0	$0	$0	$211,101	$37,205	$0	$0	$0	$(78,443)	$0	$0	$0	$0	$0	$0	$0	$0	$55,624	$(164,426)	$0	$0	$0	$0	$0	$61,060	$17,323,179
	Customer Accounting																													
57	Supervision	9010		$114,817	$0	$0	$0	$997	$(13)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$983	$115,800
58	Meter Reading	9020		612,274	0	0	0	12,468	2,278	0	0	0	0	0	0	0	0	0	0	0	0	64	(10,695)	0	0	0	0	0	4,116	616,390
59	Customer Accounting	9030		3,106,876	0	0	0	16,671	(162)	0	0	0	(71)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16,438	3,123,314
60	Bad Debts	9040		1,447,900	0	0	0	0	0	0	0	0	(66,151)	0	0	(499,049)	0	0	0	0	0	0	0	0	0	0	0	0	(565,200)	882,700
61	Miscellaneous	9050		467,414	0	0	0	32	6	0	0	0	(50,353)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(50,315)	417,099
62	Total Customer Accounting			$5,749,282	$0	$0	$0	$30,168	$2,109	$0	$0	$0	$(116,575)	$0	$0	$(499,049)	$0	$0	$0	$0	$0	$64	$(10,695)	$0	$0	$0	$0	$0	$(593,978)	$5,155,304
	Customer Information																													
63	Supervision	9070		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
64	Customer Assistance Expense	9080		655,833	0	0	0	13,804	2,278	0	0	0	(868)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15,215	671,047
65	Inform. & Instruct. Adver. Exp.	9090		48,036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48,036
66	Customer Svc and Informational Svc	9100		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total Customer Information			$703,868	$0	$0	$0	$13,804	$2,278	$0	$0	$0	$(868)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,215	$719,083
	Sales																												0	
68	Supervision	9110		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

WKP G.a.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE ADJUSTMENTS

LINE		ACCT.	SUB	PER BOOKS	REMOVE COST OF GAS RELATED ADJ	NORMALIZE GAS SALES REVENUE ADJ	NORMALIZE OTHER UTILITY SALES REVENUE ADJ	BASE PAYROLL ADJ	OVERTIME PAYROLL ADJ	BENEFITS & PAYROLL TAX ADJ	PENSION & OPEB REGULATORY ASSET AMORTIZATION ADJ	INCENTIVE COMPENSATIO N ADJ	MISC. ADJ
69	Demonstrating and Selling Expense	9120		$0	0	0	0	0	0	0	0	0	0
70	Advertising	9130		4,501	0	0	0	0	0	0	0	0	0
71	Employee Sales Referrals	9140		0	0	0	0	0	0	0	0	0	0
72	Misc. Gas Sales Expense	9163		0	0	0	0	0	0	0	0	0	0
73	Total Sales			$4,501	$0	$0	$0	$0	$0	$0	$0	$0	$0
74	Total Customer Accounts Expense			$6,457,651	$0	$0	$0	$43,972	$4,387	$0	$0	$0	$(117,443)
	Administrative & General												
75	Salaries	9200		$6,261,046	$0	$0	$0	$28,154	$606	$0	$0	$(357,312)	$(676)
76	Office Supplies & Expenses	9210		1,804,140	0	0	0	0	0	0	0	0	(549,783)
77	Transferred Credit	9220		(4,461,726)	0	0	0	0	0	0	0	0	0
78	Outside Services	9230		430,521	0	0	0	0	0	0	0	0	(11,908)
79	Property Insurance	9240		272,311	0	0	0	0	0	0	0	0	8,427
80	Injuries & Damages	9250		1,446,512	0	0	0	0	0	0	0	0	108,908
81	Employee Pensions & Benefits	9260		5,148,771	0	0	0	0	0	(14,968)	0	(66,598)	(192,484)
82	A&G Franchise Elections	9270		150,367	0	0	0	0	0	0	0	0	(150,000)
83	Regulatory Commission Expenses	9280		320,533	0	0	0	0	0	0	0	0	(30)
84	Duplicate Charges- Credit	9290		0	0	0	0	0	0	0	0	0	0
85	General Advertising Expense	9301		7,402	0	0	0	0	0	0	0	0	0
86	Misc. General Expenses	9302		17,641,222	0	0	0	178,854	(1,681)	155,579	0	(740,956)	(3,298,251)
87	Rents	9310		705,740	0	0	0	0	0	0	0	0	0
88	Maintenace of General Plant	9320		263,127	0	0	0	5	1	0	0	0	0
89	Misc. General Expenses	9400's		0	0	0	0	0	0	0	0	0	0
90	Total A&G Operations			$29,989,964	$0	$0	$0	$207,014	$(1,074)	$140,611	$0	$(1,164,866)	$(4,085,798)
91	Total Operating Expense			$165,798,968	$(82,080,953)	$0	$0	$472,427	$42,285	$136,645	$121,170	$(1,171,956)	$(4,386,505)
92	Net Income before Income Tax			$32,253,496	$(0)	$11,082,471	$411,793	$(472,427)	$(42,285)	$(136,645)	$(121,170)	$1,171,956	$4,386,505

LINE	RENT ADJ	CUSTOMER DEPOSITS ADJ	UNCOLLECTIBLE EXPENSE ADJ	INJURIES & DAMAGES ADJ	ADVERTISING ADJ	DEPRECIATION ADJ	AD VALOREM TAX ADJ	TEXAS FRANCHISE TAX ADJ	STORES LOAD ADJ	TWE LOAD ADJ	REGULATORY EXP ADJ	DISTRIGAS % ADJ	CAUSAL % ADJ	PIPELINE INTEGRITY TESTING EXPENSE ADJ	EXCESS DEFERERED INCOME TAX AMORTIZATION ADJ	TOTAL	TEST YEAR
69	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
70	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,501
71	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
72	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
73	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,501
74	$0	$0	$(499,049)	$0	$0	$0	$0	$0	$64	$(10,695)	$0	$0	$0	$0	$0	$(578,763)	$5,878,888
75	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$(329,228)	$5,931,818
76	0	0	0	0	0	0	0	0	1,047	0	0	0	0	0	0	(548,737)	1,255,404
77	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(4,461,726)
78	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(11,908)	418,613
79	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8,427	280,738
80	0	0	0	41,773	0	0	0	0	0	0	0	0	0	0	0	150,681	1,597,193
81	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(274,049)	4,874,721
82	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(150,000)	367
83	0	0	0	0	0	0	0	0	0	0	209,691	0	0	0	0	209,661	530,194
84	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
85	0	0	0	0	(695)	0	0	0	0	0	0	0	0	0	0	(695)	6,707
86	0	0	0	0	0	0	0	0	0	0	0	451,168	0	0	0	(3,255,286)	14,385,935
87	19,623	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19,623	725,362
88	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	263,133
89	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
90	$19,623	$0	$0	$41,773	$(695)	$0	$0	$0	$1,047	$0	$209,691	$451,168	$0	$0	$0	$(4,181,506)	$25,808,458
91	$19,623	$(43,282)	$(499,049)	$41,773	$(695)	$4,964,496	$573,762	$949,373	$56,735	$(182,716)	$209,691	$451,168	$0	$802,014	$(1,422,666)	$(80,946,660)	$84,852,308
92	$(19,623)	$43,282	$499,049	$(41,773)	$695	$(4,964,496)	$(573,762)	$(949,373)	$(56,735)	$182,716	$(209,691)	$(451,168)	$0	$(802,014)	$1,422,666	$10,359,971	$42,613,467

NOTE 2: Account 407.3 116,743
Pension & OPEB 28,315 (Schedule G-7)

Amortization expense of regulatory asset (GUD 10256) 88,428 (Schedule G-20)

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
	Revenue							
1	Gas Sales Revenue	480-482		$191,931,191	$0	$0	$0	$191,931,191
2	Forfeited Discounts	4870		0	0	0	0	0
3	Misc Fees	4880		1,190,570	0	0	0	1,190,570
4	Transportation	4893		4,646,058	0	0	0	4,646,058
5	Misc. Rent Revenue	4930		0	0	0	0	0
6	Other Utility Revenue	4950		284,645	0	0	0	284,645
7	Total Revenue			$198,052,464	$0	$0	$0	$198,052,464
8	Cost of Gas	805		$82,080,953	$0	$0	$0	$82,080,953
	Deprec. & Amort. Expense							
9	Depreciation and Amortization Expense	4030-4050		$17,512,491	$160,231	$6,261,192	$2,761,242	$20,433,963
10	Pension and OPEB Reg Asset Amortization Expense (Note 2)	4073		116,743	0	0	0	116,743
11	Total Depr. & Amort.			$17,629,233	$160,231	$6,261,192	$2,761,242	$20,550,706
	Taxes Other Than Income							
12	Payroll	4081		$0	$0	$2,878,369	$1,269,387	$1,269,387
13	Ad Valorem	4081	190	6,728,322	0	(269,799)	(118,984)	6,609,338
14	Revenue Related	4081	133, 138 & 140	0	0	0	0	0
15	Other	4081	131, 233 & 995	0	0	1,380,873	608,977	608,977
16	Total Taxes Other Than Income			$6,728,322	$0	$3,989,443	$1,759,380	$8,487,702
17	Excess Deferred Income Tax Amortization	4101	102	$0	$0	$0	$0	$0
17	Interest on Customer Deposits	4310		$47,985	$0	$0	$0	$47,985

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
18	Storage Misc.	8140-8360		$0	$0	$0	$0	$0
	Transmission & High-Pressure Distribution							
19	Operation Supervision and Engineering	8500		$0	$0	$7,333	$3,234	$3,234
20	Transmission Communication Equip	8520		0	0	0	0	0
21	Compressor Station Labor and Expenses	8530		0	0	0	0	0
22	Mains Expenses	8560		304,998	0	505,448	222,907	527,905
23	Measuring and Regulating Station Expenses	8570		283,408	0	0	0	283,408
24	Trans/Compression of Gas by Others	8580		0	0	0	0	0
25	Other Expenses	8590		0	0	346	152	152
26	Rent	8600		60,806	0	3,456	1,524	62,330
27	Maintenance Supervision and Engineering	8610		0	0	2,233	985	985
28	Maintenance of Mains	8630		3,664	0	13,484	5,947	9,611
29	Maintenance of Measuring and Regulating Station Equipment	8650		34,265	0	0	0	34,265
30	Maintenance of Communication Equipment	8660		0	0	0	0	0
31	Total Transmission			$687,140	$0	$532,300	$234,749	$921,889
	Distribution Operations							
32	Supervision and Engineering	8700		$467,095	$0	$998,112	$440,177	$907,272
33	Distribution Load Dispatch	8710		0	0	512,843	226,169	226,169
34	Mains & Services	8740		4,293,443	0	148,044	65,289	4,358,732
35	Meas & Reg. Stat. Exp. - General	8750		382,323	0	74,885	33,025	415,348
36	Meas & Reg. Stat. Exp. - Ind.	8760		0	0	62,968	27,770	27,770
37	Meas & Reg. Stat. Exp. - City Gate	8770		57,100	0	11,441	5,046	62,145
38	Meter & House Reg. Exp.	8780		4,283,427	0	82,909	36,564	4,319,991

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
39	Customer Installation Exp	8790		131,201	0	0	0	131,201
40	Other Expense	8800		651,415	0	494,623	218,133	869,548
41	Rents	8810		60,654	0	954	421	61,075
42	Corporate & TGS Division Expenses Credit	8820		0	0	0	0	0
43	Total Distribution Operations			$10,326,657	$0	$2,386,780	$1,052,591	$11,379,249
	Distribution Maintenance							
44	Supervision and Engineering	8850		$23,908	$0	$0	$0	$23,908
45	Struct. & Improv.	8860		472,809	0	71,724	31,631	504,440
46	Mains	8870		3,233,235	0	17,852	7,873	3,241,108
47	Meas. & Reg. Stat. Exp. - Gen	8890		635,549	0	766	338	635,887
48	Meas. & Reg. Stat. Exp. - Ind.	8900		393,298	0	1,456	642	393,940
49	Meas. & Reg. Stat. Exp. - City Gate	8910		6,431	0	11	5	6,436
50	Maintenance of Services	8920		1,077,151	0	0	0	1,077,151
51	Meters & House Reg.	8930		0	0	0	0	0
52	Other Equipment	8940		0	0	0	0	0
53	Clearing - Meter Shop - Small Meters	8950		0	0	0	0	0
54	Clearing - Meter Shop - Large Meters	8960		0	0	0	0	0
55	Total Distribution Maintenance			5,842,381	0	91,809	40,488	5,882,870
56	Total Distribution			16,169,039	0	2,478,588	1,093,080	17,262,118
	Customer Accounting							
57	Supervision	9010		$0	$0	$260,350	$114,817	$114,817
58	Meter Reading	9020		612,274	0	0	0	612,274

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
59	Customer Accounting	9030		20,424	0	6,998,615	3,086,452	3,106,876
60	Bad Debts	9040		1,381,749	0	150,000	66,151	1,447,900
61	Miscellaneous	9050		98,448	0	836,641	368,966	467,414
62	Total Customer Accounting			$2,112,896	$0	$8,245,605	$3,636,386	$5,749,282
	Customer Information							
63	Supervision	9070		$0	$0	$0	$0	$0
64	Customer Assistance Expense	9080		507,285	0	336,836	148,548	655,833
65	Inform. & Instruct. Adver. Exp.	9090		445	0	107,914	47,591	48,036
66	Customer Svc and Informational Svc	9100		0	0	0	0	0
67	Total Customer Information			$507,730	$0	$444,750	$196,139	$703,868
	Sales							
68	Supervision	9110		$0	$0	$0	$0	$0
69	Demonstrating and Selling Expense	9120		0	0	0	0	0
70	Advertising	9130		3,716	0	1,780	785	4,501
71	Employee Sales Referrals	9140		0	0	0	0	0
72	Misc. Gas Sales Expense	9163		0	0	0	0	0
73	Total Sales			$3,716	$0	$1,780	$785	$4,501
74	Total Customer Accounts Expense			2,624,341	0	8,692,134	3,833,310	6,457,651
	Administrative & General							
75	Salaries	9200		$200,384	$0	$13,742,717	$6,060,662	$6,261,046
76	Office Supplies & Expenses	9210		732,279	0	2,430,475	1,071,861	1,804,140

WKP G.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OPERATING REVENUE & EXPENSE PER BOOK

LINE NO.	DESCRIPTION	ACCT. NO.	SUB ACCT.	SERVICE AREA PER BOOKS	FORT BLISS	SHARED SERVICES INCLUDING DISTRIGAS	ALLOCATED SHARED SERVICES PER BOOKS (Note 1)	TOTAL SERVICE AREA AND ALLOCATED SHARED SERVICES PER BOOKS
				(a)	(b)	(c)	(d)	(e) = (a) + (b) + (d)
77	Transferred Credit	9220		0	0	(10,117,087)	(4,461,726)	(4,461,726)
78	Outside Services	9230		12,095	0	948,792	418,426	430,521
79	Property Insurance	9240		0	0	617,472	272,311	272,311
80	Injuries & Damages	9250		(36,267)	0	3,362,243	1,482,779	1,446,512
81	Employee Pensions & Benefits	9260		(51,528)	0	11,791,819	5,200,298	5,148,771
82	A&G Franchise Elections	9270		150,367	0	0	0	150,367
83	Regulatory Commission Expenses	9280		246,195	0	168,563	74,338	320,533
84	Duplicate Charges- Credit	9290		0	0	0	0	0
85	General Advertising Expenses	9301		7,226	0	400	176	7,402
86	Miscellaneous General Expenses	9302		(12,965)	0	40,031,351	17,654,186	17,641,222
87	Rents	9310		53,088	0	1,479,906	652,652	705,740
88	Maintenance of General Plant	9320		2,125	0	591,829	261,002	263,127
89	Misc. General Expenses	9400's		0	0	0	0	0
90	Total A&G Operations			$1,302,998	$0	$65,048,482	$28,686,966	$29,989,964
91	Total Operating Expense			$127,270,012	$160,231	$87,002,138	$38,368,726	$165,798,968
92	Net Income before Income Tax			$70,782,453	$(160,231)	$(87,002,138)	$(38,368,726)	$32,253,496

Note 1: Allocation Factor 0.44101

Source 1: WKP G.a.2 Op Inc Per Book TY 12 31 2021 GL Detail Rev Exp acct (CONFIDENTIAL)_WNSA

WKP G.a.2.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	4030995	DEPR INDIRECT ALLOCATION	$0	$1,719,726	$3,882,984	$5,602,710
2	4030	4030100	DEPRECIATION EXPENSE	621,638	0	0	621,638
3	4030	4030300	DEPR EXP-TEXAS 8.209 ACCRUAL	2,983	0	0	2,983
4	4030	4030500	DEPRECIATION EXPENSE - NSC	191	0	0	191
5	4043	4043100	AMORT OF GAS PLANT	33,664	0	0	33,664
6	4043	4043500	AMORT OF GAS PLANT - NSC	5	0	0	5
7	4081	4081100	GEN TAX O/H TRF TO CAPITAL	(2,144,748)	0	0	(2,144,748)
8	4081	4081101	GEN TAX FED UNEMPL INS TAX	40,344	0	0	40,344
9	4081	4081102	GEN TAX FICA	4,504,142	0	0	4,504,142
10	4081	4081131	GEN TAX SALES TAX ALLOWANCE	(47,714)	0	0	(47,714)
11	4081	4081132	GEN TAX STATE UNEMPL INS	151,386	0	0	151,386
12	4081	4081995	GEN TAX DISTRIGAS ALLOCATION	0	0	1,428,587	1,428,587
13	4081	4081191	GEN TAX AD VALOREM RULE 8.209	0	0	0	0
14	4081	4081103	GEN TAX FICA INCENTIVE	327,245	0	0	327,245
15	4081	4081190	GEN TAX AD VALOREM	(269,799)	0	0	(269,799)
16	4091	4091100	CURRENT INCOME TAX ACCR	0	0	0	0
17	4101	4101100	DEFERRED INCOME TAX ACCR	0	0	0	0
18	4101	4101102	DEFERRED INCOME TAX AMORTIZATION EXCESS DTL	0	0	0	0
19	4140	4140230	MISC UTIL INCOME-DISTR	0	0	0	0
20	4171	4171995	OPER REV DISTRIGAS ALLOCATION	0	0	0	0
21	4191	4191120	INT CAP AFTER CONSTRUC	0	0	0	0
22	4210	4210995	MISC NONOP INCOME DISTRIGAS ALLOCATION	0	0	0	0
23	4210	4210100	MISC NONOPERATING INCOME	0	0	0	0
24	4261	4261212	CIVIC EXPENSES - BUSINESS & COMMERCIAL DEVEL SPONSORSHIPS	0	0	0	0
25	4261	4261213	CIVIC EXPENSES - PROFESSIONAL ASSOCIATIONS SPONSORSHIPS	0	0	0	0
26	4261	4261210	CIVIC EXPENSES - CONTRIBUTIONS	0	0	0	0
27	4264	4264102	GOVERNMENTAL AFFAIRS EXPENSE	0	0	0	0
28	4265	4265995	MISC NONOP DISTRIGAS ALLOCATION	0	0	0	0
29	4265	4265101	MISCELLANEOUS NONOPERATING EXPENSES	0	0	0	0

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30	4265	4265116	WRITE-OFF DISALLOWED CAPITAL	0	0	0	0
31	4300	4300901	ALLOC INTERCO INTEREST	0	0	0	0
32	4310	4310901	ST DEBT INT EXP INTERCO	0	0	0	0
33	4310	4310103	INT EXP CUSTOMER DEPOSITS	0	0	0	0
34	4320	4320100	INT CAP DURING CONSTRUC	0	0	0	0
35	4320	4320101	INT CAP AFTER CONSTRUC	0	0	0	0
36	4800	4800111	UTIL GAS SALES RES UNBILLED	0	0	0	0
37	4810	4810111	UTIL GAS SALES COMM UNBILLED	0	0	0	0
38	4810	4810211	UTIL GAS SALES IND UNBILLED	0	0	0	0
39	4820	4820111	UTIL GAS SALES CITY GATE UNBILLED	0	0	0	0
40	4880	4880100	SVC REVENUE MISC	0	0	0	0
41	4950	4950300	OTH GAS REV UTIL MISC	0	0	0	0
42	8040	8040100	NATURAL GAS CITY GATE PURCHASES	0	0	0	0
43	8050	8050108	OTH GAS PURCH RESIDENTIAL UNBILLED	0	0	0	0
44	8050	8050134	OTH GAS PURCH UNBILLED COMM	0	0	0	0
45	8050	8050144	OTH GAS PURCH UNBILLED IND	0	0	0	0
46	8050	8050208	OTH GAS PURCH PUBLIC AUTHORITY UNBILLED	0	0	0	0
47	8051	8051100	OTH GAS PURCH UNRECOV GAS ADJ	0	0	0	0
48	8500	8500100	TRANS GEN SUPERVISION	0	7,333	0	7,333
49	8560	8560100	TRANS MAINS MISC EXP	109,401	0	0	109,401
50	8560	8560250	TRANS MAINS PIPELINE INTEGRITY MANAGEMENT	206,593	177,700	0	384,293
51	8560	8560150	TRANS MAINS REGULATORY COMPLIANCE	397	0	0	397
52	8560	8560302	TRANS MAINS CODE LINE LOCATE	11,174	0	0	11,174
53	8560	8560207	TRANS MAINS TOOLS	183	0	0	183
54	8590	8590100	TRANS OTH MISC EXP	346	0	0	346
55	8600	8600100	TRANS RENT	0	3,456	0	3,456
56	8610	8610100	TRANS MNT GEN SUPERVISION	0	2,233	0	2,233
57	8700	8700100	DISTR GEN SUPERVISION	752,137	245,976	0	998,112
58	8710	8710100	DISTR LOAD DISPATCHING	512,812	0	0	512,812
59	8710	8710228	DISTR LOAD PERS USE AUTO	32	0	0	32
60	8740	8740250	DISTR MAINS & SVC DISTR INTEGRITY MGMT PROGRAM	38,469	88,474	0	126,943
61	8740	8740100	DISTR MAINS & SVC MISC	1,733	236	0	1,969
62	8740	8740240	DISTR MAINS & SVC PERMITS/FEES/ASSESSMENTS	865	0	0	865
63	8740	8740207	DISTR MAINS & SVC TOOLS	9,830	231	0	10,060
64	8740	8740225	DISTR MAINS & SVC UNIFORMS	1,441	0	0	1,441
65	8740	8740302	DISTR MAINS & SVC CODE LINE LOCATE	6,277	0	0	6,277
66	8740	8740403	DISTR MAINS & SVC LINE LOCATE UNLOCATABLE	489	0	0	489
67	8750	8750100	DISTR MEAS & REG ST MISC	74,860	0	0	74,860
68	8750	8750114	DISTR MEAS & REG ST ODORIZATION	23	0	0	23
69	8750	8750121	DISTR MEAS & REG ST MECH CHARTS	2	0	0	2

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70	8760	8760100	DISTR IND MEAS & REG ST MISC	61,332	0	0	61,332
71	8760	8760117	DISTR IND ROTARY METER DIFF TEST	586	0	0	586
72	8760	8760112	DISTR IND MEAS & REG VOL PROC EFM	1,050	0	0	1,050
73	8770	8770100	DISTR C G MEAS & REG ST MISC	11,441	0	0	11,441
74	8780	8780100	DISTR MEAS & HOUSE REG MISC	2,351	64,555	0	66,907
75	8780	8780139	DISTR MEAS & HOUSE MEAS SVC CTR	(7,921)	23,783	0	15,862
76	8780	8780112	DISTR MEAS & HOUSE REG TURN ON/OFFS & SVC ORDER	141	0	0	141
77	8800	8800100	DISTR OTHER EXPENSES	459,369	29,560	0	488,929
78	8800	8800400	DISTR OTH SAFETY	1,089	0	0	1,089
79	8800	8800210	DISTR OTH OFFICE SUPPLIES	1,716	5	0	1,721
80	8800	8800228	DISTR OTH PERS USE AUTO	174	0	0	174
81	8800	8800120	DISTR OTH SVC BLDG	2,698	0	0	2,698
82	8800	8800221	DISTR OTH TRAINING & EDUCATION	12	0	0	12
83	8860	8860120	DISTR MNT STRUC & IMPROV SVC BLDG	71,724	0	0	71,724
84	8870	8870101	DISTR MNT MAINS CATHODIC PROTECT	9,125	0	0	9,125
85	8870	8870100	DISTR MNT MAINS MISC	8,249	23	0	8,272
86	8870	8870120	DISTR MNT MAINS LEAK REPAIR	456	0	0	456
87	8890	8890112	DISTR MNT MEAS & REG ST - EFM	145	0	0	145
88	8890	8890100	DISTR MNT MEAS & REG ST MISC	621	0	0	621
89	8890	8890114	DISTR MNT MEAS & REG ODORIZATION	0	0	0	0
90	9010	9010100	CUST ACCTG/COLL SUPERVISION	260,350	0	0	260,350
91	9030	9030210	CUST REC/COLLEC OFFICE SUPPLIES	256,122	0	0	256,122
92	9030	9030100	CUST REC/COLLEC EXP MISC	1,496,936	62	0	1,496,998
93	9030	9030110	CUST RECORDS EXPENSE	2,974,616	23	0	2,974,639
94	9030	9030170	CUST COLLEC AGENCY FEE	76,772	0	0	76,772
95	9030	9030226	CUST REC/COLLEC POSTAGE	1,970,567	0	0	1,970,567
96	9030	9030125	CUST REC/COLLEC LOCKBOX	223,515	0	0	223,515
97	9050	9050100	CUST ACCTS MISC EXP	3,691	678,529	0	682,220
98	9050	9050120	CUST ACCTS SVC BLDG	154,421	0	0	154,421
99	9080	9080100	CUST ASST MISC EXP	336,836	0	0	336,836
100	9090	9090321	INFO/INSTRUC CORP COMM DIRECT	107,754	0	0	107,754
101	9090	9090100	INFO/INSTRUC MISC	159	0	0	159
102	9130	9130100	ADVERTISING MISC EXP	1,780	0	0	1,780
103	9200	9200712	A&G SALARIES ESPP	211,022	0	0	211,022
104	9200	9200713	A&G SALARIES LT INCENT-RESTRICTED	213,576	0	0	213,576
105	9200	9200714	A&G SALARIES LT INCENT-PERFORMANCE	185,085	0	0	185,085
106	9200	9200100	A&G SALARIES	5,884,339	3,058,617	0	8,942,957
107	9200	9200700	A&G SALARIES INCENTIVE PLAN	4,190,078	0	0	4,190,078
108	9210	9210880	A&G S&E Auto-NSC	7,834	0	0	7,834
109	9210	9210207	A&G S&E TRAVEL/ENTERTAINMENT	70,730	16,672	0	87,402

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110	9210	9210221	A&G S&E TRAINING & ED	58,568	2,392	0	60,960
111	9210	9210100	A&G SUPPLIES & EXPENSES MISC	717,055	105,995	0	823,050
112	9210	9210210	A&G S&E OFFICE SUPPLIES	1,151	17	0	1,168
113	9210	9210301	A&G S&E TELE LONG DISTANCE	36,853	0	0	36,853
114	9210	9210303	A&G S&E TELE LOCAL LINES	121,522	0	0	121,522
115	9210	9210304	A&G S&E CELLULAR PHONES	411,255	0	0	411,255
116	9210	9210308	A&G S&E TELE DATA	273,226	0	0	273,226
117	9210	9210309	A&G S&E TELE SCADA	2,887	0	0	2,887
118	9210	9210411	A&G S&E TRAIN MGMT PROGRAM	2,030	22	0	2,052
119	9210	9210102	A&G S&E EMPL MISC	3,211	133	0	3,344
120	9210	9210220	A&G S&E MEMBERSHIP DUES	7,802	3,764	0	11,566
121	9210	9210226	A&G S&E POSTAGE	225	72	0	296
122	9210	9210202	A&G S&E SUBS/PUBLICATIONS	617	896	0	1,513
123	9210	9210404	A&G S&E MAIL ROOM	31,389	33	0	31,422
124	9210	9210402	A&G S&E OTH BLDG OPER	57,941	32,683	0	90,624
125	9210	9210807	A&G S&E TRANSITION COSTS	23,416	0	0	23,416
126	9210	9210240	A&G S&E PERMITS/FEES/ASSESSMENTS	7,997	0	0	7,997
127	9210	9210413	A&G S&E TECH/CUST SVC TRAINING	13,392	0	0	13,392
128	9210	9210106	A&G COVID 19 RESPONSE	398,784	11,317	0	410,100
129	9210	9210224	A&G S&E COMPUTER EXP	16	0	0	16
130	9210	9210228	A&G S&E PERS USE AUTO	0	5	0	5
131	9210	9210417	A&G S&E VISA/IMMIGRATION AND NATIONALITY COSTS	0	1,453	0	1,453
132	9210	9210201	A&G S&E ASSOC MTGS	3,383	0	0	3,383
133	9210	9210209	A&G S&E ENVIRONMENTAL EXP	1,694	0	0	1,694
134	9210	9210809	A&G S&E EMPLOYEE ONBOARDING PROGRAM	23	0	0	23
135	9210	9210101	A&G S&E ADMIN	1,216	0	0	1,216
136	9210	9210400	A&G S&E SAFETY	750	0	0	750
137	9210	9210223	A&G S&E AIRFARE	0	56	0	56
138	9220	9220902	A&G TRF TO CONSTRUCTION	(10,117,087)	0	0	(10,117,087)
139	9230	9230120	A&G OUTSIDE SVC LEGAL	183,621	0	0	183,621
140	9230	9230115	A&G OUTSIDE SVC LEGAL REGULATORY	243,837	0	0	243,837
141	9230	9230302	A&G OUTSIDE SVC IT APPLICATION SUPPORT	0	16,026	0	16,026
142	9230	9230307	A&G OUTSIDE SVC CLOUD COMPUTING ARRANGEMENTS	95,327	68,815	0	164,142
143	9230	9230110	A&G OUTSIDE SVC MISC	173,860	162,629	0	336,489
144	9230	9230810	A&G OUTSIDE SVC CONTRACT	4,676	0	0	4,676
145	9240	9240100	A&G PROPERTY INSURANCE	617,472	0	0	617,472

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146	9250	9250100	A&G INSURANCE	39,864	0	0	39,864
147	9250	9250120	A&G INJ & DAMAGES WORKERS COMP	285,789	0	0	285,789
148	9250	9250180	A&G INJ & DAMAGES LIABILITY INSURANCE	2,854,179	0	0	2,854,179
149	9250	9250140	A&G INJ & DAMAGES 3RD PARTY VEHICLE ACCIDENT DAMAGES	16,512	0	0	16,512
150	9250	9250200	A&G INJ & DAMAGES MISC SETTLEMENTS	222,917	0	0	222,917
151	9250	9250130	A&G INJ & DAMAGES 3RD PARTY GENERAL LIABILITY DAMAGES	(57,019)	0	0	(57,019)
152	9260	9260902	A&G EMPL BEN O/H TRF CAPITAL	(8,132,138)	0	0	(8,132,138)
153	9260	9260995	A&G EMPL BEN SERP DISTRIGAS ALLOC	0	0	608,628	608,628
154	9260	9260996	A&G EMPL BEN PENSION DISTRIGAS	0	0	1,114,632	1,114,632
155	9260	9260997	A&G EMPL BEN FAS 106 DISTRIGAS ALLOC	0	0	(104,422)	(104,422)
156	9260	9260310	A&G EMPL BEN SVC RECOGNITION	72,200	0	0	72,200
157	9260	9260102	A&G EMPL BEN 401(K) ADMIN	67,449	19,403	0	86,853
158	9260	9260112	A&G EMPL BEN SERP ADMIN	0	384	0	384
159	9260	9260115	A&G EMPL BEN PENSION ADMIN	51,822	6,426	0	58,248
160	9260	9260140	A&G EMPL BEN PROFIT SHARING ADMIN	60,167	15,187	0	75,355
161	9260	9260190	A&G EMPL BEN RESERVE	9,170,868	0	0	9,170,868
162	9260	9260101	A&G EMPL BEN 401(K) CO MATCH	3,108,501	0	0	3,108,501
163	9260	9260141	A&G EMPL BEN PROFIT SHARING	2,296,331	0	0	2,296,331
164	9260	9260413	A&G EMPL BEN ACTUARY ONE GAS PENSION-SC	2,700,665	0	0	2,700,665
165	9260	9260431	A&G EMPL BEN ACTUARY OPEB-SC	96,278	0	0	96,278
166	9260	9260511	A&G EMPL BEN ACTUARY SERP-NSC	7,905	0	0	7,905
167	9260	9260513	A&G EMPL BEN ACTUARY ONE GAS PENSION-NSC	1,271,116	0	0	1,271,116
168	9260	9260531	A&G EMPL BEN ACTUARY OPEB-NSC	32,853	0	0	32,853
169	9260	9260905	A&G EMPL BEN O/H TRF CAPITAL - NSC	(648,220)	0	0	(648,220)
170	9260	9260302	A&G EMPL BEN TUITION LOANS	56,321	953	0	57,274
171	9260	9260328	A&G EMPL BEN DISABILITY	47,979	0	0	47,979
172	9260	9260197	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	219,054	0	0	219,054
173	9260	9260198	A&G EMPL BEN ACCR PSP ON STI	181,000	0	0	181,000
174	9260	9260192	A&G EMPL BEN RESERVE IBNR	(529,523)	0	0	(529,523)
175	9302	9302901	A&G MISC O/H TRF TO AFFIL	1,856,974	0	0	1,856,974
176	9302	9302995	A&G MISC DISTRIGAS ALLOC	0	0	29,056,473	29,056,473
177	9302	9302920	A&G MISC HR ALLOC BASED ON HEADCOUNT	0	582,575	0	582,575
178	9302	9302100	A&G MISC EXPENSES	1,794	120	0	1,915
179	9302	9302800	A&G MISC PROCUREMENT CARD CLEARING	74,804	0	0	74,804
180	9302	9302915	A&G MISC ROYALTY ALLOCATED	8,126,734	0	0	8,126,734
181	9302	9302106	A&G MISC AGA INDUSTRY DUES	153,028	0	0	153,028
182	9302	9302409	A&G MISC	18	27	0	46
183	9302	9302120	A&G MISC EMPL MOVING	121,347	1,868	0	123,216

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184	9302	9302105	A&G MISC INDUSTRY DUES	24,540	0	0	24,540
185	9302	9302121	A&G ENTERPRISE SERVICES OWNED ASSETS MOVING COSTS	30,814	0	0	30,814
186	9302	9302310	A&G MISC UNITED WAY	233	0	0	233
187	9310	9310120	A&G RENTS EQUIPMENT	45,890	0	0	45,890
188	9310	9310100	A&G RENTS LAND/FACILITY	1,434,016	0	0	1,434,016
189	9320	9320140	A&G MNT AGREEMENT FEES	281,941	309,888	0	591,829
190	4170	4170112	MISC NONUTIL REV CNG EXCISE TAX	0	0	0	0
191	8810	8810100	DISTR RENTS	954	0	0	954
192	9040	9040100	UNCOLLECTIBLE CUST ACCTS	150,000	0	0	150,000
193	9301	9301100	A&G ADVERTISING MISC	400	0	0	400
194	8900	8900100	DISTR MNT IND MEAS & REG ST MISC	1,456	0	0	1,456
195	8910	8910100	DISTR MNT C G MEAS & REG ST MISC	4	0	0	4
196	8910	8910122	DISTR MNT C G EFM	6	0	0	6
197	8630	8630115	TRANS MNT MAINS REPAIRS FR LEAKAGE	5	0	0	5
198	8630	8630100	TRANS MNT MAINS	13,479	0	0	13,479
199	9280	9280100	A&G REG COMMISSION EXP	168,563	0	0	168,563
200	Total			$43,554,923	$7,460,333	$35,986,882	$87,002,138
201							
202							

203	Calculation of O&M Expense Factor	
204		
205	Per Book Shared Services (net of the A&G transfer credit)	$87,002,138
206	Less: depreciation expense that does not get an O&M factor	(6,261,192)
207	Less: tax expense accounts	(3,989,443)
208	Total O&M Shared Service Expenses	$76,751,504
209		
210		
211		
212	Total O&M Shared Service Expenses	$76,751,504
213	Add back Account 9220902 A&G Transfer Credit/Construction Overhead	10,117,087
214	Grand Total Shared Service Expenses:	$86,868,591
215		
216	O&M effective expense factor	88.35%
217	Capitalization factor	11.65%
218		100.00%

Source: WKP G.a.2.a1 Shared Service per book including Distrigas (CONFIDENTIAL) - WNSA.xlsx

Source: WKP G.a.2.a2 Corporate Costs Allocated on a Causal Basis and Through Distrigas-(CONFIDENTIAL) - WNSA.xlsx

SCHEDULE G-1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

REMOVE GAS REVENUE AND COST OF GAS

LINE NO.	DESCRIPTION	AMOUNT
		(a)
1	Cost of Gas Revenue Collected through Cost of Gas Clause	$82,080,953
2	Remove Test Year Cost of Gas Expense	(82,080,953)
3	Net Adjustment	$0

Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx

SCHEDULE G-2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

NORMALIZE GAS SALES REVENUE

LINE NO.	DESCRIPTION	TOTAL # OF BILLS	CCF	REVENUE	
		(a)	(b)	(c)	
1	Operating Gas Sales Revenue (1):	3,611,004	198,516,057	$191,931,191	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx, SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx
2	Less: Test Year Gas Costs collected through Cost of Gas Clause			(82,080,953)	
3	Base Sales Revenue as Recorded	3,611,004	198,516,057	$109,850,237	
	Adjustments:				
4	Remove Test Year WNA Collections			$(675,828)	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
5	Weather Normalization Adjustment		(1,264,700)	(144,456)	Source: SCH G-2 and SCH G-3 Weather Adjustment 10 Norm.xlsx, SCH G-2 and SCH G-3 HDD Detail.xlsx
6	Customers Switching between Gas Sales and Transport	10	342,977	34,507	Source: SCH G-2 and SCH G-3 Switching and Termination Adjustment.xlsx
7	Customer Growth (Loss) Adjustment	19,665	(32,538)	344,280	Source: SCH G-2 Growth Adjustment.xlsx
8	Remove Test Year GRIP			(20,569,000)	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
9	Annualize to Current Rates - GRIP			31,069,529	Source: SCH G-2 and SCH G-3 GRIP Annualization.xlsx
10	Annualize to Current Rates - COSA			1,023,439	Source: SCH G-2 COSA Annualization.xlsx
11	Total Adjustments	19,675	(954,260)	$11,082,471	
12	Base Revenue As Adjusted	3,630,679	197,561,796	$120,932,709	

Calculation of Normalized Gas Sales Revenue used for Advertising Limitation Calculation:

LINE NO.	DESCRIPTION	(a)	(b)
	Calculation of Normalized Cost of Gas Revenue		
13	Normalized CCF		197,561,796
14	Test Year Cost of Gas Revenue	$82,080,953	
15	Test Year CCF	198,516,057	
16	Effective Rate	0.41347	0.41347
17	Normalized Cost of Gas Revenue		$81,685,876

Note 1: Operating gas sales revenue does not include franchise or gross receipt taxes.

SCHEDULE G-3

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

NORMALIZE OTHER UTILITY REVENUE

LINE NO.	DESCRIPTION	TOTAL BILLS	REVENUE	
		(a)	(a)	
1	Test Year Transportation Revenue - Acct 4893	686	$4,646,058	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
	Adjustments:			
2	Remove Estimated Revenue Journal Entries		$(2,533)	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
3	Adjustment to Normalize Weather		(5,450)	Source: SCH G-2 and SCH G-3 Weather Adjustment 10 Norm.xlsx, SCH G-2 and SCH G-3 HDD Detail.xlsx
4	Customers Switching between Gas Sales and Transport	(10)	(37,183)	Source: SCH G-2 and SCH G-3 Switching and Termination Adjustment.xlsx
5	Customer Terminated	(4)	(2,937)	Source: SCH G-2 and SCH G-3 Switching and Termination Adjustment.xlsx
6	Remove Test Year GRIP		(87,836)	Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx
7	Annualize to Current Rates - GRIP		140,105	Source: SCH G-2 and SCH G-3 GRIP Annualization.xlsx
8	Annualize to Current Rates - Fort Bliss CRC		15,555	Source: SCH G-3 Fort Bliss CRC Annualization.xlsx, SCH G-3 2021 Ft. Bliss Legacy System CRC.pdf
9	East Bliss Maintenance Agreement Annualization		300,000	Source: SCH G-3 East Bliss Maint. Agreement Annualization.xlsx
10	Total Adjustments	(14)	$319,721	
11	Total Transportation Revenue As Adjusted	672	$4,965,779	
12	Test Year Service Fees - Acct 4880		$1,190,570	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
13	Service Fee Adjustment		376,717	Source: SCH G-3 Service Fee Annualization.xlsx, SCH G-3 Service Fee Change Adjustment.xlsx
14	Total Service Fee Revenue As Adjusted		$1,567,287	
15	Test Year Other Utility Revenue - Acct 4950		$284,645	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
16	Remove Interest on Storage Gas		(284,645)	Source: SCH G-2 and SCH G-3 Revenue Reconciliation.xlsx
17	Total Other Utility Revenue As Adjusted		$0	
18	Total Transportation, Service Fees, and Misc. Revenue As Adjusted		$6,533,067	

SCHEDULE G-4

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

BASE PAYROLL ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)
1	Hourly Base Payroll for December 2021	WKP G-4.c	$1,422,944	$681,626	$529,535	
2	Salary Base Payroll for December 2021	WKP G-4.c	315,158	1,000,351	4,816,822	
3	Total Base Payroll for December 2021		$1,738,102	$1,681,977	$5,346,357	
4	Annualized Hourly Base Payroll		$12,332,179	$5,907,422	$4,589,301	
5	Annualized Salary Base Payroll		3,781,902	12,004,218	57,801,868	
6	Total Proforma Base Payroll		$16,114,081	$17,911,640	$62,391,169	
7	December Merit Increase Percent		0.000%	0.000%	0.000%	
8	Adjustment to include December Merit Increases		0	0	0	
9	Total Proforma Base Payroll		$16,114,081	$17,911,640	$62,391,169	
10	Total Test Year Base Payroll	WKP G-4.b	15,658,732	17,747,828	60,591,314	
11	Total Allocable Base Payroll Adjustment (Ln 9 minus Ln 10)		$455,349	$163,811	$1,799,855	
12	Allocation to TGS		100%	100%	27.15%	
13	Allocated Base Payroll Adjustment to TGS (Ln 11 times Ln 12)		$455,349	$163,811	$488,661	
14	Allocation to Service Area	WKP A.b	100%	44.10%	44.10%	
15	Allocated Base Payroll Adjustment to Service Area (Ln 13 times Ln 14)		$455,349	$72,242	$215,504	
16	Payroll Expense Factor	WKP G-4.b	53.62%	68.38%	82.99%	
17	Test Year Base Payroll O&M Expense Adjustment (Ln 15 times Ln 16)		$244,172.72	$49,400	$178,854	
18	Adjustment Summary:					
19	Account 9302		$0	$0	$178,854	$178,854
20	Other O&M Accounts (See WKP G-4.a for Distribution by FERC Account)		244,173	49,400	0	293,573
21	Total		$244,173	$49,400	$178,854	$472,427
22	Total Test Year Base Payroll Expense after Allocation		$8,396,718	$5,352,134	$6,021,056	$19,769,908
23	Total as Adjusted Base Payroll Expense after Allocation		$8,640,891	$5,401,534	$6,199,910	$20,242,335

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	$0	0.00%	$0
2	8530	0	0.00%	0	8530	0	0.00%	0
3	8560	142,082	1.45%	3,544	8560	146,234	1.16%	575
4	8570	219,055	2.24%	5,464	8570	0	0.00%	0
5	8590	0	0.00%	0	8590	0	0.00%	0
6	8610	0	0.00%	0	8610	0	0.00%	0
7	8630	0	0.00%	0	8630	13,307	0.11%	52
8	8650	28,210	0.29%	704	8650	0	0.00%	0
9	8700	465,558	4.76%	11,614	8700	728,948	5.81%	2,869
10	8710	0	0.00%	0	8710	510,061	4.06%	2,007
11	8740	1,179,187	12.05%	29,416	8740	45,250	0.36%	178
12	8750	261,763	2.67%	6,530	8750	32,768	0.26%	129
13	8760	0	0.00%	0	8760	62,968	0.50%	248
14	8770	43,923	0.45%	1,096	8770	11,441	0.09%	45
15	8780	3,146,619	32.15%	78,494	8780	141	0.00%	1
16	8790	128,346	1.31%	3,202	8790	0	0.00%	0
17	8800	185,696	1.90%	4,632	8800	383,952	3.06%	1,511
18	8850	23,908	0.24%	596	8850	0	0.00%	0
19	8860	16	0.00%	0	8860	0	0.00%	0
20	8870	1,271,843	12.99%	31,727	8870	2,117	0.02%	8

WKP G-4.a

21		8890	328,765	3.36%	8,201		8890	669	0.01%	3
22		8900	304,177	3.11%	7,588		8900	1,456	0.01%	6
23		8910	0	0.00%	0		8910	11	0.00%	0
24		8920	841,889	8.60%	21,001		8920	0	0.00%	0
25		8930	0	0.00%	0		8930	0	0.00%	0
26		9010	0	0.00%	0		9010	253,280	2.02%	997
27		9020	499,806	5.11%	12,468		9020	0	0.00%	0
28		9030	12,187	0.12%	304		9030	4,159,219	33.13%	16,367
29		9050	1,284	0.01%	32		9050	0	0.00%	0
30		9080	503,318	5.14%	12,556		9080	317,357	2.53%	1,249
31		9120	0	0.00%	0		9120	0	0.00%	0
32		9130	0	0.00%	0		9130	0	0.00%	0
33		9200	200,384	2.05%	4,999		9200	5,884,339	46.87%	23,156
34		9210	0	0.00%	0		9210	0	0.00%	0
35		9260	0	0.00%	0		9260	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	189	0.00%	5		9320	0	0.00%	0
39	Total		$9,788,205	100.00%	$244,173	Total		$12,553,518	100.00%	$49,400

WKP G-4.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

TEST YEAR TOTAL PAYROLL

		BASE AND OVERTIME						BASE						OVERTIME					
		HOURLY			SALARY			HOURLY			SALARY			HOURLY			SALARY		
LINE NO.	DESCRIPTION	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL
		(a)	(b)	(c)	(d)	(e)	(f)	(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	220,263	0	13,261	68,949	0	32,160	212,765	0	12,823	68,949	0	32,160	7,499	0	437	0	0	0
4	1840	6,295,513	2,199,270	737,601	1,880,564	3,580,148	9,553,576	4,973,988	1,812,529	700,253	1,880,243	3,579,920	9,553,576	1,321,525	386,741	37,348	321	228	0
5	1860	171	0	0	0	25,308	0	0	0	0	0	25,308	0	171	0	0	0	0	0
6	2530	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Total Capital	$6,515,947	$2,199,270	$750,862	$1,949,513	$3,605,456	$9,585,736	$5,186,753	$1,812,529	$713,077	$1,949,192	$3,605,228	$9,585,736	$1,329,194	$386,741	$37,785	$321	$228	$0
	Expense																		
8	8500	$0	$0	$0	$0	$0	$66,308	$0	$0	$0	$0	$0	$66,308	$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	118,009	11,593	158,710	24,073	134,641	82,827	98,547	8,150	158,440	24,073	134,641	82,827	19,462	3,443	270	0	0	0
11	8570	197,680	0	0	21,376	0	0	173,317	0	0	21,376	0	0	24,363	0	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	29,390	0	0	0	0	0	29,390	0	0	0	0	0	0
14	8630	0	13,307	0	0	0	0	0	11,722	0	0	0	0	0	1,586	0	0	0	0
15	8650	6	0	0	28,204	0	0	0	0	0	28,204	0	0	6	0	0	0	0	0
16	8700	51,630	63,629	131,171	413,928	665,319	1,177,485	50,945	63,588	122,427	413,928	665,319	1,177,481	685	41	8,743	0	0	4
17	8710	0	410,826	0	0	99,235	0	0	303,662	0	0	99,235	0	0	107,164	0	0	0	0
18	8740	1,021,338	6,781	67,615	157,849	38,469	287,674	865,229	5,965	67,488	157,777	38,469	287,674	156,110	815	128	72	0	0
19	8750	170,011	7,636	0	91,751	25,132	0	149,846	7,475	0	91,751	25,132	0	20,165	161	0	0	0	0
20	8760	0	60,068	0	0	2,900	0	0	58,704	0	0	2,900	0	0	1,364	0	0	0	0
21	8770	39,647	8,541	0	4,275	2,900	0	34,773	8,325	0	4,275	2,900	0	4,875	216	0	0	0	0
22	8780	2,938,688	141	121,722	207,931	0	69,851	2,467,234	91	115,076	207,781	0	69,851	471,454	49	6,646	150	0	0
23	8790	127,760	0	0	585	0	0	90,648	0	0	550	0	0	37,112	0	0	36	0	0
24	8800	175,183	14,300	53,962	10,514	369,652	59,273	158,171	13,416	53,962	10,514	369,652	59,273	17,011	884	0	0	0	0
25	8850	0	0	0	23,908	0	116,851	0	0	0	23,908	0	116,851	0	0	0	0	0	0
26	8860	16	0	0	0	0	0	0	0	0	0	0	0	16	0	0	0	0	0
27	8870	1,088,631	2,117	0	183,211	0	0	849,677	1,490	0	183,099	0	0	238,954	627	0	113	0	0
28	8890	272,239	669	0	56,526	0	0	240,877	660	0	56,526	0	0	31,362	9	0	0	0	0
29	8900	247,651	1,456	0	56,526	0	0	220,339	1,268	0	56,526	0	0	27,311	188	0	0	0	0
30	8910	0	11	0	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0
31	8920	737,504	0	0	104,386	0	0	569,879	0	0	104,313	0	0	167,624	0	0	72	0	0
32	8930	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
33	9010	0	49,552	0	0	203,728	3,399	0	47,431	0	0	203,728	3,399	0	2,121	0	0	0	0
34	9020	435,770	0	0	64,036	0	5,409	414,126	0	0	64,036	0	5,409	21,645	0	0	0	0	0
35	9030	5,072	3,047,606	0	7,115	1,111,613	0	5,049	2,991,570	0	7,115	1,111,225	0	23	56,036	0	0	388	0
36	9050	1,284	0	542,053	0	0	1,667,053	1,269	0	525,153	0	0	1,666,733	15	0	16,900	0	0	320
37	9080	331,927	0	0	171,390	317,357	1,024,415	306,799	0	0	171,390	317,357	1,024,415	25,128	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	66,880	640,444	3,405,565	133,503	5,243,895	41,372,936	65,226	592,556	3,288,438	133,503	5,243,441	41,371,288	1,654	47,888	117,128	0	454	1,648
41	9210	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	9260	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
44	9320	189	0	0	0	0	621	189	0	0	0	0	621	0	0	0	0	0	0
45	Total Expense	$8,027,116	$4,338,676	$4,480,799	$1,761,089	$8,214,842	$45,963,491	$6,762,141	$4,116,072	$4,330,984	$1,760,646	$8,214,000	$45,961,518	$1,264,975	$222,604	$149,815	$442	$842	$1,972
46	Total Test Year	$14,543,063	$6,537,946	$5,231,660	$3,710,602	$11,820,298	$55,549,226	$11,948,894	$5,928,601	$5,044,060	$3,709,839	$11,819,228	$55,547,254	$2,594,169	$609,345	$187,600	$764	$1,070	$1,972
47	Payroll Expense Factor	54%	68%	83%															
48	Overtime Factor	22%	10%	4%															

Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Direct and Shared Service(CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Corporate(CONFIDENTIAL).xlsx

WKP G-4.b

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	289,213	1.58%
1840 (non TWE)	8,176,727	44.79%
1840 (TWE 1840100-1840289)	0	0.00%
1860	171	0.00%
2530	0	0.00%
Total Non-Exp Mains	$8,466,110	46.38%
Total Expense Mains	9,788,205	53.62%
Total Payroll	$18,253,665	100.00%

Percentages to use on TWE and Stores calculation of proforma payroll for Shared Svcs:

Main Account	Shared Services Per Book Capital Payroll	Ratio by Account to Total Payroll
FERC 1540	$0	0.00%
1630	0	0.00%
1840 (non TWE)	5,644,385	30.75%
1840 (TWE 1840100-1840289)	135,032	0.74%
1860	25,308	0.14%
2530	0	0.00%
Total Non-Exp Mains	$5,804,725	31.62%
Total Expense Mains	12,553,518	68.38%
Total Payroll	$18,358,244	100.00%

Note: Average load rate for Stores during the test year 22.79 %

Note: Average load rate for TWE during the test year 41.88 %

ogs WKP G-4.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

BASE PAYROLL

		BASE					
		HOURLY			SALARY		
LINE NO.	DESCRIPTION	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL
		(a)	(b)	(c)	(d)	(e)	(f)
	Capital						
1	1010	$0	$0	$0	$0	$0	$0
2	1540	0	0	0	0	0	0
3	1630	25,855	0	1,992	5,982	0	2,760
4	1840	572,998	209,077	95,584	158,522	301,251	722,619
5	1860	0	0	0	0	3,708	0
6	2530	0	0	0	0	0	0
7	Total Capital	$598,852	$209,077	$97,576	$164,504	$304,959	$725,379
	Expense						
8	8500	$0	$0	$0	$0	$0	$7,241
9	8530	0	0	0	0	0	0
10	8560	12,585	0	17,774	2,092	13,983	7,012
11	8570	23,502	0	0	1,856	0	0
12	8590	0	0	0	0	0	0
13	8610	0	0	0	0	0	2,623
14	8630	0	10,366	0	0	0	0
15	8650	0	0	0	2,431	0	0
16	8700	5,228	7,503	18,126	36,765	54,528	90,231
17	8710	0	34,604	0	0	8,535	0
18	8740	114,516	0	6,889	13,666	3,995	28,453
19	8750	18,802	0	0	7,986	2,157	0
20	8760	0	5,617	0	0	267	0
21	8770	4,700	1,123	0	371	267	0
22	8780	310,295	0	16,659	19,854	0	6,002
23	8790	3,815	0	0	0	0	0
24	8800	14,465	1,414	6,324	409	30,872	5,098
25	8850	0	0	0	2,043	0	10,369
26	8860	0	0	0	0	0	0
27	8870	98,711	230	0	13,834	0	0
28	8890	29,034	0	0	4,908	0	0
29	8900	28,591	0	0	4,908	0	0
30	8910	0	0	0	0	0	0
31	8920	78,129	0	0	7,747	0	0
32	8930	0	0	0	0	0	0
33	9010	0	4,790	0	0	10,854	283
34	9020	43,442	0	0	6,132	0	0
35	9030	599	342,111	0	681	107,021	0
36	9050	185	0	48,840	0	0	147,173
37	9080	32,212	0	0	15,058	17,860	92,319
38	9120	0	0	0	0	0	0
39	9130	0	0	0	0	0	0
40	9200	5,281	64,791	317,347	9,911	445,052	3,694,639
41	9210	0	0	0	0	0	0
42	9260	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	$824,091	$472,548	$431,959	$150,654	$695,392	$4,091,443
47	Total Base Payroll	$1,422,944	$681,626	$529,535	$315,158	$1,000,351	$4,816,822

Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Direct and Shared Service(CONFIDENTIAL).xlsx
Source: WKP G-4.b and WKP G-4.c Test Year and Dec Payroll Corporate(CONFIDENTIAL).xlsx

SCHEDULE G-5

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

OVERTIME PAYROLL ADJUSTMENT

LINE NO.	DESCRIPTION	REFERENCE	PAYROLL DIRECTLY CHARGED TO SERVICE AREA	SHARED SERVICES PAYROLL NOT DIRECTLY CHARGED TO SERVICE AREA	DISTRIGAS PAYROLL	TOTAL ADJUSTMENT
			(a)	(b)	(c)	(d)
1	Total Proforma Hourly Base Payroll	G-4	$12,332,179	$5,907,422	$4,589,301	
2	Overtime as a % of Hourly Base Payroll (Actual for the Test Period)	WKP G-4.b	22%	10%	4%	
3	Total Annualized Overtime Payroll (Ln 1 times Ln 2)		$2,677,383	$607,168	$170,687	
4	Test Period Overtime Payroll	WKP G-4.b	2,594,169	609,345	187,600	
5	Overtime Payroll Adjustment Total (Ln 3 minus Ln 4)		$83,213	$(2,177)	$(16,914)	
6	Allocation to TGS		100.00%	100.00%	27.15%	
7	Allocated Base Payroll Adjustment to TGS (Ln 5 times Ln 6)		$83,213	$(2,177)	$(4,592)	
8	Allocation to Service Area	WKP A.b	100.00%	44.10%	44.10%	
9	Allocated Base Payroll Adjustment to Service Area (Ln 7 times Ln 8)		$83,213	$(960)	$(2,025)	
10	Payroll Expense Factor	WKP G-4.b	54%	68%	83%	
11	Test Year Base Payroll O&M Expense Adjustment (Ln 9 times Ln 10)		$44,622	$(656)	$(1,681)	
	Adjustment Summary:					
12	Account 9302		$0	$0	$(1,681)	$(1,681)
13	Other O&M Accounts (See WKP G-5.a for Distribution by FERC Account)		44,622	(656)	0	43,965
14	Total (Ln 12 plus Ln 13)		$44,622	$(656)	$(1,681)	$42,285
15	Total Test Year Overtime Expense after Allocation		$1,391,077	$183,758	$18,642	$1,593,477
16	Total As Adjusted Overtime Expense after Allocation		1,435,699	183,101	16,961	1,635,762

WKP G-5.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	$0	0.00%	$0
2	8530	0	0.00%	0	8530	0	0.00%	0
3	8560	142,082	1.45%	648	8560	146,234	1.16%	(8)
4	8570	219,055	2.24%	999	8570	0	0.00%	0
5	8590	0	0.00%	0	8590	0	0.00%	0
6	8610	0	0.00%	0	8610	0	0.00%	0
7	8630	0	0.00%	0	8630	13,307	0.11%	(1)
8	8650	28,210	0.29%	129	8650	0	0.00%	0
9	8700	465,558	4.76%	2,122	8700	728,948	5.81%	(38)
10	8710	0	0.00%	0	8710	510,061	4.06%	(27)
11	8740	1,179,187	12.05%	5,376	8740	45,250	0.36%	(2)
12	8750	261,763	2.67%	1,193	8750	32,768	0.26%	(2)
13	8760	0	0.00%	0	8760	62,968	0.50%	(3)
14	8770	43,923	0.45%	200	8770	11,441	0.09%	(1)
15	8780	3,146,619	32.15%	14,345	8780	141	0.00%	(0)
16	8790	128,346	1.31%	585	8790	0	0.00%	0
17	8800	185,696	1.90%	847	8800	383,952	3.06%	(20)
18	8850	23,908	0.24%	109	8850	0	0.00%	0
19	8860	16	0.00%	0	8860	0	0.00%	0
20	8870	1,271,843	12.99%	5,798	8870	2,117	0.02%	(0)
21	8890	328,765	3.36%	1,499	8890	669	0.01%	(0)
22	8900	304,177	3.11%	1,387	8900	1,456	0.01%	(0)
23	8910	0	0.00%	0	8910	11	0.00%	(0)
24	8920	841,889	8.60%	3,838	8920	0	0.00%	0
25	8930	0	0.00%	0	8930	0	0.00%	0
26	9010	0	0.00%	0	9010	253,280	2.02%	(13)
27	9020	499,806	5.11%	2,278	9020	0	0.00%	0
28	9030	12,187	0.12%	56	9030	4,159,219	33.13%	(217)
29	9050	1,284	0.01%	6	9050	0	0.00%	0
30	9080	503,318	5.14%	2,294	9080	317,357	2.53%	(17)
31	9120	0	0.00%	0	9120	0	0.00%	0
32	9130	0	0.00%	0	9130	0	0.00%	0
33	9200	200,384	2.05%	913	9200	5,884,339	46.87%	(308)
34	9210	0	0.00%	0	9210	0	0.00%	0
35	9260	0	0.00%	0	9260	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	189	0.00%	1	9320	0	0.00%	0
39	Total	$9,788,205	100.00%	$44,622	Total	$12,553,518	100.00%	$(656)

SCHEDULE G-6

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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		$18,791,464		$18,518,808		$62,561,856	
2	BENEFITS COMPUTED PER PAYROLL $								
3	H&W BENEFITS*	WKP G-6.b	16.02%	$3,009,716	16.02%	$2,966,047	11.98%	$7,492,286	
4	PENSION	WKP G-6.b	4.51%	847,207	4.51%	834,915	4.27%	2,669,920	
5	OPEB	WKP G-6.b	0.12%	21,656	0.12%	21,341	-0.26%	(164,447)	
6	SERP	WKP G-6.b	0.01%	1,087	0.01%	0	1.79%	0	
7	401K & NQDC	WKP G-6.b	4.93%	926,737	4.93%	913,291	4.81%	3,009,967	
8	PROFIT SHARING	WKP G-6.b	3.66%	687,852	3.66%	677,871	3.29%	2,058,488	
9	A&G EMPL BEN ESPP ADMIN FEES	WKP G-6.b	0.00%	0	0.00%	0	0.00%	0	
10	A&G EMPL BEN RESERVE IBNR	WKP G-6.b	-0.82%	(153,576)	-0.82%	(151,347)	-0.52%	(326,876)	
11	A&G EMPL BEN STOCK RECEIVED	WKP G-6.b	0.00%	0	0.00%	0	0.00%	0	
				$5,340,680		$5,262,118		$14,739,338	
12	ADDITIONAL BENEFITS								
13	A&G EMPL BEN HEALTH	WKP G-6.b		$0		$0		$0	
14	A&G EMPL BEN DEF COMP INVESTMENT GAIN/LOSS	WKP G-6.b		0		0		2,107,928	
15	A&G EMPL BEN MISC ADMIN	WKP G-6.b		0		0		(6,296)	
16	A&G EMPL BEN FAS 112	WKP G-6.b		0		0		4,235	
17	A&G EMPL BEN HRA	WKP G-6.b		0		0		0	
18	A&G EMPL BEN RESERVE IBNR	WKP G-6.b		0		0		0	
19	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	WKP G-6.b		0		219,054		518,696	
20	A&G EMPL BEN ACCR PSP ON STI	WKP G-6.b		0		181,000		478,944	
21	A&G EMPL BEN SCHOLARSHIPS	WKP G-6.b		0		0		106,523	
22	A&G EMPL BEN TUITION LOANS	WKP G-6.b		0		56,807		67,736	
23	A&G EMPL BEN ADOPTION ALLOW	WKP G-6.b		0		0		0	
24	A&G EMPL BEN CLUB MEMBERSHIP	WKP G-6.b		0		0		0	
25	A&G EMPL BEN SPR/SUMMER ACTIVITIES	WKP G-6.b		0		0		0	
26	A&G EMPL BEN EMPLOYEE EVENTS	WKP G-6.b		0		112		1,380	
27	A&G EMPL BEN SVC RECOGNITION	WKP G-6.b		0		72,200		38,200	
28	A&G EMPL BEN STOCK RECEIVED	WKP G-6.b		0		0		0	
29	A&G EMPL BEN EMPLOYEE REFERRAL	WKP G-6.b		0		0		64,000	
30	A&G EMPL BEN DRUG & ALCOHOL TESTING	WKP G-6.b		0		0		104,902	
31	A&G EMPL BEN EMPL ASST PROGRAM	WKP G-6.b		0		0		82,007	
32	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	WKP G-6.b		0		0		0	
33	A&G EMPL BEN DISABILITY	WKP G-6.b		0		47,979		54,060	
34	A&G EMPL BEN ACCOMMODATIONS	WKP G-6.b		0		0		3,685	
35	A&G EMPL BEN WELLNESS PROGRAM	WKP G-6.b		0		0		144,802	
36	A&G EMPL BEN MEDICAL CLINIC	WKP G-6.b		0		0		0	
37	A&G EMPL BEN EMPL APPL LOANS	WKP G-6.b		0		0		0	
38	A&G EMPL BEN INTERCO PARKING	WKP G-6.b		0		0		0	

SCHEDULE G-6

				$0		$577,152		$3,770,802	
39	Annualized Test Year Benefits			$5,340,680		$5,839,270		$18,510,140	
40	PAYROLL TAX RATE PER PAYROLL $	WKP G-6.b	7.60%	$1,428,075	7.60%	$1,407,354	7.48%	$4,679,032	
41	Total Annualized Benefits and Payroll Tax			$6,768,755		$7,246,624		$23,189,172	
42	Test Year Benefits and Payroll Tax			6,216,816		8,290,847		21,623,541	
43	Allocable Adjustment to Benefits and Payroll Tax			$551,938		$(1,044,223)		$1,565,631	
44	Allocation to TGS			100%		100%		27.15%	
45	Allocated Benefits and Payroll Tax Adjustment to TGS			$551,938		$(1,044,223)		$425,069	
46	Allocation to Service Area	WKP A.b		100%		44.10%		44.10%	
47	Allocated Benefits and Payroll Tax Adjustment to Service Area			$551,938		$(460,512)		187,459	
48	Payroll Expense Factor	WKP G-4.b		54%		68%		83%	
49	Test Year Benefits and Payroll Tax Adjustment			$295,967		$(314,902)		$155,579	
50	Adjustment Summary:								
51	Account 9302			$0		$0		$155,579	$155,579
52	Other O&M Accounts (See WKP G4a for Distribution by FERC Account)			295,967		(314,902)		0	(18,935)
53	Total			$295,967		$(314,902)		$155,579	$136,645

* 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		$3,333,658	$2,500,234	$2,148,766	$7,982,658
Total As Adjusted Benefits and Payroll Tax Expense after Allocation		3,629,625	2,185,332	2,304,345	8,119,302
	Taxes only	$765,780	$424,410	$464,963	$1,655,152

Source: SCH G-6 -Corporate Test Year Benefits and Payroll Taxes (CONFIDENTIAL).xlsx

Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes-Direct and Shared Services.xlsx

WKP G-6.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

BENEFITS AND PAYROLL TAX EXPENSE

	DISTRIBUTION OF DIRECT BENEFITS AND PAYROLL TAX O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT				DISTRIBUTION OF SHARED SERVICE BENEFITS AND PAYROLL TAX O&M EXPENSE ADJUSTMENT- BY FERC ACCOUNT			
LINE NO.	MAIN ACCOUNT	TEST YEAR BEENFITS AND PAYROLL TAX ADJUSTMENT	RATIO OF PAYROLL BY ACCOUNT	TOTAL	MAIN ACCOUNT	TEST YEAR BEENFITS AND PAYROLL TAX ADJUSTMENT	RATIO OF PAYROLL BY ACCOUNT	TOTAL
		(a)	(b)	(c)		(d)	(e)	(f)
1	4081	$1,312,148	20.95%	$62,005	4081	$1,712,447	20.95%	$(65,972)
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

WKP G-6.a

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	$4,904,669	79.05%	233,962	9260	6,578,400	79.05%	(248,930)
35		9302	$0	0.00%	0	9302	0	0.00%	0
36		9320	$0	0.00%	0	9320	0	0.00%	0
37	Total		$6,216,816	100.00%	$295,967	Total	$8,290,847	100.00%	$(314,902)

WKP G-6.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

BENEFITS AND TAXES

LINE NO.		DESCRIPTION	TEXAS EMPLOYEES (a)	(b)	CORPORATE SHARED SERVICE AND DISTRIGAS EMPLOYEES (c)	(d)
	Based on Known and Measurable for 2022					
	H&W Benefits					
1	9260190	A&G EMPL BEN RESERVE	$10,377,381		$9,005,856	
2	9260191	A&G EMPL BEN RESERVE UNION	0		0	
3			$10,377,381	16.02%	$9,005,856	11.98%
	Pension					
4	9260413	ONE GAS RETIREMENT PLAN SC	$2,420,054		$2,665,324	
5	9260513	ONE GAS RETIREMENT PLAN NSC	449,589		504,222	
6	9260115	EMPL BEN PENSION ADMIN	51,494		39,744	
			$2,921,137	4.51%	$3,209,290	4.27%
	OPEB					
7	9260431	OPEB SC	$74,944		$162,265	
8	9260531	OPEB NSC	(276)		(359,933)	
9	9260132	A&G EMPL BEN FAS 106 ADMIN	0		0	
			$74,668	0.12%	$(197,668)	-0.26%
	SERP					
10	9260411	SERP SC	$0		$401,787	
11	9260511	SERP NSC	3,748		874,504	
12	9260112	A&G EMPL BEN SERP ADMIN	0		72,000	
			$3,748	0.01%	$1,348,291	1.79%
	Based on Test Year Data					
	401k & NQDC					
13	9260101	A&G EMPL BEN 401(K) CO MATCH	$3,108,501		$3,309,218	
14	9260102	A&G EMPL BEN 401(K) ADMIN	86,853		14,399	
15	9260103	A&G EMPL BEN DEF COMP CO MATCH	0		270,217	
16	9260104	A&G EMPL BEN DEF COMP ADMIN	0		24,199	
			$3,195,353	4.93%	$3,618,032	4.81%
	Profit Sharing Plan					
17	9260141	A&G EMPL BEN PROFIT SHARING	$2,296,331		$2,463,067	
18	9260140	A&G EMPL BEN PROFIT SHARING ADMIN	75,355		11,271	
			$2,371,685	3.66%	$2,474,338	3.29%
	Payroll Related 9260 Expenditures					
19	9260123	A&G EMPL BEN ESPP ADMIN FEES	$0	0.00%	$0	0.00%
20	9260192	A&G EMPL BEN RESERVE IBNR	(529,523)	-0.82%	(392,911)	-0.52%
21	9260312	A&G EMPL BEN STOCK RECEIVED	0	0.00%	0	0.00%
			$(529,523)		$(392,911)	
	Non - Payroll Related 9260 Expenditures					
22	9260100	A&G EMPL BEN HEALTH	$0		$0	
23	9260105	A&G EMPL BEN DEF COMP INVESTMENT GAIN/LOSS	0		2,107,928	
24	9260118	A&G EMPL BEN MISC ADMIN	0		(6,296)	
25	9260119	A&G EMPL BEN FAS 112	0		4,235	
26	9260120	A&G EMPL BEN HRA	0		0	
27	9260192	A&G EMPL BEN RESERVE IBNR	0		0	
28	9260197	A&G EMPL BEN ACCR 401(K) CO MATCH - STI	219,054		518,696	
29	9260198	A&G EMPL BEN ACCR PSP ON STI	181,000		478,944	
30	9260301	A&G EMPL BEN SCHOLARSHIPS	0		106,523	
31	9260302	A&G EMPL BEN TUITION LOANS	56,807		67,736	
32	9260303	A&G EMPL BEN ADOPTION ALLOW	0		0	
33	9260304	A&G EMPL BEN CLUB MEMBERSHIP	0		0	
34	9260306	A&G EMPL BEN SPR/SUMMER ACTIVITIES	0		0	
35	9260307	A&G EMPL BEN EMPLOYEE EVENTS	112		1,380	
36	9260310	A&G EMPL BEN SVC RECOGNITION	72,200		38,200	

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37	9260312	A&G EMPL BEN STOCK RECEIVED	0		0	
38	9260314	A&G EMPL BEN EMPLOYEE REFERRAL	0		64,000	
39	9260321	A&G EMPL BEN DRUG & ALCOHOL TESTING	0		104,902	
40	9260326	A&G EMPL BEN EMPL ASST PROGRAM	0		82,007	
41	9260327	A&G EMPL BEN CHEMICAL DEPENDENCY TREATMENT	0		0	
42	9260328	A&G EMPL BEN DISABILITY	47,979		54,060	
43	9260329	A&G EMPL BEN ACCOMMODATIONS	0		3,685	
44	9260337	A&G EMPL BEN WELLNESS PROGRAM	0		144,802	
45	9260338	A&G EMPL BEN MEDICAL CLINIC	0		0	
46	9260340	A&G EMPL BEN EMPL APPL LOANS	0		0	
47	9260901	A&G EMPL BEN INTERCO PARKING	0		0	
			$577,152		$3,770,802	
	Based on Known and Measurable for 2022					
	Payroll Taxes					
48	4081102	GEN TAX FICA	$4,410,000	6.81%	$4,753,000	6.32%
49	4081101	GEN TAX FED UNEMPL INS TAX	40,000	0.06%	30,800	0.04%
50	4081103	GEN TAX FICA INCENTIVE	327,245	0.51%	637,277	0.85%
51	4081132	GEN TAX STATE UNEMPL INS	146,700	0.23%	203,200	0.27%
			4,923,945	7.60%	5,624,277	7.48%
52		Total Benefit and Payroll Expense	$23,915,546		$28,460,307	
53		Total Labor*	$64,792,214	36.02%	$75,200,424	32.83%

54 *Total Labor used to calculate % is adjusted for known and measurable changes

Source: WKP G-6.b Benefits and Payroll Tax Support.xlsx

SCHEDULE G-7

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

AMORTIZATION OF PENSION & OTHER POST EMPLOYMENT BENEFITS

LINE NO.	YEAR ENDED DECEMBER 2020	BEGINNING OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION	END OF YEAR RATE BASE ADJUSTMENT AMOUNT	ANNUAL AMMORTIZATION
	(a)	(b)	(c)	(d)	(e)
1	2020			$896,913	
2	2021	$896,913		896,913	
3	2022	896,913	$149,485	747,427	
4	2023	747,427	149,485	597,942	
5	2024	597,942	149,485	448,456	
6	2025	448,456	149,485	298,971	
7	2026	298,971	149,485	149,485	
8	2027	149,485	149,485	0	
9	Annualized Amortization of Pension & Other Post Employment Benefits Reg Asset - Account 4073				$149,485
10	Test Year Pension & Other Post Employment Benefits Reg Asset Amortization Expense - Account 4073				28,315
11	Total Adjustment to Test Period Expense				$121,170

SCHEDULE G-8

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

INCENTIVE COMPENSATION

			CORPORATE ALLOCATED TO TGS							ALLOCATED TO WNSA		
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 WNSA	TOTAL ADJUSTMENT AS ALLOCATED TO WNSA	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO WNSA
										44.1009%		
1	GEN TAX FICA INCENTIVE	4081	$637,277	$(64,928)	$572,349	27.15%	$173,021	$(17,628)	$155,393	$76,304	$(7,774)	$68,530
2	A&G SALARIES INCENTIVE PLAN	9302	11,440,303	(2,995,990)	8,444,314	27.15%	3,106,042	(813,411)	2,292,631	1,369,793	(358,722)	1,011,071
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9302	518,696	(87,787)	430,910	27.15%	140,826	(23,834)	116,992	62,106	(10,511)	51,595
4	A&G EMPL BEN ACCR PSP ON STI	9302	478,944	(420,569)	58,375	27.15%	130,033	(114,184)	15,849	57,346	(50,356)	6,989
5	TOTAL SHORT TERM INCENTIVE		$13,075,220	$(3,569,273)	$9,505,947		$3,549,922	$(969,058)	$2,580,865	$1,565,548	$(427,363)	$1,138,185
6	A&G SALARIES LT INCENT-RESTRICTED	9302	$2,419,099	$0	$2,419,099	27.15%	$656,785	$0	$656,785	$289,648	$0	$289,648
7	A&G SALARIES LT INCENT-PERFORMANCE	9302	5,338,712	(2,684,012)	2,654,700	27.15%	1,449,460	(728,709)	720,751	639,225	(321,367)	317,858
8	TOTAL LONG TERM INCENTIVE		$7,757,811	$(2,684,012)	$5,073,799	27.15%	$2,106,246	$(728,709)	$1,377,536	$928,873	$(321,367)	$607,506

			TGS DIRECT			ALLOCATED TO WNSA		
LINE NO.	DESCRIPTION	ACCT. 'NO.	TGS PER BOOK	ADJUSTMENTS	TGS ADJUSTED TEST YEAR	TOTAL PER BOOK AS ALLOCATED TO WNSA	TOTAL ADJUSTMENT AS ALLOCATED TO WNSA	TOTAL TEST YEAR ADJUSTED AS ALLOCATED TO WNSA
						44.1009%		
	Short Term Incentive							
1	GEN TAX FICA INCENTIVE	4081	$327,245	$1,551	$328,796	$144,318	$684	$145,002
2	A&G SALARIES INCENTIVE PLAN	9200	4,190,078	(810,214)	3,379,864	1,847,862	(357,312)	1,490,550
3	A&G EMPL BEN ACCR 401(K) CO MATCH	9260	219,054	147	219,200	96,605	65	96,669
4	A&G EMPL BEN ACCR PSP ON STI	9260	181,000	(151,159)	29,841	79,823	(66,663)	13,160
5	TOTAL SHORT TERM INCENTIVE		$4,917,376	$(959,675)	$3,957,701	$2,168,607	$(423,225)	$1,745,382
6								
7	A&G SALARIES LT INCENT-RESTRICTED	9200	$213,576	$0	$213,576	$94,189	$0	$94,189
8	A&G SALARIES LT INCENT-PERFORMANCE	9200	185,085	0	185,085	81,624	0	81,624
9	TOTAL LONG TERM INCENTIVE		$398,661	$0	$398,661	$175,813	$0	$175,813
	Total Test Year Incentive Compensation after Allocation					$4,838,841		
	Total As Adjusted Benefits and Payroll Tax Expense after Allocation					$3,666,885		

Source: SCH G-8 Incentive Compensation per book and URI Adjustments WNSA.xlsx
Source: SCH G-8 NEO Adjustment WNSA.xlsx

SCHEDULE G-9

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

MISCELLANEOUS ADJUSTMENTS

LINE NO.	DESCRIPTION	ACCT	DIRECT SERVICE AREA	SHARED SERVICES ALLOCATION TO SERVICE AREA	DISTRIGAS ALLOCATION TO SERVICE AREA	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)
1	Payroll Taxes	4081	$751,892	$(836,636)	$(439)	$(85,183)
2	Transmission O & M - Mains Expenses	8560	(19,551)	(88)	0	(19,638)
3	Transmission Other Misc Expenses	8590	0	0	0	0
4	Maintenance of Mains	8630	0	0	0	0
5	Distr. Operations- General Supervision	8700	0	(1,940)	0	(1,940)
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0
7	Distr. Operations - Mains & Services	8740	(43,871)	0	0	(43,871)
8	Distr Meas & Reg St Misc	8750	(61)	0	0	(61)
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	(4,185)	0	(4,185)
10	Distr. Operations - Other Expense	8800	(28,143)	82	0	(28,061)
11	Distr. Operations - Rents	8810	0	0	0	0
12	Distr. Operations - Struct. & Improv.	8860	(298)	40	0	(258)
13	Distr. Maintenance - Mains	8870	(67)	(0)	0	(67)
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	(71)	0	(71)
19	Customer Accounting - Bad Debt	9040	0	(66,151)	0	(66,151)
20	Customer Accounting - Misc. Expense	9050	(73,188)	22,836	0	(50,353)
21	Customer Assistance-Misc. Expense	9080	0	(868)	0	(868)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0
24	Advertising-Misc. Expense	9130	0	0	0	0
25	Salaries	9200	0	(676)	0	(676)
26	Admin & Gen - Office Supp & Exp	9210	(391,424)	(158,360)	0	(549,783)
27	Admin & Gen - Outside Services	9230	0	(11,908)	0	(11,908)
28	Property Insurance	9240	0	8,427	0	8,427
29	Admin & Gen - Injuries & Damages	9250	0	108,908	0	108,908
30	Admin & Gen - Employee Pensions & Benefits	9260	2,611,632	(2,566,965)	(237,150)	(192,484)
31	Admin & Gen - A&G Franchise Elections	9270	(150,000)	0	0	(150,000)
32	Admin & Gen - Regulatory Commission Expense	9280	(30)	0	0	(30)
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	(21,750)	(3,222,894)	(53,607)	(3,298,251)
36	Admin & Gen - Rents	9310	0	0	0	0
37	Totals		$2,635,141	$(6,730,449)	$(291,196)	$(4,386,505)

WKP G-9.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

MISCELLANEOUS ADJUSTMENTS
DIRECT SERVICE AREA

LINE NO.	DESCRIPTION	ACCT	REMOVAL OF CLUBS AND CIVIC EXPENSE	REMOVAL OF MEAL/HOTEL COSTS OVER RRC THRESHOLD AND REMOVAL OF SPOUSE AND ALCOHOL ACTIVITY	ADJUSTMENT TO INCLUDE DIRECT BENEFITS AND PAYROLL RELATED TAXES	ADJUSTMENT TO INCLUDE DIRECT O/H FOR PAYROLL RELATED TAXESA DN BENEFITS	DIRECT SERP WITH PAYROLL FACTOR APPLIED SCH G-6 BENEFITS & PAYROLL	REMOVAL OF COVID EXPENSES; INCLUDED IN SCH G-20 REGULATORY EXPENSE AMORTIZATION	OTHER ADJUSTMENTS	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Payroll Taxes	4081	$0	$0	$1,312,147	$(560,255)	$0	$0	$0	$751,892
2	Transmission O & M - Mains Expenses	8560	$0	$0	$0	$0	$0	$0	$(19,551)	(19,551)
3	Transmission Other Misc Expenses	8590	$0	$0	$0	$0	$0	$0	$0	0
4	Maintenance of Mains	8630	$0	$0	$0	$0	$0	$0	$0	0
5	Distr. Operations- General Supervision	8700	$0	$0	$0	$0	$0	$0	$0	0
6	Distr. Operations - Distribution Load Dispatch	8710	$0	$0	$0	$0	$0	$0	$0	0
7	Distr. Mains & Services	8740	$0	$0	$0	$0	$0	$0	$(43,871)	(43,871)
8	Distr Meas & Reg St Misc	8750	$0	$(61)	$0	$0	$0	$0	$0	(61)
9	Distr. Operations - Meter & House Reg. Exp.	8780	$0	$0	$0	$0	$0	$0	$0	0
10	Distr. Operations - Other Expense	8800	$(13)	$(380)	$0	$0	$0	$(70)	$(27,681)	(28,143)
11	Distr. Operations - Rents	8810	$0	$0	$0	$0	$0	$0	$0	0
12	Distr. Structuctures & Improvements	8860	$0	$0	$0	$0	$0	$0	$(298)	(298)
13	Distr. Maintenance - Mains	8870	$0	$(67)	$0	$0	$0	$0	$0	(67)
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	$0	$0	$0	$0	$0	$0	$0	0
15	Distr. Maintenance- Cathodic Protection	8900	$0	$0	$0	$0	$0	$0	$0	0
16	Customer Accounting - Supervision	9010	$0	$0	$0	$0	$0	$0	$0	0
17	Customer Accounting - Meter Reading	9020	$0	$0	$0	$0	$0	$0	$0	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	$0	$0	$0	$0	$0	$0	$0	0
19	Customer Accounting - Bad Debts	9040	$0	$0	$0	$0	$0	$0	$0	0
20	Customer Accounting - Misc. Expense	9050	$0	$0	$0	$0	$0	$0	$(73,188)	(73,188)
21	Customer Asst.- Misc. Expenses	9080	$0	$0	$0	$0	$0	$0	$0	0
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	$0	$0	$0	$0	$0	$0	$0	0
23	Demo/Sell- Misc. Expenses	9120	$0	$0	$0	$0	$0	$0	$0	0
24	Advertising-Misc. Expense	9130	$0	$0	$0	$0	$0	$0	$0	0
25	Advertising-Misc. Expense	9200	$0	$0	$0	$0	$0	$0	$0	0
26	Admin & Gen - Office Supp & Exp	9210	$(804)	$(345)	$0	$0	$0	$(390,177)	$(98)	(391,424)
27	Admin & Gen - Outside Services	9230	$0	$0	$0	$0	$0	$0	$0	0
28	Property Insurance	9240	$0	$0	$0	$0	$0	$0	$0	0
29	Admin & Gen - Injuries & Damages	9250	$0	$0	$0	$0	$0	$0	$0	0
30	Admin & Gen - Employee Pensions & Benefits	9260	$0	$0	$4,904,669	$(2,293,620)	$583	$0	$0	2,611,632
31	Admin & Gen - A&G Franchise Elections	9270	$0	$0	$0	$0	$0	$0	$(150,000)	(150,000)
32	Admin & Gen - Regulatory Commission Expense	9280	$0	$0	$0	$0	$0	$0	$(30)	(30)
33	Admin & Gen - Labor Attends Credit	9290	$0	$0	$0	$0	$0	$0	$0	0
34	Admin & Gen - Advertising	9301	$0	$0	$0	$0	$0	$0	$0	0
35	Admin & Gen - Misc General	9302	$(21,750)	$0	$0	$0	$0	$0	$0	(21,750)
36	Admin & Gen - Rents	9310	$0	$0	$0	$0	$0	$0	$0	0
37	Totals		$(22,567)	$(853)	$6,216,816	$(2,853,875)	$583	$(390,247)	$(314,717)	$2,635,141

Source: SCH G-9.a Direct TY12 31 2021_ Civic Charitable Misc Adjustments_WNSA
Source: SCH G-20 Regulatory Expenses - COVID WNSA.xlsx
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr WNSA(CONFIDENTIAL)
Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes-Direct and Shared Services.xlsx

WKP G-9.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

MISCELLANEOUS ADJUSTMENTS
SHARED SERVICES

LINE NO.	DESCRIPTION	ACCT	Adjustment for Known and measurable change in Insurance premiums	Adjustment to remove costs associated with Royalty fees	Removal of Meal/Hotel Costs over RRC Threshold and Removal of Spouse and Alcohol Activity	Management decision to not seek recovery	Remove - Rule 7.5414 Contributions, donations to charitable, religious, or other nonprofit organizations	Remove portion of AGA dues attributable to lobbying.	Remove Area Specific Activity	Adjustment to Include Area Specific Activity	Removal of COVID expenses; Included in SCH G-20 Regulatory Expense	Remove December 2021 Meter Shop entry	Remove Bad Debt Activity as it's included as a Direct Service Area Cost	Adjustment to Remove Payroll Related Taxes and Benefits	Adjustment to Include Shared Service Payroll Related Taxes and Benefits	Adjustment to Remove total O/H for Payroll Related Taxes and Benefits	Adjustment to include Shared Services portion of O/H for Payroll Related Taxes and Benefits	Total	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(i)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
1	Payroll Taxes	4081	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		$(5,023,117)	$1,712,447	$2,144,748	$(731,173)	$(1,897,095)	100.00000 %	44.10090 %	$(836,636)
2	Transmission O & M - Mains Expenses	8560	$0	0	(41)	0	0	0	(183)	0	0	0		0	0	0	0	(225)	88.35357 %	44.10090 %	$(88)
3	Transmission Other Misc Expenses	8590	$0	0		0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
4	Maintenance of Mains	8630	$0	0		0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
5	Distr. Operations- General Supervision	8700	$0	0	(37)	(4,941)	0	0	0	0	0	0		0	0	0	0	(4,978)	88.35357 %	44.10090 %	$(1,940)
6	Distr. Operations - Distribution Load Dispatch	8710	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
7	Distr. Mains & Services	8740	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
8	Distr Meas & Reg St Misc	8750	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
9	Distr. Operations - Meter & House Reg. Exp.	8780	$0	0	(29)	0	0	0	0	0	0	(10,713)		0	0	0	0	(10,741)	88.35357 %	44.10090 %	$(4,185)
10	Distr. Operations - Other Expense	8800	$0	0	0	0	0	0	0	210	0	0		0	0	0	0	210	88.35357 %	44.10090 %	$82
11	Distr. Operations - Rents	8810	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
12	Distr. Structuctures & Improvements	8860	$0	0	0	0	0	0	0	104	0	0		0	0	0	0	104	88.35357 %	44.10090 %	$40
13	Distr. Maintenance - Mains	8870	$0	0	(1)	0	0	0	0	0	0	0		0	0	0	0	(1)	88.35357 %	44.10090 %	$(0)
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
15	Distr. Maintenance- Cathodic Protection	8900	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
16	Customer Accounting - Supervision	9010	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
17	Customer Accounting - Meter Reading	9020	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
18	Customer Records and Collections	9030	$0	0	0	(183)	0	0	0	0	0	0		0	0	0	0	(183)	88.35357 %	44.10090 %	$(71)
19	Customer Accounting - Bad Debts	9040	$0	0	0	0	0	0	0	0	0	0	(150,000)	0	0	0	0	(150,000)	100.00000 %	44.10090 %	$(66,151)
20	Customer Accounting - Misc. Expense	9050	$0	0	0	0	0	0	(2,485)	61,092	0	0		0	0	0	0	58,606	88.35357 %	44.10090 %	$22,836
21	Customer Asst.- Misc. Expenses	9080	$0	0	(89)	(2,094)	(44)	0	0	0	0	0		0	0	0	0	(2,227)	88.35357 %	44.10090 %	$(868)
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
23	Demo/Sell- Misc. Expenses	9120	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
24	Advertising-Misc. Expense	9130	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
25	Administrative and General Salaries	9200	$0	0	0	0	0	0	0	0	0	(1,736)		0	0	0	0	(1,736)	88.35357 %	44.10090 %	$(676)
26	Admin & Gen - Office Supp & Exp	9210	$0	0	(1,973)	(467)	(2,900)	0	(1,959)	11,123	(410,095)	(148)		0	0	0	0	(406,419)	88.35357 %	44.10090 %	$(158,360)
27	Admin & Gen - Outside Services	9230	$0	0	0	(30,561)		0	0	0	0	0		0	0	0	0	(30,561)	88.35357 %	44.10090 %	$(11,908)
28	Property Insurance	9240	$21,628	0	0	0	0	0	0	0	0	0		0	0	0	0	21,628	88.35357 %	44.10090 %	$8,427
29	Admin & Gen - Injuries & Damages	9250	$279,503	0	0	0	0	0	0	0	0	0		0	0	0	0	279,503	88.35357 %	44.10090 %	$108,908
30	Admin & Gen - Employee Pensions & Benefits	9260	$0	0	0	0	0	0	0	0	0	(49)		(18,953,291)	6,578,400	8,780,358	(2,993,340)	(6,587,921)	88.35357 %	44.10090 %	$(2,566,965)
31	Admin & Gen - A&G Franchise Elections	9270	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
32	Admin & Gen - Regulatory Commission Expense	9280	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
33	Admin & Gen - Labor Attends Credit	9290	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
34	Admin & Gen - Advertising	9301	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
35	Admin & Gen - Misc General	9302	$0	(8,126,734)	0	(108,716)	(7,733)	(5,815)	(22,314)	0	0	0		0	0	0	0	(8,271,312)	88.35357 %	44.10090 %	$(3,222,894)
36	Admin & Gen - Rents	9310	$0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	88.35357 %	44.10090 %	$0
37	Totals		$301,131	$(8,126,734)	$(2,169)	$(146,962)	$(10,677)	$(5,815)	$(26,942)	$72,528	$(410,095)	$(12,646)	$(150,000)	$(23,976,408)	$8,290,847	$10,925,106	$(3,724,513)	$(17,003,347)			$(6,730,449)

Source: SCH G-6 Shared Service Test Year Benefits and Payroll Taxes-Direct and Shared Services.xlsx
Source: WKP G-9.b.3 Insurance Adjustment - WNSA.xlsx
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr WNSA(CONFIDENTIAL)

WKP G-9.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

MISCELLANEOUS ADJUSTMENTS
DISTRIGAS AMOUNT ALLOCATED TO TGS

LINE NO.	DESCRIPTION	ACCT	Remove - Rule 7.5414 Contributions, donations to charitable, religious, or other nonprofit organizations	Remove of Meal/Hotel Costs over RRC Threshold and Removal of Spouse and Alcohol Activity	Remove SERP Activity	Remove Activity Management decided to not seek recovery of	Remove of Corporate Aircraft	Adjustment for Known and measurable change in Insurance premiums	Removal of COVID expenses; Included in SCH G-20 Regulatory Expense	Remove Legistlative/Governmental activity.	Total	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Payroll Taxes	4081	$0	$0	$(1,127)	$0	$0	$0	$0	$0	$(1,127)	88.35%	44.1009%	$(439)
2	Transmission O & M - Mains Expenses	8560	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
3	Transmission Other Misc Expenses	8590	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
4	Maintenance of Mains	8630	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
5	Distr. Operations- General Supervision	8700	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
6	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
7	Distr. Mains & Services	8740	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
8	Distr Meas & Reg St Misc	8750	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
9	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
10	Distr. Operations - Other Expense	8800	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
11	Distr. Operations - Rents	8810	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
12	Distr. Structuctures & Improvements	8860	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
13	Distr. Maintenance - Mains	8870	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
14	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
15	Distr. Maintenance- Cathodic Protection	8900	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
16	Customer Accounting - Supervision	9010	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
17	Customer Accounting - Meter Reading	9020	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
18	Customer Accounting - Rec. Coll. Misc. Expense	9030	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
19	Customer Accounting - Bad Debts	9040	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
20	Customer Accounting - Misc. Expense	9050	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
21	Customer Asst.- Misc. Expenses	9080	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
22	Customer Information-Inform. & Instruct. Adver. Exp.	9090	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
23	Demo/Sell- Misc. Expenses	9120	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
24	Advertising-Misc. Expense	9130	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
25	Advertising-Misc. Expense	9200	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
26	Admin & Gen - Office Supp & Exp	9210	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
27	Admin & Gen - Outside Services	9230	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
28	Property Insurance	9240	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
29	Admin & Gen - Injuries & Damages	9250	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
30	Admin & Gen - Employee Pensions & Benefits	9260	0	0	(608,628)	0	0	0	0	0	(608,628)	88.35%	44.1009%	(237,150)
31	Admin & Gen - A&G Franchise Elections	9270	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
32	Admin & Gen - Regulatory Commission Expense	9280	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
33	Admin & Gen - Labor Attends Credit	9290	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
34	Admin & Gen - Advertising	9301	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
35	Admin & Gen - Misc General	9302	(37,572)	(3,141)	(19,567)	(51,618)	(73,211)	55,108	0	(7,578)	(137,578)	88.35%	44.1009%	(53,607)
36	Admin & Gen - Rents	9310	0	0	0	0	0	0	0	0	0	88.35%	44.1009%	0
37	Totals		$(37,572)	$(3,141)	$(629,322)	$(51,618)	$(73,211)	$55,108	$0	$(7,578)	$(747,333)			$(291,196)

Source: WKP G-9.b.2 Misc Adjustments Distrigas - WNSA.xlsx
Source: WKP G-9.c Meal and Hotel Adjustments to Direct SS and Distr WNSA(CONFIDENTIAL)

SCHEDULE G-10

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

RENTS AND LEASES ADJUSTMENT

LINE NO.	DESCRIPTION	ACCT	DIRECT SERVICE AREA	SHARED SERVICES ALLOCATION TO SERVICE AREA	DISTRIGAS ALLOCATION TO SERVICE AREA	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)	(c)	(d)
1	Transmission O & M - Mains Expenses	8560	$0	$0	$0	$0
2	Distr. Operations - Supervision and Engineering	8700	0	0	0	0
3	Distr. Operations - Distribution Load Dispatch	8710	0	0	0	0
4	Distr. Operations - Mains & Services	8740	0	0	0	0
5	Distr. Operations - Meter & House Reg. Exp.	8780	0	0	0	0
6	Distr. Operations - Other Expense	8800	0	0	0	0
7	Distr. Operations - Rents	8810	0	0	0	0
8	Distr. Maintenance - Mains	8870	0	0	0	0
9	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0	0	0
10	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0	0	0
11	Customer Accounting - Supervision	9010	0	0	0	0
12	Customer Accounting - Customer Accounting	9030	0	0	0	0
13	Customer Accounting - Miscellaneous	9050	0	0	0	0
14	Customer Accounting - Customer Assistance Expense	9080	0	0	0	0
15	Admin & Gen - Office Supp & Exp	9210	0	0	0	0
16	Admin & Gen - Outside Services	9230	0	0	0	0
17	Admin & Gen - Injuries & Damages	9250	0	0	0	0
18	Admin & Gen - Employee Pensions & Benefits	9260	0	0	0	0
19	Admin & Gen - General Advertising Expense	9301	0	0	0	0
20	Admin & Gen - Misc General	9302	0	0	0	0
21	Admin & Gen - Rents	9310	0	19,623	0	19,623
22	Totals		$0	$19,623	$0	$19,623

WKP G-10.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

RENTS AND LEASES ADJUSTMENTS
DIRECT SERVICE AREA

LINE NO.	DESCRIPTION	ACCT	ANNUALIZE LEASE PAYMENTS	TOTAL ADJUSTMENT TO SERVICE AREA
			(a)	(b)
1	Transmission O & M - Mains Expenses	8560	$0	$0
2	Distr. Operations - Supervision and Engineering	8700	0	0
3	Distr. Operations - Distribution Load Dispatch	8710	0	0
4	Distr. Operations - Mains & Services	8740	0	0
5	Distr. Operations - Meter & House Reg. Exp.	8780	0	0
6	Distr. Operations - Other Expense	8800	0	0
7	Distr. Operations - Rents	8810	0	0
8	Distr. Maintenance - Mains	8870	0	0
9	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	0	0
10	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	0	0
11	Customer Accounting - Supervision	9010	0	0
12	Customer Accounting - Customer Accounting	9030	0	0
13	Customer Accounting - Miscellaneous	9050	0	0
14	Customer Accounting - Customer Assistance Expense	9080	0	0
15	Admin & Gen - Office Supp & Exp	9210	0	0
16	Admin & Gen - Outside Services	9230	0	0
17	Admin & Gen - Injuries & Damages	9250	0	0
18	Admin & Gen - Employee Pensions & Benefits	9260	0	0
19	Admin & Gen - General Advertising Expense	9301	0	0
20	Admin & Gen - Misc General	9302	0	0
21	Admin & Gen - Rents	9310	0	0
22	Totals		$0	$0

WKP G-10.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

RENTS AND LEASES ADJUSTMENTS
SHARED SERVICES

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ADUSTMENT TO FIRST PLACE TOWER LEASE	ADJUSTMENT TO BARTON SKYWAY LEASE	GRAND TOTAL	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
				(a)	(b)	(c)	(d)	(e)	(f)
1	Shared Service	Transmission O & M - Mains Expenses	8560	$0	$0	$0	88.35%	44.1009%	$0
2	Shared Service	Distr. Operations - Supervision and Engineering	8700	$0	$0	0	88.35%	44.1009%	0
3	Shared Service	Distr. Operations - Distribution Load Dispatch	8710	$0	$0	0	88.35%	44.1009%	0
4	Shared Service	Distr. Operations - Mains & Services	8740	$0	$0	0	88.35%	44.1009%	0
5	Shared Service	Distr. Operations - Meter & House Reg. Exp.	8780	$0	$0	0	88.35%	44.1009%	0
6	Shared Service	Distr. Operations - Other Expense	8800	$0	$0	0	88.35%	44.1009%	0
7	Shared Service	Distr. Operations - Rents	8810	$0	$0	0	88.35%	44.1009%	0
8	Shared Service	Distr. Maintenance - Mains	8870	$0	$0	0	88.35%	44.1009%	0
9	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Gen	8890	$0	$0	0	88.35%	44.1009%	0
10	Shared Service	Distr. Maintenance - Meas. & Reg. Stat. Exp. - Ind.	8900	$0	$0	0	88.35%	44.1009%	0
11	Shared Service	Customer Accounting - Supervision	9010	$0	$0	0	88.35%	44.1009%	0
12	Shared Service	Customer Accounting - Customer Accounting	9030	$0	$0	0	88.35%	44.1009%	0
13	Shared Service	Customer Accounting - Miscellaneous	9050	$0	$0	0	88.35%	44.1009%	0
14	Shared Service	Customer Accounting - Customer Assistance Expense	9080	$0	$0	0	88.35%	44.1009%	0
15	Shared Service	Admin & Gen - Office Supp & Exp	9210	$0	$0	0	88.35%	44.1009%	0
16	Shared Service	Admin & Gen - Outside Services	9230	$0	$0	0	88.35%	44.1009%	0
17	Shared Service	Admin & Gen - Injuries & Damages	9250	$0	$0	0	88.35%	44.1009%	0
18	Shared Service	Admin & Gen - Employee Pensions & Benefits	9260	$0	$0	0	88.35%	44.1009%	0
19	Shared Service	Admin & Gen - General Advertising Expense	9301	$0	$0	0	88.35%	44.1009%	0
20	Shared Service	Admin & Gen - Misc General	9302	$0	$0	0	88.35%	44.1009%	0
21	Shared Service	Admin & Gen - Rents	9310	$0	$50,361	50,361	88.35%	44.1009%	19,623
22	Grand Total Shared Services			$0	$50,361	$50,361			$19,623
23									
24		O&M Expense Factor		88.35%	88.35%	88.35%			
25		Adjustment to TGS O&M		$0	$44,495	$44,495			
26									
27		Allocation to Service Area		44.1009%	44.1009%	44.1009%			
28									
29		Adjustment to Service Area O&M		$0	$19,623	$19,623			

DISTRIGAS

LINE NO.	CATEGORY	ACCOUNT DESCRIPTION	FERC ACCT	ADUSTMENT TO FIRST PLACE TOWER LEASE	ADJUSTMENT TO BARTON SKYWAY LEASE	GRAND TOTAL	DISTRIGAS ALLOCATION FACTOR	O&M EXPENSE FACTOR	ALLOCATION TO SERVICE AREA	AMOUNT ALLOCATED TO SERVICE AREA BY FERC ACCT
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
30	OGS Corporate Allocated through Distrigas (1007)	Admin & Gen - Misc General	9302	$0	$0	$0	27.15%	88.35%	44.1009%	$0
31	Grand Total Distrigas			$0	$0	$0				$0
32										
33		Distrigas Allocation Percent		27.15%	27.15%	27.15%				
34		Corporate Adjustment Allocated to TGS		$0	$0	$0				
35										
36		O&M Expense Factor		88.35%	88.35%	88.35%				
37		Adjustment to TGS O&M		$0	$0	$0				
38										
39		Allocation to Service Area		44.1009%	44.1009%	44.1009%				
40										
41		Adjustment to Service Area O&M		$0	$0	$0				

Source: WKP G-10.b.1 Rent Adjustment SS (CONFIDENTIAL) - WNSA.xlsx

SCHEDULE G-11

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

INTEREST ON CUSTOMER DEPOSITS

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	Service Area Active Customer Deposits		$7,838,323
2	Interest Rate on Customer Deposits		0.06%
3	Annualized Interest on Customer Deposits		$4,703
4	Test Year Interest on Customer Deposits - Acct 4310	WKP G.a.2	47,985
5	Adjustment to Test Year Expense		$(43,282)

Source: SCH G-11 Customer Deposit Interest_ PUC Interest Rate for Deposits_WNSA.pdf

SCHEDULE G-12

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

UNCOLLECTIBLE EXPENSE

LINE NO.	DESCRIPTION	REFERENCE		AMOUNT
		(a)	(b)	(c)
1	As Adjusted Base (Non-Gas) Revenue	G-2		$120,932,709
2	As Adjusted Transportation, Fees & Other Utility Revenue	G-3		$6,533,067
3	Total Adjusted Base and Other Revenue (Note 2)			$127,465,775
4	Uncollectible Expense Ratio (Note 1)			0.006925
5	Adjusted Uncollectible Expense			$882,700
6	Test Year Uncollectible Expense - Acct 9040			1,381,749
7	Adjustment to Test Year Expense			$(499,049)

	Note 1: Calculation of Uncollectible Ratio	Base Revenue Write Offs	Base Revenue	Uncollectible Ratio
8	Twelve Months Ended December 2019	$686,945	$102,010,906	0.00673
9	Twelve Months Ended December 2020	396,395	107,325,422	0.00369
10	Twelve Months Ended December 2021	1,167,388	115,686,866	0.01009
11	Average	$750,243	$108,341,065	0.00693

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 by Svc Area TYE 12 31 2021 WNSA.xlsx

SCHEDULE G-13

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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. 2018 - Dec. 2018		$141,213	$6,504	$314,749	$462,466
2	Jan. 2019 - Dec. 2019		190,838	6,482	345,156	542,477
3	Jan. 2020 - Dec. 2020		150,370	9,167	162,493	322,030
4	Jan. 2021 - Dec. 2021		163,140	8,834	152,762	324,736
5	Total		$645,561	$30,988	$975,160	$1,651,709
6	Average Claims for TGS Division		$161,390	$7,747	$243,790	$412,927
7	Per Book	Acct 9250	95,030	16,512	194,177	305,720
8	Adjustment					$107,208
9	Allocation to Service Area					44.1009%
10	Adjustment to Employee Injury, Auto, and General Liability Claims					$47,280
11	O&M Expense Factor					88.35%
12	Adjustment to Employee Injury, Auto, and General Liability Claims with O&M factor applied					$41,773

Source: SCH G-13 Inj and Dam per book (CONFIDENTIAL) - WNSA.xlsx

WKP G-13.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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.

Employee Injuries

	Period Reporting: January 1, 2018 through December 31, 2021			
Employee Injuries	2021	2020	2019	2018
	$ Paid	$ Paid	$ Paid	$ Paid
January	$14,253	$13,328	$23,494	$8,344
February	18,962	16,122	11,302	17,235
March	9,353	7,548	37,662	13,632
April	16,695	8,887	15,093	15,510
May	7,068	4,992	13,294	16,055
June	11,697	15,145	4,827	12,769
July	22,311	6,647	9,832	9,165
August	12,090	10,705	13,505	5,266
September	12,261	19,240	20,997	10,544
October	4,753	15,085	16,832	8,216
November	13,882	19,095	9,655	12,538
December	19,816	13,578	14,345	11,940
Sub Total	$163,140	$150,370	$190,838	$141,213
4 Year Average			$161,390	

Auto Accidents

	Period Reporting: January 1, 2018 through December 31, 2021			
Auto Accidents	2021	2020	2019	2018
	$ Paid	$ Paid	$ Paid	$ Paid
January	$0	$0	$0	$0
February	0	0	1,367	0
March	0	0	0	0
April	1,641	0	0	0
May	0	0	0	0
June	0	0	0	0
July	0	5,346	5,116	0
August	0	0	0	6,504
September	7,193	0	0	0
October	0	3,822	0	0
November	0	0	0	0
December	0	0	0	0
Sub Total	$8,834	$9,167	$6,482	$6,504
4 Year Average			$7,747	

General Liability

	Period Reporting: January 1, 2018 through December 31, 2021			
General Liability	2021	2020	2019	2018
	$ Paid	$ Paid	$ Paid	$ Paid
January	$27,456	$9,118	$14,691	$12,940
February	2,139	14,715	16,019	36,025
March	2,797	34,864	9,186	20,650
April	9,609	52,812	49,505	9,470
May	20,052	983	5,274	3,588
June	25,712	295	72,806	1,300
July	9,161	2,574	103,969	5,809
August	13,695	8,716	1,902	63,567
September	8,519	10,926	43,508	5,932
October	19,448	13,310	22,875	86,114
November	5,028	5,022	2,690	48,366
December	9,145	9,157	2,730	20,987
Sub Total	$152,762	$162,493	$345,156	$314,749
4 Year Average			$243,790	

SCHEDULE G-14

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	$4,501	$0	$0	$0	$4,501
2	Advertising - Misc. Adm & Gen. Expense	WKP G.a.1	9301	7,402	0	(695)	(695)	6,707
3	Distrigas Allocated Advertising	WKP G.a.2	9302	13,633	0	0	0	13,633
4	Total Adjusted Advertising Expense			$25,535	$0	$(695)	$(695)	$24,840

5 Note 1: Adjusted Test Year Advertising Expense is below 0.50% limitation calculated below, therefore no adjustment is needed for amounts over limitation.

ALLOWABLE ADVERTISING EXPENSE CALCULATION:

LINE NO.	DESCRIPTION	REFERENCE			
6	Revenue Requirement	A			$140,460,903
7	Normalized CCF	G-2		197,561,796	
8	Test Year Cost of Gas Revenue	G-2	$82,080,953		
9	Test Year CCF	G-2	198,516,057		
10	Effective Rate		0.413472615	0.413472615	
11	Normalized Cost of Gas Revenue			$81,686,393	$81,686,393
12	Total Revenue				$222,147,296
13	Allowed Rate				0.50 %
14	Allowable Advertising (Note 1)				$1,110,736

O&M Expense Factor	88.35%
Allocation to Service Area	44.1009%
Distrigas Allocation Factor	27.1500%

Source: WKP G-14 Advertising Direct_WNSA.xlsx
Source: WKP G.a.2.a1 Shared Service per book including Distrigas (CONFIDENTIAL) - WNSA.xlsx

Source: WKP G.a.2.a2 Corporate Costs Allocated on a Causal Basis and Through Distrigas-(CONFIDENTIAL) - WNSA.xlsx
Actual Advertising expense represents in gross receipts 0.01%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC. **SCHEDULE G-15**
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

DEPRECIATION AND AMORTIZATION EXPENSE

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT DEPR & AMORT EXP	TGS DIVISION ALLOCATED DEPR & AMORT EXP	CORPORATED ALLOCATED DEPR & AMORT EXP	TOTAL DEPR & AMORT EXP
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$5,217	$0	$0	$5,217
2	302	Franchises & Consents	382	0	0	382
3	303	Misc. Intangible	0	0	0	0
4	303.1	Misc. Intangible	11,220	0	0	11,220
5		Total Intangible Plant	$16,818	$0	$0	$16,818
		GATHERING AND TRANSMISSION PLANT				
6	325	Land & Land Rights	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0
9	329	Other Structures	0	0	0	0
10	332	Field Lines	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0
13	336	Purification Equipment	0	0	0	0
14	337	Other Equip	0	0	0	0
15	365	Land & Land Rights	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0
18	367	Mains	1,142,945	0	0	1,142,945
19	368	Compressor Station Equip	0	0	0	0
20	369	Meas & Reg Stations Equip	107,007	0	0	107,007
21	371	Other Equipment	0	0	0	0
22		Plant	$1,249,952	$0	$0	$1,249,952
		DISTRIBUTION PLANT				
23	374	Land	$0	$0	$0	$0
24	374.1	Land	0	0	0	0
25	374.2	Land Rights	0	0	0	0
26	375	Structures & Improvements	0	0	0	0
27	375.1	Structures & Improvements	10,650	0	0	10,650
28	375.2	Other System Structures	0	0	0	0
29	376	Mains	6,746,138	0	0	6,746,138
30	376.9	Mains - Cathodic Protection Anodes	1,689,584	0	0	1,689,584
31	377	Compressor Station Equipment	0	0	0	0
32	378	Meas. & Reg. Station - General	352,235	0	0	352,235
33	379	Meas. & Reg. Station - C.G.	151,519	0	0	151,519
34	380	Services	6,237,028	0	0	6,237,028
35	380.1	Ind Service Line Equip	2,034	0	0	2,034
36	380.2	Comm Service Line Equip	3,452	0	0	3,452
37	380.4	Yard Lines-Customer Svc	3,094	0	0	3,094
38	381	Meters	2,394,004	0	0	2,394,004
39	382	Meter Installations	0	0	0	0
40	383	House Regulators	545,653	0	0	545,653
41	385	Indust. Meas. & Reg. Stat. Equipment	414,825	0	0	414,825
42	386	Other Property on Customer Premises	90,947	0	0	90,947
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0
44		Total Distribution Plant	$18,641,164	$0	$0	$18,641,164
		GENERAL PLANT				
45	389	Land & Land Rights	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0
47	390.1	Leasehold Improvements	237,477	50,513	11,599	299,589
48	390.17	Building Improv Plum	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0
50	390.2	Leasehold Improvement	0	19,365	88,826	108,191
51	390.21	Leasehold Equipment EOL	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0
53	391.1	Office Furniture & Equipment	78,424	77,579	31,550	187,554
54	391.19	Airplane Hanger Furniture	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0
57	391.3	Office Machines	0	0	1,917	1,917
58	391.4	Audio Visual Equipment	0	0	25,949	25,949
59	391.5	Artwork	0	0	0	0
60	391.6	Purchased Software	0	0	1,052,814	1,052,814
61	391.6	Banner Software	0	0	56,940	56,940
62	391.6	PowerPlant System	0	0	19,215	19,215
63	391.6	Riskworks	0	0	0	0
64	391.6	Maximo	0	0	38,787	38,787
65	391.6	Dynamic Risk Assessment	0	0	0	0
66	391.6	Concur Project	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	639,540	639,540
68	391.6	Journey-Employee Count	0	0	18,033	18,033
69	391.6	Payroll-Time Management	0	0	28,726	28,726
70	391.6	Accounts Payable Software	0	0	11,779	11,779
71	391.8	Micro Computer Software	0	0	519,544	519,544
72	391.81	Aircraft Computer Equipment	0	0	0	0
73	391.9	Computer & Equipment	189,010	97,278	0	286,288
74	391.99	Cloud Computing	0	0	6,683	6,683
75	392	Transportation Equipment	0	0	0	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
78	392.5	Trailers	0	0	0	0
79	392.6	Aircraft	0	0	0	0
80	393	Stores Equipment	2,034	0	0	2,034
81	394	Tools, Shop & Garage	438,538	389	0	438,928
82	394.1	Tools	5,703	0	0	5,703
83	394.2	Shop Equipment	0	0	0	0
84	395	CNG Equipment	0	0	0	0
85	396	Major Work Equipment	0	0	0	0
86	397	Communication Equipment	1,706,567	35,132	614	1,742,313
87	397.2	Telephone Equipment	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0
89		Total General Plant	$2,657,754	$280,256	$2,552,516	$5,490,525
90		Total	$22,565,688	$280,256	$2,552,516	$25,398,459
91		Amortization Expense	$22,565,688	$280,256	$2,552,516	$25,398,459
92		Expense				
		Accts 403 & 404	17,672,721	290,396	2,470,846	20,433,963
93		Adjustment to Test Year	$4,892,967	$(10,141)	$81,670	$4,964,496

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

DEPRECIATION AND AMORTIZATION EXPENSE - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT AS ADJUSTED ACCT 1010 PLANT (WKP C.a)	DIRECT AS ADJUSTED ACCT 1060 CCNC (WKP C-1.a)	LESS LAND	LESS TRANSPORT & WORK EQUIP	LESS FULLY DEPRECIATED PLANT	PLUS DIMP DEFERRAL (Rule 8.209)	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA DIRECT EXPENSE
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT									
1	301	Organization	$130,422	$0	$0	$0	$0	$0	$130,422	4.0000 %	$5,217
2	302	Franchises & Consents	9,496	0	0	0	0	0	9,496	4.0200 %	382
3	303	Misc. Intangible	276,605	0	0	0	(276,605)	0	0	4.0600 %	0
4	303.1	Misc. Intangible	616,460	0	0	0	0	0	616,460	1.8200 %	11,220
5		Total Intangible Plant	$1,032,983	$0	$0	$0	$(276,605)	$0	$756,378		$16,818
		GATHERING AND TRANSMISSION PLANT									
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0.0000%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000%	0
9	329	Other Structures	0	0	0	0	0	0	0	0.0000%	0
10	332	Field Lines	0	0	0	0	0	0	0	0.0000%	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0.0000%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0.0000%	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0.0000%	0
14	337	Other Equip	0	0	0	0	0	0	0	0.0000%	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0.0000%	0
16	365.2	Rights-of-Way	190,844	0	(190,844)	0	0	0	0	0.0000%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000%	0
18	367	Mains	39,623,073	5,374,645	0	0	0	114	44,997,832	2.5400 %	1,142,945
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0.0000%	0
20	369	Meas & Reg Stations Equip	2,871,564	194,532	0	0	0	0	3,066,097	3.4900 %	107,007
21	371	Other Equipment	0	0	0	0	0	0	0	0.0000%	0
22		Total Gathering and Transmission Plant	$42,685,481	$5,569,178	$(190,844)	$0	$0	$114	$48,063,929		$1,249,952
		DISTRIBUTION PLANT									
23	374	Land	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
24	374.1	Land	88,912	(399)	(88,513)	0	0	0	0	0.0000%	0
25	374.2	Land Rights	1,504,834	88,958	0	0	0	137	1,593,930	0.0000%	0
26	375	Structures & Improvements	0	0	0	0	0	0	0	0.0000%	0
27	375.1	Structures & Improvements	295,712	9,439	0	0	0	0	305,151	3.4900 %	10,650
28	375.2	Other System Structures	0	0	0	0	0	0	0	0.0000%	0
29	376	Mains	258,222,471	29,163,028	0	0	0	672,833	288,058,332	2.3000 %	6,625,342
30	376.9	Mains - Cathodic Protection Anodes	24,950,517	234,897	0	0	0	37,311	25,222,725	6.6667 %	1,681,515
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0.0000%	0
32	378	Meas. & Reg. Station - General	11,005,276	4,082,480	0	0	0	4,925	15,092,681	2.2400 %	338,076
33	379	Meas. & Reg. Station - C.G.	4,672,745	2,753,804	0	0	0	850	7,427,400	2.0400 %	151,519
34	380	Services	185,332,397	6,340,839	0	0	0	1,106,897	192,780,133	3.2200 %	6,207,520
35	380.1	Ind Service Line Equip	1,311	61,959	0	0	0	(97)	63,173	3.2200%	2,034
36	380.2	Comm Service Line Equip	(70)	107,496	0	0	0	(222)	107,204	3.2200%	3,452
37	380.4	Yard Lines-Customer Svc	(141)	96,157	0	0	0	87	96,102	3.2200%	3,094
38	381	Meters	58,524,271	146,020	0	0	0	2,991	58,673,282	4.0700 %	2,388,003
39	382	Meter Installations	(20)	93,768	0	0	0	(169)	93,579	0.0000%	0
40	383	House Regulators	15,108,237	210,483	0	0	0	2,902	15,321,623	3.5400 %	542,385
41	385	Indust. Meas. & Reg. Stat. Equipment	16,895,288	189,011	0	0	0	15,233	17,099,532	2.3800 %	406,969
42	386	Other Property on Customer Premises	638,227	0	0	0	0	0	638,227	14.2500 %	90,947
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	0.0000%	0
44		Total Distribution Plant	$577,239,969	$43,577,941	$(88,513)	$0	$0	$1,843,677	$622,573,074		$18,451,507
		GENERAL PLANT									
45	389	Land & Land Rights	$320,363	$0	$(320,363)	$0	$0	$0	$0	0.0000%	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0.0000%	0
47	390.1	Structures & Improvements	6,874,080	1,068,298	0	0	0	0	7,942,378	2.9900 %	237,477
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	2.9900 %	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	2.9900 %	0
50	390.2	Leasehold Improvement	98,696	0	0	0	(98,696)	0	0	0.0000%	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	0.0000%	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	0.0000%	0
53	391.1	Office Furniture & Equipment	1,161,128	15,239	0	0	0	0	1,176,367	6.6667 %	78,424
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0.0000%	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0.0000%	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0.0000%	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0.0000%	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0.0000%	0

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59	391.5	Artwork	0	0	0	0	0	0	0	0.0000%	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0.0000%	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0.0000%	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0.0000%	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0.0000%	0
64	391.6	Maximo	0	0	0	0	0	0	0	0.0000%	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0.0000%	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0.0000%	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0.0000%	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0.0000%	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0.0000%	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0.0000%	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0.0000%	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0.0000%	0
73	391.9	Computer & Equipment	1,323,072	0	0	0	0	0	1,323,072	14.2857 %	189,010
74	391.99	Cloud Computing	0	0	0	0	0	0	0	14.2857%	0
75	392	Transportation Equipment	10,208,259	328,143	0	(10,536,402)	0	0	0	7.7800 %	0
76	392.2	Transport Equip Pickup Trucks& Vans	76,807	0	0	(76,807)	0	0	0	7.7800%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	7.7800%	0
78	392.5	Trailers	0	0	0	0	0	0	0	7.7800%	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0.0000%	0
80	393	Stores Equipment	30,503	0	0	0	0	0	30,503	6.6667 %	2,034
81	394	Tools, Shop & Garage	5,912,601	653,783	0	0	0	0	6,566,384	6.6667 %	437,759
82	394.1	Tools	84,941	503	0	0	0	106	85,550	6.6667%	5,703
83	394.2	Shop Equipment	0	0	0	0	0	0	0	6.6667%	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0.0000%	0
85	396	Major Work Equipment	2,260,869	119,721	0	(2,380,590)	0	0	0	5.9000 %	0
86	397	Communication Equipment	11,559,215	13,990,371	0	0	0	25	25,549,611	6.6667 %	1,703,307
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	6.6667 %	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0.0000%	0
89		Total General Plant	$39,910,534	$16,176,059	$(320,363)	$(12,993,799)	$(98,696)	$131	$42,673,866		$2,653,715
90		Total Plant in Service	$660,868,968	$65,323,177	$(599,720)	$(12,993,799)	$(375,301)	$1,843,921	$714,067,247		$22,371,992
91		Amortization Expense									$22,371,992
92		Expense (Accts. 403 & 404)									17,512,491
93		Adjustment to Test Year									$4,859,501

Note: Depreciation Related to Transportation Work Equipment:		Vehicles (392)	Work Equip (396)	Total
94	Plant in Service + CCNC	$10,613,209	$2,380,590	$12,993,799
95	Less Fully Depreciated Plant	0	0	0
96	Net Depreciable Plant	$10,613,209	$2,380,590	$12,993,799
97	Depreciation Rate	7.7800%	5.900%	
98	Proforma Depreciation Expense	$825,708	$140,455	$966,162

WKP G-15.a.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

FULLY DEPRECIATED PLANT - SERVICE AREA DIRECT

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT AS ADJUSTED PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT AS ADJUSTED	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$130,422	$(114,906)	$15,516	$0
2	302	Franchises & Consents	9,496	629	10,125	0
3	303	Misc. Intangible	276,605	(284,067)	(7,462)	(276,605)
4	303.1	Misc. Intangible	616,460	(87,939)	528,521	0
5		Total Intangible Plant	$1,032,983	$(486,283)	$546,700	$(276,605)
		GATHERING AND TRANSMISSION PLANT				
6	325	Land & Land Rights	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0
9	329	Other Structures	0	0	0	0
10	332	Field Lines	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0
13	336	Purification Equipment	0	0	0	0
14	337	Other Equip	0	0	0	0
15	365	Land & Land Rights	0	0	0	0
16	365.2	Rights-of-Way	190,844	0	190,844	0
17	366	Meas/Reg Station Structures	0	0	0	0
18	367	Mains	44,997,719	(2,808,326)	42,189,392	0
19	368	Compressor Station Equip	0	0	0	0
20	369	Meas & Reg Stations Equip	3,066,097	(432,338)	2,633,759	0
21	371	Other Equipment	0	0	0	0
22		Total Gathering and Transmission Plant	$48,254,659	$(3,240,665)	$45,013,995	$0
		DISTRIBUTION PLANT				
23	374	Land	$0	$(31)	$(31)	$0
24	374.1	Land	88,513	0	88,513	0
25	374.2	Land Rights	1,593,793	(46,974)	1,546,818	0
26	375	Structures & Improvements	0	0	0	0
27	375.1	Structures & Improvements	305,151	(149,046)	156,106	0
28	375.2	Other System Structures	0	0	0	0
29	376	Mains	287,385,499	(33,729,420)	253,656,079	0
30	376.9	Mains - Cathodic Protection Anodes	25,185,414	(10,218,549)	14,966,865	0
31	377	Compressor Station Equipment	0	0	0	0
32	378	Meas. & Reg. Station - General	15,087,756	(1,050,262)	14,037,494	0
33	379	Meas. & Reg. Station - C.G.	7,426,550	(929,487)	6,497,062	0
34	380	Services	191,673,236	(26,297,732)	165,375,504	0
35	380.1	Ind Service Line Equip	63,270	0	63,270	0
36	380.2	Comm Service Line Equip	107,426	0	107,426	0
37	380.4	Yard Lines-Customer Svc	96,015	0	96,015	0
38	381	Meters	58,670,292	(16,835,649)	41,834,643	0
39	382	Meter Installations	93,748	(8,293)	85,455	0
40	383	House Regulators	15,318,721	(5,122,147)	10,196,574	0
41	385	Indust. Meas. & Reg. Stat. Equipment	17,084,299	(2,978,842)	14,105,457	0
42	386	Other Property on Customer Premises	638,227	(441,058)	197,169	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0
44		Total Distribution Plant	$620,817,910	$(97,807,490)	$523,010,420	$0
		GENERAL PLANT				
45	389	Land & Land Rights	$320,363	$0	$320,363	$0
46	390	Structures & Improvements	0	0	0	0
47	390.1	Structures & Improvements	7,942,378	(1,618,380)	6,323,998	0
48	390.17	Building Improv Plum	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0
50	390.2	Leasehold Improvement	98,696	(98,730)	(35)	(98,696)

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51	390.21	Leasehold Equipment EOL	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0
53	391.1	Office Furniture & Equipment	1,176,367	(616,903)	559,464	0
54	391.19	Airplane Hanger Furniture	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0
57	391.3	Office Machines	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0
59	391.5	Artwork	0	0	0	0
60	391.6	Purchased Software	0	0	0	0
61	391.6	Banner Software	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0
63	391.6	Riskworks	0	0	0	0
64	391.6	Maximo	0	0	0	0
65	391.6	Foundation Software	0	0	0	0
66	391.6	Concur Project	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0
73	391.9	Computer & Equipment	1,323,072	(481,427)	841,645	0
74	391.99	Cloud Computing	0	0	0	0
75	392	Transportation Equipment	10,536,402	(2,132,014)	8,404,388	0
76	392.2	Transport Equip Pickup Trucks& Vans	76,807	0	76,807	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
78	392.5	Trailers	0	0	0	0
79	392.6	Aircraft	0	0	0	0
80	393	Stores Equipment	30,503	(22,026)	8,477	0
81	394	Tools, Shop & Garage	6,566,384	(2,510,671)	4,055,713	0
82	394.1	Tools	85,444	0	85,444	0
83	394.2	Shop Equipment	0	0	0	0
84	395	CNG Equipment	0	(47)	(47)	0
85	396	Major Work Equipment	2,380,590	(587,853)	1,792,737	0
86	397	Communication Equipment	25,549,586	(6,283,039)	19,266,548	0
87	397.2	Telephone Equipment	0	0	0	0
88	398	Miscellaneous General Plant	0	14,531	14,531	0
89		Total General Plant	$56,086,593	$(14,336,560)	$41,750,033	$(98,696)
90		Total Orig Cost Plant in Service	$726,192,146	$(115,870,997)	$610,321,148	$(375,301)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	4.0000 %	$0
2	302	Franchises & Consents	0	0	0	0	0	0	0	4.0200 %	0
3	303	Misc. Intangible	0	0	0	0	0	0	0	4.0600 %	0
4	303.1	Misc. Intangible	0	0	0	0	0	0	0	1.8200 %	0
5		Total Intangible Plant	$0	$0	$0	$0	$0	$0	$0		$0
		GATHERING AND TRANSMISSION PLANT									
6	325	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
7	327	Field Comprss Station Strucutres	0	0	0	0	0	0	0	0.0000%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000%	0
9	329	Other Structures	0	0	0	0	0	0	0	0.0000%	0
10	332	Field Lines	0	0	0	0	0	0	0	0.0000%	0
11	333	Field Compressor Station Equip	0	0	0	0	0	0	0	0.0000%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0	0	0	0.0000%	0
13	336	Purification Equipment	0	0	0	0	0	0	0	0.0000%	0
14	337	Other Equip	0	0	0	0	0	0	0	0.0000%	0
15	365	Land & Land Rights	0	0	0	0	0	0	0	0.0000%	0
16	365.2	Rights-of-Way	0	0	0	0	0	0	0	0.0000%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0	0	0	0.0000%	0
18	367	Mains	0	0	0	0	0	0	0	2.5400 %	0
19	368	Compressor Station Equip	0	0	0	0	0	0	0	0.0000%	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0	0	0	3.4600 %	0
21	371	Other Equipment	0	0	0	0	0	0	0	0.0000%	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0	$0	$0	$0		$0
		DISTRIBUTION PLANT									
23	374	Land	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
24	374.1	Land	0	0	0	0	0	0	0	0.0000%	0
25	374.2	Land Rights	19,533	0	0	0	0	0	19,533	0.0000%	0
26	375	Structures & Improvements	0	0	0	0	0	0	0	2.0400%	0
27	375.1	Structures & Improvements	0	0	0	0	0	0	0	3.4900 %	0
28	375.2	Other System Structures	0	0	0	0	0	0	0	2.3800%	0
29	376	Mains	5,178,343	73,685	0	0	0	0	5,252,028	2.3000 %	120,797
30	376.9	Mains - Cathodic Protection Anodes	121,036	0	0	0	0	0	121,036	6.6667 %	8,069
31	377	Compressor Station Equipment	0	0	0	0	0	0	0	0.0000%	0
32	378	Meas. & Reg. Station - General	494,534	137,573	0	0	0	0	632,107	2.2400 %	14,159
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0	0	0	2.0400 %	0
34	380	Services	942,233	(25,836)	0	0	0	0	916,397	3.2200 %	29,508
35	380.1	Ind Service Line Equip	0	0	0	0	0	0	0	3.2200%	0
36	380.2	Comm Service Line Equip	0	0	0	0	0	0	0	3.2200%	0

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37	380.4	Yard Lines-Customer Svc	0	0	0	0	0	0	0	3.2200%	0
38	381	Meters	108,468	38,984	0	0	0	0	147,452	4.0700 %	6,001
39	382	Meter Installations	0	0	0	0	0	0	0	0.0000%	0
40	383	House Regulators	57,282	35,020	0	0	0	0	92,302	3.5400 %	3,267
41	385	Indust. Meas. & Reg. Stat. Equipment	330,071	0	0	0	0	0	330,071	2.3800 %	7,856
42	386	Other Property on Customer Premises	0	0	0	0	0	0	0	14.2500 %	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0	0	0	1.9500%	0
44		Total Distribution Plant	$7,251,501	$259,426	$0	$0	$0	$0	$7,510,927		$189,657
		GENERAL PLANT									
45	389	Land & Land Rights	$0	$0	$0	$0	$0	$0	$0	0.0000%	$0
46	390	Structures & Improvements	0	0	0	0	0	0	0	0.0000%	0
47	390.1	Structures & Improvements	0	0	0	0	0	0	0	2.9900 %	0
48	390.17	Building Improv Plum	0	0	0	0	0	0	0	2.9900 %	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0.0000%	0
50	390.2	Leasehold Improvement	0	0	0	0	0	0	0	14.8800%	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	0	0	0	14.8800%	0
52	391	Office Furniture & Equipment	0	0	0	0	0	0	0	6.6700%	0
53	391.1	Office Furniture & Equipment	0	0	0	0	0	0	0	6.6667 %	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	0	0	0	0.0000%	0
55	391.2	Data Processing Equipment	0	0	0	0	0	0	0	0.0000%	0
56	391.2	Oracle Equipment	0	0	0	0	0	0	0	0.0000%	0
57	391.3	Office Machines	0	0	0	0	0	0	0	0.0000%	0
58	391.4	Audio Visual Equipment	0	0	0	0	0	0	0	0.0000%	0
59	391.5	Artwork	0	0	0	0	0	0	0	0.0000%	0
60	391.6	Purchased Software	0	0	0	0	0	0	0	0.0000%	0
61	391.6	Banner Software	0	0	0	0	0	0	0	0.0000%	0
62	391.6	PowerPlant System	0	0	0	0	0	0	0	0.0000%	0
63	391.6	Riskworks	0	0	0	0	0	0	0	0.0000%	0
64	391.6	Maximo	0	0	0	0	0	0	0	0.0000%	0
65	391.6	Foundation Software	0	0	0	0	0	0	0	0.0000%	0
66	391.6	Concur Project	0	0	0	0	0	0	0	0.0000%	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0	0	0	0.0000%	0
68	391.6	Journey-Employee Count	0	0	0	0	0	0	0	0.0000%	0
69	391.6	Payroll - Time Management	0	0	0	0	0	0	0	0.0000%	0
70	391.6	Accounts Payable Software	0	0	0	0	0	0	0	0.0000%	0
71	391.8	Micro Computer Software	0	0	0	0	0	0	0	0.0000%	0

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72	391.81	Aircraft Computer Equipment	0	0	0	0	0	0	0	0.0000%	0
73	391.9	Computer & Equipment	0	0	0	0	0	0	0	14.2857 %	0
74	391.99	Cloud Computing	0	0	0	0	0	0	0	0.0000%	0
75	392	Transportation Equipment	0	0	0	0	0	0	0	7.7800 %	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0	0	0	7.7800%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0	0	0	7.7800%	0
78	392.5	Trailers	0	0	0	0	0	0	0	7.7800%	0
79	392.6	Aircraft	0	0	0	0	0	0	0	0.0000%	0
80	393	Stores Equipment	0	0	0	0	0	0	0	6.6667 %	0
81	394	Tools, Shop & Garage	11,690	0	0	0	0	0	11,690	6.6667 %	779
82	394.1	Tools	0	0	0	0	0	0	0	6.6700%	0
83	394.2	Shop Equipment	0	0	0	0	0	0	0	0.0000%	0
84	395	CNG Equipment	0	0	0	0	0	0	0	0.0000%	0
85	396	Major Work Equipment	0	0	0	0	0	0	0	5.9000 %	0
86	397	Communication Equipment	48,893	0	0	0	0	0	48,893	6.6667 %	3,260
87	397.2	Telephone Equipment	0	0	0	0	0	0	0	6.6667 %	0
88	398	Miscellaneous General Plant	0	0	0	0	0	0	0	0.0000%	0
89		Total General Plant	$60,583	$0	$0	$0	$0	$0	$60,583		$4,039
90		Total Plant in Service	$7,312,083	$259,426	$0	$0	$0	$0	$7,571,509		$193,696
			7,312,083	259,426			0		7,571,509		
91		Total Annualized Depreciation & Amortization Expense	0.00	0.00	0.00	0.00	0.00	-	-		$193,696
92		Test Year Depreciation & Amortization Expense (Accts. 403 & 404)									160,231
93		Adjustment to Test Year									$33,466

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

FULLY DEPRECIATED PLANT - FORT BLISS

LINE NO.	ACCOUNT	DESCRIPTION	DIRECT AS ADJUSTED PLANT 1010 & 1060	DIRECT AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT AS ADJUSTED	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$0	$0	$0	$0
2	302	Franchises & Consents	0	0	0	0
3	303	Misc. Intangible	0	0	0	0
4	303.1	Misc. Intangible	0	0	0	0
5		Total Intangible Plant	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT				
6	325	Land & Land Rights	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0
9	329	Other Structures	0	0	0	0
10	332	Field Lines	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0
13	336	Purification Equipment	0	0	0	0
14	337	Other Equip	0	0	0	0
15	365	Land & Land Rights	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0
18	367	Mains	0	0	0	0
19	368	Compressor Station Equip	0	0	0	0
20	369	Meas & Reg Stations Equip	0	0	0	0
21	371	Other Equipment	0	0	0	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0
		DISTRIBUTION PLANT				
23	374	Land	$0	$0	$0	$0
24	374.1	Land	0	0	0	0
25	374.2	Land Rights	19,533	(6,316)	13,218	0
26	375	Structures & Improvements	0	0	0	0
27	375.1	Structures & Improvements	0	0	0	0
28	375.2	Other System Structures	0	0	0	0
29	376	Mains	5,252,028	(741,508)	4,510,520	0
30	376.9	Mains - Cathodic Protection Anodes	121,036	(43,264)	77,772	0
31	377	Compressor Station Equipment	0	0	0	0
32	378	Meas. & Reg. Station - General	632,107	(34,385)	597,722	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0
34	380	Services	916,397	(158,249)	758,148	0
35	380.1	Ind Service Line Equip	0	0	0	0
36	380.2	Comm Service Line Equip	0	0	0	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0
38	381	Meters	147,452	(47,576)	99,877	0
39	382	Meter Installations	0	0	0	0
40	383	House Regulators	92,302	(15,489)	76,813	0
41	385	Indust. Meas. & Reg. Stat. Equipment	330,071	(36,930)	293,142	0
42	386	Other Property on Customer Premises	0	0	0	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0
44		Total Distribution Plant	$7,510,927	$(1,083,716)	$6,427,211	$0
		GENERAL PLANT				
45	389	Land & Land Rights	$0	$0	$0	$0
46	390	Structures & Improvements	0	0	0	0
47	390.1	Structures & Improvements	0	0	0	0
48	390.17	Building Improv Plum	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0
50	390.2	Leasehold Improvement	0	0	0	0

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51	390.21	Leasehold Equipment EOL	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0
53	391.1	Office Furniture & Equipment	0	0	0	0
54	391.19	Airplane Hanger Furniture	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0
57	391.3	Office Machines	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0
59	391.5	Artwork	0	0	0	0
60	391.6	Purchased Software	0	0	0	0
61	391.6	Banner Software	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0
63	391.6	Riskworks	0	0	0	0
64	391.6	Maximo	0	0	0	0
65	391.6	Foundation Software	0	0	0	0
66	391.6	Concur Project	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0
73	391.9	Computer & Equipment	0	15,138	15,138	0
74	391.99	Cloud Computing	0	0	0	0
75	392	Transportation Equipment	0	0	0	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
78	392.5	Trailers	0	0	0	0
79	392.6	Aircraft	0	0	0	0
80	393	Stores Equipment	0	0	0	0
81	394	Tools, Shop & Garage	11,690	(1,169)	10,521	0
82	394.1	Tools	0	0	0	0
83	394.2	Shop Equipment	0	0	0	0
84	395	CNG Equipment	0	0	0	0
85	396	Major Work Equipment	0	0	0	0
86	397	Communication Equipment	48,893	(18,516)	30,377	0
87	397.2	Telephone Equipment	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0
89		Total General Plant	$60,583	$(4,547)	$56,036	$0
90		Total Orig Cost Plant in Service	$7,571,509	$(1,088,263)	$6,483,247	$0

WKP G-15.b.1

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

DEPRECIATION AND AMORTIZATION EXPENSE - TGS DIVISION

LINE NO.	ACCT	DESCRIPTION	TGS DIVISION AS ADJUSTED ACC 1010 PLANT (WKP C.b)	TGS DIVISION AS ADJUSTED ACC 1060 CCNC (WKP C-1.b)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	PROFORMA TGS DIVISION DEPR & AMORT EXPENSE	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(e)	(f)	(g)	(h)	(i)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	0.0000%	$0	44.1009%	$0
2	302	Franchises & Consents	0	0	0	0	0.0000%	0	44.1009%	0
3	303	Misc. Intangible	0	0	0	0	0.0000%	0	44.1009%	0
4	303.1	Misc. Intangible	0	0	0	0	0.0000%	0	44.1009%	0
5		Total Intangible Plant	$0	$0	$0	$0		$0		$0
		GATHERING AND TRANSMISSION PLANT								
6	325	Land & Land Rights	$0	$0	$0	$0	0.0000%	$0	44.1009%	$0
7	327	Field Comprss Station Structures	0	0	0	0	0.0000%	0	44.1009%	0
8	328	Field Meas/Reg Station Structures	0	0	0	0	0.0000%	0	44.1009%	0
9	329	Other Structures	0	0	0	0	0.0000%	0	44.1009%	0
10	332	Field Lines	0	0	0	0	0.0000%	0	44.1009%	0
11	333	Field Compressor Station Equip	0	0	0	0	0.0000%	0	44.1009%	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0.0000%	0	44.1009%	0
13	336	Purification Equipment	0	0	0	0	0.0000%	0	44.1009%	0
14	337	Other Equip	0	0	0	0	0.0000%	0	44.1009%	0
15	365	Land & Land Rights	0	0	0	0	0.0000%	0	44.1009%	0
16	365.2	Rights-of-Way	0	0	0	0	0.0000%	0	44.1009%	0
17	366	Meas/Reg Station Structures	0	0	0	0	0.0000%	0	44.1009%	0
18	367	Mains	0	0	0	0	0.0000%	0	44.1009%	0
19	368	Compressor Station Equip	0	0	0	0	0.0000%	0	44.1009%	0
20	369	Meas & Reg Stations Equip	0	0	0	0	0.0000%	0	44.1009%	0
21	371	Other Equipment	0	0	0	0	0.0000%	0	44.1009%	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
		DISTRIBUTION PLANT								
23	374	Land	$0	$0	$0	$0	0.0000%	$0	44.1009%	$0
24	374.1	Land	0	0	0	0	0.0000%	0	44.1009%	0
25	374.2	Land Rights	0	0	0	0	0.0000%	0	44.1009%	0
26	375	Structures & Improvements	0	0	0	0	0.0000%	0	44.1009%	0
27	375.1	Structures & Improvements	0	0	0	0	0.0000%	0	44.1009%	0
28	375.2	Other System Structures	0	0	0	0	0.0000%	0	44.1009%	0
29	376	Mains	0	0	0	0	0.0000%	0	44.1009%	0
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0.0000%	0	44.1009%	0
31	377	Compressor Station Equipment	0	0	0	0	0.0000%	0	44.1009%	0
32	378	Meas. & Reg. Station - General	0	0	0	0	0.0000%	0	44.1009%	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0.0000%	0	44.1009%	0
34	380	Services	0	0	0	0	0.0000%	0	44.1009%	0
35	380.1	Ind Service Line Equip	0	0	0	0	0.0000%	0	44.1009%	0
36	380.2	Comm Service Line Equip	0	0	0	0	0.0000%	0	44.1009%	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0.0000%	0	44.1009%	0
38	381	Meters	0	0	0	0	0.0000%	0	44.1009%	0
39	382	Meter Installations	0	0	0	0	0.0000%	0	44.1009%	0
40	383	House Regulators	0	0	0	0	0.0000%	0	44.1009%	0
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0	44.1009%	0
42	386	Other Property on Customer Premises	0	0	0	0	0.0000%	0	44.1009%	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0	44.1009%	0

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44		Total Distribution Plant	$0	$0	$0	$0		$0		$0
		GENERAL PLANT								
45	389	Land & Land Rights	$434,697	$0	$0	$434,697	0.0000%	$0	44.1009%	$0
46	390	Structures & Improvements	0	0	0	0	0.0000%	0	44.1009%	0
47	390.1	Structures & Improvements	4,348,153	126,029	0	4,474,183	2.5600%	114,539	44.1009%	50,513
48	390.17	Building Improv Plum	0	0	0	0	0.0000%	0	44.1009%	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0.0000%	0	44.1009%	0
50	390.2	Leasehold Improvement	234,303	18,181	0	252,484	17.3913%	43,910	44.1009%	19,365
51	390.21	Leasehold Equipment EOL	0	0	0	0	0.0000%	0	44.1009%	0
52	391	Office Furniture & Equipment	0	0	0	0	0.0000%	0	44.1009%	0
53	391.1	Office Furniture & Equipment	2,638,687	0	0	2,638,687	6.6667%	175,912	44.1009%	77,579
54	391.19	Airplane Hanger Furniture	0	0	0	0	0.0000%	0	44.1009%	0
55	391.2	Data Processing Equipment	0	0	0	0	0.0000%	0	44.1009%	0
56	391.2	Oracle Equipment	0	0	0	0	0.0000%	0	44.1009%	0
57	391.3	Office Machines	0	0	0	0	0.0000%	0	44.1009%	0
58	391.4	Audio Visual Equipment	0	0	0	0	0.0000%	0	44.1009%	0
59	391.5	Artwork	0	0	0	0	0.0000%	0	44.1009%	0
60	391.6	Purchased Software	0	0	0	0	0.0000%	0	44.1009%	0
61	391.6	Banner Software	0	0	0	0	0.0000%	0	44.1009%	0
62	391.6	PowerPlant System	0	0	0	0	0.0000%	0	44.1009%	0
63	391.6	Riskworks	0	0	0	0	0.0000%	0	44.1009%	0
64	391.6	Maximo	0	0	0	0	0.0000%	0	44.1009%	0
65	391.6	Foundation Software	0	0	0	0	0.0000%	0	44.1009%	0
66	391.6	Concur Project	0	0	0	0	0.0000%	0	44.1009%	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0	0.0000%	0	44.1009%	0
68	391.6	Journey-Employee Count	0	0	0	0	0.0000%	0	44.1009%	0
69	391.6	Payroll - Time Management	0	0	0	0	0.0000%	0	44.1009%	0
70	391.6	Accounts Payable Software	0	0	0	0	0.0000%	0	44.1009%	0
71	391.8	Micro Computer Software	0	0	0	0	0.0000%	0	44.1009%	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	0.0000%	0	44.1009%	0
73	391.9	Computer & Equipment	1,544,059	0	0	1,544,059	14.2857%	220,580	44.1009%	97,278
74	391.99	Cloud Computing	0	0	0	0	0.0000%	0	44.1009%	0
75	392	Transportation Equipment	0	0	0	0	0.0000%	0	44.1009%	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0.0000%	0	44.1009%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0.0000%	0	44.1009%	0
78	392.5	Trailers	0	0	0	0	0.0000%	0	44.1009%	0
79	392.6	Aircraft	0	0	0	0	0.0000%	0	44.1009%	0
80	393	Stores Equipment	0	0	0	0	0.0000%	0	44.1009%	0
81	394	Tools, Shop & Garage	13,242	0	0	13,242	6.6667%	883	44.1009%	389
82	394.1	Tools	0	0	0	0	0.0000%	0	44.1009%	0
83	394.2	Shop Equipment	0	0	0	0	0.0000%	0	44.1009%	0
84	395	CNG Equipment	0	0	0	0	0.0000%	0	44.1009%	0
85	396	Major Work Equipment	0	0	0	0	0.0000%	0	44.1009%	0
86	397	Communication Equipment	1,194,943	0	0	1,194,943	6.6667%	79,663	44.1009%	35,132
87	397.2	Telephone Equipment	0	0	0	0	0.0000%	0	44.1009%	0
88	398	Miscellaneous General Plant	0	0	0	0	6.6667%	0	44.1009%	0
89		Total General Plant	$10,408,084	$144,210	$0	$10,552,295		$635,487		$280,256
90		Total Plant in Service	$10,408,084	$144,210	$0	$10,552,295		$635,487		$280,256
			10,408,085	144,210	0	10,552,295				
91		Total Annualized Depreciation & Amortization Expense	0	0	0	0		$635,487	44.1009%	$280,256
92		Test Year Depreciation & Amortization Expense Accts 403 & 404						658,481	44.1009%	290,396
93		Adjustment to Test Year						$(22,994)	44.1009%	$(10,141)

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

FULLY DEPRECIATED PLANT - TGS DIVISION

LINE NO.	ACCOUNT	DESCRIPTION	TGS DIVISION AS ADJUSTED PLANT 1010 & 1060	TGS DIVISION AS ADJUSTED RESERVES 1080100 & 1110	NET PLANT AS ADJUSTED	FULLY DEPRECIATED PLANT
			(a)	(b)	(c)	(d)
		INTANGIBLE PLANT				
1	301	Organization	$0	$0	$0	$0
2	302	Franchises & Consents	0	0	0	0
3	303	Misc. Intangible	0	0	0	0
4	303.1	Misc. Intangible	0	0	0	0
5		Total Intangible Plant	$0	$0	$0	$0
		GATHERING AND TRANSMISSION PLANT				
6	325	Land & Land Rights	$0	$0	$0	$0
7	327	Field Comprss Station Strucutres	0	0	0	0
8	328	Field Meas/Reg Station Structures	0	0	0	0
9	329	Other Structures	0	0	0	0
10	332	Field Lines	0	0	0	0
11	333	Field Compressor Station Equip	0	0	0	0
12	334	Field Meas/Reg Station Equipment	0	0	0	0
13	336	Purification Equipment	0	0	0	0
14	337	Other Equip	0	0	0	0
15	365	Land & Land Rights	0	0	0	0
16	365.2	Rights-of-Way	0	0	0	0
17	366	Meas/Reg Station Structures	0	0	0	0
18	367	Mains	0	0	0	0
19	368	Compressor Station Equip	0	0	0	0
20	369	Meas & Reg Stations Equip	0	0	0	0
21	371	Other Equipment	0	0	0	0
22		Total Gathering and Transmission Plant	$0	$0	$0	$0
		DISTRIBUTION PLANT				
23	374	Land	$0	$0	$0	$0
24	374.1	Land	0	0	0	0
25	374.2	Land Rights	0	0	0	0
26	375	Structures & Improvements	0	0	0	0
27	375.1	Structures & Improvements	0	0	0	0
28	375.2	Other System Structures	0	0	0	0
29	376	Mains	0	0	0	0
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0
31	377	Compressor Station Equipment	0	0	0	0
32	378	Meas. & Reg. Station - General	0	0	0	0
33	379	Meas. & Reg. Station - C.G.	0	0	0	0
34	380	Services	0	0	0	0
35	380.1	Ind Service Line Equip	0	0	0	0
36	380.2	Comm Service Line Equip	0	0	0	0
37	380.4	Yard Lines-Customer Svc	0	0	0	0
38	381	Meters	0	0	0	0
39	382	Meter Installations	0	0	0	0
40	383	House Regulators	0	0	0	0
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0
42	386	Other Property on Customer Premises	0	0	0	0
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0
44		Total Distribution Plant	$0	$0	$0	$0

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		GENERAL PLANT				
45	389	Land & Land Rights	$434,697	$0	$434,697	$0
46	390	Structures & Improvements	0	0	0	0
47	390.1	Structures & Improvements	4,474,183	(255,880)	4,218,303	0
48	390.17	Building Improv Plum	0	0	0	0
49	390.19	Airplane Hanger Furniture	0	0	0	0
50	390.2	Leasehold Improvement	252,484	(167,523)	84,961	0
51	390.21	Leasehold Equipment EOL	0	0	0	0
52	391	Office Furniture & Equipment	0	0	0	0
53	391.1	Office Furniture & Equipment	2,638,687	(450,013)	2,188,673	0
54	391.19	Airplane Hanger Furniture	0	0	0	0
55	391.2	Data Processing Equipment	0	0	0	0
56	391.2	Oracle Equipment	0	0	0	0
57	391.3	Office Machines	0	0	0	0
58	391.4	Audio Visual Equipment	0	0	0	0
59	391.5	Artwork	0	0	0	0
60	391.6	Purchased Software	0	0	0	0
61	391.6	Banner Software	0	0	0	0
62	391.6	PowerPlant System	0	0	0	0
63	391.6	Riskworks	0	0	0	0
64	391.6	Maximo	0	0	0	0
65	391.6	Foundation Software	0	0	0	0
66	391.6	Concur Project	0	0	0	0
67	391.6	Journey-Employee-ODC Distrigas	0	0	0	0
68	391.6	Journey-Employee Count	0	0	0	0
69	391.6	Payroll - Time Management	0	0	0	0
70	391.6	Accounts Payable Software	0	0	0	0
71	391.8	Micro Computer Software	0	0	0	0
72	391.81	Aircraft Computer Equipment	0	0	0	0
73	391.9	Computer & Equipment	1,544,059	(774,085)	769,975	0
74	391.99	Cloud Computing	0	0	0	0
75	392	Transportation Equipment	0	0	0	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0
78	392.5	Trailers	0	0	0	0
79	392.6	Aircraft	0	0	0	0
80	393	Stores Equipment	0	0	0	0
81	394	Tools, Shop & Garage	13,242	(5,040)	8,202	0
82	394.1	Tools	0	0	0	0
83	394.2	Shop Equipment	0	0	0	0
84	395	CNG Equipment	0	0	0	0
85	396	Major Work Equipment	0	0	0	0
86	397	Communication Equipment	1,194,943	(773,879)	421,064	0
87	397.2	Telephone Equipment	0	0	0	0
88	398	Miscellaneous General Plant	0	0	0	0
89		Total General Plant	$10,552,295	$(2,426,419)	$8,125,875	$0
90		Total Orig Cost Plant in Service	$10,552,295	$(2,426,419)	$8,125,875	$0

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

DEPRECIATION AND AMORTIZATION EXPENSE - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACC 1010 PLANT (WKP C.c)	CORPORATE AS ADJUSTED ALLOCATED TO TGS ACCT 1060 CCNC (WKP C-1.c)	LESS FULLY DEPRECIATED PLANT	ADJUSTED DEPRECIABLE PLANT	ANNUAL DEPR/AMORT RATES	CORPORATE ALLOCATED TO TGS ANNUAL PROFORMA DEPR & AMORT EXP	ALLOCATION FACTOR TO SERVICE AREA	TOTAL ALLOCATED TO SERVICE AREA
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		INTANGIBLE PLANT								
1	301	Organization	$0	$0	$0	$0	0.0000%	$0		
2	302	Franchises & Consents	0	0	0	0	0.0000%	0		
3	303	Misc. Intangible	0	0	0	0	0.0000%	0		
4	303.1	Misc. Intangible	0	0	0	0	0.0000%	0		
5		Total Intangible Plant	$0	$0	$0	$0		$0		$0
		GATHERING AND TRANSMISSION PLANT								
6	325	Land & Land Rights	$0	$0	$0	$0	0.0000%	$0		
7	327	Field Comprss Station Strucutres	0	0	0	0	0.0000%	0		
8	328	Field Meas/Reg Station Structures	0	0	0	0	0.0000%	0		
9	329	Other Structures	0	0	0	0	0.0000%	0		
10	332	Field Lines	0	0	0	0	0.0000%	0		
11	333	Field Compressor Station Equip	0	0	0	0	0.0000%	0		
12	334	Field Meas/Reg Station Equipment	0	0	0	0	0.0000%	0		
13	336	Purification Equipment	0	0	0	0	0.0000%	0		
14	337	Other Equip	0	0	0	0	0.0000%	0		
15	365	Land & Land Rights	0	0	0	0	0.0000%	0		
16	365.2	Rights-of-Way	0	0	0	0	0.0000%	0		
17	366	Meas/Reg Station Structures	0	0	0	0	0.0000%	0		
18	367	Mains	0	0	0	0	0.0000%	0		
19	368	Compressor Station Equip	0	0	0	0	0.0000%	0		
20	369	Meas & Reg Stations Equip	0	0	0	0	0.0000%	0		
21	371	Other Equipment	0	0	0	0	0.0000%	0		
22		Total Gathering and Transmission Plant	$0	$0	$0	$0		$0		$0
		DISTRIBUTION PLANT								
23	374	Land	$0	$0	$0	$0	0.0000%	$0		
24	374.1	Land	0	0	0	0	0.0000%	0		
25	374.2	Land Rights	0	0	0	0	0.0000%	0		
26	375	Structures & Improvements	0	0	0	0	0.0000%	0		
27	375.1	Structures & Improvements	0	0	0	0	0.0000%	0		
28	375.2	Other System Structures	0	0	0	0	0.0000%	0		
29	376	Mains	0	0	0	0	0.0000%	0		
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0	0.0000%	0		
31	377	Compressor Station Equipment	0	0	0	0	0.0000%	0		

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32	378	Meas. & Reg. Station - General	0	0	0	0	0.0000%	0		
33	379	Meas. & Reg. Station - C.G.	0	0	0	0	0.0000%	0		
34	380	Services	0	0	0	0	0.0000%	0		
35	380.1	Ind Service Line Equip	0	0	0	0	0.0000%	0		
36	380.2	Comm Service Line Equip	0	0	0	0	0.0000%	0		
37	380.4	Yard Lines-Customer Svc	0	0	0	0	0.0000%	0		
38	381	Meters	0	0	0	0	0.0000%	0		
39	382	Meter Installations	0	0	0	0	0.0000%	0		
40	383	House Regulators	0	0	0	0	0.0000%	0		
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		
42	386	Other Property on Customer Premises	0	0	0	0	0.0000%	0		
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0	0.0000%	0		
44		Total Distribution Plant	$0	$0	$0	$0		$0		$0
		GENERAL PLANT								
45	389	Land & Land Rights	$12,992	$0	$0	$12,992	0.0000%	$0	44.1009%	$0
46	390	Structures & Improvements	0	0	0	0	0.0000%	0	44.1009%	0
47	390.1	Structures & Improvements	1,307,721	775	0	1,308,496	2.0100%	26,301	44.1009%	11,599
48	390.17	Building Improv Plum	0	0	0	0	0.0000%	0	44.1009%	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	0.0000%	0	44.1009%	0
50	390.2	Leasehold Improvement	1,508,842	18,560	0	1,527,402	13.1868%	201,415	44.1009%	88,826
51	390.21	Leasehold Equipment EOL	0	0	0	0	0.0000%	0	44.1009%	0
52	391	Office Furniture & Equipment	0	0	0	0	0.0000%	0	44.1009%	0
53	391.1	Office Furniture & Equipment	1,073,121	0	0	1,073,121	6.6667%	71,541	44.1009%	31,550
54	391.19	Airplane Hanger Furniture	0	0	0	0	6.6667%	0	44.1009%	0
55	391.2	Data Processing Equipment	0	0	0	0	0.0000%	0	44.1009%	0
56	391.2	Oracle Equipment	0	0	0	0	0.0000%	0	44.1009%	0
57	391.3	Office Machines	85,968	967	0	86,935	5.0000%	4,347	44.1009%	1,917
58	391.4	Audio Visual Equipment	294,196	0	0	294,196	20.0000%	58,839	44.1009%	25,949
59	391.5	Artwork	0	0	0	0	0.0000%	0	44.1009%	0
60	391.6	Purchased Software	29,910,018	1,124,671	0	31,034,689	7.6923%	2,387,284	44.1009%	1,052,814
61	391.6	Banner Software	1,678,461	0	0	1,678,461	7.6923%	129,112	44.1009%	56,940
62	391.6	PowerPlant System	566,421	0	0	566,421	7.6923%	43,571	44.1009%	19,215
63	391.6	Riskworks	0	0	0	0	7.6923%	0	44.1009%	0
64	391.6	Maximo	1,143,370	0	0	1,143,370	7.6923%	87,952	44.1009%	38,787
65	391.6	Foundation Software	0	0	0	0	7.6923%	0	44.1009%	0
66	391.6	Concur Project	13,700	0	(13,700)	0	7.6923%	0	44.1009%	0
67	391.6	Journey-Employee-ODC Distrigas	18,852,265	0	0	18,852,265	7.6923%	1,450,174	44.1009%	639,540
68	391.6	Journey-Employee Count	531,589	0	0	531,589	7.6923%	40,891	44.1009%	18,033
69	391.6	Payroll - Time Management	846,770	0	0	846,770	7.6923%	65,136	44.1009%	28,726
70	391.6	Accounts Payable Software	347,227	0	0	347,227	7.6923%	26,710	44.1009%	11,779
71	391.8	Micro Computer Software	5,890,403	0	0	5,890,403	20.0000%	1,178,081	44.1009%	519,544
72	391.81	Aircraft Computer Equipment	0	0	0	0	0.0000%	0	44.1009%	0
73	391.9	Computer & Equipment	0	0	0	0	0.0000%	0	44.1009%	0
74	391.99	Cloud Computing	196,999	0	0	196,999	7.6923%	15,154	44.1009%	6,683
75	392	Transportation Equipment	0	0	0	0	0.0000%	0	44.1009%	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	0.0000%	0	44.1009%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	0.0000%	0	44.1009%	0

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78	392.5	Trailers	0	0	0	0	0.0000%	0	44.1009%	0
79	392.6	Aircraft	0	0	0	0	6.2800%	0	44.1009%	0
80	393	Stores Equipment	0	0	0	0	0.0000%	0	44.1009%	0
81	394	Tools, Shop & Garage	0	0	0	0	0.0000%	0	44.1009%	0
82	394.1	Tools	0	0	0	0	0.0000%	0	44.1009%	0
83	394.2	Shop Equipment	0	0	0	0	0.0000%	0	44.1009%	0
84	395	CNG Equipment	0	0	0	0	0.0000%	0	44.1009%	0
85	396	Major Work Equipment	0	0	0	0	0.0000%	0	44.1009%	0
86	397	Communication Equipment	27,826	0	0	27,826	5.0000%	1,391	44.1009%	614
87	397.2	Telephone Equipment	0	0	0	0	0.0000%	0	44.1009%	0
88	398	Miscellaneous General Plant	0	0	0	0	0.0000%	0	44.1009%	0
89		Total General Plant	$64,287,889	$1,144,973	$(13,700)	$65,419,161		$5,787,899		$2,552,516
90		Total Plant in Service	$64,287,889	$1,144,973	$(13,700)	$65,419,161		$5,787,899		$2,552,516
91		Total Annualized Depreciation & Amortization Expense						$5,787,899	44.1009%	$2,552,516
92		Test Year Depreciation & Amortization Expense Accts 403 & 404						5,602,710	44.1009%	2,470,846
93		Adjustment to Test Year						$185,189	44.1009%	$81,670

WKP G-15.c.2

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

FULLY DEPRECIATED PLANT - CORPORATE

LINE NO.	ACCOUNT	DESCRIPTION	CORPORATE UNALLOCATED AS ADJUSTED PLANT 1010 & 1060	CORPORATE UNALLOCATED AS ADJUSTED RESERVES 1080100 & 1110	CORPORATE UNALLOCATED NET PLANT AS ADJUSTED	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	302	Franchises & Consents	0	0	0	0		
3	303	Misc. Intangible	0	0	0	0		
4	303.1	Misc. Intangible	0	0	0	0		
5		Total Intangible Plant	$0	$0	$0	$0		
		GATHERING AND TRANSMISSION PLANT						
6	325	Land & Land Rights	$0	$0	$0	$0		
7	327	Field Comprss Station Strucutres	0	0	0	0		
8	328	Field Meas/Reg Station Structures	0	0	0	0		
9	329	Other Structures	0	0	0	0		
10	332	Field Lines	0	0	0	0		
11	333	Field Compressor Station Equip	0	0	0	0		
12	334	Field Meas/Reg Station Equipment	0	0	0	0		
13	336	Purification Equipment	0	0	0	0		
14	337	Other Equip	0	0	0	0		
15	365	Land & Land Rights	0	0	0	0		
16	365.2	Rights-of-Way	0	0	0	0		
17	366	Meas/Reg Station Structures	0	0	0	0		
18	367	Mains	0	0	0	0		
19	368	Compressor Station Equip	0	0	0	0		
20	369	Meas & Reg Stations Equip	0	0	0	0		
21	371	Other Equipment	0	0	0	0		
22		Total Gathering and Transmission Plant	$0	$0	$0	$0		
		DISTRIBUTION PLANT						
23	374	Land	0	$0	$0	$0		
24	374.1	Land	0	0	0	0		
25	374.2	Land Rights	0	0	0	0		
26	375	Structures & Improvements	0	0	0	0		
27	375.1	Structures & Improvements	0	0	0	0		
28	375.2	Other System Structures	0	0	0	0		
29	376	Mains	0	0	0	0		
30	376.9	Mains - Cathodic Protection Anodes	0	0	0	0		
31	377	Compressor Station Equipment	0	0	0	0		
32	378	Meas. & Reg. Station - General	0	0	0	0		
33	379	Meas. & Reg. Station - C.G.	0	0	0	0		
34	380	Services	0	0	0	0		
35	380.1	Ind Service Line Equip	0	0	0	0		
36	380.2	Comm Service Line Equip	0	0	0	0		
37	380.4	Yard Lines-Customer Svc	0	0	0	0		
38	381	Meters	0	0	0	0		
39	382	Meter Installations	0	0	0	0		
40	383	House Regulators	0	0	0	0		
41	385	Indust. Meas. & Reg. Stat. Equipment	0	0	0	0		
42	386	Other Property on Customer Premises	0	0	0	0		
43	387	Meas. & Reg. Stat. Equipment	0	0	0	0		
44		Total Distribution Plant	$0	$0	$0	$0		

WKP G-15.c.2

		GENERAL PLANT						
45	389	Land & Land Rights	$47,854	$0	$47,854	$0	27.15%	$0
46	390	Structures & Improvements	0	0	0	0	27.15%	0
47	390.1	Structures & Improvements	4,819,506	(127,276)	4,692,230	0	27.15%	0
48	390.17	Building Improv Plum	0	0	0	0	27.15%	0
49	390.19	Airplane Hanger Furniture	0	0	0	0	27.15%	0
50	390.2	Leasehold Improvement	5,625,789	(2,987,848)	2,637,942	0	27.15%	0
51	390.21	Leasehold Equipment EOL	0	0	0	0	27.15%	0
52	391	Office Furniture & Equipment	0	0	0	0	27.15%	0
53	391.1	Office Furniture & Equipment	3,952,564	(1,411,252)	2,541,312	0	27.15%	0
54	391.19	Airplane Hanger Furniture	0	0	0	0	27.15%	0
55	391.2	Data Processing Equipment	0	0	0	0	27.15%	0
56	391.2	Oracle Equipment	0	0	0	0	27.15%	0
57	391.3	Office Machines	320,202	(35,309)	284,893	0	27.15%	0
58	391.4	Audio Visual Equipment	1,083,596	(298,175)	785,421	0	27.15%	0
59	391.5	Artwork	0	0	0	0	27.15%	0
60	391.6	Purchased Software	114,308,246	(44,325,399)	69,982,847	0	27.15%	0
61	391.6	Banner Software	5,459,261	(1,343,962)	4,115,299	0	30.75%	0
62	391.6	PowerPlant System	2,171,982	(602,259)	1,569,723	0	26.08%	0
63	391.6	Riskworks	0	0	0	0	27.15%	0
64	391.6	Maximo	4,573,482	(3,021,131)	1,552,351	0	25.00%	0
65	391.6	Foundation Software	0	0	0	0	0.00%	0
66	391.6	Concur Project	47,648	(47,648)	0	(47,648)	28.75%	(13,700)
67	391.6	Journey-Employee-ODC Distrigas	69,437,442	(38,312,052)	31,125,389	0	27.15%	0
68	391.6	Journey-Employee Count	1,848,836	(1,153,517)	695,319	0	28.75%	0
69	391.6	Payroll - Time Management	2,945,016	(175,382)	2,769,635	0	28.75%	0
70	391.6	Accounts Payable Software	1,026,973	(241,670)	785,302	0	33.81%	0
71	391.8	Micro Computer Software	21,695,773	(11,451,445)	10,244,329	0	27.15%	0
72	391.81	Aircraft Computer Equipment	0	0	0	0	27.15%	0
73	391.9	Computer & Equipment	0	0	0	0	27.15%	0
74	391.99	Cloud Computing	725,594	(33,008)	692,586	0	27.15%	0
75	392	Transportation Equipment	0	0	0	0	27.15%	0
76	392.2	Transport Equip Pickup Trucks& Vans	0	0	0	0	27.15%	0
77	392.3	Transport Equip (Trucks 3/4- 3 Ton)	0	0	0	0	27.15%	0
78	392.5	Trailers	0	0	0	0	27.15%	0
79	392.6	Aircraft	0	(0)	(0)	0	27.15%	0
80	393	Stores Equipment	0	0	0	0	27.15%	0
81	394	Tools, Shop & Garage	0	0	0	0	27.15%	0
82	394.1	Tools	0	0	0	0	27.15%	0
83	394.2	Shop Equipment	0	0	0	0	27.15%	0
84	395	CNG Equipment	0	0	0	0	27.15%	0
85	396	Major Work Equipment	0	0	0	0	27.15%	0
86	397	Communication Equipment	102,489	(19,858)	82,631	0	27.15%	0
87	397.2	Telephone Equipment	0	0	0	0	27.15%	0
88	398	Miscellaneous General Plant	0	0	0	0	27.15%	0
89		Total General Plant	$240,192,252	$(105,587,189)	$134,605,063	$(47,648)		$(13,700)
90		Total Orig Cost Plant in Service	$240,192,252	$(105,587,189)	$134,605,063	$(47,648)		$(13,700)

SCHEDULE G-16

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

AD VALOREM TAX EXPENSE

LINE NO.	DESCRIPTION	AMOUNT	AMOUNT	AMOUNT
		(a)	(b)	(c)
	DIRECT SERVICE AREA PLANT @ 12/31/2021			
1	Plant In Service - Gathering/Transmission/Distribution		$627,176,951	
2	Plant In Service - General		39,971,117	
3	CCNC - Gathering/Transmission/Distribution		49,406,545	
4	CCNC - General		16,176,059	
5	Accumulated Depreciation - Gathering/Transmission/Distribution		(102,131,870)	
6	Accumulated Depreciation - General		(14,341,107)	
7	Net Plant - Service Area Direct 12/31/2021		$616,257,695	$616,257,695
	CALCULATION OF EFFECTIVE RATE			
8	Ad Valorem Taxes Paid TYE 2021 for Service Area Direct Plant at 1/1/2020		$5,713,430	
	DIRECT SERVICE AREA PLANT @ 1/1/2020:			
9	Plant In Service - Gathering/Transmission/Distribution	$521,914,381		
10	Plant In Service - General	39,265,734		
11	CCNC - Gathering/Transmission/Distribution	32,704,204		
12	CCNC - General	1,035,984		
13	Accumulated Depreciation - Gathering/Transmission/Distribution	(92,858,965)		
14	Accumulated Depreciation - General	(11,903,052)		
		$490,158,286	490,158,286	
15	Effective Tax Rate		0.011656	0.011656
16	Annualized Ad Valorem Tax Expense			$7,183,100
17	Test Year Ad Valorem Tax Expense - Acct 4081190			6,609,338
18	Adjustment to Test Year Expense			$573,762

Source: WKP G-16 Ad Valorem Tax Liability TY 12 31 2021 (CONFIDENTIAL)_WNSA

WKP G-16.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PLANT IN SERVICE - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/19	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization	$130,422	$0	$130,422
2	(302) Franchises & Consents	9,496	0	9,496
3	(303) Misc. Intangible	893,065	0	893,065
4	Total Intangible Plant - Direct	$1,032,983	$0	$1,032,983
	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	190,844	0	190,844
15	(366) Meas/Reg Station Structures	0	0	0
16	(367) Mains	36,867,610	0	36,867,610
17	(368) Compressor Station Equip	0	0	0
18	(369) Measure/Reg. Station Equipment	2,805,173	0	2,805,173
19	(371) Other Equipment	0	0	0
20	Total Gathering and Transmission Plant - Direct	$39,863,627	$0	$39,863,627
	DISTRIBUTION PLANT			
21	(374) Land & Land Rights	$1,613,313	$0	$1,613,313
22	(375) Structures & Improvements	249,633	0	249,633
23	(376) Mains	218,097,679	0	218,097,679
24	(376.9) Cathodic Protection Anodes	22,082,064	0	22,082,064
25	(377) Compressor Station Equipment	0	0	0
26	(378) Meas. & Reg. Station - General	9,673,588	0	9,673,588
27	(379) Meas. & Reg. Station - C.G.	4,466,491	0	4,466,491
28	(380) Services	141,926,844	0	141,926,844
29	(381) Meters	53,973,378	0	53,973,378
30	(382) Meter Installations	0	0	0
31	(383) House Regulators	14,177,516	0	14,177,516
32	(385) Indust. Meas. & Reg. Stat. Equipment	15,152,022	0	15,152,022
33	(386) Other Property on Customer Premises	638,227	0	638,227
34	(387) Meas. & Reg. Stat. Equipment	0	0	0
35	Total Distribution Plant - Direct	$482,050,755	$0	$482,050,755
	GENERAL PLANT			
36	(389) Land & Land Rights	$320,363	$0	$320,363
37	(390) Structures & Improvements	6,672,572	0	6,672,572
38	(391) Office Furniture & Equipment	4,896,193	0	4,896,193
39	(392) Transportation Equipment	9,073,326	0	9,073,326
40	(393) Stores Equipment	30,808	0	30,808
41	(394) Tools, Shop & Garage	5,041,807	0	5,041,807
42	(395) CNG Equipment	0	0	0
43	(396) Major Work Equipment	2,082,131	0	2,082,131
44	(397) Communication Equipment	11,141,420	0	11,141,420
45	(398) Miscellaneous General Plant	7,115	0	7,115
46	Total General Plant - Direct	$39,265,734	$0	$39,265,734
47	Total Orig Cost Plant in Service - Direct	$562,213,099	$0	$562,213,099

Source: WKP G-16.a WNSA_091_PP Rpt_1010_Plant In Service Dec 31 2019.xlsx

WKP G-16.b

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

COMPLETED CONSTRUCTION NOT CLASSIFIED (CCNC) - DIRECT
AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/19	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)			
1	(301) Organization	$0	$0	$0
2	(302) Franchises & Consents	0	0	0
3	(303) Misc. Intangible	0	0	0
4	Total Intangible CCNC - Direct	$0	$0	$0
	GATHERING AND TRANSMISSION PLANT			
5	(325) Land & Land Rights	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0
8	(329) Other Structures	0	0	0
9	(332) Field Lines	0	0	0
10	(333) Field Compressor Station Equip	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0
12	(336) Purification Equipment	0	0	0
13	(337) Other Equip	0	0	0
14	(365) Land & Land Rights	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0
16	(367) Mains	2,336,146	0	2,336,146
17	(368) Compressor Station Equip	0	0	0
18	(369) Measure/Reg. Station Equipment	0	0	0
19	(371) Other Equipment	0	0	0
20	Total Gathering and Transmission CCNC - Direct	$2,336,146	$0	$2,336,146
	DISTRIBUTION PLANT			

WKP G-16.b

21	(374) Land & Land Rights	$1,306	$0	$1,306
22	(375) Structures & Improvements	47,339	0	47,339
23	(376) Mains	19,840,767	0	19,840,767
24	(376.9) Cathodic Proteciton Anodes	107,459	0	107,459
25	(377) Compressor Station Equipment	0	0	0
26	(378) Meas. & Reg. Station - General	1,293,940	0	1,293,940
27	(379) Meas. & Reg. Station - C.G.	208,246	0	208,246
28	(380) Services	7,828,099	0	7,828,099
29	(381) Meters	483,147	0	483,147
30	(382) Meter Installations	19,175	0	19,175
31	(383) House Regulators	68,209	0	68,209
32	(385) Indust. Meas. & Reg. Stat. Equipment	470,371	0	470,371
33	(386) Other Property on Customer Premises	0	0	0
34	(387) Meas. & Reg. Stat. Equipment	0	0	0
35	Total Distribution CCNC - Direct	$30,368,058	$0	$30,368,058
	GENERAL PLANT			
36	(389) Land & Land Rights	$0	$0	$0
37	(390) Structures & Improvements	77,102	0	77,102
38	(391) Office Furniture & Equipment	15,374	0	15,374
39	(392) Transportation Equipment	718,231	0	718,231
40	(393) Stores Equipment	0	0	0
41	(394) Tools, Shop & Garage	71,184	0	71,184
42	(395) CNG Equipment	0	0	0
43	(396) Major Work Equipment	87,213	0	87,213
44	(397) Communication Equipment	37,753	0	37,753
45	(398) Miscellaneous General Plant	29,125	0	29,125
46	Total General CCNC - Direct	$1,035,984	$0	$1,035,984
47	Total Orig Cost CCNC - Direct	$33,740,188	$0	$33,740,188

Source: WKP G-16.b WNSA_091_PP Rpt_1060_CCNC Dec 31 2019.xlsx

WKP G-16.c

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

ACCUMULATED RESERVES FOR DEPRECIATION AND AMORTIZATION- DIRECT

AD VALOREM TAX WORKPAPER

LINE NO.	DESCRIPTION	YTD BALANCE 12/31/19 1080100	YTD BALANCE 12/31/19 1110000	ADJUSTMENTS	ADJUSTED BALANCE
		(a)	(b)	(c)	(d)
	INTANGIBLE PLANT (NOT USED FOR AD VALOREM)				
1	(301) Organization	$(106,324)	$0	$0	$(106,324)
2	(302) Franchises & Consents	638	0	0	638
3	(303) Misc. Intangible	0	(348,322)	0	(348,322)
4	Total Intangible Plant Reserves - Direct	$(105,686)	$(348,322)	$0	$(454,008)
	GATHERING AND TRANSMISSION PLANT				
5	(325) Land & Land Rights	$0	$0	$0	$0
6	(327) Field Comprss Station Strucutres	0	0	0	0
7	(328) Field Meas/Reg Station Structures	0	0	0	0
8	(329) Other Structures	0	0	0	0
9	(332) Field Lines	0	0	0	0
10	(333) Field Compressor Station Equip	0	0	0	0
11	(334) Field Meas/Reg Station Equipment	0	0	0	0
12	(336) Purification Equipment	0	0	0	0
13	(337) Other Equip	0	0	0	0
14	(365) Land & Land Rights	0	0	0	0
15	(366) Meas/Reg Station Structures	0	0	0	0
16	(367) Mains	(1,553,795)	0	0	(1,553,795)
17	(368) Compressor Station Equip	0	0	0	0
18	(369) Measure/Reg. Station Equipment	(401,219)	0	0	(401,219)
19	(371) Other Equipment	0	0	0	0
20	Total Gathering and Transmission Plant Reserves - Direct	$(1,955,014)	$0	$0	$(1,955,014)
	DISTRIBUTION PLANT				
21	(374) Land & Land Rights	$(51,759)	$0	$0	$(51,759)
22	(375) Structures & Improvements	(160,695)	0	0	(160,695)
23	(376) Mains	(46,422,762)	0	0	(46,422,762)
24	(376.9) Cathodic Protection Anodes	28,152	0	0	28,152
25	(377) Compressor Station Equipment	0	0	0	0
26	(378) Meas. & Reg. Station - General	(2,136,401)	0	0	(2,136,401)
27	(379) Meas. & Reg. Station - C.G.	(1,672,426)	0	0	(1,672,426)
28	(380) Services	(21,408,167)	0	0	(21,408,167)
29	(381) Meters	(11,655,483)	0	0	(11,655,483)
30	(382) Meter Installations	(8,007)	0	0	(8,007)
31	(383) House Regulators	(3,670,002)	0	0	(3,670,002)
32	(385) Indust. Meas. & Reg. Stat. Equipment	(3,541,022)	0	0	(3,541,022)
33	(386) Other Property on Customer Premises	(205,380)	0	0	(205,380)
34	(387) Meas. & Reg. Stat. Equipment	0	0	0	0
35	Total Distribution Plant Reserves - Direct	$(90,903,952)	$0	$0	$(90,903,952)
	GENERAL PLANT				
36	(389) Land & Land Rights	$0	$0	$0	$0
37	(390) Structures & Improvements	(1,069,333)	(30,150)	0	(1,099,483)
38	(391) Office Furniture & Equipment	(354,327)	0	0	(354,327)
39	(391.9) Computer & Equipment	(1,727,443)	0	0	(1,727,443)
40	(392) Transportation Equipment	(4,206,896)	0	0	(4,206,896)
41	(393) Stores Equipment	(5,874)	0	0	(5,874)
42	(394) Tools, Shop & Garage	(894,056)	0	0	(894,056)
43	(395) CNG Equipment	(47)	0	0	(47)
44	(396) Major Work Equipment	(1,219,538)	0	0	(1,219,538)
45	(397) Communication Equipment	(2,422,846)	0	0	(2,422,846)
46	(398) Miscellaneous General Plant	27,459	0	0	27,459
47	Total General Plant Reserves - Direct	$(11,872,902)	$(30,150)	$0	$(11,903,052)
48	Total Accumulated Reserves - Direct	$(104,837,553)	$(378,472)	$0	$(105,216,026)

Source: WKP G-16.c WNSA_091_PP Rpt_1080100_Accum Depr Dec 31 2019.xlsx

Source: WKP G-16.c.2 WNSA_091_PP Rpt_1110_Accum Amort Dec 31 2019.xlsx

SCHEDULE G-17

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

TEXAS FRANCHISE ("GROSS MARGIN") TAX EXPENSE

LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
			(a)
1	As Adjusted Base (Non-Gas) Revenue	WKP G.a.1	$127,465,775
	Less:		
2	Taxes Other Than Federal Income Tax - Revenue Related	WKP G.a.1	0
3	Bad Debt Expense, not included in Purchased Gas Costs	WKP G.a.1	882,700
	Gross Profit		$126,583,075
4	Tax Rate		0.0075
5	Gross Margin Tax		$949,373
6	Test Year Expense - Acct 4091100		0
7	Adjustment to Test Year		$949,373

SCHEDULE G-18

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

STORES LOAD CLEARING

LINE NO.	DESCRIPTION				AMOUNT
		(a)	(b)	(c)	(d)
1	Test Year Charges into Stores Account 1630 for direct and allocated charges:		$1,924,929		
2	Test Year Amounts Cleared Out of Account 1630 to Service Area		1,306,898		
3	Test Year Amount Under/(Over) Cleared		$618,031		$618,031
	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)	$296,694	$294,749	$1,945	
5	Benefits & Payroll Taxes	118,916	116,923	1,993	
6	Other	1,513,257	1,513,257	0	
7	Total Other Adjustments	$1,928,867	$1,924,929	$3,938	3,938
8	Total Adjusted Amount Under/(Over) Cleared				$621,969
	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				
9	Adjustment to Test Year Expense Accounts (See account breakdown below)				$56,735
10	Adjustment to Test Year Non-Expense Accounts				565,234
11	Total Adjustment to Test Year Clearing Acct 1630				$621,969

	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				Amount Under/
12		Acct.	Amount	Percentage	(Over) Cleared
13		8700	$2	0.000001	$1
14		8740	42,296	0.032364	20,129
15		8750	33	0.000025	16
16		8770	0	0.000000	0
17		8780	5,531	0.004232	2,632
18		8800	25,063	0.019177	11,928
19		8870	28,696	0.021958	13,657
20		8890	0	0.000000	0
21		8920	15,257	0.011674	7,261
22		9020	135	0.000104	64
23		9210	2,199	0.001683	1,047
24	Total Adjustment to Test Year Expense Accounts		$119,212	0.091218	$56,735
25	Total Adjustment to Test Year Non-Expense Accounts		1,187,685	0.908782	565,234
	Adjustment to Test Year Clearing		$1,306,898	1.000000	$621,969

SCHEDULE G-19

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

TRANSPORTATION AND WORK EQUIPMENT CLEARING

LINE NO.	DESCRIPTION				AMOUNT
		(a)	(b)	(c)	(d)
1	Test Year Charges into TWE Clearing Accounts 1840100-1840289		2,955,912		
2	Test Year Amounts Cleared Out of TWE Accounts 1840100-1840289		3,082,916		
3	Test Year Amount Under/(Over) Cleared		$(127,004)		$(127,004)
	Plus/Minus Adjustments To Test Year Amounts Charged into TWE Acct 1840100-1840289:				
		Adjusted Test Year	Recorded Test Year	Adjustment	
4	Depreciation	$966,162	$ 1,134,717	$(168,554)	
5	Lease Costs	0	0	0	
6	Payroll	78,013	77,515	498	
7	Benefits & Payroll Taxes	98,804	102,021	(3,217)	
8	Other (gasoline, maintenance, etc)	1,641,659	1,641,659	0	
9	Total	$2,784,639	$2,955,912	$(171,273)	(171,273)
10	Total Adjusted Amount Under/(Over) Cleared				$(298,277)
	Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:				
11	Adjustment to Test Year Expense Accounts (See account breakdown below)				$(182,716)
12	Adjustment to Test Year Non-Expense Accounts				(115,561)
13	Total Adjustment to Test Year TWE Clearing Acct 1840				$(298,277)

Spread Under/(Over) Clearing to Accounts based on Test Year Clearing:

LINE NO.	DESCRIPTION	Acct.	Amount	Percentage	Amount Under/ (Over) Cleared
14					
15		8560	$47,341	0.015356	$(4,580)
16		8570	28,794	0.009340	$(2,786)
17		8630	2,366	0.000768	(229)
18		8700	1,526	0.000495	(148)
19		8740	194,942	0.063233	(18,861)
20		8750	1,847	0.000599	(179)
21		8760	0	0.000000	-
22		8770	462	0.000150	(45)
23		8780	675,019	0.218955	(65,309)
24		8790	0	0.000000	-
25		8800	0	0.000000	-
26		8870	462,412	0.149992	(44,739)
27		8890	91,419	0.029653	(8,845)
28		8900	84,196	0.027310	(8,146)
29		8910	0	0.000000	-
30		8920	187,644	0.060866	(18,155)
31		8930	0	0.000000	-
32		9020	110,543	0.035857	(10,695)
33		9030	0	0.000000	-
34		9050	0	0.000000	-
35		9210	0	0.000000	0
36	Total Adjustment to Test Year Expense Accounts		$1,888,509	0.612572	$(182,716)
37	Total Adjustment to Test Year Non-Expense Accounts		1,194,407	0.387428	-115,561
38	Adjustment to Test Year Clearing		$3,082,916	1.000000	$(298,277)

SCHEDULE G-20

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

REGULATORY ASSET AMORTIZATION

LINE NO.	DESCRIPTION	TOTAL AMOUNT
		(a)
1	Unamortized balance of Reg Assets from GUD 10506	$66,312
2	Less 12 mos. Amortization (line 20, January 2022 - January 2023) Note 1	(66,312)
3	Overcollection of rate case expense from GUD 10739 and GUD 10766	(140)
4	Deferred Regulatory Expense at December 31, 2021 not included in prior cases	22,250
5	Deferred Winter Storm URI O&M at December 31, 2021	62,540
6	Winter Storm URI related STI	351,330
7	Covid related O&M	608,467
8	Uncollected GRIP charges - City of El Paso - Case No. 00006942	744,266
9	Regulatory Assets - Total	$1,788,715
10	Amortization Period (in years)	6
11	Annual Regulatory Asset Amortization Expense	$298,119
12	Test Year Regulatory Asset Amortization Expense - Acct 407.3	$88,428
13	Adjustment to Test Year Expense	$209,691

Note 1: Amortization of Regulatory Asset between end of Test Year and beginning of effective rates.

	MONTH	2022	GRAND TOTAL
14	January	$(7,368)	$(7,368)
15	February	(7,368)	(7,368)
16	March	(7,368)	(7,368)
17	April	(7,368)	(7,368)
18	May	(7,368)	(7,368)
19	June	(7,368)	(7,368)
20	July	(7,368)	(7,368)
21	August	(7,368)	(7,368)
22	September	(7,368)	(7,368)
23	October	0	0
24	November	0	0
25	December	0	0
26			$(66,312)

Source SCH G-20 Rate Case Exp TY 12 31 2021(CONFIDENTIAL)_WNSA
SCH G-20 Regulatory Expenses - Winter Storm URI WNSA.xlsx
SCH G-20 Regulatory Expenses - COVID WNSA.xlsx

SCHEDULE G-21

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

DISTRIGAS ALLOCATION PERCENTAGE

							ADJUSTMENT FOR Q1 2022 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	2021	1	$478,140	25.71%	$122,934			
2		2021	2	797,672	25.71%	205,089			
3		2021	3	664,706	25.71%	170,902			
4		2021	4	355,665	25.72%	91,487			
5		2021	5	366,653	25.72%	94,314			
6		2021	6	461,047	25.72%	118,595			
7		2021	7	287,677	26.10%	75,084			
8		2021	8	353,991	26.10%	92,392			
9		2021	9	409,194	26.10%	106,800			
10		2021	10	336,102	26.73%	89,840			
11		2021	11	328,785	26.73%	87,884			
12		2021	12	648,406	26.73%	173,319			
13	4081 Total			$5,488,039		$1,428,639			
14	9260	2021	1	$491,812	25.71%	$126,449			
15		2021	2	517,481	25.71%	133,049			
16		2021	3	517,481	25.71%	133,049			
17		2021	4	517,481	25.72%	133,111			
18		2021	5	517,481	25.72%	133,111			
19		2021	6	517,481	25.72%	133,111			
20		2021	7	517,481	26.10%	135,063			
21		2021	8	517,481	26.10%	135,063			
22		2021	9	517,481	26.10%	135,063			
23		2021	10	517,481	26.73%	138,323			
24		2021	11	517,481	26.73%	138,323			
25		2021	12	543,145	26.73%	145,183			
26	9260 Total			$6,209,767		$1,618,896			
27	9302	2021	1	$7,325,135	25.71%	$1,883,358			
28		2021	2	7,716,896	25.71%	1,984,083			
29		2021	3	12,523,186	25.71%	3,219,824			
30		2021	4	8,166,174	25.72%	2,100,577			
31		2021	5	7,804,243	25.72%	2,007,478			
32		2021	6	9,480,226	25.72%	2,438,589			
33		2021	7	8,098,816	26.10%	2,113,791			
34		2021	8	7,804,431	26.10%	2,036,956			
35		2021	9	8,420,286	26.10%	2,197,695			
36		2021	10	8,725,917	26.73%	2,332,438			
37		2021	11	7,748,311	26.73%	2,071,124			
38		2021	12	17,476,795	26.73%	4,671,547			
39	9302 Total			$111,290,416		$29,057,459	27.15%	$30,215,348	$1,157,889
40	Total			$122,988,222		$32,104,995		$30,215,348	$1,157,889
41								O&M Expense Factor	88.35%
42								Adjustment to TGS O&M	1,023,036
43								Allocation to Service Area	44.1009%
44								Adjustment to Service Area after O&M	$451,168

WKP G-21.a

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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 2021 - based on 12 months Ended Dec 2020							
1	Oklahoma Natural Gas Company	$2,784,399,599	42.28%	$134,423,211	44.25%	$51,868,788	36.43%	40.99%
2	Kansas Gas Service Company	2,123,261,256	32.24%	90,519,361	29.80%	51,557,830	36.21%	32.75%
3	Texas Gas Service Company	1,677,303,103	25.47%	73,814,311	24.30%	38,959,229	27.36%	25.71%
4	Utility Insurance Company	0	0.00%	5,016,019	1.65%	0	0.00%	0.55%
5	Total	$6,584,963,958	100.00%	$303,772,902	100.00%	$142,385,847	100.00%	100.00%
	2nd Quarter 2021 - based on 12 months Ended Mar 2021							
6	Oklahoma Natural Gas Company	$2,818,374,710	42.33%	$137,542,478	45.63%	$52,055,236	36.41%	41.46%
7	Kansas Gas Service Company	2,138,392,716	32.12%	85,744,450	28.44%	51,761,028	36.20%	32.26%
8	Texas Gas Service Company	1,701,065,046	25.55%	73,049,510	24.23%	39,155,100	27.39%	25.72%
9	Utility Insurance Company	0	0.00%	5,118,991	1.70%	0	0.00%	0.57%
10	Total	$6,657,832,472	100.00%	$301,455,429	100.00%	$142,971,364	100.00%	100.00%
	3rd Quarter 2021 - based on 12 months Ended Jun 2021							
11	Oklahoma Natural Gas Company	$2,860,863,740	42.25%	$139,362,071	45.74%	$52,618,125	36.38%	41.46%
12	Kansas Gas Service Company	2,172,506,696	32.09%	87,219,720	28.62%	52,245,682	36.12%	32.28%
13	Texas Gas Service Company	1,737,149,300	25.66%	76,630,327	25.15%	39,762,762	27.49%	26.10%
14	Utility Insurance Company	0	0.00%	1,501,101	0.49%	0	0.00%	0.16%
15	Total	$6,770,519,736	100.00%	$304,713,219	100.00%	$144,626,569	100.00%	100.00%
	4th Quarter 2021 - based on 12 months Ended Sep 2021							
16	Oklahoma Natural Gas Company	$2,904,432,852	42.26%	$135,604,353	44.20%	$53,271,260	36.39%	40.95%
17	Kansas Gas Service Company	2,190,812,775	31.88%	86,709,538	28.26%	52,680,714	35.98%	32.04%
18	Texas Gas Service Company	1,777,718,516	25.87%	81,888,927	26.69%	40,446,833	27.63%	26.73%
19	Utility Insurance Company	0	0.00%	2,587,742	0.84%	0	0.00%	0.28%
20	Total	$6,872,964,143	100.01%	$306,790,560	100.00%	$146,398,807	100.00%	100.00%

WKP G-21.a

	1st Quarter 2022 - based on 12 months Ended Dec 2021								
21		Oklahoma Natural Gas Company	$2,953,947,853	42.20%	$131,513,137	43.29%	$54,017,182	36.37%	40.62%
22		Kansas Gas Service Company	2,220,951,169	31.73%	87,988,341	28.96%	53,422,385	35.97%	32.22%
23		Texas Gas Service Company	1,825,636,345	26.08%	84,165,380	27.71%	41,063,761	27.65%	27.15%
24		ONE Gas Pipeline	0	0.00%	0	0.00%	0	0.00%	0.00%
25		Utility Insurance Company	0	0.00%	114,465	0.04%	0	0.00%	0.01%
26		Total	$7,000,535,367	100.01%	$303,781,323	100.00%	$148,503,328	99.99%	100.00%

SCHEDULE G-22

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	2021	1	$30,472	25.17 %	$7,670
2	Invoice Count	2021	2	30,612	25.17%	7,705
3	Invoice Count	2021	3	30,451	25.17%	7,665
4	Invoice Count	2021	4	30,539	25.17%	7,687
5	Invoice Count	2021	5	30,342	25.17%	7,637
6	Invoice Count	2021	6	31,016	25.17%	7,807
7	Invoice Count	2021	7	37,744	25.17%	9,500
8	Invoice Count	2021	8	30,501	25.17%	7,677
9	Invoice Count	2021	9	36,712	25.17%	9,240
10	Invoice Count	2021	10	32,594	25.17%	8,204
11	Invoice Count	2021	11	32,476	25.17%	8,174
12	Invoice Count	2021	12	35,380	25.17%	8,905
13	Invoice Count Total			$388,840		$97,871
14	Employee Headcount	2021	1	$824,802	24.04 %	$198,282
15	Employee Headcount	2021	2	957,537	24.04%	230,192
16	Employee Headcount	2021	3	871,249	24.04%	209,448
17	Employee Headcount	2021	4	948,654	24.04%	228,056
18	Employee Headcount	2021	5	829,246	24.04%	199,351
19	Employee Headcount	2021	6	838,303	24.04%	201,528
20	Employee Headcount	2021	7	885,406	24.04%	212,852
21	Employee Headcount	2021	8	1,085,746	24.04%	261,013
22	Employee Headcount	2021	9	738,579	24.04%	177,554
23	Employee Headcount	2021	10	935,567	24.04%	224,910
24	Employee Headcount	2021	11	912,120	24.04%	219,274
25	Employee Headcount	2021	12	1,111,840	24.04%	267,286
26	Employee Headcount Total			$10,939,048		$2,629,747
27	Gross PP&E	2021	1	$452	25.47 %	$115
28	Gross PP&E	2021	2	47	25.47%	12
29	Gross PP&E	2021	3	141	25.47%	36
30	Gross PP&E	2021	4	75	25.47%	19
31	Gross PP&E	2021	5	675	25.47%	172
32	Gross PP&E	2021	6	77	25.47%	20
33	Gross PP&E	2021	7	426	25.47%	108
34	Gross PP&E	2021	8	0	25.47%	0
35	Gross PP&E	2021	9	77	25.47%	20
36	Gross PP&E	2021	10	684	25.47%	174
37	Gross PP&E	2021	11	0	25.47%	0
38	Gross PP&E	2021	12	566	25.47%	144
39	Gross PP&E Total			$3,220		$820
40	Budgeted Admin Cost-SERP	2021	1	$18,372	0.42 %	77
41	Budgeted Admin Cost-SERP	2021	2	9,514	0.42%	40
42	Budgeted Admin Cost-SERP	2021	3	6,318	0.42%	27
43	Budgeted Admin Cost-SERP	2021	4	2,318	0.42%	10
44	Budgeted Admin Cost-SERP	2021	5	7,876	0.42%	33
45	Budgeted Admin Cost-SERP	2021	6	6,818	0.42%	29
46	Budgeted Admin Cost-SERP	2021	7	5,528	0.42%	23
47	Budgeted Admin Cost-SERP	2021	8	4,640	0.42%	19
48	Budgeted Admin Cost-SERP	2021	9	12,421	0.42%	52
49	Budgeted Admin Cost-SERP	2021	10	3,584	0.42%	15
50	Budgeted Admin Cost-SERP	2021	11	6,598	0.42%	28
51	Budgeted Admin Cost-SERP	2021	12	7,318	0.42%	31
52	Budgeted Admin Cost-SERP Total			$91,305		$383
53	Budgeted Admin Cost-Pension	2021	1	$2,645	17.00 %	$450
54	Budgeted Admin Cost-Pension	2021	2	2,743	17.00%	466
55	Budgeted Admin Cost-Pension	2021	3	2,644	17.00%	449
56	Budgeted Admin Cost-Pension	2021	4	777	17.00%	132
57	Budgeted Admin Cost-Pension	2021	5	2,331	17.00%	396
58	Budgeted Admin Cost-Pension	2021	6	777	17.00%	132
59	Budgeted Admin Cost-Pension	2021	7	1,335	17.00%	227
60	Budgeted Admin Cost-Pension	2021	8	2,622	17.00%	446
61	Budgeted Admin Cost-Pension	2021	9	1,815	17.00%	309
62	Budgeted Admin Cost-Pension	2021	10	777	17.00%	132
63	Budgeted Admin Cost-Pension	2021	11	2,701	17.00%	459
64	Budgeted Admin Cost-Pension	2021	12	16,635	17.00%	2,828
65	Budgeted Admin Cost-Pension Total			$37,802		$6,426
66	Customer Count	2021	1	$624,093	30.65 %	$191,285
67	Customer Count	2021	2	608,300	30.65%	186,444
68	Customer Count	2021	3	634,992	30.65%	194,625
69	Customer Count	2021	4	589,431	30.65%	180,660
70	Customer Count	2021	5	603,400	30.65%	184,942
71	Customer Count	2021	6	546,717	30.65%	167,569

SCHEDULE G-22

72	Customer Count	2021	7	626,041	30.65%	191,882
73	Customer Count	2021	8	524,499	30.65%	160,759
74	Customer Count	2021	9	569,059	30.65%	174,417
75	Customer Count	2021	10	574,224	30.65%	176,000
76	Customer Count	2021	11	589,528	30.65%	180,690
77	Customer Count	2021	12	789,083	30.65%	241,854
78	Customer Count Total			$7,279,368		$2,231,126
79	ALLOCATE BY MILES OF PIPE	2021	1	$197,374	24.90 %	$49,146
80	ALLOCATE BY MILES OF PIPE	2021	2	178,400	24.90%	44,421
81	ALLOCATE BY MILES OF PIPE	2021	3	188,405	24.90%	46,913
82	ALLOCATE BY MILES OF PIPE	2021	4	341,602	24.90%	85,059
83	ALLOCATE BY MILES OF PIPE	2021	5	479,623	24.90%	119,426
84	ALLOCATE BY MILES OF PIPE	2021	6	348,971	24.90%	86,894
85	ALLOCATE BY MILES OF PIPE	2021	7	255,754	24.90%	63,683
86	ALLOCATE BY MILES OF PIPE	2021	8	218,938	24.90%	54,516
87	ALLOCATE BY MILES OF PIPE	2021	9	185,973	24.90%	46,307
88	ALLOCATE BY MILES OF PIPE	2021	10	287,244	24.90%	71,524
89	ALLOCATE BY MILES OF PIPE	2021	11	216,874	24.90%	54,002
90	ALLOCATE BY MILES OF PIPE	2021	12	254,388	24.90%	63,343
91	Miles of Pipe Total			$3,153,546		$785,233
92	ALLOCATE BY PROFIT SHARE	2021	1	$0	24.04 %	$0
93	ALLOCATE BY PROFIT SHARE	2021	2	280	24.04%	67
94	ALLOCATE BY PROFIT SHARE	2021	3	9,907	24.04%	2,382
95	ALLOCATE BY PROFIT SHARE	2021	4	422	24.04%	102
96	ALLOCATE BY PROFIT SHARE	2021	5	9,620	24.04%	2,313
97	ALLOCATE BY PROFIT SHARE	2021	6	10,359	24.04%	2,490
98	ALLOCATE BY PROFIT SHARE	2021	7	20,023	24.04%	4,814
99	ALLOCATE BY PROFIT SHARE	2021	8	(9,495)	24.04%	(2,283)
100	ALLOCATE BY PROFIT SHARE	2021	9	10,886	24.04%	2,617
101	ALLOCATE BY PROFIT SHARE	2021	10	244	24.04%	59
102	ALLOCATE BY PROFIT SHARE	2021	11	43	24.04%	10
103	ALLOCATE BY PROFIT SHARE	2021	12	10,886	24.04%	2,617
104	ALLOCATE BY PROFIT SHARE Total			$63,176		$15,187
105	ALLOCATE BY THRIFT	2021	1	$0	24.04 %	$0
106	ALLOCATE BY THRIFT	2021	2	1,003	24.04%	$241
107	ALLOCATE BY THRIFT	2021	3	11,217	24.04%	$2,697
108	ALLOCATE BY THRIFT	2021	4	(2,380)	24.04%	$(572)
109	ALLOCATE BY THRIFT	2021	5	15,600	24.04%	$3,750
110	ALLOCATE BY THRIFT	2021	6	14,391	24.04%	$3,459
111	ALLOCATE BY THRIFT	2021	7	15,600	24.04%	$3,750
112	ALLOCATE BY THRIFT	2021	8	(880)	24.04%	$(211)
113	ALLOCATE BY THRIFT	2021	9	14,434	24.04%	$3,470
114	ALLOCATE BY THRIFT	2021	10	(2,982)	24.04%	$(717)
115	ALLOCATE BY THRIFT	2021	11	205	24.04%	$49
116	ALLOCATE BY THRIFT	2021	12	14,503	24.04%	$3,487
117	ALLOCATE BY THRIFT Total			$80,712		$19,403
118	Total			$22,037,016		$5,786,198

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TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CAUSAL ALLOCATION FACTORS

	2021			2022		
LINE NO.	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR	DESCRIPTION	CAUSAL METRIC	CAUSAL ALLOCATION FACTOR
		(a)	(b)		(c)	(d)
	Based on number of invoices processed by company in 2020	Invoices		Based on number of invoices processed by company in 2021	Invoices	
1	Oklahoma Natural Gas Company	43,296	24.91%	Oklahoma Natural Gas Company	45,431	25.59%
2	Kansas Gas Service Company	32,525	18.71%	Kansas Gas Service Company	32,357	18.23%
3	Texas Gas Service Company	43,738	25.17%	Texas Gas Service Company	45,221	25.47%
4	ONE Gas Inc.	54,250	31.21%	ONE Gas Inc.	54,509	30.71%
5	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
6	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
7	Total	173,809	100%	Total	177,518	100.00%
	Based on employee headcount in 2020	Employees		Based on employee headcount in 2021	Employees	
8	Oklahoma Natural Gas Company	1,125	30.87%	Oklahoma Natural Gas Company	1,123	30.88%
9	Kansas Gas Service Company	993	27.25%	Kansas Gas Service Company	986	27.11%
10	Texas Gas Service Company	876	24.04%	Texas Gas Service Company	866	23.81%
11	ONE Gas Inc.	650	17.84%	ONE Gas Inc.	662	18.20%
12	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
13	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
14	Total	3,644	100%	Total	3,637	100%
	Based on Gross PP&E year end 2020	Gross PP&E		Based on Gross PP&E year end 2021	Gross PP&E	
15	Oklahoma Natural Gas Company	2,784,399,599	42.28%	Oklahoma Natural Gas Company	2,953,947,853	42.20%
16	Kansas Gas Service Company	2,123,261,256	32.24%	Kansas Gas Service Company	2,220,951,169	31.73%
17	Texas Gas Service Company	1,677,303,103	25.47%	Texas Gas Service Company	1,825,636,345	26.08%
18	ONE Gas Inc.	0	0%	ONE Gas Inc.	0	0.00%
19	Utility Insurance Company	0		Utility Insurance Company	0	0.00%
20	ONE Gas Foundation	0		ONE Gas Foundation	0	0.00%
21	Total	$6,584,963,958	99.99%	Total	$7,000,535,367	100%
	Based on Miles of Pipe at year end 2020	Miles		Based on Miles of Pipe at year end 2021	Miles	
22	Oklahoma Natural Gas Company	19,680	45.10%	Oklahoma Natural Gas Company	19,800	45.00%
23	Kansas Gas Service Company	13,086	29.99%	Kansas Gas Service Company	13,200	30.00%

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Line	Company	2021 Amount	2021 %	Company	2022 Amount	2022 %
24	Texas Gas Service Company	10,866	24.90%	Texas Gas Service Company	11,000	25.00%
25	ONE Gas Inc.	0	0.00%	ONE Gas Inc.	0	0.00%
26	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
27	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
28	Total	43,632	99.99%	Total	44,000	100%
	Based on Customer Count at year end 2020	Customers		Based on Customer Count at year end 2021	Customers	
29	Oklahoma Natural Gas Company	894,227	40.29%	Oklahoma Natural Gas Company	905,000	40.38%
30	Kansas Gas Service Company	645,049	29.06%	Kansas Gas Service Company	647,000	28.87%
31	Texas Gas Service Company	680,181	30.65%	Texas Gas Service Company	689,000	30.75%
32	ONE Gas Inc.	0	0.00%	ONE Gas Inc.	0	0.00%
33	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
34	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
35	Total	2,219,457	100%	Total	2,241,000	100%
	SERP Adminstrative costs are allocated using Distrigas in 2021. These costs were incurred by Corporate only.			SERP Adminstrative costs are allocated using Distrigas in 2022.	Percent of Total Cost	
36	Oklahoma Natural Gas Company	0	15.73%	Oklahoma Natural Gas Company	118,438	7.40%
37	Kansas Gas Service Company	0	22.98%	Kansas Gas Service Company	202,126	12.63%
38	Texas Gas Service Company	0	0.42%	Texas Gas Service Company	3,748	0.23%
39	ONE Gas Inc.	70,000	60.87%	ONE Gas Inc.	1,276,291	79.74%
40	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
41	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
42	Total	70,000	100%	Total	$1,600,603	100%
	Based on employee headcount Profit Sharing cost for 2021	Percent of Total Cost		Profit Share based on company's employee head count for 2022	Profit Share	
43	Oklahoma Natural Gas Company	1,125	30.87%	Oklahoma Natural Gas Company	1,123	30.88%
44	Kansas Gas Service Company	993	27.25%	Kansas Gas Service Company	986	27.11%
45	Texas Gas Service Company	876	24.04%	Texas Gas Service Company	866	23.81%
46	ONE Gas Inc.	650	17.84%	ONE Gas Inc.	662	18.20%
47	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
48	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
49	Total	3,644	100%	Total	$3,637	100%
	Based on each company's percent of total cost of Pension for 2021	Percent of Total Cost		Based on each company's percent of total cost of Pension for 2022	Percent of Total Cost	
50	Oklahoma Natural Gas Company	-990,094	-4.24%	Oklahoma Natural Gas Company	-2,967,239	-18.40%
51	Kansas Gas Service Company	16,111,553	68.94%	Kansas Gas Service Company	13,058,077	80.96%
52	Texas Gas Service Company	3,971,781	17.00%	Texas Gas Service Company	2,869,643	17.79%
53	ONE Gas Inc.	4,276,355	18.30%	ONE Gas Inc.	3,169,546	19.65%
54	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
55	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
56	Total	23,369,595	100%	Utility Insurance Company	0	0.00%
				Total	$16,130,027	100%

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	Based on employee headcount Thrift cost for 2021	Percent of Total Cost		Thrift based on company's employee head count for 2022	Thrift	
57	Oklahoma Natural Gas Company	1,125	30.87%	Oklahoma Natural Gas Company	1,123	30.88%
58	Kansas Gas Service Company	993	27.25%	Kansas Gas Service Company	986	27.11%
59	Texas Gas Service Company	876	24.04%	Texas Gas Service Company	866	23.81%
60	ONE Gas Inc.	650	17.84%	ONE Gas Inc.	662	18.20%
61	Utility Insurance Company	0	0.00%	Utility Insurance Company	0	0.00%
62	ONE Gas Foundation	0	0.00%	ONE Gas Foundation	0	0.00%
63	Total	3,644	100%	Total	$3,637	100%

SCHEDULE G-23

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PIPELINE INTEGRITY EXPENSE

LINE NO.	DESCRIPTION		AMOUNT
			(a)
1	Total Expense for Planned Testing 2021 through 2027	$	5,614,100
2	Number of Years to Levelize Expense		7
3	Levelized Pipeline Integrity Expense		$802,014
4	Test Year Pipeline Integrity Expense[(1)]		0
5	Adjustment to Test Year		$802,014

Source: SCH G-23 WNSA 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

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

AMORTIZATION OF EXCESS DEFERRED INCOME TAXES

LINE NO.	MONTH	MONTHLY AMMORTIZATION
	(a)	(b)
1	January 2021	$(292,785)
2	Febuary 2021	(231,183)
3	March 2021	(115,663)
4	April 2021	(90,908)
5	May 2021	(57,191)
6	June 2021	(28,738)
7	July 2021	(65,585)
8	August 2021	(57,049)
9	September 2021	(34,571)
10	October 2021	(96,457)
11	November 2021	(182,101)
12	December 2021	(170,435)
13	Test Year EDIT Amortization - Account 4101110	$(1,422,666)

Source: SCH B-10 EDIT WNSA

Study Summary

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: SUMMARY

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Customer Costs	$ 107,044,548	$ 98,176,625	$ 7,368,917	$ 32,152	$ 732,168	$ 30,872	$ 12,969	$ 21,145	$ 14,646	$ 6,758	$ 4,024	$ 644,272
2	Demand Costs	$ 32,587,813	$ 21,010,892	$ 6,031,698	$ 116,708	$ 2,352,133	$ 86,556	$ 50,517	$ 541,557	$ 289,752	$ 218,976	$ 190,247	$ 1,698,777
3	Commodity Costs	$ 828,542	$ 480,552	$ 180,143	$ 5,279	$ 39,643	$ 1,275	$ 5,727	$ 31,722	$ 25,279	$ 8,449	$ 19,882	$ 30,592
4	Cost of Service Before Revenue Credits	$ 140,460,903	$ 119,668,070	$ 13,580,758	$ 154,139	$ 3,123,943	$ 118,703	$ 69,213	$ 594,423	$ 329,676	$ 234,184	$ 214,153	$ 2,373,641
5	Revenues Credited to Cost of Service (1)	$ 3,068,852	$ 2,735,711	$ 254,430	$ 1,694	$ 34,816	$ 1,376	$ 748	$ 6,361	$ 3,534	$ 2,509	$ 2,298	$ 25,375
6	Total Cost of Service	$ 137,392,051	$ 116,932,358	$ 13,326,328	$ 152,446	$ 3,089,128	$ 117,327	$ 68,465	$ 588,062	$ 326,143	$ 231,675	$ 211,854	$ 2,348,266
7	Revenue at Current Rates	$ 124,396,924	$ 94,066,743	$ 20,232,521	$ 634,581	$ 4,551,682	$ 266,348	$ 153,220	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 2,299,383
8	Revenue Deficiency	$ 12,995,128	$ 22,865,615	$ (6,906,193)	$ (482,136)	$ (1,462,554)	$ (149,021)	$ (84,755)	$ (7,179)	$ (553,209)	$ (18,578)	$ (255,745)	$ 48,883
9	Revenue-to-Cost Ratios:												
10	Current Revenue	0.9075	0.8089	1.5085	4.1279	1.4682	2.2554	2.2246	1.0121	2.6780	1.0793	2.1942	0.9794
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

(1) Service charge (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	$ 1,567,287
Special Contract	$ 1,067,474
Irrigation	$ 434,091
Other Revenue	$ -
	$ 3,068,852

	Service Charges	$ 1,567,257	$ 1,456,428	$ 109,248	$ 46	$ 1,420	$ 107	$ 9	$ 6	$ 9	$ 5	$ 9	$ -
	Special Contract + Irrigation + Other	$ 1,501,564	$ 1,279,283	$ 145,182	$ 1,648	$ 33,396	$ 1,269	$ 740	$ 6,355	$ 3,524	$ 2,503	$ 2,289	$ 25,375
	Service Charges Allocation		0.92928	0.06971	0.00003	0.00091	0.00007	0.00001	0.00000	0.00001	0.00000	0.00001	0.00000
			$ 35.01	$ 64.38	$ 305.67	$ 199.08	$ 232.99	$ 264.52	$ 2,131.44	$ 1,691.10	$ 2,687.32	$ 4,047.31	$ 10,231.65

Study Summary
for Rate Design

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: SUMMARY FOR RATE DESIGN

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Customer Costs	$ 107,044,548	$ 98,176,625	$ 7,390,062	$ 46,798	$ 782,767	$ 4,024	$ 644,272
2	Demand Costs	$ 32,587,813	$ 21,010,892	$ 6,573,255	$ 406,460	$ 2,708,182	$ 190,247	$ 1,698,777
3	Commodity Costs	$ 828,542	$ 480,552	$ 211,865	$ 30,557	$ 55,094	$ 19,882	$ 30,592
4	Cost of Service Before Revenue Credits	$ 140,460,903	$ 119,668,070	$ 14,175,182	$ 483,816	$ 3,546,043	$ 214,153	$ 2,373,641
5	Revenues Credited to Cost of Service	$ 3,068,852	$ 2,735,711	$ 260,791	$ 5,227	$ 39,448	$ 2,298	$ 25,375
6	Total Cost of Service	$ 137,392,051	$ 116,932,358	$ 13,914,391	$ 478,588	$ 3,506,594	$ 211,854	$ 2,348,266
7	Revenue at Current Rates	$ 124,396,924	$ 94,066,743	$ 20,827,763	$ 1,513,933	$ 5,221,502	$ 467,600	$ 2,299,383
8	Revenue Deficiency	$ 12,995,128	$ 22,865,615	$ (6,913,372)	$ (1,035,345)	$ (1,714,908)	$ (255,745)	$ 48,883
9	Revenue-to-Cost Ratios							
10	Current Revenue	0.9075	0.8089	1.4877	3.1400	1.4836	2.1942	0.9794
11	Required Revenue	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
12	Customer and Demand Costs Per Bill		$ 35.01	$ 67.00	$ 679.55	$ 213.89	$ 4,047.31	$ 10,231.65
13	Commodity Cost Per Ccf	$ 0.0039						

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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	$ 94,064	$ 36,156	$ 202
2	302	Franchises and Consents	NONINTPLT	$ 9,496	$ 6,849	$ 2,633	$ 15
3	303	Miscellaneous Intangible Plant	NONINTPLT	$ 893,065	$ 644,102	$ 247,580	$ 1,384
4		Total Intangible Plant		$ 1,032,983	$ 745,015	$ 286,368	$ 1,600
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	$ 44,997,719	$ -	$ 44,997,719	$ -
10	368	Compression Station Equipment	DEM	$ -	$ -	$ -	$ -
11	369	Measuring and Reg. Station Equipment	DEM	$ 2,964,422	$ -	$ 2,964,422	$ -
12	369	Odorization Tank	COM	$ 101,675	$ -	$ -	$ 101,675
13	371	Other Equipment	DEM	$ -	$ -	$ -	$ -
14		Total Transmission Plant		$ 48,254,659	$ -	$ 48,152,984	$ 101,675
15							
16		**Distribution Plant**					
17	374	Land & Land Rights - Allocated	DIS376-379-ALL	$ 1,682,306	$ 1,031,838	$ 650,468	$ -
18	374	Land & Land Rights - Directly Assn.	DIS376-379-DA	$ 19,533	$ 8,458	$ 11,076	$ -
19	375	Structures and Improvements	DIS376-379-ALL	$ 305,151	$ 187,164	$ 117,987	$ -
20	376	Distribution Mains-Allocated	MAINS-ALLOC	$ 312,570,914	$ 204,927,048	$ 107,643,866	$ -
21	376	Distribution Mains-Directly Assigned	MAINS-DA	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
22	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -
23	378	Meas. & Reg. Sta. Equip.- Gen. - Allocated	DEM	$ 14,880,562	$ -	$ 14,880,562	$ -
24	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ 632,107	$ -	$ 632,107	$ -
25	378	Odorization Tank	COM	$ 207,194	$ -	$ -	$ 207,194
26	379	Meas. & Reg. Sta. Equip.- City Gate	DEM	$ 6,660,931	$ -	$ 6,660,931	$ -
27	379	Odorization Tank	COM	$ 765,618	$ -	$ -	$ 765,618
28	380	Services - Allocated	CUS	$ 191,939,948	$ 191,939,948	$ -	$ -
29	380	Services - Directly Assigned	CUS	$ 916,397	$ 916,397	$ -	$ -
30	381	Meters - Allocated	CUS	$ 58,670,292	$ 58,670,292	$ -	$ -
31	381	Meters - Directly Assigned	CUS	$ 147,452	$ 147,452	$ -	$ -
32	382	Meter Installations	CUS	$ 93,748	$ 93,748	$ -	$ -
33	383	House Regulators - Allocated	CUS	$ 15,318,721	$ 15,318,721	$ -	$ -
34	383	House Regulators - Directly Assigned	CUS	$ 92,302	$ 92,302	$ -	$ -
35	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	DEM	$ 17,084,299	$ -	$ 17,084,299	$ -
36	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ 330,071	$ -	$ 330,071	$ -
37	386	Other Property - Customer Premises	CUS	$ 638,227	$ 638,227	$ -	$ -
38	387	Other Equipment	DIS376-379-ALL	$ -	$ -	$ -	$ -
39		Total Distribution Plant		$ 628,328,837	$ 476,571,818	$ 150,784,206	$ 972,813
40							
41		**General Plant**					
42	389	Land & Land Rights	GENPLT	$ 517,798	$ 440,422	$ 76,880	$ 496
43	390	Structures & Improvements	GENPLT	$ 11,376,233	$ 9,434,114	$ 1,929,669	$ 12,450
44	391	Office Furniture and Equipment	GENPLT	$ 31,931,891	$ 31,328,215	$ 599,807	$ 3,870
45	392	Transportation Equipment	GENPLT	$ 10,613,209	$ 8,049,855	$ 2,546,922	$ 16,432
46	393	Stores Equipment	GENPLT	$ 30,503	$ 23,136	$ 7,320	$ 47
47	394	Tools, Shop & Garage - Allocated	GENPLT	$ 6,631,900	$ 5,031,542	$ 1,590,099	$ 10,259
48	394	Tools, Shop & Garage - Dir. Assn.	GENPLT	$ 11,690	$ 5,860	$ 5,830	$ -
49	394	Odorization Tank	COM	$ 25,769	$ -	$ -	$ 25,769
50	395	CNG Equipment	GENPLT	$ -	$ -	$ -	$ -
51	396	Major Work Equipment	GENPLT	$ 2,380,590	$ 1,805,619	$ 571,286	$ 3,686
52	397	Communication Equipment - Allocated	GENPLT	$ 26,088,838	$ 19,917,979	$ 6,131,302	$ 39,557
53	397	Communication Equipment - Dir. Assn.	GENPLT	$ 48,893	$ 24,507	$ 24,385	$ -
54	398	Miscellaneous General Plant	GENPLT	$ -	$ -	$ -	$ -
55		Total General Plant		$ 89,657,313	$ 76,061,248	$ 13,483,501	$ 112,565
56							
57		Total Plant in Service		$ 767,273,792	$ 553,378,080	$ 212,707,059	$ 1,188,653
58							
59		**Depreciation & Amortization Reserve**					
60	301-303	Intangible Plant	DISPLTRES-ALLOC	$ (486,283)	$ (385,157)	$ (100,039)	$ (1,088)
61	325-371	Transmission Plant	DEM	$ (3,240,665)	$ -	$ (3,240,665)	$ -
62	374-387	Distribution Plant - Allocated	DISPLTRES-ALLOC	$ (97,807,490)	$ (77,467,660)	$ (20,121,060)	$ (218,771)
63	374	Land & Land Rights - Directly Assigned	DIS376-379-DA	$ (6,316)	$ (2,735)	$ (3,581)	$ -
64	376	Distribution Mains - Directly Assigned	MAINSRES-DA	$ (784,772)	$ (379,780)	$ (404,992)	$ -
65	378	Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	DEM	$ (34,385)	$ -	$ (34,385)	$ -
66	380	Services - Directly Assigned	CUS	$ (158,249)	$ (158,249)	$ -	$ -

Classified Rate Base

67	381	Meters - Directly Assigned	CUS	$ (47,576)	$ (47,576)	$ -	$ -
68	383	House Regulators - Directly Assigned	CUS	$ (15,489)	$ (15,489)	$ -	$ -
69	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	DEM	$ (36,930)	$ -	$ (36,930)	$ -
70	389-398	General Plant -Allocated	GEN-ALLOCRES	$ (28,040,510)	$ (24,575,931)	$ (3,435,034)	$ (29,546)
71	389-398	General Plant - Directly Assigned	GEN-DARES	$ (19,685)	$ (9,867)	$ (9,818)	$ -
72		Total Depreciation & Amortization Reserve		$ (130,678,349)	$ (103,042,442)	$ (27,386,502)	$ (249,405)
73							
74		Net Plant in Service		$ 636,595,444	$ 450,335,638	$ 185,320,557	$ 939,248
75							
76		Customer Deposits	CUS	$ (7,838,323)	$ (7,838,323)	$ -	$ -
77							
78		Customer Advances	MAINS/SVCS	$ (3,132,466)	$ (2,455,339)	$ (677,127)	$ -
79							
80		Accumulated Deferred Income Taxes	TOTPLT	$ (50,432,867)	$ (36,373,513)	$ (13,981,224)	$ (78,130)
81							
82		Excess Deferred Income Taxes	TOTPLT	$ (14,871,247)	$ (10,725,535)	$ (4,122,673)	$ (23,038)
83							
84		Materials and Supplies	TOTPLT	$ 5,675,575	$ 4,093,374	$ 1,573,408	$ 8,793
85							
86		Prepayments	OPEXP	$ 3,292,141	$ 2,688,427	$ 560,256	$ 43,458
87							
88		Pension & FAS 106 Regulatory Asset	OPEXP	$ 20,010,546	$ 16,341,006	$ 3,405,391	$ 264,148
89							
90		DIMP Deferrals	OPEXP	$ 1,843,921	$ 1,505,782	$ 313,798	$ 24,341
91							
92		Regulatory Assets	OPEXP	$ 1,788,715	$ 1,460,700	$ 304,403	$ 23,612
93							
94		Cash Working Capital	OPEXP	$ (3,535,483)	$ (2,887,145)	$ (601,668)	$ (46,670)
95							
96		Total Rate Base		$ 589,395,955	$ 416,145,073	$ 172,095,122	$ 1,155,761

Classified Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: CLASSIFIED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	CLASSIFICATION FACTOR	TOTAL	CUSTOMER	DEMAND	COMMODITY			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)			
1		**Transmission & Distribution Operations Exp.**								
2	814-866	Transmission Expenses	DEM	$ 1,708,777	$ -	$ 1,708,777	$ -			
3	8700	Operation Supervision & Engineering	DIS871-879	$ 921,752	$ 764,375	$ 135,275	$ 22,102			
4	8710	Distribution Load Dispatch	COM	$ 228,149	$ -	$ -	$ 228,149			Mains & Services
5	8740	Mains & Services - Allocated	MAINS/SVCS-ALLOC	$ 4,295,976	$ 3,379,375	$ 916,602	$ -		Allocated	98.77 %
6	8740	Mains & Services - Dir. Assn.	MAINS/SVCS-DA	$ 53,575	$ 29,955	$ 23,620	$ -		DA	1.23 %
7	8740	Odorization	COM	$ 1,545	$ -	$ -	$ 1,545			Measuring & Reg.
8	8750	Measuring & Reg. Stat. Exp.-Gen.-Allocated	DEM	$ 347,458	$ -	$ 347,458	$ -		Allocated	95.93 %
9	8750	Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	DEM	$ 17,235	$ -	$ 17,235	$ -		DA	4.07 %
10	8750	Odorization	COM	$ 58,281	$ -	$ -	$ 58,281			Measuring & Reg. - Ind.
11	8760	Meas. & Reg. Stat. Exp.- Ind.- Allocated	DEM	$ 27,483	$ -	$ 27,483	$ -		Allocated	98.10 %
12	8760	Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	DEM	$ 531	$ -	$ 531	$ -		DA	1.90 %
13	8770	Meas. & Regulating Station Exp.- City Gate	DEM	$ 63,441	$ -	$ 63,441	$ -			Meter and House Reg.
14	8780	Meter and House Regulator Exp.- Allocated	CUS	$ 4,331,875	$ 4,331,875	$ -	$ -		Allocated	99.68 %
15	8780	Meter and House Regulator Exp.- Dir. Assn.	CUS	$ 14,037	$ 14,037	$ -	$ -		DA	0.32 %
16	8780	Odorization	COM	$ 56	$ -	$ -	$ 56			
17	8790	Customer Installation Expenses	CUS	$ 134,987	$ 134,987	$ -	$ -			
18	8800	Other Expenses	DIS871-879	$ 860,384	$ 713,485	$ 126,269	$ 20,631			
19	8810	Rents	DIS871-879	$ 61,075	$ 50,647	$ 8,963	$ 1,464			
20	8820	Corporate & Div. Exp.	DEM	$ -	$ -	$ -	$ -			
21		Total Transmission & Distribution Oper. Exp.		$ 13,126,616	$ 9,418,736	$ 3,375,653	$ 332,228			
22										
23		**Distribution Maintenance Expenses**								
24	8850	Maintenance Supervision and Engineering	DIS887-893	$ 24,613	$ 14,988	$ 9,625	$ -			
25	8860	Structures and Improvements	DIS887-893	$ 504,182	$ 307,020	$ 197,163	$ -			Mains
26	8870	Maintenance of Mains-Allocated	MAINS-ALLOC	$ 3,192,611	$ 2,093,133	$ 1,099,479	$ -		Allocated	98.31 %
27	8870	Maintenance of Mains - Directly Assn.	MAINS-DA	$ 54,881	$ 26,559	$ 28,322	$ -		DA	1.69 %
28	8890	Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	DEM	$ 506,952	$ -	$ 506,952	$ -			
29	8890	Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	DEM	$ 25,946	$ -	$ 25,946	$ -			
30	8890	Odorization	COM	$ 103,847	$ -	$ -	$ 103,847			
31	8900	Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	DEM	$ 387,292	$ -	$ 387,292	$ -			
32	8900	Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	DEM	$ 7,483	$ -	$ 7,483	$ -			
33	8910	Maint. of Meas. & Reg. Sta. Equip. - City Gate	DEM	$ 6,436	$ -	$ 6,436	$ -			Services
34	8920	Maintenance of Services - Allocated	CUS	$ 1,085,912	$ 1,085,912	$ -	$ -		Allocated	99.52 %
35	8920	Maintenance of Services - Directly Assn.	CUS	$ 5,185	$ 5,185	$ -	$ -		DA	0.48 %
36	8930	Main. of Meters & House Reg. - Allocated	CUS	$ -	$ -	$ -	$ -			Meters & House Reg.
37	8930	Main. of Meters & House Reg. - Dir. Assn.	CUS	$ -	$ -	$ -	$ -		Allocated	99.68 %
38	8940	Maintenance of Other Equipment	DIS887-893	$ -	$ -	$ -	$ -		DA	0.32 %
39	8950	Clearing - Meter Shop - Small Meters	CUS	$ -	$ -	$ -	$ -			
40	8960	Clearing - Meter Shop - Large Meters	CUS	$ -	$ -	$ -	$ -			
41		Total Distribution Maintenance Expenses		$ 5,905,339	$ 3,532,796	$ 2,268,696	$ 103,847			
42										
43		Total Operations & Maintenance Expenses		$ 19,031,955	$ 12,951,532	$ 5,644,349	$ 436,075			
44										
45		**Customer Accounts Expenses**								
46	9010	Supervision	CUS	$ 115,800	$ 115,800	$ -	$ -			
47	9020	Meter Reading Expense	CUS	$ 616,390	$ 616,390	$ -	$ -			
48	9030	Customer Accounting	CUS	$ 3,123,314	$ 3,123,314	$ -	$ -	Gross Up		
49	9040	Bad Debts (includes gross up)	CUS	$ 972,692	$ 972,692	$ -	$ -	$89,991.26		
50	9050	Miscellaneous Customer Accounts Expenses	CUS	$ 417,099	$ 417,099	$ -	$ -			
51		Total Customer Accounts Expenses		$ 5,245,295	$ 5,245,295	$ -	$ -			
52										
53		**Customer Information Expenses**								
54	9070	Supervision	CUS	$ -	$ -	$ -	$ -			
55	9080	Customer Assistance	CUS	$ 671,047	$ 671,047	$ -	$ -			
56	9090	Informational and Instructional Advertising	CUS	$ 48,036	$ 48,036	$ -	$ -			
57	9100	Customer Service & Informational Svc.	CUS	$ -	$ -	$ -	$ -			
58		Total Customer Information Expenses		$ 719,083	$ 719,083	$ -	$ -			
59										
60		**Sales and Advertising Expenses**								
61	9110	Supervision	CUS	$ -	$ -	$ -	$ -			
62	9120	Demonstrating and Selling	CUS	$ -	$ -	$ -	$ -			
63	9130	Advertising	CUS	$ 4,501	$ 4,501	$ -	$ -			
64	9140	Employee Sales Referrals	CUS	$ -	$ -	$ -	$ -			
65	9163	Misc. Gas Sales Expense	CUS	$ -	$ -	$ -	$ -			
66		Total Sales and Advertising Expenses		$ 4,501	$ 4,501	$ -	$ -			
67										
68		**Administrative & General Expenses**								

Classified Cost of Service

69	920-940	Administrative & General Expenses	ADMINGEN	$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631					
70		Total Administrative & General Expenses		$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631					
71												
72		**Depreciation and Amortization Expense**										
73	301-303	Intangible Plant	PLT301-03	$ 16,818	$ 12,130	$ 4,662	$ 26					
74	365	Land and Land Rights	DEM	$ -	$ -	$ -	$ -					
75	366	Meas. and Reg. Station Structures	PLT366	$ -	$ -	$ -	$ -					
76	367	Transmission Mains	PLT367	$ 1,142,945	$ -	$ 1,142,945	$ -					
77	368	Compression Station Equipment	PLT368	$ -	$ -	$ -	$ -					
78	369	Measuring and Reg. Station Equipment	PLT369	$ 107,007	$ -	$ 107,007	$ -					
79	371	Other Equipment	PLT371	$ -	$ -	$ -	$ -					
80	375	Structures and Improvements	PLT375	$ 10,650	$ 6,532	$ 4,118	$ -					
81	376	Mains - Allocated	MAINS-ALLOC	$ 8,306,857	$ 5,446,123	$ 2,860,734	$ -					
82	376	Mains - Directly Assigned	MAINS-DA	$ 128,866	$ 62,363	$ 66,503	$ -					
83	377	Compressor Station Equipment	DEM	$ -	$ -	$ -	$ -					
84	378	Meas. & Reg. Sta. Equip. - General - Alloc.	PLT378	$ 333,435	$ -	$ 333,435	$ -					
85	378	Meas. & Reg. Sta. Equip.- General - Dir. Assn.	PLT378	$ 14,159	$ -	$ 14,159	$ -					
86	378	Odorization Tank	COM	$ 4,641	$ -	$ -	$ 4,641					
87	379	Meas. & Reg. Sta. Equipment - City Gate	PLT379	$ 135,900	$ -	$ 135,900	$ -					
88	379	Odorization Tank	COM	$ 15,619	$ -	$ -	$ 15,619					
89	380	Services - Allocated	PLT380	$ 6,216,101	$ 6,216,101	$ -	$ -					
90	380	Services - Directly Assigned	PLT380	$ 29,508	$ 29,508	$ -	$ -					
91	381	Meters - Allocated	PLT381	$ 2,388,003	$ 2,388,003	$ -	$ -					
92	381	Meters - Directly Assigned	PLT381	$ 6,001	$ 6,001	$ -	$ -					
93	382	Meter Installations	PLT382	$ -	$ -	$ -	$ -					
94	383	House Regulators - Allocated	PLT383	$ 542,385	$ 542,385	$ -	$ -					
95	383	House Regulators - Directly Assigned	PLT383	$ 3,267	$ 3,267	$ -	$ -					
96	385	Meas. & Reg. Sta. Equip. - Ind. - Allocated	PLT385	$ 406,969	$ -	$ 406,969	$ -					
97	385	Meas. & Reg. Sta. Equip. - Ind. - Dir. Assn.	PLT385	$ 7,856	$ -	$ 7,856	$ -					
98	386	Other Property - Customer Premises	PLT386	$ 90,947	$ 90,947	$ -	$ -					
99	387	Other Equipment	PLT387	$ -	$ -	$ -	$ -					
100	389-398	General Plant - Allocated	GENDEP	$ 5,484,769	$ 4,838,866	$ 640,070	$ 5,833					
101	389-398	General Plant - Directly Assigned	GENDEP	$ 4,039	$ 3,563	$ 471	$ 4					
102	389-398	General Plant - Odorization	COM	$ 1,718	$ -	$ -	$ 1,718					
103	40730	Pension & FAS 106 Amortization Expense	OPEXP	$ 237,913	$ 194,285	$ 40,488	$ 3,141					
104		Total Depreciation and Amortization Expense		$ 25,636,372	$ 19,840,074	$ 5,765,317	$ 30,981					
105												
106		**Taxes Other Than Income**										
107	4080	Payroll and Other	OPEXP	$ 2,731,498	$ 2,230,595	$ 464,846	$ 36,057			Total Plant		
108	4080	Ad Valorem - Allocated	TPLT-ALLOC	$ 7,112,217	$ 5,145,111	$ 1,955,978	$ 11,128			Allocated	759,702,283	99.01 %
109	4080	Ad Valorem - Directly Assigned	TPLT-DA	$ 70,883	$ 35,530	$ 35,353	$ -	Gross Up		DA	7,571,509	0.99 %
110	4080	Revenue Related (includes gross up)	CUS	$ 97,463	$ 97,463	$ -	$ -	$	97,463		767,273,792	
111		Total Taxes Other Than Income		$ 10,012,061	$ 7,508,699	$ 2,456,177	$ 47,185					
112												
113	4101	Excess Deferred Income Tax Amort. - Dir. Assn.	RB-DA	$ (14,455)	$ (7,110)	$ (7,345)	$ -					
114	4101	Excess Deferred Income Tax Amort. - Allocated	RB-ALLOC	$ (1,408,211)	$ (999,302)	$ (406,810)	$ (2,099)					
115												
116	4310	Interest on Customer Deposits	CUS	$ 4,703	$ 4,703	$ -	$ -					
117										Net Plant		
118		Required Return - Other Than Directly Assigned	RB-ALLOC	$ 45,326,077	$ 32,164,519	$ 13,093,996	$ 67,562			Allocated	630,127,335	98.98 %
119		Required Return - Directly Assigned	RB-DA	$ 465,262	$ 228,851	$ 236,411	$ -			DA	6,468,109	1.02 %
120		Income Taxes - Other Than Directly Assigned	RB-ALLOC	$ 9,531,958	$ 6,764,116	$ 2,753,634	$ 14,208					
121		Income Taxes - Directly Assigned	RB-DA	$ 97,843	$ 48,127	$ 49,717	$ -			Rate Base		
122		Total Cost of Service Before Revenue Credits		$ 140,460,903	$ 107,044,548	$ 32,587,813	$ 828,542			Allocated	583,407,416	98.98 %
										DA	5,988,540	1.02 %

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: CLASSIFICATION FACTORS

LINE NO.	ACCT.	CLASSIFICATION FACTOR	DESCRIPTION	TOTAL	CUSTOMER	DEMAND	COMMODITY
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		CUS	Customer Factor		1.00000	0.00000	0.00000
2							
3		DEM	Demand Factor		0.00000	1.00000	0.00000
4							
5		COM	Commodity Factor		0.00000	0.00000	1.00000
6							
7			Total Transmission Plant	$ 48,254,659	$ -	$ 48,152,984	$ 101,675
8			Total Distribution Plant	$ 628,328,837	$ 476,571,818	$ 150,784,206	$ 972,813
9			Total General Plant	$ 89,657,313	$ 76,061,248	$ 13,483,501	$ 112,565
10			Total Non-Intangible Plant	$ 766,240,809	$ 552,633,066	$ 212,420,691	$ 1,187,053
11		NONINTPLT	Non-Intangible Plant Factor	1.00000	0.72123	0.27722	0.00155
12							
13	376		Distribution Mains-Allocated	$ 312,570,914	$ 204,927,048	$ 107,643,866	$ -
14	377		Compressor Station Equipment	$ -	$ -	$ -	$ -
15	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 14,880,562	$ -	$ 14,880,562	$ -
16	379		Meas. & Reg. Sta. Equip.- City Gate	$ 6,660,931	$ -	$ 6,660,931	$ -
17			Total Accounts 376-379	$ 334,112,407	$ 204,927,048	$ 129,185,359	$ -
18		DIS376-379-All	Accounts 376-379 Allocated Factor	1.00000	0.61335	0.38665	0.00000
19							
20	376		Distribution Mains-Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
21	378		Meas. & Reg. Sta. Equip.-Gen. - Dir. Assn	$ 632,107	$ -	$ 632,107	$ -
22			Total Accounts 376-379 Directly Assigned	$ 6,005,171	$ 2,600,224	$ 3,404,946	$ -
23		DIS376-379-DA	Accounts 376-379 Directly Assigned Factor	1.00000	0.43300	0.56700	0.00000
24							
25	376		Mains-Allocated	$ 312,570,914	$ 204,927,048	$ 107,643,866	$ -
26		MAINS-ALLOC	Distribution Mains Allocated Factor	1.00000	0.65562	0.34438	0.00000
27							
28	376		Mains-Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
29		MAINS-DA	Distribution Mains Directly Assigned Factor	1.00000	0.48394	0.51606	0.00000
30							
31	376/380		Mains and Services-Directly Assigned	$ 6,289,461	$ 3,516,621	$ 2,772,839	$ -
32		MAINS/SVCS-DA	Mains and Services Directly Assigned Factor	1.00000	0.55913	0.44087	0.00000
33							
34	376/380		Mains and Services-Allocated	$ 504,510,861	$ 396,866,996	$ 107,643,866	$ -
35		MAINS/SVCS-ALLOC	Mains and Services Allocated Factor	1.00000	0.78664	0.21336	0.00000
36							
37	376/380		Mains and Services	$ 510,800,322	$ 400,383,617	$ 110,416,705	$ -
38		MAINS/SVCS	Mains and Services Factor	1.00000	0.78384	0.21616	0.00000
39							
40	374-387		Total Distribution Plant	$ 628,328,837	$ 476,571,818	$ 150,784,206	$ 972,813
41		DISPLT	Distribution Plant Factor	1.00000	0.75848	0.23998	0.00155
42							
43	374		Land & Land Rights - Directly Assigned	$ 19,533	$ 8,458	$ 11,076	$ -
44	376		Mains - Directly Assigned	$ 5,373,064	$ 2,600,224	$ 2,772,839	$ -
45	378		Meas. & Reg. Sta. Equip.- Gen. - Dir. Assn.	$ 632,107	$ -	$ 632,107	$ -
46	380		Service - Directly Assigned	$ 916,397	$ 916,397	$ -	$ -
47	381		Meters - Directly Assigned	$ 147,452	$ 147,452	$ -	$ -
48	383		House Regulators - Directly Assigned	$ 92,302	$ 92,302	$ -	$ -
49	385		Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ 330,071	$ -	$ 330,071	$ -
50			Total Distribution Plant - Directly Assigned	$ 7,510,927	$ 3,764,833	$ 3,746,093	$ -
51		DISPLT-DA	Distribution Plant - Directly Assn. Factor	1.00000	0.50125	0.49875	0.00000
52							
53	374		Land & Land Rights - Allocated	$ (47,006)	$ (28,831)	$ (18,175)	$ -
54	375		Structures and Improvements	$ (149,046)	$ (91,417)	$ (57,629)	$ -
55	376		Distribution Mains - Allocated	$ (43,947,969)	$ (28,813,070)	$ (15,134,899)	$ -
56	377		Compressor Station Equipment	$ -	$ -		
57	378		Meas. & Reg. Sta. Equip.-Gen. - Alloc.	$ (1,013,107)	$ -	$ (1,013,107)	$ -

Classification Factors

58	379		Meas. & Reg. Sta. Equip.-City Gate	$ (747,871)	$ -	$ (747,871)	$ -
59	378-379		Odorization Tank	$ (218,771)	$ -	$ -	$ (218,771)
60	380		Services - Allocated	$ (26,297,732)	$ (26,297,732)	$ -	$ -
61	381		Meters - Allocated	$ (16,835,649)	$ (16,835,649)	$ -	$ -
62	382		Meter Installations	$ (8,293)	$ (8,293)	$ -	$ -
63	383		House Regulators - Allocated	$ (5,122,147)	$ (5,122,147)	$ -	$ -
64	385		Meas. & Reg. Sta. Equip.-Ind. - Allocated	$ (2,978,842)	$ -	$ (2,978,842)	$ -
65	386		Other Property-Customer Premises	$ (441,058)	$ (270,522)	$ (170,536)	$ -
66	387		Other Equipment	$ -	$ -	$ -	$ -
67			Total Distribution Plant - Allocated Reserve	$ (97,807,490)	$ (77,467,660)	$ (20,121,060)	$ (218,771)
68		DISPLTRES-ALLOC	Distribution Plant Allocated Reserve Factor	$ 1.00000	0.79204	0.20572	0.00224
69							
70	376		Distribution Mains - Directly Assigned	$ (784,772)	$ (379,780)	$ (404,992)	$ -
71		MAINSRES-DA	Distribution Mains Dir. Assn. Reserve Factor	1.00000	0.48394	0.51606	0.00000
72							
73			General Plant - Allocated Reserve	$ (28,040,510)	$ (24,575,931)	$ (3,435,034)	$ (29,546)
74		GEN-ALLOCRES	General Plant Alloc. Reserve Factor	1.00000	0.87644	0.12250	0.00105
75							
76			General Plant - Directly Assigned Reserve	$ (19,685)	$ (9,867)	$ (9,818)	$ -
77		GEN-DARES	General Plant Directly Assn. Reserve Factor	1.00000	0.50125	0.49875	0.00000
78							
79			Total Plant - Allocated	$ 759,702,283	$ 549,582,880	$ 208,930,750	$ 1,188,653
80		TPLT-ALLOC	Total Plant Allocated Factor	1.00000	0.72342	0.27502	0.00156
81							
82			Total Plant - Directly Assigned	$ 7,571,509	$ 3,795,200	$ 3,776,309	$ -
83		TPLT-DA	Total Plant Directly Assigned Factor	$ 1.00000	$ 0.50125	$ 0.49875	$ -
84							
85			Total Plant	$ 767,273,792	$ 553,378,080	$ 212,707,059	$ 1,188,653
86		TOTPLT	Total Plant Factor	1.00000	0.72123	0.27722	0.00155
87							
88			Total Operations and Maintenance Expenses	$ 19,031,955	$ 12,951,532	$ 5,644,349	$ 436,075
89			Total Customer Accounts Expenses	$ 5,245,295	$ 5,245,295	$ -	$ -
90			Total Customer Service Expenses	$ 719,083	$ 719,083	$ -	$ -
91			Total Sales and Advertising Expenses	$ 4,501	$ 4,501	$ -	$ -
92			Administrative and General Expenses	$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631
93			Total Operating Expenses	$ 50,809,292	$ 41,491,870	$ 8,646,717	$ 670,705
94		OPEXP	Operating Expense Factor	1.00000	0.81662	0.17018	0.01320
95							
96	8710		Distribution Load Dispatch	$ 228,149	$ -	$ -	$ 228,149
97	8740		Mains and Services Expenses - Allocated	$ 4,295,976	$ 3,379,375	$ 916,602	$ -
98	8740		Mains and Services Expenses - Dir. Assn.	$ 53,575	$ 29,955	$ 23,620	$ -
99	8750		Measuring & Reg. Stat. Exp.-Gen.-Allocated	$ 347,458	$ -	$ 347,458	$ -
100	8750		Measuring & Reg. Stat. Exp.-Gen.-Dir. Assn.	$ 17,235	$ -	$ 17,235	$ -
101	8760		Meas. & Reg. Stat. Exp.- Ind.- Allocated	$ 27,483	$ -	$ 27,483	$ -
102	8760		Meas. & Reg. Stat. Exp.- Ind.- Dir. Assn.	$ 531	$ -	$ 531	$ -
103	8770		Meas. & Regulating Station Exp.- City Gate	$ 63,441	$ -	$ 63,441	$ -
104	8780		Meter and House Regulator Exp.- Allocated	$ 4,331,875	$ 4,331,875	$ -	$ -
105	8780		Meter and House Regulator Exp.- Dir. Assn.	$ 14,037	$ 14,037	$ -	$ -
106	8790		Customer Installation Expenses	$ 134,987	$ 134,987	$ -	$ -
107			Total Accounts 871-879	$ 9,514,748	$ 7,890,230	$ 1,396,369	$ 228,149
108		DIS871-879	Accounts 871-879 Factor	1.00000	0.82926	0.14676	0.02398
109							
110	8870		Maintenance of Mains-Allocated	$ 3,192,611	$ 2,093,133	$ 1,099,479	$ -
111	8870		Maintenance of Mains - Directly Assn.	$ 54,881	$ 26,559	$ 28,322	$ -
112	8890		Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.	$ 506,952	$ -	$ 506,952	$ -
113	8890		Maint. of Meas. & Reg. Sta. Equip. - Gen. - Dir. Assn.	$ 25,946	$ -	$ 25,946	$ -
114	8900		Maint. of Meas. & Reg. Sta. Equip. - Ind. - Alloc.	$ 387,292	$ -	$ 387,292	$ -
115	8900		Maint. of Meas. & Reg. Sta. Equip - Ind. - Dir. Assn.	$ 7,483	$ -	$ 7,483	$ -
116	8910		Maint. of Meas. & Reg. Sta. Equip. - City Gate	$ 6,436	$ -	$ 6,436	$ -
117	8920		Maintenance of Services - Allocated	$ 1,085,912	$ 1,085,912	$ -	$ -
118	8920		Maintenance of Services - Directly Assn.	$ 5,185	$ 5,185	$ -	$ -
119	8930		Main. of Meters & House Reg. - Allocated	$ -	$ -	$ -	$ -
120	8930		Main. of Meters & House Reg. - Dir. Assn.	$ -	$ -	$ -	$ -
121			Total Accounts 887-893	$ 5,272,697	$ 3,210,788	$ 2,061,909	$ -
122		DIS887-893	Accounts 887-893 Factor	1.00000	0.60895	0.39105	0.00000
123							
124			Total Operations and Maintenance Expenses	$ 19,031,955	$ 12,951,532	$ 5,644,349	$ 436,075
125			Total Customer Accounts Expenses	$ 5,245,295	$ 5,245,295	$ -	$ -
126			Total Customer Service Expenses	$ 719,083	$ 719,083	$ -	$ -

Classification Factors

127			Total Sales and Advertising Expenses	$ 4,501	$ 4,501	$ -	$ -		
128			Total Operating Exp. Without A&G Expenses	$ 25,000,834	$ 18,920,411	$ 5,644,349	$ 436,075		
129		NONAGOPEXP	Non-A&G Operating Expenses Factor	1.00000	0.75679	0.22577	0.01744		
130									
131	920-932		Administrative and General Expenses	$ 25,808,458	$ 22,571,459	$ 3,002,368	$ 234,631		
132		ADMINGEN	Administrative and General Expenses Factor	1.00000	0.87458	0.11633	0.00909		
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	$ 44,997,719	$ -	$ 44,997,719	$ -		
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	$ 2,964,422	$ -	$ 2,964,422	$ -		
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	$ 305,151	$ 187,164	$ 117,987	$ -		
150		PLT375	Structures and Improvements Factor	1.00000	0.61335	0.38665	0.00000		
151									
152	378		Meas. & Reg. Sta. Equip.- Gen. - Allocated	$ 14,880,562	$ -	$ 14,880,562	$ -		
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	$ 6,660,931	$ -	$ 6,660,931	$ -		
156		PLT379	Meas. & Reg. Station Equip. - City Gate Factor	1.00000	0.00000	1.00000	0.00000		
157									
158	380		Services - Allocated	$ 191,939,948	$ 191,939,948	$ -	$ -		
159		PLT380	Services Factor	1.00000	1.00000	0.00000	0.00000		
160									
161	381		Meters - Allocated	$ 58,670,292	$ 58,670,292	$ -	$ -		
162		PLT381	Meters Factor	1.00000	1.00000	0.00000	0.00000		
163									
164	382		Meter Installations	$ 93,748	$ 93,748	$ -	$ -		
165		PLT382	Meter Installations Factor	1.00000	1.00000	0.00000	0.00000		
166									
167	383		House Regulators - Allocated	$ 15,318,721	$ 15,318,721	$ -	$ -		
168		PLT383	House Regulators Factor	1.00000	1.00000	0.00000	0.00000		
169									
170	385		Meas. & Reg. Sta. Equip. - Ind. - Allocated	$ 17,084,299	$ -	$ 17,084,299	$ -		
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	$ 745,015	$ 286,368	$ 1,600		
180		PLT301-03	Intangible Plant	1.00000	0.72123	0.27722	0.00155		
181									
182	389-398		General Plant Depreciation Expense	$ 5,490,525	$ 4,843,945	$ 640,742	$ 5,839		
183		GENDEP	General Plant Depreciation Expense Factor	1.00000	0.88224	0.11670	0.00106		
184									
185			Net Plant Directly Assigned	$ 6,468,109	$ 3,181,505	$ 3,286,604	$ -	$ 6,468,109	DA Net Plant
186		NETPLT-DA	Net Plant Directly Assigned Factor	1.00000	0.49188	0.50812	0.00000	$ 630,127,335	Alloc. Net Plant
187								$ 636,595,444	(G195+G196)
188			Net Plant Allocated	$ 630,127,335	$ 447,154,133	$ 182,033,953	$ 939,248	630,127,335	Alloc. Net Plant
189		NETPLT-ALLOC	Net Plant Allocated Assigned Factor	1.00000	0.70963	0.28888	0.00149	99%	
190								(47,199,488)	Non-Plant Rate Base
191			Rate Base Directly Assigned	$ 5,988,540	$ 2,945,617	$ 3,042,923	$ -	(46,719,919)	Alloc. Non-Plant Rate Base
192		RB-DA	Rate Base Directly Assigned Factor	1.00000	0.49188	0.50812	0.00000	630,127,335	Alloc. Net Plant
193								583,407,416	Alloc. Rate Base
194			Rate Base Allocated	$ 583,407,416	$ 414,000,509	$ 168,537,298	$ 869,609		
195		RB-ALLOC	Rate Base Allocated Factor	1.00000	0.70963	0.28888	0.00149	6,468,109	DA Net Plant

Classification Factors

196							630,127,335	Alloc. Net Plant
197		Required Return	$ 45,791,339	$ 32,393,370	$ 13,330,407	$ 67,562	636,595,444	(G195+G198)
198	REQRET	Required Return Factor	1.00000	0.70741	0.29111	0.00148	6,468,109	DA Net Plant
199							1.0%	
200		Non-Plant Rate Base	$ (47,199,488)	$ (34,190,566)	$ (13,225,435)	$ 216,512	(47,199,488)	Non-Plant Rate Base
201	NPLT-RB	Non-Plant Rate Base Factor	1.00000	0.72438	0.28020	-0.00459	(479,569)	DA Non-Plant Rate Base
							6,468,109	DA Net Plant
							5,988,540	DA Rate Base

Allocated Rate Base

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: ALLOCATED RATE BASE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUBLIC AUTHORITY TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	301-303	**Intangible Plant**													
2		Customer	NONINCUS	$ 745,015	$ 698,691	$ 42,726	$ 100	$ 3,180	$ 103	$ 49	$ 54	$ 37	$ 17	$ 10	$ 47
3		Demand	NONINDEM	$ 286,368	$ 195,453	$ 49,891	$ 965	$ 19,455	$ 716	$ 418	$ 4,479	$ 2,397	$ 1,811	$ 1,574	$ 9,209
4		Commodity	COM	$ 1,600	$ 928	$ 348	$ 10	$ 77	$ 2	$ 11	$ 61	$ 49	$ 16	$ 38	$ 59
5		Total Intangible Plant		$ 1,032,983	$ 895,071	$ 92,965	$ 1,076	$ 22,712	$ 822	$ 478	$ 4,595	$ 2,482	$ 1,845	$ 1,622	$ 9,315
6	365-371	**Transmission Plant**													
7		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	DEM	$ 48,152,984	$ 32,865,460	$ 8,389,153	$ 162,323	$ 3,271,451	$ 120,385	$ 70,261	$ 753,221	$ 403,000	$ 304,562	$ 264,604	$ 1,548,563
9		Commodity	COM	$ 101,675	$ 58,972	$ 22,106	$ 648	$ 4,865	$ 156	$ 703	$ 3,893	$ 3,102	$ 1,037	$ 2,440	$ 3,754
10		Total Transmission Plant		$ 48,254,659	$ 32,924,431	$ 8,411,260	$ 162,971	$ 3,276,315	$ 120,542	$ 70,964	$ 757,114	$ 406,102	$ 305,599	$ 267,044	$ 1,552,317
11		**Distribution Plant**													
12	374	**Land & Land Rights - Allocated**													
13		Customer	376-379CUS	$ 1,031,838	$ 955,555	$ 58,434	$ 137	$ 4,349	$ 141	$ 67	$ 74	$ 51	$ 24	$ 13	$ 12,993
14		Demand	DEM	$ 650,468	$ 443,958	$ 113,324	$ 2,193	$ 44,192	$ 1,626	$ 949	$ 10,175	$ 5,444	$ 4,114	$ 3,574	$ 20,919
15		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16		Total Land & Land Rights - Allocated		$ 1,682,306	$ 1,399,513	$ 171,758	$ 2,329	$ 48,541	$ 1,768	$ 1,016	$ 10,249	$ 5,494	$ 4,138	$ 3,588	$ 33,911
17	374	**Land & Land Rights - DA**													
18		Customer	CUS-DA	$ 8,458	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,458
19		Demand	DEM-DA	$ 11,076	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,076
20		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Total Land & Rights - DA		$ 19,533	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,533
22	375	**Structures and Improvements**													
23		Customer	376-379CUS	$ 187,164	$ 173,327	$ 10,599	$ 25	$ 789	$ 26	$ 12	$ 13	$ 9	$ 4	$ 2	$ 2,357
24		Demand	DEM	$ 117,987	$ 80,529	$ 20,556	$ 398	$ 8,016	$ 295	$ 172	$ 1,846	$ 987	$ 746	$ 648	$ 3,794
25		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Total Structures and Improvements		$ 305,151	$ 253,856	$ 31,155	$ 423	$ 8,805	$ 321	$ 184	$ 1,859	$ 997	$ 751	$ 651	$ 6,151
27	376	**Distribution Mains-Allocated**													
28		Customer	CUS	$ 204,927,048	$ 192,184,905	$ 11,752,444	$ 27,496	$ 874,746	$ 28,456	$ 13,550	$ 14,905	$ 10,163	$ 4,743	$ 2,710	$ 12,929
29		Demand	DEM	$ 107,643,866	$ 73,469,282	$ 18,753,581	$ 362,866	$ 7,313,183	$ 269,116	$ 157,066	$ 1,683,792	$ 900,888	$ 680,835	$ 591,511	$ 3,461,745
30		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31		Total Distribution Mains - Allocated		$ 312,570,914	$ 265,654,187	$ 30,506,025	$ 390,362	$ 8,187,929	$ 297,572	$ 170,616	$ 1,698,698	$ 911,051	$ 685,578	$ 594,221	$ 3,474,674
32		**Distribution Mains - Directly Assn.**													
33		Customer	CUS-DA	$ 2,600,224	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,600,224
34		Demand	DEM-DA	$ 2,772,839	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,772,839
35		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36		Total Distribution Mains - Dir. Assn.		$ 5,373,064	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,373,064
37	377	**Compressor Station Equipment**													
38		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Total Compressor Station Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	378	**Meas. & Reg. Sta. Equip.- Gen.-Alloc.**													
43		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Demand	DEM	$ 14,880,562	$ 10,156,307	$ 2,592,473	$ 50,162	$ 1,010,966	$ 37,202	$ 21,713	$ 232,765	$ 124,538	$ 94,118	$ 81,770	$ 478,548
45		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Total Meas. & Reg. Sta. Equip.- Gen.-Alloc.		$ 14,880,562	$ 10,156,307	$ 2,592,473	$ 50,162	$ 1,010,966	$ 37,202	$ 21,713	$ 232,765	$ 124,538	$ 94,118	$ 81,770	$ 478,548
47	378	**Meas. & Reg. Sta. Equip.- Gen.- DA**													
48		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49		Demand	DEM-DA	$ 632,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 632,107
50		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51		Total Meas. & Reg. Sta. Equip.-Gen. - DA		$ 632,107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 632,107
52	378	**Odorization Tank**													
53		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Commodity	COM	$ 207,194	$ 120,173	$ 45,049	$ 1,320	$ 9,914	$ 319	$ 1,432	$ 7,933	$ 6,322	$ 2,113	$ 4,972	$ 7,649
56		Total Odorization Tank		$ 207,194	$ 120,173	$ 45,049	$ 1,320	$ 9,914	$ 319	$ 1,432	$ 7,933	$ 6,322	$ 2,113	$ 4,972	$ 7,649
57	379	**Meas. & Reg. Station - City Gate**													
58		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59		Demand	DEM	$ 6,660,931	$ 4,546,231	$ 1,160,459	$ 22,454	$ 452,535	$ 16,653	$ 9,719	$ 104,192	$ 55,746	$ 42,130	$ 36,602	$ 214,210
60		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61		Total Meas. & Reg. Equip.-City Gate		$ 6,660,931	$ 4,546,231	$ 1,160,459	$ 22,454	$ 452,535	$ 16,653	$ 9,719	$ 104,192	$ 55,746	$ 42,130	$ 36,602	$ 214,210
62	379	**Odorization Tank**													
63		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65		Commodity	COM	$ 765,618	$ 444,059	$ 166,463	$ 4,878	$ 36,632	$ 1,178	$ 5,292	$ 29,313	$ 23,359	$ 7,807	$ 18,372	$ 28,265
66		Total Odorization Tank		$ 765,618	$ 444,059	$ 166,463	$ 4,878	$ 36,632	$ 1,178	$ 5,292	$ 29,313	$ 23,359	$ 7,807	$ 18,372	$ 28,265
67	380	**Services - Allocated**													
68		Customer	SERCUS-ALL	$ 191,939,948	$ 176,017,191	$ 14,675,429	$ 51,771	$ 1,084,355	$ 36,718	$ 13,369	$ 28,011	$ 19,098	$ 8,913	$ 5,093	$ -
69		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71		Total Services - Allocated		$ 191,939,948	$ 176,017,191	$ 14,675,429	$ 51,771	$ 1,084,355	$ 36,718	$ 13,369	$ 28,011	$ 19,098	$ 8,913	$ 5,093	$ -
72	380	**Services-Directly Assigned**													
73		Customer	CUS-DA	$ 916,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 916,397
74		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76		Total Services - Directly Assigned		$ 916,397	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 916,397
77	381	**Meters - Allocated**													
78		Customer	METCUS-ALL	$ 58,670,292	$ 50,706,813	$ 6,459,866	$ 62,112	$ 1,238,955	$ 67,297	$ 24,323	$ 50,759	$ 34,711	$ 16,199	$ 9,256	$ -
79		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Total Meters - Allocated		$ 58,670,292	$ 50,706,813	$ 6,459,866	$ 62,112	$ 1,238,955	$ 67,297	$ 24,323	$ 50,759	$ 34,711	$ 16,199	$ 9,256	$ -
82	381	**Meters-Directly Assigned**													
83		Customer	CUS-DA	$ 147,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,452
84		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86		Total Meters - Directly Assigned		$ 147,452	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 147,452
87	382	**Meter Installations**													
88		Customer	METCUS-ALL	$ 93,748	$ 81,023	$ 10,322	$ 99	$ 1,980	$ 108	$ 39	$ 81	$ 55	$ 26	$ 15	$ -
89		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		Total Meter Installations		$ 93,748	$ 81,023	$ 10,322	$ 99	$ 1,980	$ 108	$ 39	$ 81	$ 55	$ 26	$ 15	$ -
92	383	**House Regulators - Allocated**													
93		Customer	REGCUS-ALL	$ 15,318,721	$ 12,971,782	$ 1,914,208	$ 16,797	$ 360,998	$ 17,916	$ 7,404	$ 13,574	$ 9,255	$ 4,319	$ 2,468	$ -
94		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96		Total House Regulators - Allocated		$ 15,318,721	$ 12,971,782	$ 1,914,208	$ 16,797	$ 360,998	$ 17,916	$ 7,404	$ 13,574	$ 9,255	$ 4,319	$ 2,468	$ -
97	383	**House Regulators - Directly Assigned**													
98		Customer	CUS-DA	$ 92,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,302
99		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101		Total House Regulators - Dir. Assigned		$ 92,302	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 92,302
102	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**													
103		Customer	NRCUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104		Demand	NRDEM	$ 17,084,299	$ -	$ 9,375,148	$ 181,401	$ 3,655,951	$ 134,535	$ 78,519	$ 841,749	$ 450,365	$ 340,358	$ 295,704	$ 1,730,569
105		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106		Total Meas. & Reg. Sta. Equip.- Ind. - Alloc.		$ 17,084,299	$ -	$ 9,375,148	$ 181,401	$ 3,655,951	$ 134,535	$ 78,519	$ 841,749	$ 450,365	$ 340,358	$ 295,704	$ 1,730,569
107	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**													
108		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109		Demand	DEM-DA	$ 330,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,071
110		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111		Total Meas. & Reg. Sta. Equip.-Ind. - DA		$ 330,071	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 330,071
112	386	**Other Prop.-Customer Premises**													
113		Customer	CUS	$ 638,227	$ 598,543	$ 36,602	$ 86	$ 2,724	$ 89	$ 42	$ 46	$ 32	$ 15	$ 8	$ 40
114		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116		Total Other Prop.- Cust. Premises		$ 638,227	$ 598,543	$ 36,602	$ 86	$ 2,724	$ 89	$ 42	$ 46	$ 32	$ 15	$ 8	$ 40
117	387	**Other Equipment**													
118		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121		Total Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122		**Total Distribution Plant**													
123		Customer		$ 476,571,818	$ 433,689,139	$ 34,917,904	$ 158,521	$ 3,568,896	$ 150,751	$ 58,807	$ 107,465	$ 73,374	$ 34,241	$ 19,566	$ 3,793,153
124		Demand		$ 150,784,206	$ 88,696,307	$ 32,015,540	$ 619,473	$ 12,484,843	$ 459,427	$ 268,138	$ 2,874,519	$ 1,537,969	$ 1,162,301	$ 1,009,810	$ 9,655,878

Allocated Rate Base

125	Commodity		$ 972,813	$ 564,231	$ 211,512	$ 6,198	$ 46,546	$ 1,497	$ 6,725	$ 37,246	$ 29,681	$ 9,920	$ 23,344	$ 35,914
126	Total Distribution Plant		$ 628,328,837	$ 522,949,678	$ 67,144,956	$ 784,192	$ 16,100,284	$ 611,675	$ 333,669	$ 3,019,229	$ 1,641,024	$ 1,206,463	$ 1,052,720	$ 13,484,945
127	**General Plant**													
128	**General Plant - Allocated**													
129	Customer	GENPTCUS	$ 76,030,881	$ 70,120,801	$ 5,037,448	$ 18,642	$ 461,508	$ 18,106	$ 7,463	$ 12,028	$ 8,210	$ 3,831	$ 2,189	$ 340,653
130	Demand	DISPLTDEM	$ 13,453,285	$ 7,913,672	$ 2,856,494	$ 55,271	$ 1,113,924	$ 40,991	$ 23,924	$ 256,471	$ 137,221	$ 103,703	$ 90,097	$ 861,518
131	Commodity	COM	$ 112,565	$ 65,288	$ 24,474	$ 717	$ 5,386	$ 173	$ 778	$ 4,310	$ 3,434	$ 1,148	$ 2,701	$ 4,156
132	Total General Plant - Allocated		$ 89,596,731	$ 78,099,761	$ 7,918,417	$ 74,630	$ 1,580,818	$ 59,270	$ 32,165	$ 272,808	$ 148,865	$ 108,682	$ 94,988	$ 1,206,326
133	**Total General Plant - Directly Assigned**													
134	Customer	CUS-DA	$ 30,367	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,367
135	Demand	DEM-DA	$ 30,216	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,216
136	Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137	Total General Plant - Directly Assigned		$ 60,583	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60,583
138	**Total General Plant**													
139	Customer		$ 76,061,248	$ 70,120,801	$ 5,037,448	$ 18,642	$ 461,508	$ 18,106	$ 7,463	$ 12,028	$ 8,210	$ 3,831	$ 2,189	$ 371,020
140	Demand		$ 13,483,501	$ 7,913,672	$ 2,856,494	$ 55,271	$ 1,113,924	$ 40,991	$ 23,924	$ 256,471	$ 137,221	$ 103,703	$ 90,097	$ 891,734
141	Commodity		$ 112,565	$ 65,288	$ 24,474	$ 717	$ 5,386	$ 173	$ 778	$ 4,310	$ 3,434	$ 1,148	$ 2,701	$ 4,156
142	Total General Plant		$ 89,657,313	$ 78,099,761	$ 7,918,417	$ 74,630	$ 1,580,818	$ 59,270	$ 32,165	$ 272,808	$ 148,865	$ 108,682	$ 94,988	$ 1,266,909
143	**Total Plant in Service**													
144	Customer		$ 553,378,080	$ 504,508,632	$ 39,998,079	$ 177,264	$ 4,033,584	$ 168,960	$ 66,319	$ 119,547	$ 81,621	$ 38,090	$ 21,766	$ 4,164,219
145	Demand		$ 212,707,059	$ 129,670,891	$ 43,311,078	$ 838,032	$ 16,889,673	$ 621,520	$ 362,741	$ 3,888,690	$ 2,080,586	$ 1,572,378	$ 1,366,086	$ 12,105,385
146	Commodity		$ 1,188,653	$ 689,419	$ 258,440	$ 7,573	$ 56,873	$ 1,829	$ 8,217	$ 45,509	$ 36,266	$ 12,121	$ 28,523	$ 43,883
147	Total Plant in Service		$ 767,273,792	$ 634,868,941	$ 83,567,598	$ 1,022,869	$ 20,980,130	$ 792,309	$ 437,277	$ 4,053,746	$ 2,198,473	$ 1,622,589	$ 1,416,374	$ 16,313,487
148	**Depreciation & Amort. Reserve**													
149	**Intangible Plant**													
150	Customer	NONINCUS	$ (385,157)	$ (361,208)	$ (22,089)	$ (52)	$ (1,644)	$ (53)	$ (25)	$ (28)	$ (19)	$ (9)	$ (5)	$ (24)
151	Demand	NONINDEM	$ (100,039)	$ (68,279)	$ (17,429)	$ (337)	$ (6,796)	$ (250)	$ (146)	$ (1,565)	$ (837)	$ (633)	$ (550)	$ (3,217)
152	Commodity	COM	$ (1,088)	$ (631)	$ (236)	$ (7)	$ (52)	$ (2)	$ (8)	$ (42)	$ (33)	$ (11)	$ (26)	$ (40)
153	Total Intangible Plant		$ (486,283)	$ (430,118)	$ (39,754)	$ (396)	$ (8,493)	$ (305)	$ (179)	$ (1,634)	$ (890)	$ (653)	$ (581)	$ (3,282)
154	**Transmission Plant**													
155	Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
156	Demand	DEM	$ (3,240,665)	$ (2,211,824)	$ (564,585)	$ (10,924)	$ (220,166)	$ (8,102)	$ (4,729)	$ (50,691)	$ (27,122)	$ (20,497)	$ (17,808)	$ (104,217)
157	Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158	Total Transmission Plant		$ (3,240,665)	$ (2,211,824)	$ (564,585)	$ (10,924)	$ (220,166)	$ (8,102)	$ (4,729)	$ (50,691)	$ (27,122)	$ (20,497)	$ (17,808)	$ (104,217)
159	**Distribution Plant - Allocated**													
160	Customer	DISPLTCUS	$ (77,467,660)	$ (70,496,998)	$ (5,675,972)	$ (25,768)	$ (580,131)	$ (24,505)	$ (9,559)	$ (17,469)	$ (11,927)	$ (5,566)	$ (3,181)	$ (616,584)
161	Demand	DISPLTDEM	$ (20,121,060)	$ (11,835,879)	$ (4,272,242)	$ (82,664)	$ (1,666,012)	$ (61,307)	$ (35,781)	$ (383,584)	$ (205,231)	$ (155,101)	$ (134,752)	$ (1,288,507)
162	Commodity	COM	$ (218,771)	$ (126,887)	$ (47,566)	$ (1,394)	$ (10,467)	$ (337)	$ (1,512)	$ (8,376)	$ (6,675)	$ (2,231)	$ (5,250)	$ (8,077)
163	Total Distribution Plant - Allocated		$ (97,807,490)	$ (82,459,765)	$ (9,995,780)	$ (109,826)	$ (2,256,610)	$ (86,149)	$ (46,852)	$ (409,428)	$ (223,833)	$ (162,898)	$ (143,182)	$ (1,913,168)
164	**Distribution Plant - Dir. Assn.**													
165	Customer	CUS-DA	$ (603,828)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (603,828)
166	Demand	DEM-DA	$ (479,887)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (479,887)
167	Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168	Total Distribution Plant - Dir. Assn.		$ (1,083,716)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,083,716)
169	**General Plant - Allocated**													
170	Customer	GENPTCUS	$ (24,575,931)	$ (22,665,579)	$ (1,628,286)	$ (6,026)	$ (149,176)	$ (5,852)	$ (2,412)	$ (3,888)	$ (2,654)	$ (1,238)	$ (708)	$ (110,111)
171	Demand	DISPLTDEM	$ (3,435,034)	$ (2,020,602)	$ (729,350)	$ (14,112)	$ (284,419)	$ (10,466)	$ (6,108)	$ (65,485)	$ (35,037)	$ (26,479)	$ (23,005)	$ (219,972)
172	Commodity	COM	$ (29,546)	$ (17,137)	$ (6,424)	$ (188)	$ (1,414)	$ (45)	$ (204)	$ (1,131)	$ (901)	$ (301)	$ (709)	$ (1,091)
173	Total General Plant - Allocated		$ (28,040,510)	$ (24,703,317)	$ (2,364,060)	$ (20,326)	$ (435,008)	$ (16,364)	$ (8,725)	$ (70,504)	$ (38,592)	$ (28,018)	$ (24,421)	$ (331,174)
174	**General Plant - Directly Assigned**													
175	Customer	CUS-DA	$ (9,867)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,867)
176	Demand	DEM-DA	$ (9,818)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (9,818)
177	Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178	Total General Plant - Directly Assn.		$ (19,685)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,685)
179	**Total Depr. & Amort. Reserve**													
180	Customer		$ (103,042,442)	$ (93,523,785)	$ (7,326,346)	$ (31,846)	$ (730,951)	$ (30,411)	$ (11,997)	$ (21,384)	$ (14,600)	$ (6,813)	$ (3,893)	$ (1,340,415)
181	Demand		$ (27,386,502)	$ (16,136,584)	$ (5,583,605)	$ (108,038)	$ (2,177,394)	$ (80,125)	$ (46,764)	$ (501,325)	$ (268,226)	$ (202,709)	$ (176,114)	$ (2,105,618)
182	Commodity		$ (249,405)	$ (144,655)	$ (54,226)	$ (1,589)	$ (11,933)	$ (384)	$ (1,724)	$ (9,549)	$ (7,609)	$ (2,543)	$ (5,985)	$ (9,208)
183	Total Depr. & Amortization Reserve		$ (130,678,349)	$ (109,805,024)	$ (12,964,177)	$ (141,472)	$ (2,920,278)	$ (110,920)	$ (60,485)	$ (532,258)	$ (290,436)	$ (212,065)	$ (185,992)	$ (3,455,241)
184	**Net Plant in Service**													
185	Customer		$ 450,335,638	$ 410,984,846	$ 32,671,733	$ 145,418	$ 3,302,633	$ 138,549	$ 54,322	$ 98,162	$ 67,021	$ 31,277	$ 17,872	$ 2,823,804
186	Demand		$ 185,320,557	$ 113,534,307	$ 37,727,473	$ 729,994	$ 14,712,279	$ 541,394	$ 315,977	$ 3,387,365	$ 1,812,360	$ 1,369,669	$ 1,189,972	$ 9,999,766
187	Commodity		$ 939,248	$ 544,764	$ 204,214	$ 5,984	$ 44,940	$ 1,445	$ 6,493	$ 35,961	$ 28,656	$ 9,578	$ 22,538	$ 34,675
188	Total Net Plant in Service		$ 636,595,444	$ 525,063,917	$ 70,603,420	$ 881,396	$ 18,059,852	$ 681,389	$ 376,792	$ 3,521,488	$ 1,908,038	$ 1,410,523	$ 1,230,382	$ 12,858,245
189	**Customer Deposits**													
190	Customer	DEPCUS	$ (7,838,323)	$ (4,548,685)	$ (3,129,742)	$ (39,642)	$ (40,374)	$ (3,122)	$ (371)	$ (65,205)	$ -	$ -	$ (11,183)	$ -
191	Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
192	Commodity	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
193	Total Customer Deposits		$ (7,838,323)	$ (4,548,685)	$ (3,129,742)	$ (39,642)	$ (40,374)	$ (3,122)	$ (371)	$ (65,205)	$ -	$ -	$ (11,183)	$ -
194	**Customer Advances**													
195	Customer	MSCUS-ALL	$ (2,455,339)	$ (2,277,995)	$ (163,504)	$ (490)	$ (12,121)	$ (403)	$ (167)	$ (266)	$ (181)	$ (84)	$ (48)	$ (80)
196	Demand	DEM	$ (677,127)	$ (462,154)	$ (117,968)	$ (2,283)	$ (46,003)	$ (1,693)	$ (988)	$ (10,592)	$ (5,667)	$ (4,283)	$ (3,721)	$ (21,776)
197	Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
198	Total Customer Advances		$ (3,132,466)	$ (2,740,149)	$ (281,472)	$ (2,773)	$ (58,124)	$ (2,096)	$ (1,155)	$ (10,857)	$ (5,848)	$ (4,367)	$ (3,769)	$ (21,856)
199	**Accum. Deferred Income Taxes**													
200	Customer	TPLTCUS	$ (36,373,513)	$ (33,161,326)	$ (2,629,072)	$ (11,652)	$ (265,127)	$ (11,106)	$ (4,359)	$ (7,858)	$ (5,365)	$ (2,504)	$ (1,431)	$ (273,714)
201	Demand	TPLTDEM	$ (13,981,224)	$ (8,523,261)	$ (2,846,835)	$ (55,084)	$ (1,110,157)	$ (40,852)	$ (23,843)	$ (255,603)	$ (136,757)	$ (103,352)	$ (89,793)	$ (795,686)
202	Commodity	COM	$ (78,130)	$ (45,315)	$ (16,987)	$ (498)	$ (3,738)	$ (120)	$ (540)	$ (2,991)	$ (2,384)	$ (797)	$ (1,875)	$ (2,884)
203	Total Accum. Deferred Inc. Taxes		$ (50,432,867)	$ (41,729,903)	$ (5,492,894)	$ (67,233)	$ (1,379,023)	$ (52,078)	$ (28,742)	$ (266,453)	$ (144,506)	$ (106,653)	$ (93,098)	$ (1,072,285)
204	**Excess Deferred Income Taxes**													
205	Customer	TPLTCUS	$ (10,725,535)	$ (9,778,351)	$ (775,240)	$ (3,436)	$ (78,179)	$ (3,275)	$ (1,285)	$ (2,317)	$ (1,582)	$ (738)	$ (422)	$ (80,711)
206	Demand	TPLTDEM	$ (4,122,673)	$ (2,513,272)	$ (839,452)	$ (16,243)	$ (327,354)	$ (12,046)	$ (7,031)	$ (75,370)	$ (40,326)	$ (30,476)	$ (26,477)	$ (234,626)
207	Commodity	COM	$ (23,038)	$ (13,362)	$ (5,009)	$ (147)	$ (1,102)	$ (35)	$ (159)	$ (882)	$ (703)	$ (235)	$ (553)	$ (851)
208	**Total Excess Deferred Income Taxes**		$ (14,871,247)	$ (12,304,985)	$ (1,619,701)	$ (19,825)	$ (406,635)	$ (15,356)	$ (8,475)	$ (78,569)	$ (42,611)	$ (31,449)	$ (27,452)	$ (316,187)
209	**Materials and Supplies**													
210	Customer	TPLTCUS	$ 4,093,374	$ 3,731,884	$ 295,868	$ 1,311	$ 29,837	$ 1,250	$ 491	$ 884	$ 604	$ 282	$ 161	$ 30,803
211	Demand	TPLTDEM	$ 1,573,408	$ 959,184	$ 320,375	$ 6,199	$ 124,934	$ 4,597	$ 2,683	$ 28,765	$ 15,390	$ 11,631	$ 10,105	$ 89,544
212	Commodity	COM	$ 8,793	$ 5,100	$ 1,912	$ 56	$ 421	$ 14	$ 61	$ 337	$ 268	$ 90	$ 211	$ 325
213	Total Materials and Supplies		$ 5,675,575	$ 4,696,168	$ 618,155	$ 7,566	$ 155,191	$ 5,861	$ 3,235	$ 29,986	$ 16,262	$ 12,002	$ 10,477	$ 120,672
214	**Prepayments**													
215	Customer	OPEXPCUS	$ 2,688,427	$ 2,440,815	$ 206,313	$ 1,090	$ 23,012	$ 1,045	$ 413	$ 748	$ 511	$ 239	$ 136	$ 14,105
216	Demand	OPEXPDEM	$ 560,256	$ 344,102	$ 113,011	$ 2,187	$ 44,070	$ 1,622	$ 946	$ 10,147	$ 5,429	$ 4,103	$ 3,564	$ 31,076
217	Commodity	COM	$ 43,458	$ 25,205	$ 9,449	$ 277	$ 2,079	$ 67	$ 300	$ 1,664	$ 1,326	$ 443	$ 1,043	$ 1,604
218	Total Prepayments		$ 3,292,141	$ 2,810,123	$ 328,772	$ 3,554	$ 69,161	$ 2,733	$ 1,659	$ 12,559	$ 7,266	$ 4,785	$ 4,744	$ 46,785
219	**Pension & FAS 106 Reg. Asset**													
220	Customer	OPEXPCUS	$ 16,341,006	$ 14,835,952	$ 1,254,026	$ 6,627	$ 139,873	$ 6,349	$ 2,508	$ 4,547	$ 3,108	$ 1,450	$ 829	$ 85,736
221	Demand	OPEXPDEM	$ 3,405,391	$ 2,091,550	$ 686,909	$ 13,291	$ 267,869	$ 9,857	$ 5,753	$ 61,674	$ 32,998	$ 24,938	$ 21,666	$ 188,886
222	Commodity	COM	$ 264,148	$ 153,206	$ 57,432	$ 1,683	$ 12,639	$ 406	$ 1,826	$ 10,113	$ 8,059	$ 2,694	$ 6,339	$ 9,752
223	Total Pen. & FAS 106 Reg. Asset		$ 20,010,546	$ 17,080,708	$ 1,998,367	$ 21,601	$ 420,380	$ 16,613	$ 10,087	$ 76,335	$ 44,165	$ 29,082	$ 28,833	$ 284,374
224	**DIMP Deferrals**													
225	Customer	TPLTCUS	$ 1,505,782	$ 1,372,805	$ 108,838	$ 482	$ 10,976	$ 460	$ 180	$ 325	$ 222	$ 104	$ 59	$ 11,331
226	Demand	TPLTDEM	$ 313,798	$ 191,298	$ 63,895	$ 1,236	$ 24,917	$ 917	$ 535	$ 5,737	$ 3,069	$ 2,320	$ 2,015	$ 17,859
227	Commodity	COM	$ 24,341	$ 14,118	$ 5,292	$ 155	$ 1,165	$ 37	$ 168	$ 932	$ 743	$ 248	$ 584	$ 899
228	Total DIMP Deferrals		$ 1,843,921	$ 1,578,221	$ 178,025	$ 1,874	$ 37,057	$ 1,414	$ 884	$ 6,994	$ 4,034	$ 2,672	$ 2,659	$ 30,088
229	**Regulatory Asset**													
230	Customer	TPLTCUS	$ 1,460,700	$ 1,331,704	$ 105,579	$ 468	$ 10,647	$ 446	$ 175	$ 316	$ 215	$ 101	$ 57	$ 10,992
231	Demand	TPLTDEM	$ 304,403	$ 185,571	$ 61,982	$ 1,199	$ 24,171	$ 889	$ 519	$ 5,565	$ 2,978	$ 2,250	$ 1,955	$ 17,324
232	Commodity	COM	$ 23,612	$ 13,695	$ 5,134	$ 150	$ 1,130	$ 36	$ 163	$ 904	$ 720	$ 241	$ 567	$ 872
233	**Total Regulatory Asset**		$ 1,788,715	$ 1,530,969	$ 172,695	$ 1,818	$ 35,947	$ 1,372	$ 857	$ 6,785	$ 3,913	$ 2,592	$ 2,579	$ 29,188
234	**Cash Working Capital**													
235	Customer	OPEXPCUS	$ (2,887,145)	$ (2,621,231)	$ (221,563)	$ (1,171)	$ (24,713)	$ (1,122)	$ (443)	$ (803)	$ (549)	$ (256)	$ (146)	$ (15,148)
236	Demand	OPEXPDEM	$ (601,668)	$ (369,537)	$ (121,364)	$ (2,348)	$ (47,327)	$ (1,742)	$ (1,016)	$ (10,897)	$ (5,830)	$ (4,406)	$ (3,828)	$ (33,373)
237	Commodity	COM	$ (46,670)	$ (27,069)	$ (10,147)	$ (297)	$ (2,233)	$ (72)	$ (323)	$ (1,787)	$ (1,424)	$ (476)	$ (1,120)	$ (1,723)
238	Total Cash Working Capital		$ (3,535,483)	$ (3,017,836)	$ (353,074)	$ (3,816)	$ (74,273)	$ (2,935)	$ (1,782)	$ (13,487)	$ (7,803)	$ (5,138)	$ (5,094)	$ (50,243)
239	**Total Rate Base**													
240	Customer		$ 416,145,073	$ 382,310,419	$ 27,723,237	$ 99,006	$ 3,096,465	$ 129,071	$ 51,464	$ 28,534	$ 64,005	$ 29,869	$ 5,885	$ 2,607,119
241	Demand		$ 172,095,122	$ 105,437,789	$ 35,048,026	$ 678,149	$ 13,667,397	$ 502,944	$ 293,536	$ 3,146,791	$ 1,683,644	$ 1,272,393	$ 1,105,459	$ 9,258,995
242	Commodity		$ 1,155,761	$ 670,341	$ 251,289	$ 7,364	$ 55,299	$ 1,778	$ 7,989	$ 44,250	$ 35,262	$ 11,786	$ 27,734	$ 42,668
243	Total Rate Base		$ 589,395,955	$ 488,418,549	$ 63,022,552	$ 784,518	$ 16,819,161	$ 633,793	$ 352,989	$ 3,219,575	$ 1,782,911	$ 1,314,048	$ 1,139,078	$ 11,908,782

Allocated Cost of Service

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: ALLOCATED COST OF SERVICE

LINE NO.	ACCT.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1		**Transmission and Distribution Op. Exp.**													
2	814-866	**Transmission Expenses**													
3		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
4		Demand	DEM	1,708,777	1,166,277	297,701	5,760	116,092	4,272	2,493	26,729	14,301	10,808	9,390	54,953
5		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
6		Total Transmission Expense		1,708,777	1,166,277	297,701	5,760	116,092	4,272	2,493	26,729	14,301	10,808	9,390	54,953
7	8700	**Operation Supervision & Engineering**													
8		Customer	871-879CUS	764,375	679,476	71,583	531	11,102	556	211	415	283	132	76	11
9		Demand	DEM	135,275	92,328	23,567	456	9,190	338	197	2,116	1,132	856	743	4,350
10		Commodity	COM	22,102	12,819	4,806	141	1,058	34	153	846	674	225	530	816
11		Total Supervision & Engineering		921,752	784,623	99,956	1,128	21,350	928	561	3,377	2,090	1,213	1,349	5,177
12	8710	**Distribution Load Dispatch**													
13		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
14		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
15		Commodity	COM	228,149	132,326	49,605	1,454	10,916	351	1,577	8,735	6,961	2,327	5,475	8,423
16		Total Distribution Load Dispatch		228,149	132,326	49,605	1,454	10,916	351	1,577	8,735	6,961	2,327	5,475	8,423
17	8740	**Mains & Services - Allocated**													
18		Customer	MSCUS-ALL	3,379,375	3,135,289	225,037	675	16,682	555	229	365	249	116	66	110
19		Demand	DEM	916,602	625,601	159,689	3,090	62,273	2,292	1,337	14,338	7,671	5,797	5,037	29,477
20		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
21		Total Mains & Services - Allocated		4,295,976	3,760,890	384,726	3,765	78,955	2,847	1,567	14,703	7,920	5,914	5,103	29,587
22	8740	**Mains & Services - Dir. Assn.**													
23		Customer	MSCUS-DA	29,955	-	-	-	-	-	-	-	-	-	-	29,955
24		Demand	DEM-DA	23,620	-	-	-	-	-	-	-	-	-	-	23,620
25		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
26		Total Mains & Services - Dir. Assn.		53,575	-	-	-	-	-	-	-	-	-	-	53,575
27	8740	**Odorization**													
28		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
29		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
30		Commodity	COM	1,545	896	336	10	74	2	11	59	47	16	37	57
31		Total Odorization		1,545	896	336	10	74	2	11	59	47	16	37	57
32	8750	**Meas. & Reg. Station - Gen. - Allocated**													
33		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
34		Demand	DEM	347,458	237,148	60,534	1,171	23,606	869	507	5,435	2,908	2,198	1,909	11,174
35		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
36		Total Meas. & Reg. Station - Gen. - Allocated		347,458	237,148	60,534	1,171	23,606	869	507	5,435	2,908	2,198	1,909	11,174
37		**Meas. & Reg. Station - Gen. - DA**													
38	8750	Customer	CUS-DA	-	-	-	-	-	-	-	-	-	-	-	-
39		Demand	DEM-DA	17,235	-	-	-	-	-	-	-	-	-	-	17,235
40		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
41		Total Meas. & Reg. Station - Gen. - DA		17,235	-	-	-	-	-	-	-	-	-	-	17,235
42	8750	**Odorization**													
43		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
44		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
45		Commodity	COM	58,281	33,803	12,672	371	2,789	90	403	2,231	1,778	594	1,399	2,152
46		Total Odorization		58,281	33,803	12,672	371	2,789	90	403	2,231	1,778	594	1,399	2,152
47	8760	**Meas. & Reg. Stat. - Ind. - Allocated**													
48		Customer	NRCUS	-	-	-	-	-	-	-	-	-	-	-	-
49		Demand	NRDEM	27,483	-	15,082	292	5,881	216	126	1,354	724	548	476	2,784
50		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
51		Total Meas. & Reg. Stat. - Ind. - Allocated		27,483	-	15,082	292	5,881	216	126	1,354	724	548	476	2,784
52	8760	**Meas. & Reg. Stat. - Ind. - DA**													
53		Customer	CUS-DA	-	-	-	-	-	-	-	-	-	-	-	-
54		Demand	DEM-DA	531	-	-	-	-	-	-	-	-	-	-	531
55		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
56		Total Meas. & Reg. Stat. - Ind. - DA		531	-	-	-	-	-	-	-	-	-	-	531
57	8770	**Meas. & Reg. Stat.- City Gate**													
58		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
59		Demand	DEM	63,441	43,300	11,053	214	4,310	159	93	992	531	401	349	2,040
60		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
61		Total Meas. & Reg. Stat. - City Gate		63,441	43,300	11,053	214	4,310	159	93	992	531	401	349	2,040
62	8780	**Meter & House Reg. Exp. - Alloc.**													
63		Customer	MTRGCUS-ALL	4,331,875	3,722,803	494,891	4,632	94,433	4,996	1,879	3,773	2,578	1,203	687	-
64		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
65		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
66		Total Meter & House Reg. Exp. - Alloc.		4,331,875	3,722,803	494,891	4,632	94,433	4,996	1,879	3,773	2,578	1,203	687	-
67	8780	**Meter & House Reg. Exp - Dir. Assn.**													
68		Customer	CUS-DA	14,037	-	-	-	-	-	-	-	-	-	-	14,037
69		Demand	DEM-DA	-	-	-	-	-	-	-	-	-	-	-	-
70		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
71		Total Meter & House Reg. Exp. - DA		14,037	-	-	-	-	-	-	-	-	-	-	14,037
72	8780	**Odorization**													
73		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
74		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
75		Commodity	COM	56	32	12	0	3	0	0	2	2	1	1	2
76		Total Odorization		56	32	12	0	3	0	0	2	2	1	1	2
77	8790	**Customer Installation Expense**													
78		Customer	METCUS-ALL	134,987	116,665	14,863	143	2,851	155	56	117	80	37	21	-
79		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
80		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
81		Total Customer Install. Expense		134,987	116,665	14,863	143	2,851	155	56	117	80	37	21	-
82	8800	**Other Expenses**													
83		Customer	871-879CUS	713,485	634,238	66,817	496	10,363	519	197	387	264	123	70	10
84		Demand	DEM	126,269	86,181	21,998	426	8,579	316	184	1,975	1,057	799	694	4,061
85		Commodity	COM	20,631	11,966	4,486	131	987	32	143	790	629	210	495	762
86		Total Other Expenses		860,384	732,385	93,301	1,053	19,929	866	524	3,152	1,951	1,132	1,259	4,832
87	8810	**Rents**													
88		Customer	871-879CUS	50,647	45,022	4,743	35	736	37	14	27	19	9	5	1
89		Demand	DEM	8,963	6,118	1,562	30	609	22	13	140	75	57	49	288
90		Commodity	COM	1,464	849	318	9	70	2	10	56	45	15	35	54
91		Total Rents		61,075	51,989	6,623	75	1,415	61	37	224	138	80	89	343
92	8820	**Corporate & Div. Exp.**													
93		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
94		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
95		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
96		Total Corporate & Div. Exp.		-	-	-	-	-	-	-	-	-	-	-	-
97		**Total Distr. & Trans. Op. Expense**													
98		Customer		9,418,736	8,333,492	877,934	6,511	136,166	6,817	2,586	5,084	3,473	1,621	926	44,124
99		Demand		3,375,653	2,256,952	591,185	11,439	230,540	8,484	4,951	53,080	28,399	21,463	18,647	150,513
100		Commodity		332,228	192,692	72,234	2,117	15,896	511	2,297	12,720	10,136	3,388	7,972	12,265
101		Total Distr. & Trans. Operations Exp.		13,126,616	10,783,136	1,541,353	20,067	382,602	15,812	9,834	70,884	42,009	26,471	27,545	206,903
102		**Distribution Maintenance Expenses**													
103	8850	**Maintenance Supervision and Engineering**													
104		Customer	887-893CUS	14,988	13,950	957	3	71	2	1	1	1	0	0	1
105		Demand	887-893DEM	9,625	5,297	2,375	46	926	34	20	213	114	86	75	438
106		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
107		Total Supervision and Engineering		24,613	19,247	3,332	49	997	36	21	215	115	87	75	439
108	8860	**Structures and Improvements**													
109		Customer	887-893CUS	307,020	285,751	19,611	55	1,455	48	21	30	20	10	5	13
110		Demand	887-893DEM	197,163	108,511	48,648	941	18,971	698	407	4,368	2,337	1,766	1,534	8,980
111		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
112		Total Structures and Improvements		504,182	394,262	68,260	997	20,426	746	428	4,398	2,357	1,776	1,540	8,993
113	8870	**Maintenance of Mains-Allocated**													
114		Customer	CUS	2,093,133	1,962,984	120,040	281	8,935	291	138	152	104	48	28	132
115		Demand	DEM	1,099,479	750,418	191,550	3,706	74,697	2,749	1,604	17,198	9,202	6,954	6,042	35,358
116		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
117		Total Mains - Allocated		3,192,611	2,713,402	311,590	3,987	83,632	3,039	1,743	17,351	9,306	7,003	6,069	35,490
118	8870	**Maintenance of Mains - Directly Assigned**													
119		Customer	CUS-DA	26,559	-	-	-	-	-	-	-	-	-	-	26,559
120		Demand	DEM-DA	28,322	-	-	-	-	-	-	-	-	-	-	28,322
121		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
122		Total Mains - Directly Assigned		54,881	-	-	-	-	-	-	-	-	-	-	54,881
123	8890	**Maint. of Meas. & Reg. Sta. Equip.- Gen. - Alloc.**													
124		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
125		Demand	DEM	506,952	346,006	88,321	1,709	34,442	1,267	740	7,930	4,243	3,206	2,786	16,303
126		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
127		Total Meas. & Reg. Sta. Equip. - Gen. - Alloc.		506,952	346,006	88,321	1,709	34,442	1,267	740	7,930	4,243	3,206	2,786	16,303
128	8890	**Maint. of Meas. & Reg. Sta. Equip.-Gen. - DA**													
129		Customer	CUS-DA	-	-	-	-	-	-	-	-	-	-	-	-
130		Demand	DEM-DA	25,946	-	-	-	-	-	-	-	-	-	-	25,946
131		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
132		Total Meas. & Reg. Sta. Equip.-Gen. - DA		25,946	-	-	-	-	-	-	-	-	-	-	25,946
133	8890	**Odorization**													
134		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
135		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
136		Commodity	COM	103,847	60,231	22,579	662	4,969	160	718	3,976	3,168	1,059	2,492	3,834
137		Total Odorization		103,847	60,231	22,579	662	4,969	160	718	3,976	3,168	1,059	2,492	3,834
138	8900	**Meas. & Reg. Sta. Equip. - Ind. - Alloc.**													
139		Customer	NRCUS	-	-	-	-	-	-	-	-	-	-	-	-
140		Demand	NRDEM	387,292	-	212,529	4,112	82,878	3,050	1,780	19,082	10,210	7,716	6,703	39,231

Allocated Cost of Service

Line	Acct	Description	Allocator												
141		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142		Total Meas. & Reg. Sta. Eq.- Ind. - Alloc.		$ 387,292	$ -	$ 212,529	$ 4,112	$ 82,878	$ 3,050	$ 1,780	$ 19,082	$ 10,210	$ 7,716	$ 6,703	$ 39,231
143	8900	**Meas. & Reg. Sta. Equip. - Ind. - DA**													
144		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
145		Demand	DEM-DA	$ 7,483	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,483
146		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147		Total Meas. & Reg. Sta. Eq.-Ind. - DA		$ 7,483	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,483
148	8910	**Meas. & Reg. Sta. Eq.- City Gate**													
149		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
150		Demand	DEM	$ 6,436	$ 4,393	$ 1,121	$ 22	$ 437	$ 16	$ 9	$ 101	$ 54	$ 41	$ 35	$ 207
151		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Total Meas. & Reg. Sta. Eq.- City Gate		$ 6,436	$ 4,393	$ 1,121	$ 22	$ 437	$ 16	$ 9	$ 101	$ 54	$ 41	$ 35	$ 207
153	8920	**Services - Allocated**													
154		Customer	SERCUS-ALL	$ 1,085,912	$ 995,828	$ 83,027	$ 293	$ 6,135	$ 208	$ 76	$ 158	$ 108	$ 50	$ 29	$ -
155		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
156		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157		Total Services - Allocated		$ 1,085,912	$ 995,828	$ 83,027	$ 293	$ 6,135	$ 208	$ 76	$ 158	$ 108	$ 50	$ 29	$ -
158	8920	**Services - Directly Assigned**													
159		Customer	CUS-DA	$ 5,185	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,185
160		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
161		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
162		Total Services - Directly Assigned		$ 5,185	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,185
163	8930	**Meters & House Regulators - Alloc.**													
164		Customer	MTRGCUS-ALL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
165		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
166		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167		Total Meters & House Regulators - Alloc.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168	8930	**Meters & House Regulators - DA**													
169		Customer	CUS-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
170		Demand	DEM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
171		Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172		Total Meters & House Regulators - DA		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173	8940	**Maintenance of Other Equipment**													
174		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
176		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177		Total Maintenance of Other Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178	8950	**Clearing - Meter Shop - Small Meters**													
179		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
180		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
181		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
182		Total Clearing-Meter-Shop-Small Meters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183	8960	**Clearing - Meter Shop - Large Meters**													
184		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
185		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
186		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
187		Total Clearing-Meter Shop-Large Meters		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
188		**Total Distr. Maintenance Expense**													
189		Customer		$ 3,532,796	$ 3,258,513	$ 223,636	$ 632	$ 16,596	$ 549	$ 236	$ 342	$ 233	$ 109	$ 62	$ 31,889
190		Demand		$ 2,268,696	$ 1,214,625	$ 544,544	$ 10,536	$ 212,351	$ 7,814	$ 4,561	$ 48,892	$ 26,159	$ 19,769	$ 17,176	$ 162,268
191		Commodity		$ 103,847	$ 60,231	$ 22,579	$ 662	$ 4,969	$ 160	$ 718	$ 3,976	$ 3,168	$ 1,059	$ 2,492	$ 3,834
192		Total Distr. Maintenance Expense		$ 5,905,339	$ 4,533,369	$ 790,759	$ 11,830	$ 233,916	$ 8,523	$ 5,514	$ 53,210	$ 29,561	$ 20,937	$ 19,730	$ 197,991
193		**Total Oper. & Maint. Expense**													
194		Customer		$ 12,951,532	$ 11,592,005	$ 1,101,570	$ 7,143	$ 152,762	$ 7,366	$ 2,822	$ 5,426	$ 3,707	$ 1,730	$ 988	$ 76,013
195		Demand		$ 5,644,349	$ 3,471,577	$ 1,135,729	$ 21,975	$ 442,891	$ 16,298	$ 9,512	$ 101,972	$ 54,558	$ 41,232	$ 35,822	$ 312,782
196		Commodity		$ 436,075	$ 252,923	$ 94,813	$ 2,778	$ 20,865	$ 671	$ 3,014	$ 16,696	$ 13,305	$ 4,447	$ 10,464	$ 16,099
197		Total Operations & Maint. Expense		$ 19,031,955	$ 15,316,505	$ 2,332,112	$ 31,897	$ 616,518	$ 24,335	$ 15,348	$ 124,094	$ 71,570	$ 47,408	$ 47,275	$ 404,894
198		**Customer Accounts Expense**													
199	901	**Supervision**													
200		Customer	902-904CUS	$ 115,800	$ 106,879	$ 8,282	$ 38	$ 523	$ 24	$ 12	$ 15	$ 10	$ 5	$ 3	$ 11
201		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
202		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
203		Total Supervision		$ 115,800	$ 106,879	$ 8,282	$ 38	$ 523	$ 24	$ 12	$ 15	$ 10	$ 5	$ 3	$ 11
204	902	**Meter Reading Expense**													
205		Customer	METCUS-TOT	$ 616,390	$ 532,412	$ 67,827	$ 652	$ 13,009	$ 707	$ 255	$ 533	$ 364	$ 170	$ 97	$ 363
206		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
207		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
208		Total Meter Reading Expense		$ 616,390	$ 532,412	$ 67,827	$ 652	$ 13,009	$ 707	$ 255	$ 533	$ 364	$ 170	$ 97	$ 363
209	903	**Customer Accounting**													
210		Customer	903CUS	$ 3,123,314	$ 2,965,743	$ 150,563	$ 268	$ 6,188	$ 100	$ 228	$ 69	$ 52	$ 24	$ 14	$ 66
211		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
212		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
213		Total Customer Accounting		$ 3,123,314	$ 2,965,743	$ 150,563	$ 268	$ 6,188	$ 100	$ 228	$ 69	$ 52	$ 24	$ 14	$ 66
214	904	**Bad Debt Expense**													
215		Customer	904CUS	$ 972,692	$ 851,205	$ 118,618	$ 626	$ 2,079	$ 163	$ -	$ -	$ -	$ -	$ -	$ -
216		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
217		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
218		Total Bad Debt Expense		$ 972,692	$ 851,205	$ 118,618	$ 626	$ 2,079	$ 163	$ -	$ -	$ -	$ -	$ -	$ -
219	905	**Miscellaneous Customer Accounts**													
220		Customer	902-904CUS	$ 417,099	$ 384,967	$ 29,829	$ 137	$ 1,883	$ 86	$ 43	$ 53	$ 37	$ 17	$ 10	$ 38
221		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
222		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
223		Total Misc. Customer Accounts		$ 417,099	$ 384,967	$ 29,829	$ 137	$ 1,883	$ 86	$ 43	$ 53	$ 37	$ 17	$ 10	$ 38
224	907-910	**Customer Information Expense**													
225		Customer	CUS	$ 719,083	$ 674,371	$ 41,239	$ 96	$ 3,069	$ 100	$ 48	$ 52	$ 36	$ 17	$ 10	$ 45
226		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
227		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
228		Total Customer Information Expense		$ 719,083	$ 674,371	$ 41,239	$ 96	$ 3,069	$ 100	$ 48	$ 52	$ 36	$ 17	$ 10	$ 45
229		**Sales and Advertising Expense**													
230	911	**Supervision**													
231		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
233		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
234		Total Supervision Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
235	912	**Demonstrating and Selling**													
236		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
237		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
238		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
239		Total Demon. and Selling Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240	913	**Advertising**													
241		Customer	CUS	$ 4,501	$ 4,221	$ 258	$ 1	$ 19	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
242		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
243		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
244		Total Advertising		$ 4,501	$ 4,221	$ 258	$ 1	$ 19	$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
245	914	**Employee Sales Referrals**													
246		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
247		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
248		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249		Total Employee Sales Referrals		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250	916	**Misc. Gas Sales Expense**													
251		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
253		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254		Total Misc. Gas Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
255		**Administrative & General Exp.**													
256	920-940	**Administrative & General Expenses**													
257		Customer	OPEXPCUS	$ 22,571,459	$ 20,492,563	$ 1,732,158	$ 9,153	$ 193,204	$ 8,770	$ 3,464	$ 6,281	$ 4,293	$ 2,003	$ 1,145	$ 118,425
258		Demand	OPEXPDEM	$ 3,002,368	$ 1,844,018	$ 605,615	$ 11,718	$ 236,167	$ 8,691	$ 5,072	$ 54,375	$ 29,093	$ 21,986	$ 19,102	$ 166,532
259		Commodity	COM	$ 234,631	$ 136,086	$ 51,014	$ 1,495	$ 11,226	$ 361	$ 1,622	$ 8,983	$ 7,159	$ 2,393	$ 5,630	$ 8,662
260		Total Administrative & General Exp.		$ 25,808,458	$ 22,472,666	$ 2,388,787	$ 22,366	$ 440,597	$ 17,822	$ 10,158	$ 69,640	$ 40,544	$ 26,382	$ 25,877	$ 293,619
261		**Depreciation & Amortization Expense**													
262	301-303	**Intangible Plant**													
263		Customer	CUS	$ 12,130	$ 11,376	$ 696	$ 2	$ 52	$ 2	$ 1	$ 1	$ 1	$ 0	$ 0	$ 1
264		Demand	DEM	$ 4,662	$ 3,182	$ 812	$ 16	$ 317	$ 12	$ 7	$ 73	$ 39	$ 29	$ 26	$ 150
265		Commodity	COM	$ 26	$ 15	$ 6	$ 0	$ 1	$ 0	$ 0	$ 1	$ 1	$ 0	$ 1	$ 1
266		Total Intangible Plant		$ 16,818	$ 14,573	$ 1,514	$ 18	$ 370	$ 13	$ 8	$ 75	$ 40	$ 30	$ 26	$ 152
267	365	**Land and Land Rights**													
268		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
269		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271		Total Land and Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
272	366	**Meas. and Reg. Station Structures**													
273		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
275		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276		Total Measuring and Reg. Stat. Struct.		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
277	367	**Transmission Mains**													
278		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
279		Demand	DEM	$ 1,142,945	$ 780,085	$ 199,122	$ 3,853	$ 77,650	$ 2,857	$ 1,668	$ 17,878	$ 9,565	$ 7,229	$ 6,281	$ 36,756
280		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
281		Total Transmission Mains		$ 1,142,945	$ 780,085	$ 199,122	$ 3,853	$ 77,650	$ 2,857	$ 1,668	$ 17,878	$ 9,565	$ 7,229	$ 6,281	$ 36,756
282	368	**Compression Station Equipment**													
283		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
284		Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
285		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
286		Total Compression Sta. Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
287	369	**Meas. & Reg. Station Equipment**													
288		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
289		Demand	DEM	$ 107,007	$ 73,034	$ 18,643	$ 361	$ 7,270	$ 268	$ 156	$ 1,674	$ 896	$ 677	$ 588	$ 3,441
290		Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
291		Total Meas. & Reg. Stat. Equipment		$ 107,007	$ 73,034	$ 18,643	$ 361	$ 7,270	$ 268	$ 156	$ 1,674	$ 896	$ 677	$ 588	$ 3,441
292	371	**Other Equipment**													
293		Customer	CUS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Allocated Cost of Service

294		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
295		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
296		Total Other Equipment		-	-	-	-	-	-	-	-	-	-	-	-
297	375	**Structures and Improvements**													
298		Customer	376-379CUS	6,532	6,049	370	1	28	1	0	0	0	0	0	82
299		Demand	DEM	4,118	2,810	717	14	280	10	6	64	34	26	23	132
300		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
301		Total Structures and Improvements		10,650	8,860	1,087	15	307	11	6	65	35	26	23	215
302	376	**Distribution Mains - Allocated**													
303		Customer	CUS	5,446,123	5,107,489	312,332	731	23,247	756	360	396	270	126	72	344
304		Demand	DEM	2,860,734	1,952,513	498,393	9,643	194,354	7,152	4,174	44,748	23,942	18,094	15,720	91,999
305		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
306		Total Distribution Mains - Allocated		8,306,857	7,060,002	810,725	10,374	217,602	7,908	4,534	45,144	24,212	18,220	15,792	92,343
307	376	**Distribution Mains - Directly Assigned**													
308		Customer	CUS-DA	62,363	-	-	-	-	-	-	-	-	-	-	62,363
309		Demand	DEM-DA	66,503	-	-	-	-	-	-	-	-	-	-	66,503
310		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
311		Distribution Mains - Directly Assigned		128,866	-	-	-	-	-	-	-	-	-	-	128,866
312	377	**Compressor Station Equipment**													
313		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
314		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
315		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
316		Total Compressor Station Equipment		-	-	-	-	-	-	-	-	-	-	-	-
317	378	**Meas. & Reg. Sta. Equip. - Gen. - Alloc.**													
318		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
319		Demand	DEM	333,435	227,577	58,091	1,124	22,653	834	487	5,216	2,791	2,109	1,832	10,723
320		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
321		Total Meas. & Reg. Sta. Eq.- Gen. - Alloc		333,435	227,577	58,091	1,124	22,653	834	487	5,216	2,791	2,109	1,832	10,723
322	378	**Meas. & Reg. Sta. Equip. - Gen. - DA**													
323		Customer	CUS-DA	-	-	-	-	-	-	-	-	-	-	-	-
324		Demand	DEM-DA	14,159	-	-	-	-	-	-	-	-	-	-	14,159
325		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
326		Total Meas. & Reg. Sta. Eq. - Gen. - DA		14,159	-	-	-	-	-	-	-	-	-	-	14,159
327	378	**Odorization Tank**													
328		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
329		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
330		Commodity	COM	4,641	2,692	1,009	30	222	7	32	178	142	47	111	171
331		Total Odorization Tank		4,641	2,692	1,009	30	222	7	32	178	142	47	111	171
332	379	**Meas.& Reg. Sta. Equip.- City Gate**													
333		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
334		Demand	DEM	135,900	92,755	23,676	458	9,233	340	198	2,126	1,137	860	747	4,370
335		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
336		Total Meas. & Reg. Sta. Eq.- City Gate		135,900	92,755	23,676	458	9,233	340	198	2,126	1,137	860	747	4,370
337	379	**Odorization Tank**													
338		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
339		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
340		Commodity	COM	15,619	9,059	3,396	100	747	24	108	598	477	159	375	577
341		Total Odorization Tank		15,619	9,059	3,396	100	747	24	108	598	477	159	375	577
342	380	**Services - Allocated**													
343		Customer	SERCUS-ALL	6,216,101	5,700,432	475,273	1,677	35,118	1,189	433	907	619	289	165	-
344		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
345		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
346		Total Services - Allocated		6,216,101	5,700,432	475,273	1,677	35,118	1,189	433	907	619	289	165	-
347	380	**Services - Directly Assigned**													
348		Customer	CUS-DA	29,508	-	-	-	-	-	-	-	-	-	-	29,508
349		Demand	DEM-DA	-	-	-	-	-	-	-	-	-	-	-	-
350		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
351		Total Services - Directly Assigned		29,508	-	-	-	-	-	-	-	-	-	-	29,508
352	381	**Meters - Allocated**													
353		Customer	METCUS-ALL	2,388,003	2,063,872	262,930	2,528	50,428	2,739	990	2,066	1,413	659	377	-
354		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
355		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
356		Total Meters - Allocated		2,388,003	2,063,872	262,930	2,528	50,428	2,739	990	2,066	1,413	659	377	-
357	381	**Meters - Directly Assigned**													
358		Customer	CUS-DA	6,001	-	-	-	-	-	-	-	-	-	-	6,001
359		Demand	DEM-DA	-	-	-	-	-	-	-	-	-	-	-	-
360		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
361		Total Meters - Directly Assigned		6,001	-	-	-	-	-	-	-	-	-	-	6,001
362	382	**Meter Installations**													
363		Customer	METCUS-TOT	-	-	-	-	-	-	-	-	-	-	-	-
364		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
365		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
366		Total Meter Installations		-	-	-	-	-	-	-	-	-	-	-	-
367	383	**House Regulators - Allocated**													
368		Customer	REGCUS-ALL	542,385	459,288	67,776	595	12,782	634	262	481	328	153	87	-
369		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
370		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
371		Total House Regulators - Allocated		542,385	459,288	67,776	595	12,782	634	262	481	328	153	87	-
372	383	**House Regulators - Directly Assn.**													
373		Customer	CUS-DA	3,267	-	-	-	-	-	-	-	-	-	-	3,267
374		Demand	DEM-DA	-	-	-	-	-	-	-	-	-	-	-	-
375		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
376		House Regulators - Directly Assn.		3,267	-	-	-	-	-	-	-	-	-	-	3,267
377	385	**Meas. & Reg. Sta. Equip. - Ind. - Allocated**													
378		Customer	NRCUS	-	-	-	-	-	-	-	-	-	-	-	-
379		Demand	NRDEM	406,969	-	223,327	4,321	87,089	3,205	1,870	20,051	10,728	8,108	7,044	41,224
380		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
381		Total Meas. & Reg. Stat. Eq.- Ind. - Alloc.		406,969	-	223,327	4,321	87,089	3,205	1,870	20,051	10,728	8,108	7,044	41,224
382	385	**Meas. & Reg. Sta. Equip. - Ind. - DA**													
383		Customer	CUS-DA	-	-	-	-	-	-	-	-	-	-	-	-
384		Demand	DEM-DA	7,856	-	-	-	-	-	-	-	-	-	-	7,856
385		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
386		Total Meas. & Reg. Sta. Equip. - Ind.- DA		7,856	-	-	-	-	-	-	-	-	-	-	7,856
387	386	**Other Prop.- Customer Premises**													
388		Customer	CUS	90,947	85,292	5,216	12	388	13	6	7	5	2	1	6
389		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
390		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
391		Total Other Prop. - Customer Premises		90,947	85,292	5,216	12	388	13	6	7	5	2	1	6
392	387	**Other Equipment**													
393		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
394		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
395		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
396		Total Other Equipment		-	-	-	-	-	-	-	-	-	-	-	-
397	389-98	**General Plant - Allocated**													
398		Customer	GENPTCUS	4,838,866	4,462,728	320,601	1,186	29,372	1,152	475	765	523	244	139	21,680
399		Demand	DISPLTDEM	640,070	376,510	135,904	2,630	52,997	1,950	1,138	12,202	6,529	4,934	4,287	40,989
400		Commodity	COM	5,833	3,383	1,268	37	279	9	40	223	178	59	140	215
401		Total General Plant - Allocated		5,484,769	4,842,622	457,773	3,853	82,648	3,112	1,654	13,191	7,229	5,237	4,566	62,884
402	389-98	**General Plant - Directly Assigned**													
403		Customer	CUS-DA	3,563	-	-	-	-	-	-	-	-	-	-	3,563
404		Demand	DEM-DA	471	-	-	-	-	-	-	-	-	-	-	471
405		Commodity	COM-DA	4	-	-	-	-	-	-	-	-	-	-	4
406		Total General Plant - Directly Assn.		4,039	-	-	-	-	-	-	-	-	-	-	4,039
407	389-98	**General Plant - Odorization**													
408		Customer	CUS	-	-	-	-	-	-	-	-	-	-	-	-
409		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
410		Commodity	COM	1,718	996	374	11	82	3	12	66	52	18	41	63
411		Total General Plant - Odorization		1,718	996	374	11	82	3	12	66	52	18	41	63
412	40730	**Pension & FAS 106 Amort. Expense**													
413		Customer	CUS	194,285	182,204	11,142	26	829	27	13	14	10	4	3	12
414		Demand	DEM	40,488	27,634	7,054	136	2,751	101	59	633	339	256	222	1,302
415		Commodity	COM	3,141	1,822	683	20	150	5	22	120	96	32	75	116
416		Total Pension & FAS 106 Amort. Exp.		237,913	211,660	18,879	183	3,730	133	94	768	444	293	300	1,430
417		**Total Depreciation & Amort. Exp.**													
418		Customer		19,840,074	18,078,731	1,456,335	6,757	152,243	6,513	2,540	4,637	3,167	1,478	844	126,828
419		Demand		5,765,317	3,536,101	1,165,740	22,556	454,594	16,729	9,763	104,666	56,000	42,321	36,769	320,076
420		Commodity		30,981	17,967	6,735	197	1,482	48	214	1,186	945	316	743	1,148
421		Total Depreciation & Amort. Expense		25,636,372	21,632,798	2,628,811	29,511	608,320	23,290	12,518	110,490	60,112	44,115	38,357	448,052
422		**Taxes Other Than Income**													
423	4081	**Payroll and Other Taxes**													
424		Customer	OPEXPCUS	2,230,595	2,025,151	171,178	905	19,093	867	342	621	424	198	113	11,703
425		Demand	OPEXPDEM	464,846	285,503	93,765	1,814	36,565	1,346	785	8,419	4,504	3,404	2,957	25,784
426		Commodity	COM	36,057	20,913	7,840	230	1,725	55	249	1,380	1,100	368	865	1,331
427		Total Payroll and Other Taxes		2,731,498	2,331,566	272,783	2,949	57,383	2,268	1,377	10,420	6,029	3,970	3,936	38,818
428	4081	**Ad Valorem Taxes - Allocated**													
429		Customer	CUS	5,145,111	4,825,194	295,069	690	21,962	714	340	374	255	119	68	325
430		Demand	DEM	1,955,978	1,334,997	340,768	6,594	132,887	4,890	2,854	30,596	16,370	12,371	10,748	62,903
431		Commodity	COM	11,128	6,454	2,419	71	532	17	77	426	340	113	267	411
432		Total Ad Valorem Taxes - Allocated		7,112,217	6,166,645	638,257	7,355	155,381	5,622	3,271	31,396	16,965	12,604	11,083	63,638
433	4081	**Ad Valorem Taxes - Directly Assn.**													
434		Customer	CUS-DA	35,530	-	-	-	-	-	-	-	-	-	-	35,530
435		Demand	DEM-DA	35,353	-	-	-	-	-	-	-	-	-	-	35,353
436		Commodity	COM-DA	-	-	-	-	-	-	-	-	-	-	-	-
437		Total Ad Valorem Taxes - Directly Assn.		70,883	-	-	-	-	-	-	-	-	-	-	70,883
438		**Revenue Related Taxes**													
439		Customer	TOTREVCUS	97,463	69,527	18,888	573	4,204	192	367	284	420	119	223	2,665
440		Demand	DEM	-	-	-	-	-	-	-	-	-	-	-	-
441		Commodity	COM	-	-	-	-	-	-	-	-	-	-	-	-
442		Total Revenue Related Taxes		97,463	69,527	18,888	573	4,204	192	367	284	420	119	223	2,665
443		**Total Taxes Other Than Income**													
444		Customer		7,508,699	6,919,872	485,135	2,168	45,259	1,774	1,049	1,279	1,099	437	404	50,223
445		Demand		2,456,177	1,620,500	434,533	8,408	169,451	6,236	3,639	39,015	20,874	15,775	13,706	124,040
446		Commodity		47,185	27,367	10,259	301	2,258	73	326	1,807	1,440	481	1,132	1,742

Allocated Cost of Service

447	Total Taxes Other Than Income		$ 10,012,061	$ 8,567,739	$ 929,928	$ 10,877	$ 216,968	$ 8,082	$ 5,015	$ 42,100	$ 23,413	$ 16,693	$ 15,242	$ 176,004
448	**Excess Def. Income Tax Amort. - Directly Assn.**													
449	Customer	CUS-DA	$ (7,110)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,110)
450	Demand	DEM-DA	$ (7,345)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,345)
451	Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
452	**Total Excess Def. Income Tax Amort. - DA**		$ (14,455)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (14,455)
453	**Excess Def. Income Tax Amort. - Alloc.**													
454	Customer	CUS	$ (999,302)	$ (937,166)	$ (57,309)	$ (134)	$ (4,266)	$ (139)	$ (66)	$ (73)	$ (50)	$ (23)	$ (13)	$ (63)
455	Demand	DEM	$ (406,810)	$ (277,657)	$ (70,874)	$ (1,371)	$ (27,638)	$ (1,017)	$ (594)	$ (6,363)	$ (3,405)	$ (2,573)	$ (2,235)	$ (13,083)
456	Commodity	COM	$ (2,099)	$ (1,217)	$ (456)	$ (13)	$ (100)	$ (3)	$ (15)	$ (80)	$ (64)	$ (21)	$ (50)	$ (77)
457	**Total Excess Def. Income Tax Amort. - Alloc.**		$ (1,408,211)	$ (1,216,040)	$ (128,640)	$ (1,519)	$ (32,004)	$ (1,159)	$ (674)	$ (6,516)	$ (3,518)	$ (2,618)	$ (2,299)	$ (13,223)
458	**Interest on Customer Deposits**													
459	Customer	DEPCUS	$ 4,703	$ 2,729	$ 1,878	$ 24	$ 24	$ 2	$ 0	$ 39	$ -	$ -	$ 7	$ -
460	Demand	DEM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
461	Commodity	COM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
462	Total Interest on Cust. Deposits		$ 4,703	$ 2,729	$ 1,878	$ 24	$ 24	$ 2	$ 0	$ 39	$ -	$ -	$ 7	$ -
463	**Req. Return - Other Than Directly Assn.**													
464	Customer	CUS	$ 32,164,519	$ 30,164,564	$ 1,844,616	$ 4,316	$ 137,297	$ 4,466	$ 2,127	$ 2,340	$ 1,595	$ 744	$ 425	$ 2,029
465	Demand	DEM	$ 13,093,996	$ 8,936,938	$ 2,281,220	$ 44,140	$ 889,589	$ 32,736	$ 19,106	$ 204,820	$ 109,586	$ 82,818	$ 71,953	$ 421,093
466	Commodity	COM	$ 67,562	$ 39,186	$ 14,689	$ 430	$ 3,233	$ 104	$ 467	$ 2,587	$ 2,061	$ 689	$ 1,621	$ 2,494
467	Tot. Req. Return - Other Than Dir. Assn.		$ 45,326,077	$ 39,140,688	$ 4,140,525	$ 48,886	$ 1,030,118	$ 37,306	$ 21,700	$ 209,746	$ 113,242	$ 84,251	$ 73,999	$ 425,617
468	**Req. Return - Directly Assigned**													
469	Customer	CUS-DA	$ 228,851	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 228,851
470	Demand	DEM-DA	$ 236,411	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,411
471	Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
472	Tot. Req. Return - Directly Assigned		$ 465,262	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 465,262
473	**Income Taxes - Other Than DA**													
474	Customer	CUS	$ 6,764,116	$ 6,343,531	$ 387,918	$ 908	$ 28,873	$ 939	$ 447	$ 492	$ 335	$ 157	$ 89	$ 427
475	Demand	DEM	$ 2,753,634	$ 1,879,415	$ 479,735	$ 9,282	$ 187,078	$ 6,884	$ 4,018	$ 43,073	$ 23,046	$ 17,416	$ 15,131	$ 88,555
476	Commodity	COM	$ 14,208	$ 8,241	$ 3,089	$ 91	$ 680	$ 22	$ 98	$ 544	$ 433	$ 145	$ 341	$ 525
477	Total Income Taxes - Other Than DA		$ 9,531,958	$ 8,231,186	$ 870,742	$ 10,281	$ 216,631	$ 7,845	$ 4,563	$ 44,109	$ 23,815	$ 17,718	$ 15,562	$ 89,506
478	**Income Taxes - Directly Assigned**													
479	Customer	CUS-DA	$ 48,127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,127
480	Demand	DEM-DA	$ 49,717	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 49,717
481	Commodity	COM-DA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
482	Total Income Taxes - Dir. Assigned		$ 97,843	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 97,843
483	**Total Cost of Service Before Revenue Credits**													
484	Customer		$ 107,044,548	$ 98,176,625	$ 7,368,917	$ 32,152	$ 732,168	$ 30,872	$ 12,969	$ 21,145	$ 14,646	$ 6,758	$ 4,024	$ 644,272
485	Demand		$ 32,587,813	$ 21,010,892	$ 6,031,698	$ 116,708	$ 2,352,133	$ 86,556	$ 50,517	$ 541,557	$ 289,752	$ 218,976	$ 190,247	$ 1,698,777
486	Commodity		$ 828,542	$ 480,552	$ 180,143	$ 5,279	$ 39,643	$ 1,275	$ 5,727	$ 31,722	$ 25,279	$ 8,449	$ 19,882	$ 30,592
487	**Total Cost of Service Before Revenue Credits**		$ 140,460,903	$ 119,668,070	$ 13,580,758	$ 154,139	$ 3,123,943	$ 118,703	$ 69,213	$ 594,423	$ 329,676	$ 234,184	$ 214,153	$ 2,373,641

Allocation Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: ALLOCATION FACTORS

LINE NO.	DESCRIPTION	ALLOCATION FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANS.	INDUSTRIAL TRANS.	PUB. AUTH TRANS.	CNG TRANS.	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Customer Cost Allocation Factors													
2														
3	Total Customers		302,465	283,659	17,346	41	1,291	42	20	22	15	7	4	19
4	Total Customers Factor (CUS)	CUS	1.00000	0.93782	0.05735	0.00013	0.00427	0.00014	0.00007	0.00007	0.00005	0.00002	0.00001	0.00006
5														
6	Customers - Directly Assigned		19	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	1.00000
8														
9	Services - Allocated Weighting			1.00000	1.36341	2.05578	1.35349	1.40888	1.07720	2.05186	2.05186	2.05186	2.05186	0.00000
10	Weighted Customers		309,319	283,659	23,650	83	1,747	59	22	45	31	14	8	0
11	**Weighted Services Customer Factor (SERCUS-ALL)**	SERCUS-ALL	1.00000	0.91704	0.07646	0.00027	0.00565	0.00019	0.00007	0.00015	0.00010	0.00005	0.00003	0.00000
12														
13	Meters - Allocated Weighting			1.00000	2.08328	8.56160	5.36817	8.96348	6.80322	12.90694	12.94521	12.94521	12.94521	0.00000
14	Weighted Customers		328,207	283,659	36,137	347	6,931	376	136	284	194	91	52	0
15	**Weighted Meters Customer Factor (METCUS-ALL)**	METCUS-ALL	1.00000	0.86427	0.11010	0.00106	0.02112	0.00115	0.00041	0.00087	0.00059	0.00028	0.00016	0.00000
16														
17	Meters - Total Weighting			1.00000	2.08328	8.56160	5.36817	8.96348	6.80322	12.90694	12.94521	12.94521	12.94521	10.13457
18	Weighted Customers		328,400	283,659	36,137	347	6,931	376	136	284	194	91	52	193
19	**Weighted Meters Customer Factor (METCUS-TOT)**	METCUS-TOT	1.00000	0.86376	0.11004	0.00106	0.02110	0.00115	0.00041	0.00086	0.00059	0.00028	0.00016	0.00059
20														
21	Regulators - Allocated Weighting			1.00000	2.41313	9.05047	6.11424	9.32803	8.09525	13.49204	13.49204	13.49204	13.49204	0.00000
22	Weighted Customers		334,980	283,659	41,859	367	7,894	392	162	297	202	94	54	0
23	**Weighted Regulators Customer Factor (REGCUS-ALL)**	REGCUS-ALL	1.00000	0.84679	0.12496	0.00110	0.02357	0.00117	0.00048	0.00089	0.00060	0.00028	0.00016	0.00000
24														
25	Meters and Regulators - Allocated Weighting			1.00000	2.17386	8.69581	5.57300	9.06357	7.15953	13.06760	13.09536	13.09536	13.09536	0.00000
26	Weighted Customers		330,067	283,659	37,708	353	7,195	381	143	287	196	92	52	0
27	**Wghtd. Meters & Regs. Cust. Factor (MTRGCUS-ALL)**	MTRGCUS-ALL	1.00000	0.85940	0.11424	0.00107	0.02180	0.00115	0.00043	0.00087	0.00060	0.00028	0.00016	0.00000
28														
29	Non-Residential Customers		18,807	0	17,346	41	1,291	42	20	22	15	7	4	19
30	**Non-Residential Customers Factor (NRCUS)**	NRCUS	1.00000	0.00000	0.92233	0.00216	0.06865	0.00223	0.00106	0.00117	0.00080	0.00037	0.00021	0.00101
31														
32	Customer Cost Allocation Factors													
33														
34	Distribution Plant Customer Costs		$ 476,571,818	$ 433,689,139	$ 34,917,904	$ 158,521	$ 3,568,896	$ 150,751	$ 58,807	$ 107,465	$ 73,374	$ 34,241	$ 19,566	$ 3,793,153
35	**Distr. Plant Cust. Costs Factor (DISPLTCUS)**	DISPLTCUS	1.00000	0.91002	0.07327	0.00033	0.00749	0.00032	0.00012	0.00023	0.00015	0.00007	0.00004	0.00796
36														
37	Account 376-379 Customer Costs		$ 207,527,272	$ 192,184,905	$ 11,752,444	$ 27,496	$ 874,746	$ 28,456	$ 13,550	$ 14,905	$ 10,163	$ 4,743	$ 2,710	$ 2,613,154
38	**Acct. 376-379 Cust. Costs Factor (376-379CUS)**	376-379CUS	1.00000	0.92607	0.05663	0.00013	0.00422	0.00014	0.00007	0.00007	0.00005	0.00002	0.00001	0.01259
39														
40	Total Revenue (inc. cost of gas)		$ 204,154,608	$ 145,637,489	$ 39,564,691	$ 1,201,073	$ 8,805,953	$ 403,171	$ 767,846	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 5,581,939
41	**Total Revenue Factor (TOTREVCUS)**	TOTREVCUS	1.00000	0.71337	0.19380	0.00588	0.04313	0.00197	0.00376	0.00292	0.00431	0.00123	0.00229	0.02734
42														
43	Mains - Allocated Customer Cost Factor		0.51636	0.48426	0.02961	0.00007	0.00220	0.00007	0.00003	0.00004	0.00003	0.00001	0.00001	0.00003
44	Services - Allocated Customer Cost Factor		0.48364	0.44352	0.03698	0.00013	0.00273	0.00009	0.00003	0.00007	0.00005	0.00002	0.00001	0.00000
45	**Mains & Svcs. Cust. Alloc. Factor (MSCUS-ALL)**	MSCUS-ALL	1.00000	0.92777	0.06659	0.00020	0.00494	0.00016	0.00007	0.00011	0.00007	0.00003	0.00002	0.00003
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	1.00000
48														
49	Total Plant Customer		$ 553,378,080	$ 504,508,632	$ 39,998,079	$ 177,264	$ 4,033,584	$ 168,960	$ 66,319	$ 119,547	$ 81,621	$ 38,090	$ 21,766	$ 4,164,219
50	**Total Plant Factor (TPLTCUS)**	TPLTCUS	1.00000	0.91169	0.07228	0.00032	0.00729	0.00031	0.00012	0.00022	0.00015	0.00007	0.00004	0.00753
51														
52	Non-Intangible Plant Customer													
53	**Non-Intangible Plant Customer Factor (NONINCUS)**		$ 552,633,066	$ 518,270,938	$ 31,693,176	$ 74,150	$ 2,358,954	$ 76,738	$ 36,542	$ 40,196	$ 27,406	$ 12,790	$ 7,308	$ 34,867
54		NONINCUS	1.00000	0.93782	0.05735	0.00013	0.00427	0.00014	0.00007	0.00007	0.00005	0.00002	0.00001	0.00006
55														
56	Account 871-879 Customer Costs		$ 7,846,237	$ 6,974,757	$ 734,791	$ 5,449	$ 113,965	$ 5,706	$ 2,164	$ 4,255	$ 2,907	$ 1,357	$ 775	$ 110
57	**Account 871-879 Cust. Costs Factor (871-879CUS)**	871-879CUS	1.00000	0.88893	0.09365	0.00069	0.01452	0.00073	0.00028	0.00054	0.00037	0.00017	0.00010	0.00001
58														
59	Account 887-893 Customer Costs		$ 3,179,045	$ 2,958,812	$ 203,067	$ 574	$ 15,069	$ 498	$ 214	$ 311	$ 212	$ 99	$ 56	$ 132
60	**Account 887-893 Cust. Costs Factor (887-893CUS)**	887-893CUS	1.00000	0.93072	0.06388	0.00018	0.00474	0.00016	0.00007	0.00010	0.00007	0.00003	0.00002	0.00004
61														
62	Account 903 Customer		$ 3,123,314	$ 2,965,743	$ 150,563	$ 268	$ 6,188	$ 100	$ 228	$ 69	$ 52	$ 24	$ 14	$ 66
63	**Account 903 Customer Factor (903CUS)**	903CUS	1.00000	0.94955	0.04821	0.00009	0.00198	0.00003	0.00007	0.00002	0.00002	0.00001	0.00000	0.00002
64														
65	Customer Cost Allocation Factors													
66														
67	Account 904 Customer		$ 972,692	$ 851,205	$ 118,618	$ 626	$ 2,079	$ 163	$ -	$ -	$ -	$ -	$ -	$ -
68	**Account 904 Customer Factor (904CUS)**	904CUS	1.00000	0.87510	0.12195	0.00064	0.00214	0.00017	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
69														
70	Accounts 902-904 Customer		$ 4,712,396	$ 4,349,360	$ 337,009	$ 1,546	$ 21,276	$ 970	$ 483	$ 602	$ 416	$ 194	$ 111	$ 429
71	**Accts. 902-904 Customer Factor (902-904CUS)**	902-904CUS	1.00000	0.92296	0.07152	0.00033	0.00451	0.00021	0.00010	0.00013	0.00009	0.00004	0.00002	0.00009
72														
73	Operating Expense Customer		$ 38,760,485	$ 35,190,533	$ 2,974,521	$ 15,718	$ 331,776	$ 15,060	$ 5,948	$ 10,786	$ 7,372	$ 3,440	$ 1,966	$ 203,363
74	**Operating Exp. Customer Factor (OPEXPCUS)**	OPEXPCUS	1.00000	0.90790	0.07674	0.00041	0.00856	0.00039	0.00015	0.00028	0.00019	0.00009	0.00005	0.00525
75														
76	Direct Gen. Plant Customer Costs (DISPLTCUS)	DISPLTCUS	$ 42,551,110	$ 38,722,294	$ 3,117,674	$ 14,154	$ 318,652	$ 13,460	$ 5,251	$ 9,595	$ 6,551	$ 3,057	$ 1,747	$ 338,675
77	Div. and Corp. Gen. Plant Customer Costs (CUS)	CUS	$ 33,510,138	$ 31,426,513	$ 1,921,786	$ 4,496	$ 143,040	$ 4,653	$ 2,216	$ 2,437	$ 1,662	$ 776	$ 443	$ 2,114
78	Total General Plant Customer Costs		$ 76,061,248	$ 70,148,808	$ 5,039,460	$ 18,650	$ 461,692	$ 18,113	$ 7,466	$ 12,032	$ 8,213	$ 3,833	$ 2,190	$ 340,789
79	**General Plant Customer Factor (GENPTCUS)**	GENPTCUS	1.00000	0.92227	0.06626	0.00025	0.00607	0.00024	0.00010	0.00016	0.00011	0.00005	0.00003	0.00448
80														
81	Customer Deposits		$ (7,838,323)	$ (4,548,685)	$ (3,129,742)	$ (39,642)	$ (40,374)	$ (3,122)	$ (371)	$ (65,205)	$ -	$ -	$ (11,183)	$ -
82	**Customer Deposits Factor (DEPCUS)**	DEPCUS	1.00000	0.58031	0.39929	0.00506	0.00515	0.00040	0.00005	0.00832	0.00000	0.00000	0.00143	0.00000
83														
84	Demand Cost Allocation Factors													
85														
86	System Demand													
87	**System Demand Factor (DEM)**	DEM	1.00000	0.68252	0.17422	0.00337	0.06794	0.00250	0.00146	0.01564	0.00837	0.00632	0.00550	0.03216
88														
89	Non-Residential Demand													
90	**Non-Residential Demand Factor (NRDEM)**	NRDEM	1.00000	0.00000	0.54876	0.01062	0.21399	0.00787	0.00460	0.04927	0.02636	0.01992	0.01731	0.10130
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	1.00000
94														
95	Distribution Plant Demand		$ 150,784,206	$ 88,696,307	$ 32,015,540	$ 619,473	$ 12,484,843	$ 459,427	$ 268,138	$ 2,874,519	$ 1,537,969	$ 1,162,301	$ 1,009,810	$ 9,655,878
96	**Distribution Plant Demand Factor (DISPLTDEM)**	DISPLTDEM	1.00000	0.58823	0.21233	0.00411	0.08280	0.00305	0.00178	0.01906	0.01020	0.00771	0.00670	0.06404
97														
98	Demand Cost Allocation Factors													
99														
100	Non-Intangible Plant Demand		$ 212,420,691	$ 144,981,746	$ 37,007,669	$ 716,066	$ 14,431,583	$ 531,065	$ 309,949	$ 3,322,738	$ 1,777,782	$ 1,343,537	$ 1,167,268	$ 6,831,288
101	**Non-Int. Plant Demand Factor (NONINDEM)**	NONINDEM	1.00000	0.68252	0.17422	0.00337	0.06794	0.00250	0.00146	0.01564	0.00837	0.00632	0.00550	0.03216
102														
103	Total Plant Demand		$ 212,707,059	$ 129,670,891	$ 43,311,078	$ 838,032	$ 16,889,673	$ 621,520	$ 362,741	$ 3,888,690	$ 2,080,586	$ 1,572,378	$ 1,366,086	$ 12,105,385
104	**Total Plant Demand Factor (TPLTDEM)**	TPLTDEM	1.00000	0.60962	0.20362	0.00394	0.07940	0.00292	0.00171	0.01828	0.00978	0.00739	0.00642	0.05691
105														
106	Operating Expense Demand		$ 11,409,666	$ 7,007,678	$ 2,301,470	$ 44,531	$ 897,486	$ 33,026	$ 19,275	$ 206,638	$ 110,558	$ 83,553	$ 72,591	$ 632,858
107	**Operating Expense Demand Factor (OPEXPDEM)**	OPEXPDEM	1.00000	0.61419	0.20171	0.00390	0.07866	0.00289	0.00169	0.01811	0.00969	0.00732	0.00636	0.05547
108														
109	Acct. 887-893 Demand		$ 2,000,158	$ 1,100,816	$ 493,521	$ 9,549	$ 192,454	$ 7,082	$ 4,133	$ 44,311	$ 23,708	$ 17,917	$ 15,566	$ 91,100
110	**Acct. 887-893 Demand Factor (887-893DEM)**	887-893DEM	1.00000	0.55036	0.24674	0.00477	0.09622	0.00354	0.00207	0.02215	0.01185	0.00896	0.00778	0.04555
111														
112	Rate Base Demand		$ 172,095,122	$ 105,437,789	$ 35,048,026	$ 678,149	$ 13,667,397	$ 502,944	$ 293,536	$ 3,146,791	$ 1,683,644	$ 1,272,393	$ 1,105,459	$ 9,258,995
113	**Rate Base Demand Factor (RBDEM)**	RBDEM	1.00000	0.61267	0.20365	0.00394	0.07942	0.00292	0.00171	0.01829	0.00978	0.00739	0.00642	0.05380
114														
115	Commodity Cost Allocation Factors													
116														
117	Annual Distribution Volumes (Ccf)		215,045,986	124,726,694	46,755,918	1,370,091	10,289,191	330,915	1,486,506	8,233,369	6,561,058	2,192,902	5,160,298	7,939,044
118	**Distribution Commodity Factor (COM)**	COM	1.00000	0.58000	0.21742	0.00637	0.04785	0.00154	0.00691	0.03829	0.03051	0.01020	0.02400	0.03692
119														
120	Commodity - Direct Assignment		7,939,044	0	0	0	0	0	0	0	0	0	0	7,939,044
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	1.00000

WKP Plant

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: PLANT WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1		**Distribution Plant Reserve**					
2	374	Land & Land Rights - Allocated	$ (47,006)	DIS376-379-ALL	$ (28,831)	$ (18,175)	$ -
3	374	Land & Land Rights - Directly Assn.	$ (6,316)	DIS376-379-DA	$ (2,735)	$ (3,581)	$ -
4	375	Structures and Improvements	$ (149,046)	DIS376-379-ALL	$ (91,417)	$ (57,629)	$ -
5	376	Distribution Mains-Allocated	$ (43,947,969)	MAINS-ALLOC	$ (28,813,070)	$ (15,134,899)	$ -
6	376	Distribution Mains-Directly Asssigned	$ (784,772)	MAINS-DA	$ (379,780)	$ (404,992)	$ -
7	377	Compressor Station Equipment	$ -	DEM	$ -	$ -	$ -
8	378	Meas. & Reg. Station Equip.- Gen.- Alloc.	$ (1,013,107)	DEM	$ -	$ (1,013,107)	$ -
9	378	Meas. & Reg. Station Equip. Gen.- Dir. Assn.	$ (34,385)	DEM	$ -	$ (34,385)	$ -
10	378	Odorization Tank	$ (37,155)	COM	$ -	$ -	$ (37,155)
11	379	Meas. & Reg. Station Equip.- City Gate	$ (747,871)	DEM	$ -	$ (747,871)	$ -
12	379	Odorization Tank	$ (181,616)	COM	$ -	$ -	$ (181,616)
13	380	Services - Allocated	$ (26,297,732)	CUS	$ (26,297,732)	$ -	$ -
14	380	Services - Directly Assigned	$ (158,249)	CUS	$ (158,249)	$ -	$ -
15	381	Meters - Allocated	$ (16,835,649)	CUS	$ (16,835,649)	$ -	$ -
16	381	Meters - Directly Assigned	$ (47,576)	CUS	$ (47,576)	$ -	$ -
17	382	Meter Installations	$ (8,293)	CUS	$ (8,293)	$ -	$ -
18	383	House Regulators - Allocated	$ (5,122,147)	CUS	$ (5,122,147)	$ -	$ -
19	383	House Regulators - Directly Assigned	$ (15,489)	CUS	$ (15,489)	$ -	$ -
20	385	Meas. & Reg. Sta. Equip. -Ind. - Allocated	$ (2,978,842)	DEM	$ -	$ (2,978,842)	$ -
21	385	Meas. & Reg. Sta. Equip.-Ind. - Dir. Assn.	$ (36,930)	DEM	$ -	$ (36,930)	$ -
22	386	Other Property - Customer Premises	$ (441,058)	DIS376-379-ALL	$ (270,522)	$ (170,536)	$ -
23	387	Other Equipment	$ -	DIS376-379-ALL	$ -	$ -	$ -
24		Total Distribution Plant Reserve	$ (98,891,206)		$ (78,071,488)	$ (20,600,947)	$ (218,771)
25							
26		**General Plant - Service Area Direct**					
27	389	Land & Land Rights	$ 320,363	DISPLT	$ 242,987	$ 76,880	$ 496
28	390	Structures & Improvements	$ 8,041,074	DISPLT	$ 6,098,955	$ 1,929,669	$ 12,450
29	391	Office Furniture and Equip.	$ 2,499,440	DISPLT	$ 1,895,763	$ 599,807	$ 3,870
30	392	Transportation Equipment	$ 10,613,209	DISPLT	$ 8,049,855	$ 2,546,922	$ 16,432
31	393	Stores Equipment	$ 30,503	DISPLT	$ 23,136	$ 7,320	$ 47
32	394	Tools, Shop & Garage - Allocated	$ 6,626,060	DISPLT	$ 5,025,702	$ 1,590,099	$ 10,259
33	394	Tools, Shop & Garage - Dir. Assn.	$ 11,690	DISPLT-DA	$ 5,860	$ 5,830	$ -
34	394	Odorization Tank	$ 25,769	COM	$ -	$ -	$ 25,769
35	395	CNG Equipment	$ -	DISPLT	$ -	$ -	$ -
36	396	Major Work Equipment	$ 2,380,590	DISPLT	$ 1,805,619	$ 571,286	$ 3,686
37	397	Communication Equipment - Allocated	$ 25,549,586	DISPLT	$ 19,378,727	$ 6,131,302	$ 39,557
38	397	Communication Equip. - Dir. Assn.	$ 48,893	DISPLT-DA	$ 24,507	$ 24,385	$ -
39	398	Miscellaneous General Plant	$ -	DISPLT	$ -	$ -	$ -
40		**General Plant - Shared Svcs. & Distrigas**					
41	389	Land & Land Rights	$ 197,435	CUS	$ 197,435	$ -	$ -
42	390	Structures & Improvements	$ 3,335,159	CUS	$ 3,335,159	$ -	$ -
43	391	Office Furniture and Equipment	$ 29,432,452	CUS	$ 29,432,452	$ -	$ -
44	392	Transportation Equipment	$ -	CUS	$ -	$ -	$ -
45	393	Stores Equipment	$ -	CUS	$ -	$ -	$ -
46	394	Tools, Shop & Garage	$ 5,840	CUS	$ 5,840	$ -	$ -
47	395	CNG Equipment	$ -	CUS	$ -	$ -	$ -
48	396	Major Work Equipment	$ -	CUS	$ -	$ -	$ -
49	397	Communication Equipment	$ 539,252	CUS	$ 539,252	$ -	$ -
50	398	Miscellaneous General Plant	$ -	CUS	$ -	$ -	$ -
51		**Total General Plant**					
52	389	Land & Land Rights	$ 517,798	GENPLT	$ 440,422	$ 76,880	$ 496
53	390	Structures & Improvements	$ 11,376,233	GENPLT	$ 9,434,114	$ 1,929,669	$ 12,450
54	391	Office Furniture and Equip.	$ 31,931,891	GENPLT	$ 31,328,215	$ 599,807	$ 3,870
55	392	Transportation Equipment	$ 10,613,209	GENPLT	$ 8,049,855	$ 2,546,922	$ 16,432
56	393	Stores Equipment	$ 30,503	GENPLT	$ 23,136	$ 7,320	$ 47
57	394	Tools, Shop & Garage - Allocated	$ 6,631,900	GENPLT	$ 5,031,542	$ 1,590,099	$ 10,259
58	394	Tools, Shop & Garage - Dir. Assn.	$ 11,690	GENPLT	$ 5,860	$ 5,830	$ -
59	394	Odorization Tank	$ 25,769	COM	$ -	$ -	$ 25,769
60	395	CNG Equipment	$ -	GENPLT	$ -	$ -	$ -
61	396	Major Work Equipment	$ 2,380,590	GENPLT	$ 1,805,619	$ 571,286	$ 3,686
62	397	Communication Equipment - Allocated	$ 26,088,838	GENPLT	$ 19,917,979	$ 6,131,302	$ 39,557
63	397	Communication Equip. - Dir. Assn.	$ 48,893	GENPLT	$ 24,507	$ 24,385	$ -

WKP Plant

64	398	Miscellaneous General Plant	$ -	GENPLT	$ -	$ -	$ -
65		Total General Plant	$ 89,657,313		$ 76,061,248	$ 13,483,501	$ 112,565
66		**General Plant Depreciation Expense**					
67	389	Land & Land Rights	$ -		$ -	$ -	$ -
68	390	Structures & Improvements	$ 407,780		$ 338,165	$ 69,169	$ 446
69	391	Office Furniture and Equip.	$ 2,893,769		$ 2,839,062	$ 54,356	$ 351
70	392	Transportation Equipment	$ -		$ -	$ -	$ -
71	393	Stores Equipment	$ 2,034		$ 1,542	$ 488	$ 3
72	394	Tools, Shop & Garage - Allocated	$ 442,134		$ 335,441	$ 106,008	$ 684
73	394	Tools, Shop & Garage - Dir. Assn.	$ 779		$ 391	$ 389	$ -
74	394	Tools, Shop & Garage - Odorization	$ 1,718		$ -	$ -	$ 1,718
75	395	CNG Equipment	$ -		$ -	$ -	$ -
76	396	Major Work Equipment	$ -		$ -	$ -	$ -
77	397	Communication Equipment - Allocated	$ 1,739,053		$ 1,327,710	$ 408,706	$ 2,637
78	397	Communication Equip. - Dir. Assn.	$ 3,260		$ 1,634	$ 1,626	$ -
79	398	Miscellaneous General Plant	$ -		$ -	$ -	$ -
80		Total General Plant Depreciation Exp.	$ 5,490,525.29	GENDEP	$ 4,843,945	$ 640,742	$ 5,839
81		**General Plant**					
82		**Depreciation Reserve - Service Area Direct**					
83	389	Land & Land Rights	$ -	DISPLT	$ -	$ -	$ -
84	390	Structures & Improvements	$ (1,717,110)	DISPLT	$ (1,302,386)	$ (412,066)	$ (2,659)
85	391	Office Furniture and Equip. - Allocated	$ (1,098,330)	DISPLT	$ (833,056)	$ (263,573)	$ (1,700)
86	391	Office Furniture and Equip. - Dir. Assn.	$ 15,138	DISPLT	$ 11,482	$ 3,633	$ 23
87	392	Transportation Equipment	$ (2,132,014)	DISPLT	$ (1,617,080)	$ (511,633)	$ (3,301)
88	393	Stores Equipment	$ (22,026)	DISPLT	$ (16,706)	$ (5,286)	$ (34)
89	394	Tools, Shop & Garage - Allocated	$ (2,503,286)	DISPLT	$ (1,898,681)	$ (600,730)	$ (3,876)
90	394	Tools, Shop & Garage - Dir. Assn.	$ (1,169)	DISPLT-DA	$ (586)	$ (583)	$ -
91	394	Odorization Tank	$ (7,384)	COM	$ -	$ -	$ (7,384)
92	395	CNG Equipment	$ (47)	DISPLT	$ (36)	$ (11)	$ (0)
93	396	Major Work Equipment	$ (587,853)	DISPLT	$ (445,872)	$ (141,071)	$ (910)
94	397	Communication Equipment - Allocated	$ (6,283,039)	DISPLT	$ (4,765,529)	$ (1,507,782)	$ (9,728)
95	397	Communication Equip. - Dir. Assn.	$ (18,516)	DISPLT-DA	$ (9,281)	$ (9,235)	$ -
96	398	Miscellaneous General Plant	$ 14,531	DISPLT	$ 11,021	$ 3,487	$ 22
97			$ (14,341,107)		$ (10,866,709)	$ (3,444,852)	$ (29,546)
98		**General Plant**					
99		**Depreciation Reserve - Shared Svcs. & Distrigas**					
100	389	Land & Land Rights	$ -	CUS	$ -	$ -	$ -
101	390	Structures & Improvements	$ (559,710)	CUS	$ (559,710)	$ -	$ -
102	391	Office Furniture and Equipment	$ (12,813,490)	CUS	$ (12,813,490)	$ -	$ -
103	392	Transportation Equipment	$ (0)	CUS	$ (0)	$ -	$ -
104	393	Stores Equipment	$ -	CUS	$ -	$ -	$ -
105	394	Tools, Shop & Garage	$ (2,223)	CUS	$ (2,223)	$ -	$ -
106	395	CNG Equipment	$ -	CUS	$ -	$ -	$ -
107	396	Major Work Equipment	$ -	CUS	$ -	$ -	$ -
108	397	Communication Equipment	$ (343,665)	CUS	$ (343,665)	$ -	$ -
109	398	Miscellaneous General Plant	$ -	CUS	$ -	$ -	$ -
110			$ (13,719,089)		$ (13,719,089)	$ -	$ -
111		**General Plant**					
112		**Total Depreciation Reserve**					
113	389	Land & Land Rights	$ -		$ -	$ -	$ -
114	390	Structures & Improvements	$ (2,276,821)		$ (1,862,096)	$ (412,066)	$ (2,659)
115	391	Office Furniture and Equip. - Allocated	$ (13,911,820)		$ (13,646,547)	$ (263,573)	$ (1,700)
116	391	Office Furniture and Equip. - Dir. Assn.	$ 15,138		$ 11,482	$ 3,633	$ 23
117	392	Transportation Equipment	$ (2,132,014)		$ (1,617,080)	$ (511,633)	$ (3,301)
118	393	Stores Equipment	$ (22,026)		$ (16,706)	$ (5,286)	$ (34)
119	394	Tools, Shop & Garage - Allocated	$ (2,505,509)		$ (1,900,903)	$ (600,730)	$ (3,876)
120	394	Tool, Shop & Garage - Dir. Assn.	$ (1,169)		$ (586)	$ (583)	$ -
121	394	Odorization Tank	$ (7,384)		$ -	$ -	$ (7,384)
122	395	CNG Equipment	$ (47)		$ (36)	$ (11)	$ (0)
123	396	Major Work Equipment	$ (587,853)		$ (445,872)	$ (141,071)	$ (910)
124	397	Communication Equipment - Allocated	$ (6,626,704)		$ (5,109,194)	$ (1,507,782)	$ (9,728)
125	397	Communication Equip. - Dir. Assn.	$ (18,516)		$ (9,281)	$ (9,235)	$ -
126	398	Miscellaneous General Plant	$ 14,531		$ 11,021	$ 3,487	$ 22
127		Total General Plant Depr. Reserve	$ (28,060,195)	GENPLTRES	$ (24,585,798)	$ (3,444,852)	$ (29,546)

WKP Admin&Gen

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: ADMINISTRATIVE AND GENERAL EXPENSE WORKPAPER

Line No.	Acct.	Description	Amount	Classification Factor	CUSTOMER	DEMAND	COMMODITY
1	920	Salaries	$ 5,931,818	NONAGOPEXP	$ 4,489,147	$ 1,339,205	$ 103,465
2	921	Office Supplies & Expenses	$ 1,255,404	NONAGOPEXP	$ 950,078	$ 283,428	$ 21,897
3	922	Transferred Credit	$ (4,461,726)	NONAGOPEXP	$ (3,376,595)	$ (1,007,308)	$ (77,823)
4	923	Outside Services	$ 418,613	NONAGOPEXP	$ 316,802	$ 94,509	$ 7,302
5	924	Property Insurance	$ 280,738	NONAGOPEXP	$ 212,460	$ 63,381	$ 4,897
6	925	Injuries & Damages	$ 1,597,193	NONAGOPEXP	$ 1,208,741	$ 360,593	$ 27,859
7	926	Employee Pensions & Benefits	$ 4,397,949	NONAGOPEXP	$ 3,328,329	$ 992,909	$ 76,711
8	926	Distrigas	$ 476,772	CUS	$ 476,772	$ -	$ -
9	927	A&G Franchise Elections	$ 367	NONAGOPEXP	$ 278	$ 83	$ 6
10	928	Regulatory Commission Expenses	$ 530,194	NONAGOPEXP	$ 401,246	$ 119,700	$ 9,248
11	929	Duplicate Charges - Credit	$ -	NONAGOPEXP	$ -	$ -	$ -
12	930	Advertising	$ 6,707	NONAGOPEXP	$ 5,076	$ 1,514	$ 117
13	930	Other General	$ 2,352,808	NONAGOPEXP	$ 1,780,585	$ 531,185	$ 41,039
14	930	Distrigas	$ 12,030,455	CUS	$ 12,030,455	$ -	$ -
15	930	Odorization	$ 2,672	COM	$ -	$ -	$ 2,672
16	931	Rent	$ 725,362	NONAGOPEXP	$ 548,948	$ 163,762	$ 12,652
17	932	A&G Maintenance	$ 263,133	NONAGOPEXP	$ 199,136	$ 59,407	$ 4,590
18	940	Misc. General Expenses	$ -	NONAGOPEXP	$ -	$ -	$ -
19		Total Administrative & General Expense	$ 25,808,458	ADMINGEN	$ 22,571,459	$ 3,002,368	$ 234,631

WKP Selected Data

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: SELECTED DATA WORKPAPER

WNSA	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	3,403,902	124,726,694	$ 94,066,743	$ 51,570,746	$ 145,637,489	124,716,236	124,726,694	$ 1,456,428	
Commercial	208,155	46,755,918	$ 20,232,521	$ 19,332,169	$ 39,564,691	46,637,169	46,755,918	$ 109,248	
Industrial	487	1,370,091	$ 634,581	$ 566,492	$ 1,201,073	1,423,040	1,370,091	$ 46	
Public Authority	15,493	10,289,191	$ 4,551,682	$ 4,254,272	$ 8,805,953	11,510,313	10,289,191	$ 1,420	
Municipal Water Pumping	504	330,915	$ 266,348	$ 136,823	$ 403,171	335,045	330,915	$ 107	
School and Municipal	240	1,486,506	$ 153,220	$ 614,626	$ 767,846	1,488,751	1,486,506	$ 9	
Commercial Transportation	264	8,233,369	$ 595,241	$ -	$ 595,241	0	0	$ 6	
Industrial Transportation	180	6,561,058	$ 879,352	$ -	$ 879,352	0	0	$ 9	
Public Authority Transportation	84	2,192,902	$ 250,253	$ -	$ 250,253	0	0	$ 5	
CNG Transportation	48	5,160,298	$ 467,600	$ -	$ 467,600	0	0	$ 9	
Fort Bliss	229	7,939,044	$ 2,299,383	$ 3,282,556	$ 5,581,939	7,742,066	7,939,044	$ -	
Special Contract	96	28,100,120	$ 1,067,474	$ -	$ 1,067,474	0	0	$ -	
Irrigation	1,669	4,663,437	$ 434,091	$ -	$ 434,091	4,663,437	0	$ -	
Total	3,631,351	247,809,543	$ 125,898,488	$ 79,757,685	$ 205,656,173	198,516,057	192,898,359	1,567,287	$ 82,080,953

COG Rate $ 0.41347

Customer Portion of Mains	
WNSA	65.56%
Fort Bliss	48.39%

WNSA Odorization Plant	Account	Original Cost	Reserve	Depr. Rate	Depr. Expense	Linked to the Odorization Summary
	369	$ 101,675	$ (11,221)	3.49%	$ 3,548	
	378	$ 207,194	$ (37,155)	2.24%	$ 4,641	
	379	$ 765,618	$ (181,616)	2.04%	$ 15,619	
	394	$ 25,769	$ (7,384)	6.67%	$ 1,718	

WNSA Odorization Expense	Account	Total	Linked to the Odorization Summary
	874	$ 1,545	
	875	$ 58,281	
	878	$ 56	
	889	$ 103,847	
	930	$ 2,672	

WNSA Distrigas

Accounts	Per Book Allocated to TGS	Net Adjustments (with O&M Factor Applied)	Adjusted Allocated to TGS	Adjusted Allocated to Direct	44.10%
926	$ 1,618,838	$ (537,744)	$ 1,081,094	$ 476,772	
930	$ 29,056,473	$ (1,777,087)	$ 27,279,386	$ 12,030,455	

WNSA	Residential	Commercial	Industrial	Public Authority	Water Pumping	School and Municipal	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Fort Bliss	
WEIGHTED RELATIVE COSTS:												
Meters	1.00000	2.08328	8.56160	5.36817	8.96348	6.80322	12.90694	12.94521	12.94521	12.94521	10.13457	Linked to Meters & Regulators Factors tab within the model
Regulators	1.00000	2.41313	9.05047	6.11424	9.32803	8.09525	13.49204	13.49204	13.49204	13.49204	10.55274	Linked to Meters & Regulators Factors tab within the model
Services	1.00000	1.36341	2.05578	1.35349	1.40888	1.07720	2.05186	2.05186	2.05186	2.05186		Linked to Service Line Factors tab within the model
Meters & Regulators	1.00000	2.17386	8.69581	5.57300	9.06357	7.15953	13.06760	13.09536	13.09536	13.09536	10.24939	Linked to Meters & Regulators Factors tab within the model
PEAK DEMANDS:												
Total System	0.68252	0.17422	0.00337	0.06794	0.00250	0.00146	0.01564	0.00837	0.00632	0.00550	0.03216	Linked to Peak Demand tab within the model
Account 385 Factor	0.00000	0.54876	0.01062	0.21399	0.00787	0.00460	0.04927	0.02636	0.01992	0.01731	0.10130	Linked to Peak Demand tab within the model - Non Residential
OTHER ACCOUNTS:												
Account 903	0.94955	0.04821	0.00009	0.00198	0.00003	0.00007	0.00002	0.00002	0.00001	0.00000	0.00002	Linked to 903 Factors tab within the model
Account 904	0.87510	0.12195	0.00064	0.00214	0.00017	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	Linked to 904 Factors tab within the model
Customer Deposits	0.58031	0.39929	0.00506	0.00515	0.00040	0.00005	0.00832	0.00000	0.00000	0.00143	0.00000	Linked to Customer Deposits Factors tab within the model

WNSA	Residential	Commercial	Industrial	Public Authority	Water Pumping	School and Municipal	Comm. Trans.	Industrial Trans.	Public Authority Trans.	CNG Transport	Fort Bliss
Base Revenue	$ 94,066,743	$ 20,232,521	$ 634,581	$ 4,551,682	$ 266,348	$ 153,220	$ 595,241	$ 879,352	$ 250,253	$ 467,600	$ 2,299,383
COG Revenue	$ 51,570,746	$ 19,332,169	$ 566,492	$ 4,254,272	$ 136,823	$ 614,626	$ -	$ -	$ -	$ -	$ 3,282,556

WKP Selected Data

Fort Bliss Plant

Accounts	101	106	Total	Reserve	Net Plant	Depreciation Expense
374	$ 19,533	$ -	$ 19,533	$ (6,316)	$ 13,218	0
376	$ 5,299,379	$ 73,685	$ 5,373,064	$ (784,772)	$ 4,588,292	128,866
378	$ 494,534	$ 137,573	$ 632,107	$ (34,385)	$ 597,722	14,159
380	$ 942,233	$ (25,836)	$ 916,397	$ (158,249)	$ 758,148	29,508
381	$ 108,468	$ 38,984	$ 147,452	$ (47,576)	$ 99,877	6,001
383	$ 57,282	$ 35,020	$ 92,302	$ (15,489)	$ 76,813	3,267
385	$ 330,071	$ -	$ 330,071	$ (36,930)	$ 293,142	7,856
391	$ -	$ -		$ 15,138	$ 15,138	0
390	$ -	$ -		$ -	$ -	0
394	$ 11,690	$ -	$ 11,690	$ (1,169)	$ 10,521	779
397	$ 48,893	$ -	$ 48,893	$ (18,516)	$ 30,377	3,260
	7,312,083	259,426	7,571,509	-1,088,263	6,483,247	193,696

903 Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: 903 FACTORS

WNSA	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	28,984	0.97658	52,437	0.93424	283,659	0.93783	0.94955
Commercial	687	0.02315	3,599	0.06412	17,346	0.05735	0.04821
Industrial	1	0.00003	5	0.00009	41	0.00013	0.00009
Public Authority	5	0.00015	85	0.00152	1,291	0.00427	0.00198
Water Pumping	0	0.00000	2	0.00003	20	0.00007	0.00003
School and Municipal	2	0.00008	0	0.00000	42	0.00014	0.00007
Commercial Transport (1)	0	0.00000	0	0.00000	20	0.00007	0.00002
Industrial Transport	0	0.00000	0	0.00000	15	0.00005	0.00002
Public Authority Transport	0	0.00000	0	0.00000	7	0.00002	0.00001
CNG Transport	0	0.00000	0	0.00000	4	0.00001	0.00000
Fort Bliss	0	0.00000	0	0.00000	19	0.00006	0.00002

WTSA	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	27,074	0.97744	48,490	0.93527	264,551	0.94265	0.95178
Commercial	621	0.02242	3,266	0.06299	14,909	0.05313	0.04618
Industrial	0	0.00000	5	0.00010	33	0.00012	0.00007
Public Authority	4	0.00014	83	0.00161	1,069	0.00381	0.00185
Water Pumping	0	0.00000	2	0.00003	20	0.00007	0.00003
Commercial Transport (1)	0	0.00000	0	0.00000	20	0.00007	0.00002
Industrial Transport	0	0.00000	0	0.00000	15	0.00005	0.00002
Public Authority Transport	0	0.00000	0	0.00000	7	0.00002	0.00001
CNG Transport	0	0.00000	0	0.00000	4	0.00001	0.00000
Fort Bliss	0	0.00000	0	0.00000	19	0.00007	0.00002

NTSA	Pay Agreements		Service Orders		Customers		903
	Number	%	Number	%	Number	%	Factor
Residential	1,300	0.97087	3,039	0.91979	14,080	0.86630	0.91899
Commercial	38	0.02838	263	0.07960	1,954	0.12023	0.07607
Industrial	1	0.00075	0	0.00000	8	0.00049	0.00041
Public Authority	0	0.00000	2	0.00061	211	0.01298	0.00453

BSSA	Pay Agreements	Service Orders	Customers	903

903 Factors

	Number	%	Number	%	Number	%	Factor
Residential	610	0.95164	908	0.92843	5,027	0.90369	0.92792
Commercial	28	0.04368	70	0.07157	483	0.08678	0.06735
Public Authority	1	0.00097	0	0.00000	11	0.00198	0.00098
School and Municipal	2	0.00371	0	0.00000	42	0.00755	0.00375

(1) Electric Cogeneration Transport is included in the Commercial Transport class.

Source: Account 903 WNSA.xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: 904 FACTORS

WNSA	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
3-yr. avg.	$ 749,250	$ 655,671	$ 91,370	$ 482	$ 1,601	$ 126	$ -	$ -	$ -	$ -	$ -	$ -
Factor	1.00000	0.87510	0.12195	0.00064	0.00214	0.00017	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000

Source: Account 904 WNSA.xlsx

**Billing Determinants
Summary**

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.

WEST-NORTH SERVICE AREA

TWELVE MONTHS ENDED DECEMBER 31, 2021

BILLING DETERMINANTS SUMMARY - WNSA

Gas Sales	Test Year Bills	Test Year Volumes	As Adjusted Bills	As Adjusted Volumes
Residential	3,384,959	124,716,236	3,403,902	124,726,694
Commercial	204,650	46,355,471	206,441	46,466,874
Commercial AC	1,670	281,698	1,714	289,044
Industrial	505	1,423,040	487	1,370,091
Public Authority	16,518	11,432,423	15,433	10,211,033
Public Authority AC	60	77,890	60	78,158
School and Municipal	504	335,045	504	330,915
Municipal Water Pumping	240	1,488,751	240	1,486,506
Irrigation	1,669	4,663,437	1,669	4,663,437
Stand By	0	0	0	0
Fort Bliss (City Gate Meters)	229	7,742,066	229	7,939,044
Gas Sales Total	3,611,004	198,516,057	3,630,679	197,561,796
Standard Transportation				
Commercial	252	8,111,104	240	6,717,889
CNG	0	0	48	5,160,298
Industrial	184	6,561,082	180	6,561,058
COGEN	24	1,515,480	24	1,515,480
Public Authority	130	6,371,737	84	2,192,902
Standard Transportation Total	590	22,559,403	576	22,147,627
Transport - Special Contract	96	28,100,120	96	28,100,120
Total	3,611,690	249,175,580	3,631,351	247,809,543

Source: SCH G-2 and SCH G-3 Billing Determinants By Class.xlsx

Customer Deposit Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: CUSTOMER DEPOSIT FACTORS

WNSA

	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	MUNICIPAL WATER PUMPING	SCHOOL AND MUNICIPAL	COMMERCIAL TRANSPORT	INDUSTRIAL TRANSPORT	PUBLIC AUTHORITY TRANSPORT	CNG TRANSPORT	FORT BLISS
	$ 7,640,818	$ 4,434,070	$ 3,050,881	$ 38,644	$ 39,356	$ 3,043	$ 361	$ 63,562	$ -	$ -	$ 10,901	$ -
Assignments		0.58031	0.39929	0.00506	0.00515	0.00040	0.00005	0.00832	0.00000	0.00000	0.00143	0.00000

Source: Customer Deposits WNSA.xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: MAINS STUDY SUMMARY

EL PASO

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	46,552	1	0	27.21	3.3034	1,335,958
2	4,789,768	2	0	29.95	3.3995	159,693,819
3	40,590	3	0	40.37	3.6980	1,572,197
4	1,734,648	4	0	42.38	3.7467	78,058,821
6	432,692	6	0	61.79	4.1237	26,280,062
8	78,557	8	0	110.10	4.7014	6,439,755
10	12,922	10	0	105.33	4.6571	1,429,682
12	14,664	12	0	169.03	5.1301	2,189,872
16	25,801	16	0	221.06	5.3984	7,018,940
1	11,304	1	1	17.37	2.8549	188,827
2	6,514,870	2	1	17.76	2.8770	126,431,387
3	2,313	3	1	23.29	3.1482	52,155
4	1,269,739	4	1	24.99	3.2183	33,258,342
6	593,011	6	1	36.00	3.5834	20,964,561
8	53,283	8	1	49.96	3.9111	2,542,442
Total	15,620,714					467,456,820

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.989701179
R Square	0.979508424
Adjusted R Square	0.976093161
Standard Error	0.123461359
Observations	15

ANOVA

	df	SS	MS	F	Significance F
Regression	2	8.74331562	4.37165781	286.80324090	0.00000000
Residual	12	0.18291249	0.01524271		
Total	14	8.92622810			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.20689	0.06890	46.54395	0.00000	3.05677	3.35702
Size	0.14994	0.00802	18.69223	0.00000	0.13246	0.16742
Plastic	-0.54116	0.06907	-7.83466	0.00000	-0.69166	-0.39067

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	14.38	8,444,521	121,419,164		
Steel	24.70	7,176,193	177,268,218		
			298,687,382	467,456,820	63.90%

Minimum System Study:

	2-inch System Cost	Configured Cost	Customer Portion
Cost/Ft	403,138,057	467,456,820	86.24%

DELL CITY

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	4,644	1	0	27.21	3.3034	126,413
2	32,145	2	0	29.95	3.3995	1,026,009
3	10,664	3	0	40.37	3.6980	399,139
4	43,528	4	0	42.38	3.7467	1,910,421
6	20,712	6	0	61.79	4.1237	1,249,964
1	13,774	1	1	17.37	2.8549	220,937
2	319,344	2	1	17.76	2.8770	6,006,724
4	33,911	4	1	24.99	3.2183	877,073
6	5,915	6	1	36.00	3.58	210,348
	484,637					12,027,029

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.991767551
R Square	0.983602875
Adjusted R Square	0.978137167
Standard Error	0.061293908
Observations	9

ANOVA

	df	SS	MS	F	Significance F
Regression	2	1.35219079	0.67609540	179.95890740	0.00000441
Residual	6	0.02254166	0.00375694		
Total	8	1.37473245			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.144705207	0.045313211	69.399302192	0.000000001	3.033827774	3.255582639
Size	0.159240497	0.011275572	14.122609503	0.000007871	0.131650167	0.186830827
Plastic	-0.528820954	0.041121069	-12.860097521	0.000013589	-0.629440584	-0.428201323

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	13.68	372,944	5,101,611		
Steel	23.21	111,693	2,592,720		
			7,694,330	12,027,029	63.98%

Minimum System Study:

	2-inch System Cost	Configured Cost	Customer Portion
Cost/Ft	10,579,993	12,027,029	87.97%

PERMIAN

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	48,682	1	0	89.03	4.4890	4,234,430
2	854,532	2	0	91.77	4.5193	81,989,647
3	73,879	3	0	111.96	4.7181	7,819,037
4	211,291	4	0	113.97	4.7359	24,666,860
6	210,408	6	0	140.50	4.9452	29,887,944
1	10,600	1	1	54.67	4.0014	567,834
2	325,006	2	1	55.06	4.0085	19,204,774
3	27,114	3	1	68.78	4.2309	1,767,324
4	76,951	4	1	70.47	4.2552	5,532,670
6	48,787	6	1	88.93	4.4879	4,268,026
Total	1,887,250					179,938,546

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.991319847
R Square	0.982715039
Adjusted R Square	0.977776479
Standard Error	0.046814472
Observations	10

ANOVA

	df	SS	MS	F	Significance F
Regression	2	0.87220284	0.43610142	198.98816350	0.00000068
Residual	7	0.01534116	0.00219160		
Total	9	0.88754400			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	4.36761	0.03459	126.26675	0.00000	4.28582	4.44940
Size	0.09809	0.00860	11.39983	0.00001	0.07775	0.11844
Plastic	-0.48472	0.02961	-16.37132	0.00000	-0.55474	-0.41471

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	48.56	488,458	23,721,611		
Steel	78.86	1,398,792	110,301,754		
			134,023,365	$179,938,546	74.48%

Minimum System Study:

	2-inch System Cost	Configured Cost	Customer Portion
Cost/Ft	163,072,972	179,938,546	90.63%

NORTH TEXAS SERVICE AREA

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	97,158	1	0	40.15	3.6926	3,541,142
2	621,078	2	0	41.20	3.7184	25,650,067
3	80,012	3	0	49.69	3.9057	3,744,317
4	400,844	4	0	52.82	3.9668	21,255,435
6	109,892	6	0	68.22	4.2228	7,481,920
8	15,941	8	0	85.74	4.4513	1,393,533
10	1,703	10	0	98.28	4.5878	191,121
1	97,225	1	1	16.28	2.7898	1,624,550
2	861,732	2	1	16.90	2.8275	16,315,620
3	134,570	3	1	20.17	3.0042	2,887,066
4	716,878	4	1	22.96	3.1338	17,427,234
6	108,993	6	1	34.24	3.5335	3,401,981
8	980	8	1	47.30	3.8565	39,261
Total	3,247,006					104,953,249

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.989447582
R Square	0.979006518
Adjusted R Square	0.974807822
Standard Error	0.093605801
Observations	13

ANOVA

	df	SS	MS	F	Significance F
Regression	2	4.08607793	2.04303896	233.16916510	0.00000000
Residual	10	0.08762046	0.00876205		
Total	12	4.17369839			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.47090	0.05782	60.03298	0.00000	3.34207	3.59972
Size	0.12497	0.00941	13.27467	0.00000	0.10400	0.14595
Plastic	-0.77991	0.05270	-14.79938	0.00000	-0.89733	-0.66249

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	14.75	1,920,378	28,318,245		
Steel	32.17	1,326,627	42,671,693		
			70,989,938	$104,953,249	67.64%

Minimum System Study:

	2-inch System Cost	Configured Cost	Customer Portion
Cost/Ft	91,148,287	104,953,249	86.85%

Mains Study Summary

BORGER-SKELLYTOWN SERVICE AREA

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	3,733	1	0	38.17	3.6420	137,427
2	317,957	2	0	40.91	3.7114	13,291,164
3	5,755	3	0	50.80	3.9279	273,169
4	63,992	4	0	52.82	3.9668	3,448,836
6	27,509	6	0	68.22	4.2228	1,911,485
8	5,537	8	0	85.74	4.4513	496,087
1	9,293	1	1	16.51	2.8042	151,424
2	153,679	2	1	16.90	2.8275	2,843,419
3	12,474	3	1	21.22	3.0549	262,055
4	58,078	4	1	22.91	3.1316	1,385,459
6	12,613	6	1	34.24	3.5335	387,922
Total	670,620					24,588,447

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.995058249
R Square	0.990140920
Adjusted R Square	0.987676150
Standard Error	0.061909946
Observations	11

ANOVA

	df	SS	MS	F	Significance F
Regression	2	3.07943783	1.53971891	401.71735420	0.00000001
Residual	8	0.03066273	0.00383284		
Total	10	3.11010056			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.47884	0.04354	79.90524	0.00000	3.37844	3.57924
Size	0.12705	0.00886	14.33573	0.00000	0.10661	0.14749
Plastic	-0.81504	0.03815	-21.36253	0.00000	-0.90302	-0.72706

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	14.35	246,137	3,532,232		
Steel	32.42	424,484	13,762,646		
			17,294,878	$24,588,447	70.34%

Minimum System Study:

	2-inch System Cost	Configured Cost	Customer Portion
Cost/Ft	22,298,240	24,588,447	90.69%

	Customer Portion	Footage
EL PASO	63.90 %	15,620,714
DELL CITY	63.98 %	484,637
PERMIAN	74.48 %	1,887,250
NORTH TEXAS	67.64 %	3,247,006
BORGER SKELLYTOWN	70.34 %	670,620
		21,910,227
WNSA	65.56 %	

FORT BLISS

Size	Footage	Size	Plastic	Cost/Ft	LN(Cost/Ft)	Configured Cost
1	9,593	1	0	27.21	3.3034	275,829
2	88,185	2	0	29.95	3.3995	2,948,169
3	12,212	3	0	40.37	3.6980	474,653
4	87,405	4	0	42.38	3.7467	3,949,959
6	21,887	6	0	61.79	4.1237	1,337,053
8	22,436	8	0	110.10	4.7014	1,852,632
12	7,469	12	0	169.03	5.1301	1,127,021
16	11,037	16	0	221.06	5.3984	3,042,924
1	2,913	1	1	17.37	2.8549	48,547
2	135,115	2	1	17.76	2.8770	2,618,127
3	11,533	3	1	23.29	3.1482	259,817
4	214,776	4	1	24.99	3.2183	5,625,632
6	87,289	6	1	36.00	3.5834	3,090,598
8	1,397	8	1	49.96	3.9111	66,853
Total	713,245					26,717,813

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.988998505
R Square	0.978118044
Adjusted R Square	0.974139506
Standard Error	0.127940062
Observations	14

ANOVA

	df	SS	MS	F	Significance F
Regression	2	8.04842537	4.02421269	245.84864080	0.00000000
Residual	11	0.18005525	0.01636866		
Total	13	8.22848063			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	3.20809	0.07146	44.89521	0.00000	3.05082	3.36537
Size	0.15070	0.00851	17.70802	0.00000	0.13197	0.16943
Plastic	-0.54541	0.07230	-7.54403	0.00001	-0.70454	-0.38629

Zero-Inch Study:

	Zero-Inch Cost/Ft	Footage	Zero-Inch Cost	Configured Cost	Customer Portion
Plastic	14.33	453,022	6,493,921		
Steel	24.73	260,224	6,435,818		
			12,929,739	$26,717,813	48.39%

Minimum System Study:

	2-inch System Cost	Configured Cost	Customer Portion
Cost/Ft	17,477,883	26,717,813	65.42%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: METER AND REGULATOR FACTORS

WNSA

	Residential	Commercial	Industrial	Public Authority	Municipal Water Pumping	School and Municipal	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Fort Bliss
WNSA Weighted Factors:											
Factors:											
Meters	1.00000	2.08328	8.56160	5.36817	8.96348	6.80322	12.90694	12.94521	12.94521	12.94521	10.13457
Regulators	1.00000	2.41313	9.05047	6.11424	9.32803	8.09525	13.49204	13.49204	13.49204	13.49204	10.55274
Meters & Regulators	1.00000	2.17386	8.69581	5.57300	9.06357	7.15953	13.06760	13.09536	13.09536	13.09536	10.24939

Source: Meters and Regulators WNSA.xlsx

Odorization Summary

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: ODORIZATION PLANT AND EXPENSE SUMMARY

Odorization Equipment (Plant in Service and CCNC)

WNSA

Account		Book Cost	Allocated Reserve	Net Value
	369	$ 101,675	$ 11,221	$ 90,454
	378	$ 207,194	$ 37,155	$ 170,040
	379	$ 765,618	$ 181,616	$ 584,002
	394	$ 25,769	$ 7,384	$ 18,384
Total		$ 1,100,256	$ 237,376	$ 862,880

WTSA

Account		Book Cost	Allocated Reserve	Net Value
	369	$ 101,675	$ 11,221	$ 90,454
	378	$ 183,414	$ 36,441	$ 146,973
	379	$ 730,374	$ 179,518	$ 550,856
	394	$ 8,737	$ 87	$ 8,649
Total		$ 1,024,200	$ 227,267	$ 796,933

NTSA

Account		Book Cost	Allocated Reserve	Net Value
	378	$ 22,098	$ (195)	$ 22,293
	379	$ 21,519	$ (738)	$ 22,257
	394	$ 13,097	$ 6,228	$ 6,869
Total		$ 56,714	$ 5,295	$ 51,419

BSSA

Account		Book Cost	Allocated Reserve	Net Value
	378	$ 1,682	$ 909	$ 773
	379	$ 13,726	$ 2,837	$ 10,889
	394	$ 3,935	$ 1,069	$ 2,866
Total		$ 19,342	$ 4,815	$ 14,527

Odorization Expense

Account		WTSA	NTSA	BSSA	WNSA
	8740	$ -	$ 1,103	$ 442	$ 1,545
	8750	$ 58,181	$ 100	$ -	$ 58,281
	8780	$ 56	$ -	$ -	$ 56
	8890	$ 87,787	$ 16,059	$ -	$ 103,847
	9302	$ 2,672	$ -	$ -	2672.14
Total		$ 148,696	$ 17,263	$ 442	$ 166,400

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: PEAK DEMAND SUMMARY

WNSA PEAK DEMAND

	Total	Residential	Commercial	Industrial	Public Authority	Municipal Water Pumping	School and Municipal	Commercial Transport	Industrial Transport	Public Authority	CNG Transport	Fort Bliss
WTSA	2,153,657	1,493,123	344,367	6,620	139,915	6,016	0	37,642	20,140	15,220	13,224	77,389
NTSA	193,114	110,130	59,045	1,492	22,446	0	0	0	0	0	0	0
BSSA	59,663	39,190	15,833	0	1,128	0	3,511	0	0	0	0	0
	2,406,433	1,642,443	419,246	8,112	163,490	6,016	3,511	37,642	20,140	15,220	13,224	77,389
Peak Demand - WNSA	1.00000	0.68252	0.17422	0.00337	0.06794	0.00250	0.00146	0.01564	0.00837	0.00632	0.00550	0.03216
Non-Residential Demand - WNSA	1.00000	0.00000	0.54876	0.01062	0.21399	0.00787	0.00460	0.04927	0.02636	0.01992	0.01731	0.10130

WTSA PEAK DEMAND

El Paso	Total	Residential	Commercial	Industrial	Public Authority	Municipal Water Pumping	School and Municipal	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Fort Bliss
Monthly Base Load		14.00	214		244	5,536				16,185		23,576
Weather Factor		0.13977	0.44079		2.7613	2.7613				42.7585		92.6084
HDD		37	37		37	37	N/A			37		37
Est. Peak Day Use/Customer		5.72	24.10	213.54	111.79	300.81			1,438.56	2,174.35	3,305.88	4,299.39
Days												
28												
Customers - February		251,703	13,589	31	1,108	20			14	7	4	18
Calculated Peak Day Usage - El Paso	2,066,945	1,439,277	327,550	6,620	123,867	6,016		37,642	20,140	15,220	13,224	77,389

Permian	Total	Residential	Commercial	Industrial	Public Authority	Municipal Water Pumping	School and Municipal	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Fort Bliss
Monthly Base Load		13.05	138		229							
Weather Factor		0.1234	0.3025		1.5781							
HDD		46	46		46		N/A					
Est. Peak Day Use/Customer		6.10	18.75	0.04	80.24							
Days												
28												
Customers - February		8,828	897	4	200							
Calculated Peak Day Usage - Permian	86,712	53,846	16,817	0.1	16,049	0	0	0	0	0	0	0
Calculated Peak Day Usage - WTSA	2,153,657	1,493,123	344,367	6,620	139,915	6,016	0	37,642	20,140	15,220	13,224	77,389
Peak Factors	1.00000	0.69330	0.15990	0.00307	0.06497	0.00279		0.01748	0.00935	0.00707	0.00614	0.03593
Non Residential Demand Factors	1.00000		0.52135	0.01002	0.21182	0.00911		0.05699	0.03049	0.02304	0.02002	0.11716

NON-WEATHER SENSITIVE CLASSES - EL PASO

	Residential	Commercial	Industrial	Public Authority	Municipal Water Pumping	School and Municipal	Commercial Transport	Industrial Transport	Public Authority Transport	CNG Transport	Fort Bliss	COGEN Transport
February Per Day Usage			163					1,417	0	3,306		5855
Assumed Winter Load Factor (2)			76.49%					98.53%	0.00%	100.00%		74.10%
Calculated Peak Day Usage			214			N/A		1,439	0	3,306		7,901
Average February Usage			4,574					39,686		92,565		163,940
Average Monthly Usage			3,499					39,101		107,506		121,484

(1) Commercial Transportation included Commercial Cogeneration Transportation as follows:

	Commercial Transport	COGEN Transport	
Monthly Base Load	26,307		
Weather Factor	14.66495		
HDD	37		
Est. Peak Day Use/Customer	1,487	7,901	
Customers - February	20	1.00	
Calculated Peak Day Usage	29,741	7,901	37,642

NON-WEATHER SENSITIVE CLASSES - PERMIAN

	Residential	Commercial	Industrial	Public Authority
February Per Day Usage			0.0357	
Assumed Winter Load Factor (2)			100.00%	
Calculated Peak Day Usage/Customer			0.0357	
Average February Usage			1	
Average Monthly Usage			6	

NTSA PEAK DEMAND

	Total	Residential	Commercial	Industrial	Public Authority
Monthly Base Load		12	272		277
Weather Factor		0.14782	0.42139		1.89205
HDD		51	51		51
Est. Peak Day Use/Customer		7.98	31.21	186.51	106.38
Days					
28					
Customers - February		13,804	1,892	8	211
Calculated Peak Day Usage - NTSA	193,114	110,130	59,045	1,492	22,446

Peak Demand

	Total	Residential	Commercial	Industrial	Public Authority
Peak Factors - NTSA	1.00000	0.57029	0.30576	0.00773	0.11623
Non Residential Demand Factors - NTSA	1.00000		0.71153	0.01798	0.27049

NON-WEATHER SENSITIVE CLASSES - NTSA	Residential	Commercial	Industrial	Public Authority
February Per Day Usage			128	
Assumed Winter Load Factor (2)			68.61%	
Calculated Peak Day Usage/Customer			187	
Average February Usage			3,583	
Average Monthly Usage			2,459	

BSSA PEAK DEMAND		Total	Residential	Commercial	Industrial	Public Authority	Municipal Water Pumping	School and Municipal
Monthly Base Load			17	117		44		134
Weather Factor			0.13147	0.53991		1.54062		1.54062
HDD			55	55	N/A	55	N/A	55
Est. Peak Day Use/Customer			7.88	34.05		86.80		90.03
Days	28							
Customers - February			4,972	465		13		39
Calculated Peak Day Usage - BSSA		59,663	39,190	15,833	0	1,128	0	3,511
Peak Factors		1.00000	0.65685	0.26538	0.00000	0.01891	0.00000	0.05885
Non Residential Demand Factors		1.00000		0.77337	0.00000	0.05512	0.00000	0.17151

Source: Peak Demand WNSA.xlsx

Service Charges Summary

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: SERVICE CHARGES SUMMARY

WNSA

	Call Center	%	As Adj. Test Year	
Residential	$ 1,289,294	92.93%	$ 1,456,428	
Commercial	96,711	6.97%	109,248	
Industrial	41	0.00%	46	
Public Authority	1,257	0.09%	1,420	
Municipal Water Pumping	94	0.01%	107	
School and Municipal	8	0.00%	9	
Commercial Transport	6	0.00%	6	
Industrial Transport	8	0.00%	9	
Public Authority Transport	5	0.00%	5	
CNG Transport	8	0.00%	9	
Fort Bliss	-	0.00%	-	
	$1,387,431		$1,567,287	Linked to As Adjusted Revenues Summary tab within the model

Source: Service Charges WNSA.xlsx

Service Line Factors

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS COST OF SERVICE STUDY: SERVICE LINE FACTORS SUMMARY

WNSA	WTSA Factor	WTSA Meters	NTSA Factor	NTSA Meters	BSSA Factor	BSSA Meters	WNSA Weighted Factors
Residential	1.00000	264,551	1.00000	14,080	1.00000	5,027	1.00000
Commercial	1.40888	14,909	1.08723	1,954	1.07720	483	1.36341
Industrial	2.05186	33	2.07175	8			2.05578
Public Authority	1.40888	1,069	1.08723	211	1.07720	11	1.35349
Municipal Water Pumping	1.40888	20					1.40888
School and Municipal					1.07720	42	1.07720
Commercial Transport	2.05186	20					2.05186
Industrial Transport	2.05186	15					2.05186
Public Authority Transport	2.05186	7					2.05186
CNG Transport	2.05186	4					2.05186
Fort Bliss							

WTSA	Cost	Factor
Residential	$ 1,148.32	1.00000
Commercial	$ 1,617.85	1.40888
Industrial	$ 2,356.19	2.05186
Public Authority	$ 1,617.85	1.40888
Municipal Water Pumping	$ 1,617.85	1.40888
Commercial Transport	$ 2,356.19	2.05186
Industrial Transport	$ 2,356.19	2.05186
Public Authority Transport	$ 2,356.19	2.05186
CNG Transport	$ 2,356.19	2.05186
Fort Bliss		

NTSA	Cost	Factor
Residential	$ 1,505.66	1.00000
Commercial	$ 1,637.00	1.08723
Industrial	$ 3,119.35	2.07175
Public Authority	$ 1,637.00	1.08723

BSSA	Cost	Factor
Residential	$ 1,776.89	1.00000
Commercial	$ 1,914.07	1.07720
Public Authority	$ 1,914.07	1.07720
School and Municipal	$ 1,914.07	1.07720

Source: Service Lines WNSA.xlsx

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

SUMMARY AS ADJUSTED REVENUES - WNSA

Line No.	Revenue Class	WNSA Cost of Service	Removal of Cost of Gas	Removal of Weatherford Franchise Fee on Cost of Gas	Removal of WNA	Weather Normalization	Switching	Growth (Loss)	Removal of GRIP	GRIP Annualization	COSA Annualization	Total As Adjusted Revenue
	Gas Sales											
1	Residential	$135,896,303	$(50,639,720)	$51,286	$(590,999)	$(98,210)	$0	$542,949	$(16,518,447)	$24,904,707	$518,872	$94,066,743
2	Commercial	37.902.534	(19.894.671)	88.293	(42.156)	(38.859)	0	166.114	(2.889.290)	4.405.844	405.812	20.103.621
3	Commercial AC	228,217	(115,950)	0	(486)	(77)	0	3,387	(27,223)	41,032	0	128,900
4	Public Authority	9.087.651	(4.716.680)	10.432	(45.173)	(20.399)	34.507	(347.103)	(910.798)	1.355.445	84.566	4.532.447
5	Public Authority AC	48,529	(31,039)	0	(202)	33	0	0	(3,832)	5,746	0	19,235
6	Municipal Water Pumping	864,648	(626,678)	0	0	(115)	0	0	(53,631)	82,123	0	266,348
7	School and Municipal	287.156	(138.387)	0	3.187	(1.555)	0	0	(3.129)	5.947	0	153.220
8	Fort Bliss (City Gate)	4,363,011	(3,784,214)	0	0	14,726	0	0	0	0	0	593,523
9	Industrial	1.170.820	(637.321)	1.926	0	0	0	(21.068)	(162.650)	268.684	14.189	634.581
10	Irrigation	2,082,321	(1,648,230)	0	0	0	0	0	0	0	0	434,091
11	Total Gas Sales Revenue	$191,931,191	$(82,232,891)	151,937	$(675,828)	(144,456)	$34,507	$344,280	$(20,569,000)	$31,069,529	$1,023,439	$120,932,709

Line No.	Standard Tranportation	WNSA Cost of Service	Removal of Interest on Storage	Removal of Estimated Delivery Charges	Service Fee Annualization	Weather Normalization	Switching	Termination	Reclass to CNG Transport	Removal of GRIP	GRIP Annualization	Fort Bliss CRC Annualization	East Bliss Maintenance Agreement Annualization	Total As Adjusted Revenue
12	Commercial	$611.885	$0	$0	$0	$(2.072)	$0	$0	$(89.556)	$(3.949)	$5.897	$0	$0	$522.204
13	Cogeneration	72,824	0	0	0	0	0	0	0	(376)	590	0	0	73,037
14	CNG	-	0	0	0	0	0	0	463,857	0	3,742	0	0	467,600
15	Public Authority	664.116	0	0	0	(3.378)	(37.183)	0	(374.301)	(8.003)	9.001	0	0	250.253
16	Industrial	836,923	0	0	0	0	0	(2,937)	0	(75,508)	120,875	0	0	879,352
17	Total Standard Tranportation Revenue	$2.185.747	$0	$0	$0	$(5.450)	$(37.183)	$(2.937)	$0	$(87.836)	$140.105	$0	$0	$2.192.446
18	Special Contract Tranportation Revenue	$1.067.474	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1.067.474
19	Fort Bliss (Distribution System On the Base)	1,390,305	0	0	0	0	0	0	0	0	0	15,555	300,000	1,705,860
20	Estimated Delivery	2.533	0	(2.533)	0	0	0	0	0	0	0	0	0	0
21	Total Special Contract Transportation Revenue	$2,460,312	$0	$(2,533)	$0	$0	$0	$0	$0	$0	$0	$15,555	$300,000	$2,773,333
22	Total Transporation Revenue	$4.646.058	$0	$(2.533)	$0	$(5.450)	$(37.183)	$(2.937)	$0	$(87.836)	$140.105	$15.555	$300.000	$4.965.779
	Misc. Revenue													
23	Service Fee's - Acct 4880	$1.190.570	$0	$0	$376.717	$0	$0	$0	$0	$0	$0	$0	$0	$1.567.287
24	Utility Revenue - Acct 4950	284,645	(284,645)	0	0	0	0	0	0	0	0	0	0	$0
25	Total Misc. Revenue	$1.475.215	$(284.645)	$0	$376.717	$0	$0	$0	$0	$0	$0	$0	$0	$1.567.287
26	Total Trasnsport & Other Misc. Revenue	$6,121,274	$(284,645)	$(2,533)	$376,717	$(5,450)	$(37,183)	$(2,937)	$0	$(87,836)	$140,105	$15,555	$300,000	$6,533,067
27	Total Revenue	$198,052,464												$127,465,775

Source: SCH G-2 and SCH G-3 Proof of Revenues.xlsx

Class Revenue
Allocation

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CLASS REVENUE ALLOCATION

LINE NO.	DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Current Revenue-to-Cost Ratio (1)	0.9075	0.8089	1.4877	3.1400	1.4836	2.1942	0.9794	
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	1.0000	
5	Rate Design Revenue Increase	$ 12,995,128	$ 22,865,615	$ (6,913,372)	$ (1,035,345)	$ (1,714,908)	$ (255,745)	$ 48,883	
6	% Increase - Non-Gas Revenue (2)	10.19%	23.62%	-32.78%	-68.15%	-32.60%	-54.43%	2.10%	
7	% Increase - Total Revenue (3)	6.27%	15.41%	-17.10%	-49.64%	-16.70%	-54.43%	0.87%	
8	Revenue Allocation Two - Partial Movement Toward Cost of Service (4)								
9	Revenue-to-Cost Ratio	1.0000	0.9337	1.3902	2.7120	1.3869	1.9554	1.0000	
10	Rate Design Revenue Increase	$ 12,995,128	$ 14,930,119	$ (1,382,674)	$ (207,069)	$ (342,982)	$ (51,149)	$ 48,883	20.%
11	% Increase - Non-Gas Revenue (2)	10.19%	15.42%	-6.56%	-13.63%	-6.52%	-10.89%	2.10%	
12	% Increase - Total Revenue (3)	6.27%	10.06%	-3.42%	-9.93%	-3.34%	-10.89%	0.87%	
13	Revenue Allocation Three - No Movement Toward Cost of Service for Classes Requiring Revenue Decreases (5)								
14	Revenue-to-Cost Ratio	1.0000	0.9171	1.4877	3.1400	1.4836	2.1942	1.0000	
15	Rate Design Revenue Increase	$ 12,995,128	$ 12,946,245	$ -	$ -	$ -	$ -	$ 48,883	
16	% Increase - Non-Gas Revenue (2)	10.19%	13.37%	0.00%	0.00%	0.00%	0.00%	2.10%	
17	% Increase - Total Revenue (3)	6.27%	8.73%	0.00%	0.00%	0.00%	0.00%	0.87%	

(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.

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	PUBLIC AUTHORITY	CNG	FORT BLISS
Base With Service Charges and Other (COS)	$ 127,465,775	$ 96,802,455	$ 21,088,554	$ 1,519,161	$ 5,260,951	$ 469,898	$ 2,324,758
COG Revenue	$ 79,757,685	$ 51,570,746	$ 19,332,169	$ 566,492	$ 5,005,721	$ -	$ 3,282,556
Base Revenue	$ 124,396,924	$ 94,066,743	$ 20,827,763	$ 1,513,933	$ 5,221,502	$ 467,600	$ 2,299,383
COS	$ 140,460,903	$ 119,668,070	$ 14,175,182	$ 483,816	$ 3,546,043	$ 214,153	$ 2,373,641
COS Revenue Increase	$ 12,995,128	$ 22,865,615	$ (6,913,372)	$ (1,035,345)	$ (1,714,908)	$ (255,745)	$ 48,883
Fixed Costs		$ 119,187,517	$ 13,963,317	$ 148,861	$ 3,490,949	$ 194,271	$ 2,343,049
Bills		3,403,902	208,419	667	16,321	48	229
Fixed Costs/Bill		$ 35.01	$ 67.00	$ 223.18	$ 213.89	$ 4,047.31	$ 10,232

Proof of Revenue

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROOF OF REVENUE

Line No.	Description	Bills	Volumes		Recommended Rates: Customer Charge	Recommended Rates: Usage Charges	Calculated Revenue at Recommended Rates		Assigned Revenue	Rounding Diff.	GRIP Allocation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Residential - Small	2,037,081			$ 20.00		$ 40,741,620				
2			All Ccf	49,102,655		0.41173	$ 20,217,036				
3	Residential - Large	1,366,821			$ 35.00		$ 47,838,735				
4			All Ccf	75,624,039		0.00264	$ 199,647				
5	Residential Total							$ 108,997,039	$ 108,996,862	$ 177	80.71 %
6											
7	Commercial	208,155			$ 75.00		$ 15,611,593				
8			All Ccf	46,755,918		0.06808	$ 3,183,143	$ 18,794,736			
9											
10											
11	Commercial Transportation	240			$ 500.00		$ 120,000				
12			All Ccf	6,717,889		0.06808	$ 457,354	$ 577,354			
13											
14	Electrical Cogeneration Transportation	24			$ 700.00		$ 16,800				
15			Oct.-Apr								
16			First 5000	35,010		0.05260	$ 1,842				
17			Next 95000	665,000		0.04260	$ 28,329				
18			Next 300000	240,050		0.03260	$ 7,826				
19			Over 400000	0		0.02260	$ -				
20			May-Sep								
21			First 5000	25,000		0.04259	$ 1,065				
22			Next 95000	475,000		0.03258	$ 15,476				
23			Next 300000	75,420		0.02259	$ 1,704				
24			Over 400000	0		0.01258	$ -	$ 73,040			
25											
26	Commercial Total							$ 19,445,130	$ 19,445,088	$ 42	14.40 %
27											
28	Industrial	487			$ 850.00		$ 413,950				
29			All Ccf	1,370,091		0.08875	$ 121,596	$ 535,546			
30											
31	Industrial Transportation	180			$ 1,050.00		$ 189,000				
32			All Ccf	6,561,058		0.08875	$ 582,294	$ 771,294			
33											
34	Industrial Total							$ 1,306,840	$ 1,306,864	$ (25)	0.97 %
35											
36	Public Authority	16,237			$ 200.00		$ 3,247,429				
37			All Ccf	12,106,612		$ 0.11113	$ 1,345,408	$ 4,592,837			
38											
39	Public Authority Transportation	84			$ 500.00		$ 42,000				
40			All Ccf	2,192,902		$ 0.11113	$ 243,697	$ 285,697			
41											
42	Public Authority Total							$ 4,878,534	$ 4,878,521	$ 14	3.61 %
43											
44	CNG Transportation	48			$ 450.00		$ 21,600				
45			All Ccf	5,160,298		$ 0.07652	$ 394,866	$ 416,466			
46											
47	CNG Total							$ 416,466	$ 416,451	$ 15	0.31 %
48											
49	Total Revenue - All Classes										
50											
51	Recommended Rate Revenue							$ 135,044,009	$ 135,043,785		
52	Current Rate Revenue							$ 122,097,541	$ 122,097,541		
53	Revenue Change							$ 12,946,468	$ 12,946,245		
54											
55	Fort Bliss Assigned Rev. Change. (1)								$ 48,883		
56	Total Change - All Classes								$ 12,995,128		
57											
58	Schedule A - Revenue Deficiency								$ 12,995,128		

(1) The amount reflects the revenue change assigned to Fort Bliss shown on the Class Revenue Allocation tab within the model.

Current Rec Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CURRENT AND RECOMMENDED RATES

Description		Current Rates: WTSA Incorporated and Environs Rates	Current Rates: NTSA Environs Rates	Current Rates: NTSA Incorporated Rates	Current Rates: BSSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(c)	(d)	(e)	(f)	(g)
Residential						Small	Large
Customer Charge		$23.53	$24.50	$15.44	$16.00	$20.00	$35.00
Usage Rates	All Ccf	$0.09317	$0.59366	$0.67101	$0.21548	$0.41173	$0.00264
Commercial							
Customer Charge - Sales		$63.58	$76.33	$47.80	$37.08	$75.00	
Usage Rates	All Ccf		$0.60165	$0.68165	$0.29344	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Customer Charge - Transportation		$424.58	$509.26	$250.00	$252.08	$500.00	
Usage Rates	All Ccf		$0.57978	$0.57978	$0.29344	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Commercial Air Conditioning							
Customer Charge - Sales		$63.58	N/A	N/A	N/A	$75.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Usage Rates - (May - September)	All Ccf		N/A	N/A	N/A		
	First 500	$0.06223					
	All Over 500	$0.04223					
Electrical Cogeneration							
Customer Charge - Sales		$424.58	N/A	N/A	N/A	$700.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.05696				$0.05260	
	Next 95,000	$0.04696				$0.04260	
	Next 300,000	$0.03696				$0.03260	
	All Over 400,000	$0.02696				$0.02260	
Usage Rates - (May-September)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.04695				$0.04259	
	Next 95,000	$0.03694				$0.03258	
	Next 300,000	$0.02695				$0.02259	
	All Over 400,000	$0.01694				$0.01258	
Customer Charge - Transportation		$424.58	N/A	N/A	N/A	$700.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.05696				$0.05260	
	Next 95,000	$0.04696				$0.04260	
	Next 300,000	$0.03696				$0.03260	
	All Over 400,000	$0.02696				$0.02260	
Usage Rates - (May-September)	All Ccf		N/A	N/A	N/A		
	First 5,000 Ccf	$0.04695				$0.04259	
	Next 95,000	$0.03694				$0.03258	
	Next 300,000	$0.02695				$0.02259	
	All Over 400,000	$0.01694				$0.01258	
Industrial							
Customer Charge - Sales		$857.20	$509.26	$308.59	N/A	$850.00	
Usage Rates	All Ccf		$0.55395	$0.62874	N/A	$0.08875	
	First 500	$0.12458					
	All Over 500	$0.10458					
Customer Charge - Transportation		$424.58	$509.26	$250.00	N/A	$1,050.00	
Usage Rates	All Ccf		$0.55395	$0.55395	N/A	$0.08875	
	First 500	$0.12458					
	All Over 500	$0.10458					
Standby Service							
Customer Charge - Sales		$666.37	N/A	N/A	N/A	$666.37	

Current Rec Rates

Usage Rates	Per Mcf/Hour	$20.00	N/A	N/A	N/A	$20.00
Public Authority						
Public Authority						
Customer Charge - Sales		$195.79	$160.93	$101.32	$47.08	$200.00
Usage Rates	All Ccf		$0.54101	$0.61329	$0.23148	$0.11113
	First 500	$0.11461				
	All Over 500	$0.09461				
Customer Charge - Transportation		$495.79	$325.93	$250.00	$252.08	$500.00
Usage Rates	All Ccf		$0.54101	$0.54101	$0.23148	$0.11113
	First 500	$0.11461				
	All Over 500	$0.09461				
Public Authority Air Conditioning						
Customer Charge - Sales		$195.79	N/A	N/A	N/A	$200.00
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A	$0.11113
	First 500	$0.11461				
	All Over 500	$0.09461				
Usage Rates - (May-September)	All Ccf		N/A	N/A	N/A	
	First 500	$0.08461				
	All Over 500	$0.06461				
School and Municipal						
Customer Charge - Sales		N/A	N/A	N/A	$51.02	$200.00
Usage Rates	All Ccf		N/A	N/A	$0.37651	$0.11113
	First 500	N/A				
	All Over 500	N/A				
Customer Charge - Transportation					$256.02	$500.00
Usage Rates	All Ccf		N/A	N/A	$0.37651	$0.11113
	First 500	N/A				
	All Over 500	N/A				
Municipal Water Pumping						
Customer Charge - Sales		$768.75	N/A	N/A	N/A	$200.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.11113
	First 5000	$0.06111				
	All Over 5000	$0.05111				
CNG						
Customer Charge - Sales		N/A	N/A	N/A	N/A	$150.00
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	$0.07652
Customer Charge - Transportation (reclassed from Commercial)		$424.58	N/A	N/A	N/A	$450.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.07652
	First 500	$0.08223				
	All Over 500	$0.06223				
Customer Charge - Transportation (reclassed from Public Authority)		$495.79	N/A	N/A	N/A	$450.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.07652
	First 500	$0.11461				
	All Over 500	$0.09461				

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CURRENT AND RECOMMENDED RATES WORKPAPER

Description		Current Rates: WTSA Incorporated and Environs Rates	Current Rates: NTSA Environs Rates	Current Rates: NTSA Incorporated Rates	Current Rates: BSSA Incorporated and Environs Rates	Recommended	
(a)		(b)	(d)	(e)	(f)	(g)	(h)
Residential						Small	Large
Customer Charge		$23.53	$24.50	$15.44	$16.00	$20.00	$35.00
Usage Rates	All Ccf	$0.09317	$0.59366	$0.67101	$0.21548	$0.41173	$0.00264
Commercial							
Customer Charge - Sales		$63.58	$76.33	$47.80	$37.08	$75.00	
Usage Rates	All Ccf		$0.60165	$0.68165	$0.29344	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Customer Charge - Transportation		$424.58	$509.26	$250.00	$252.08	$500.00	
Usage Rates	All Ccf		$0.57978	$0.57978	$0.29344	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Commercial Air Conditioning (1)							
Customer Charge - Sales		63.58	N/A	N/A	N/A	75.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A	$0.06808	
	First 500	$0.08223					
	All Over 500	$0.06223					
Usage Rates - (May - September)	All Ccf		N/A	N/A	N/A		
	First 500	$0.06223					
	All Over 500	$0.04223					
Industrial							
Customer Charge - Sales		$857.20	$509.26	$308.59	N/A	$850.00	
Usage Rates	All Ccf		$0.55395	$0.62874	N/A	$0.08875	
	First 500	$0.12458					
	All Over 500	$0.10458					
Customer Charge - Transportation		$424.58	$509.26	$250.00	N/A	$1,050.00	
Usage Rates	All Ccf		$0.55395	$0.55395	N/A	$0.08875	
	First 500	$0.12458					
	All Over 500	$0.10458					
Public Authority							
Customer Charge - Sales		$195.79	$160.93	$101.32	47.08	$200.00	
Usage Rates	All Ccf		$0.54101	$0.61329	$0.23148	$0.11113	
	First 500	$0.11461					
	All Over 500	$0.09461					
Customer Charge - Transportation		$495.79	$325.93	$250.00	$252.08	$500.00	
Usage Rates	All Ccf		$0.54101	$0.54101	$0.23148	$0.11113	
	First 500	$0.11461					
	All Over 500	$0.09461					
Public Authority Air Conditioning (1)							
Customer Charge - Sales		$195.79	N/A	N/A	N/A	$200.00	
Usage Rates - (October - April)	All Ccf		N/A	N/A	N/A	$0.11113	
	First 500	$0.11461					
	All Over 500	$0.09461					
Usage Rates - (May - September)	All Ccf		N/A	N/A	N/A		
	First 500	$0.08461					
	All Over 500	$0.06461					
School and Municipal (1)							
Customer Charge - Sales		N/A	N/A	N/A	51.02	$200.00	
Usage Rates	All Ccf		N/A	N/A	0.37651	$0.11113	
	First 500	N/A					
	All Over 500	N/A					
Customer Charge - Transportation (2)							
Usage Rates	All Ccf	N/A	N/A	N/A	256.02	$500.00	
	First 500				0.37651	$0.11113	
	All Over 500						
CNG							
Customer Charge - Sales		N/A	N/A	N/A	N/A	$150.00	
Usage Rates	All Ccf	N/A	N/A	N/A	N/A	$0.07652	
Customer Charge - Transportation (switched from Commercial)		424.58	N/A	N/A	N/A	$450.00	
Usage Rates	All Ccf		N/A	N/A	N/A	$0.07652	
	First 500	0.08223					
	All Over 500	0.06223					
Customer Charge - Transportation (switched from Public Authority)		495.79	N/A	N/A	N/A	$450.00	
Usage Rates	All Ccf		N/A	N/A	N/A	$0.07652	
	First 500	0.11461					
	All Over 500	0.09461					
Electrical Cogeneration (2)							
Customer Charge - Sales		$325.08				$700.00	
Usage Rates - (October - April)	All Ccf						
	First 5,000 Ccf	$0.05696				$0.05260	
	Next 95,000	$0.04696				$0.04260	
	Next 300,000	$0.03696				$0.03260	
	All Over 400,000	$0.02696				$0.02260	

Gas Costs			Transp. Gas Cost Savings Assumed
	WNSA	$0.41347	
	WTSA	$0.40358	$0.05
	NTSA	$0.53825	
	BSSA	$0.41548	

	Residential	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Small	24	$ 35.50	$ 51.78	$ 44.59	$ 31.21	$ 39.89
Large	55	$ 51.01	$ 87.13	$ 82.35	$ 50.91	$ 58.02

	Commercial Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	225	$ 172.93	$ 332.91	$ 322.38	$ 196.65	$ 183.39

	Commercial Transport	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	27,991	$ 12,908.33	N/A			$ 13,400.49

	Commercial A/C Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
January	359	$ 238.02				$ 247.91
Aug	259	$ 184.35		NA		$ 199.85
Annual		$ 215.66				$ 227.89

	Industrial Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	2,813	$ 2,275.65	$ 3,581.98	$ 3,591.72	N/A	$ 2,262.91

	Industrial Transport	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	36,450	$ 18,221.64	N/A			$ 18,602.53

	Pub. Auth. Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	662	$ 535.41	$ 875.00	$ 863.21	$ 475.13	$ 547.09

	Pub. Auth. Transport	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	63,145	$ 30,689.79	N/A			$ 32,320.44

	Pub. Auth. A/C Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
January	3,351	$ 1,875.37				$ 1,958.09
Aug	151	$ 269.67		N/A		$ 279.39
Annual		$ 1,206.33				$ 1,258.63

	School and Municipal Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	6,194		N/A		$ 4,956.43	$ 3,449.25

	CNG Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended

	CNG Transport (3)	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	113,338	$ 50,941.58		N/A		$ 53,641.47
Annual	316,687	$ 151,885.50		N/A		$ 149,076.28

	COGEN Transport	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
January	79,655	$ 34,655.49				$ 35,431.51
August	106,900	$ 45,240.65		N/A		$ 46,153.87
Annual		$ 39,065.97				$ 39,899.16

WKP Current Rec Rates

Usage Rates - (May - September)	All Ccf					
	First 5,000	$0.04695				$0.04259
	Next 95,000	$0.03694				$0.03258
	Next 300,000	$0.02695				$0.02259
	All Over 400,000	$0.01694				$0.01258
				N/A		
Customer Charge - Transportation		$424.58				$700.00
Usage Rates - (October - April)	All Ccf					
	First 5,000 Ccf	$0.05696				$0.05260
	Next 95,000	$0.04696				$0.04260
	Next 300,000	$0.03696				$0.03260
	All Over 400,000	$0.02696				$0.02260
Usage Rates - (May - September)	All Ccf					
	First 5,000	$0.04695				$0.04259
	Next 95,000	$0.03694				$0.03258
	Next 300,000	$0.02695				$0.02259
	All Over 400,000	$0.01694				$0.01258
						$0.00000
Municipal Water Pumping (1)						
Customer Charge - Sales		$768.75	N/A	N/A	N/A	$200.00
Usage Rates	All Ccf		N/A	N/A	N/A	$0.11113
	First 5000	$0.06111				
	All Over 5000	$0.05111				
Standby Service (2)						
Customer Charge - Sales		$666.37	N/A	N/A	N/A	$666.37
Usage Rates	Per Mcf/Hour	$20.00	N/A	N/A	N/A	$20.00

	Municipal Water Pumping Sales	WTSA Inc. & Env.	NTSA Env.	NTSA Inc.	BSSA Inc. & Env.	Recommended
Annual	657	$ 1,073.85	N/A			$ 544.44
January	2,020	$ 1,707.61				$ 1,259.90

Note 1: The Commercial AC, Public Authority AC, Municipal Water Pumping, and School and Municipal tariffs will be discontinued.

Note 2: There are no Standby Service, Electric Cogeneration gas sales, and School and Municipal transportation customers.

Note 3: See SCH G-3 CNG Transport Reclass for CNG Transport Annual and January volume support.

Customer Bill Impacts

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CUSTOMER BILL IMPACTS

	Year-Round Average Bill			
			Change	
Description	Current	Recommended	Dollars	%
(a)	(b)	(c)	(d)	(e)
Sales Service: (1) (2)				
Residential - Small				
WTSA Incorporated and Environs	$ 35.50	$ 39.89	$ 4.39	12.4%
NTSA Incorporated	$ 44.59	$ 39.89	$ (4.70)	-10.5%
NTSA Environs	$ 51.78	$ 39.89	$ (11.89)	-23.0%
BSSA Incorporated and Environs	$ 31.21	$ 39.89	$ 8.68	27.8%
Residential - Large				
WTSA Incorporated and Environs	$ 51.01	$ 58.02	$ 7.01	13.7%
NTSA Incorporated	$ 82.35	$ 58.02	$ (24.33)	-29.5%
NTSA Environs	$ 87.13	$ 58.02	$ (29.11)	-33.4%
BSSA Incorporated and Environs	$ 50.91	$ 58.02	$ 7.11	14.0%
Commercial				
WTSA Incorporated and Environs	$ 172.93	$ 183.39	$ 10.46	6.0%
NTSA Incorporated	$ 322.38	$ 183.39	$ (138.99)	-43.1%
NTSA Environs	$ 332.91	$ 183.39	$ (149.52)	-44.9%
BSSA Incorporated and Environs	$ 196.65	$ 183.39	$ (13.26)	-6.7%
Commercial Air Conditioning (3)				
WTSA Incorporated and Environs	$ 215.66	227.89	$ 12.23	5.7%
Industrial				
WTSA Incorporated and Environs	$ 2,275.65	$ 2,262.91	$ (12.74)	-0.6%
NTSA Incorporated	$ 3,591.72	$ 2,262.91	$ (1,328.81)	-37.0%
NTSA Environs	$ 3,581.98	$ 2,262.91	$ (1,319.07)	-36.8%
Public Authority				
WTSA Incorporated and Environs	$ 535.41	$ 547.09	$ 11.68	2.2%
NTSA Incorporated	$ 863.21	$ 547.09	$ (316.12)	-36.6%
NTSA Environs	$ 875.00	$ 547.09	$ (327.91)	-37.5%
BSSA Incorporated and Environs	$ 475.13	$ 547.09	$ 71.96	15.1%
Public Authority Air Conditioning (3)				
WTSA Incorporated and Environs	$ 1,206.33	$ 1,258.63	$ 52.30	4.3%
Municipal Water Pumping				
WTSA Incorporated and Environs	$ 1,073.85	$ 544.44	$ (529.41)	-49.3%

Customer Bill Impacts

School and Municipal							
BSSA Incorporated and Environs	$	4,956.43	$	3,449.25	$	(1,507.18)	-30.4%
<u>Transportation Service:</u> (4)							
Commercial Transportation							
WTSA Incorporated and Environs	$	12,908.33	$	13,400.49	$	492.16	3.8%
Industrial Transportation							
WTSA Incorporated and Environs	$	18,221.64	$	18,602.53	$	380.89	2.1%
Public Authority Transportation							
WTSA Incorporated and Environs	$	30,689.79	$	32,320.44	$	1,630.65	5.3%
CNG Transportation							
WTSA Incorporated and Environs (reclassed from Commercial)	$	50,941.58	$	53,641.47	$	2,699.89	5.3%
WTSA Incorporated and Environs (reclassed from Public Authority)	$	151,885.50	$	149,076.28	$	(2,809.22)	-1.8%
Cogeneration Transportation (3)							
WTSA Incorporated and Environs	$	39,065.97	$	39,899.16	$	833.19	2.1%

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

	WNSA Year-Round
Residential - Small	24
Residential - Large	55
Commercial	225
Industrial	2,813
Public Authority	662
Municipal Water Pumping	657
School and Municipal	6,194

	August	January
Commercial AC	259.27	359.08
Public Authority AC	151.33	3,351.29

(3) Year-round average bill is approximated based on the average August bill assumed to occur in each of the 5 summer months and the average January bill assumed to occur in each of the 7 winter months.

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

	WNSA Year-Round
Commercial Transportation	27,991
Industrial Transportation	36,450
Public Authority Transportation	63,145

Customer Bill Impacts

CNG Transportation	113,338	
	August	January
Cogeneration Transportation	106,900	79,655

Residential Bill Impacts New Rates

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO NEW RATES

Annual Residential Bill Impacts of WNSA Small/Large Rate Structure in WTSA Compared to Traditional Rate Structure

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 20.00	$ 0.74154	$ 0.74154			$ 35.00	$ 0.41611	$ 0.41611	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	28	1,829 $ -	$ 240.00	$ -	$ 20.39	$ 240.00	$ 260.39	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ -	$ 0.19	0%	1%
29	55	1,648	$ 240.00	$ 21.13	$ 40.78	$ 261.13	$ 280.78	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 0.20	$ 0.38	1%	2%
56	83	2,377	$ 240.00	$ 41.53	$ 61.18	$ 281.53	$ 301.18	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 0.39	$ 0.58	2%	2%
84	110	3,165	$ 240.00	$ 61.92	$ 81.57	$ 301.92	$ 321.57	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 0.58	$ 0.77	2%	3%
111	138	4,264	$ 240.00	$ 82.31	$ 101.96	$ 322.31	$ 341.96	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 0.77	$ 0.96	3%	3%
139	165	5,763	$ 240.00	$ 102.70	$ 122.35	$ 342.70	$ 362.35	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.97	$ 1.15	3%	4%
166	193	7,282	$ 240.00	$ 123.10	$ 142.75	$ 363.10	$ 382.75	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.16	$ 1.34	4%	4%
194	220	9,197	$ 240.00	$ 143.49	$ 163.14	$ 383.49	$ 403.14	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.35	$ 1.53	4%	5%
221	248	11,601	$ 240.00	$ 163.88	$ 183.53	$ 403.88	$ 423.53	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 1.54	$ 1.73	5%	5%
249	275	13,856	$ 240.00	$ 184.27	$ 203.92	$ 424.27	$ 443.92	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 1.73	$ 1.92	5%	5%
276	303	15,556	$ 240.00	$ 204.67	$ 224.32	$ 444.67	$ 464.32	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 1.92	$ 2.11	5%	5%
304	330	16,884	$ 240.00	$ 225.06	$ 244.71	$ 465.06	$ 484.71	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 2.12	$ 2.30	5%	6%
331	358	17,462	$ 240.00	$ 245.45	$ 265.10	$ 485.45	$ 505.10	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 2.31	$ 2.49	6%	6%
359	385	17,584	$ 240.00	$ 265.84	$ 285.49	$ 505.84	$ 525.49	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 2.50	$ 2.68	6%	6%
386	413	16,555	$ 240.00	$ 286.23	$ 305.89	$ 526.23	$ 545.89	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 2.69	$ 2.88	6%	6%
414	440	15,188	$ 240.00	$ 306.63	$ 326.28	$ 546.63	$ 566.28	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 2.88	$ 3.07	6%	7%
441	1,240	100,529	$ 240.00	$ 327.02	$ 919.51	$ 567.02	$ 1,159.51	$ 420.00	$ 183.50	$ 515.98	$ 603.50	$ 935.98	$ 3.04	$ (18.63)	6%	-19%
1,241	2,040	2,807	$ 240.00	$ 920.25	$ 1,512.74	$ 1,160.25	$ 1,752.74	$ 420.00	$ 516.39	$ 848.86	$ 936.39	$ 1,268.86	$ (18.65)	$ (40.32)	-19%	-28%
2,041	2,840	548	$ 240.00	$ 1,513.48	$ 2,105.97	$ 1,753.48	$ 2,345.97	$ 420.00	$ 849.28	$ 1,181.75	$ 1,269.28	$ 1,601.75	$ (40.35)	$ (62.02)	-28%	-32%
2,841	3,640	185	$ 240.00	$ 2,106.72	$ 2,699.21	$ 2,346.72	$ 2,939.21	$ 420.00	$ 1,182.17	$ 1,514.64	$ 1,602.17	$ 1,934.64	$ (62.05)	$ (83.71)	-32%	-34%
3,641	4,440	115	$ 240.00	$ 2,699.95	$ 3,292.44	$ 2,939.95	$ 3,532.44	$ 420.00	$ 1,515.06	$ 1,847.53	$ 1,935.06	$ 2,267.53	$ (83.74)	$ (105.41)	-34%	-36%
4,441	5,240	73	$ 240.00	$ 3,293.18	$ 3,885.67	$ 3,533.18	$ 4,125.67	$ 420.00	$ 1,847.94	$ 2,180.42	$ 2,267.94	$ 2,600.42	$ (105.44)	$ (127.10)	-36%	-37%
5,241	6,040	35	$ 240.00	$ 3,886.41	$ 4,478.90	$ 4,126.41	$ 4,718.90	$ 420.00	$ 2,180.83	$ 2,513.30	$ 2,600.83	$ 2,933.30	$ (127.13)	$ (148.80)	-37%	-38%
6,041	6,840	16	$ 240.00	$ 4,479.64	$ 5,072.13	$ 4,719.64	$ 5,312.13	$ 420.00	$ 2,513.72	$ 2,846.19	$ 2,933.72	$ 3,266.19	$ (148.83)	$ (170.50)	-38%	-39%
6,841	7,640	9	$ 240.00	$ 5,072.88	$ 5,665.37	$ 5,312.88	$ 5,905.37	$ 420.00	$ 2,846.61	$ 3,179.08	$ 3,266.61	$ 3,599.08	$ (170.52)	$ (192.19)	-39%	-39%
7,641	8,440	5	$ 240.00	$ 5,666.11	$ 6,258.60	$ 5,906.11	$ 6,498.60	$ 420.00	$ 3,179.50	$ 3,511.97	$ 3,599.50	$ 3,931.97	$ (192.22)	$ (213.89)	-39%	-39%
8,441	9,240	2	$ 240.00	$ 6,259.34	$ 6,851.83	$ 6,499.34	$ 7,091.83	$ 420.00	$ 3,512.38	$ 3,844.86	$ 3,932.38	$ 4,264.86	$ (213.91)	$ (235.58)	-39%	-40%
9,241	10,040	3	$ 240.00	$ 6,852.57	$ 7,445.06	$ 7,092.57	$ 7,685.06	$ 420.00	$ 3,845.27	$ 4,177.74	$ 4,265.27	$ 4,597.74	$ (235.61)	$ (257.28)	-40%	-40%
10,041	10,840	3	$ 240.00	$ 7,445.80	$ 8,038.29	$ 7,685.80	$ 8,278.29	$ 420.00	$ 4,178.16	$ 4,510.63	$ 4,598.16	$ 4,930.63	$ (257.30)	$ (278.97)	-40%	-40%
10,841	11,640	3	$ 240.00	$ 8,039.04	$ 8,631.53	$ 8,279.04	$ 8,871.53	$ 420.00	$ 4,511.05	$ 4,843.52	$ 4,931.05	$ 5,263.52	$ (279.00)	$ (300.67)	-40%	-41%
11,641	59,201	7	$ 240.00	$ 8,632.27	$ 43,900.17	$ 8,872.27	$ 44,140.17	$ 420.00	$ 4,843.94	$ 24,634.27	$ 5,263.94	$ 25,054.27	$ (300.69)	$ (1,590.49)	-41%	-43%

Annual Residential Bill Impacts of WNSA Small/Large Rate Structure in NTSA Environs Compared to Traditional Rate Structure

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 20.00	$ 0.74154	$ 0.74154		0	$ 35.00	$ 0.41611	$ 0.41611	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	28	62	$ 240.00	$ -	$ 20.39	$ 240.00	$ 260.39	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ -	$ 0.19	0%	1%
29	55	27	$ 240.00	$ 21.13	$ 40.78	$ 261.13	$ 280.78	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 0.20	$ 0.38	1%	2%
56	83	23	$ 240.00	$ 41.53	$ 61.18	$ 281.53	$ 301.18	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 0.39	$ 0.58	2%	2%
84	110	28	$ 240.00	$ 61.92	$ 81.57	$ 301.92	$ 321.57	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 0.58	$ 0.77	2%	3%
111	138	39	$ 240.00	$ 82.31	$ 101.96	$ 322.31	$ 341.96	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 0.77	$ 0.96	3%	3%
139	165	43	$ 240.00	$ 102.70	$ 122.35	$ 342.70	$ 362.35	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.97	$ 1.15	3%	4%
166	193	42	$ 240.00	$ 123.10	$ 142.75	$ 363.10	$ 382.75	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.16	$ 1.34	4%	4%
194	220	42	$ 240.00	$ 143.49	$ 163.14	$ 383.49	$ 403.14	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.35	$ 1.53	4%	5%
221	248	61	$ 240.00	$ 163.88	$ 183.53	$ 403.88	$ 423.53	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 1.54	$ 1.73	5%	5%
249	275	52	$ 240.00	$ 184.27	$ 203.92	$ 424.27	$ 443.92	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 1.73	$ 1.92	5%	5%
276	303	55	$ 240.00	$ 204.67	$ 224.32	$ 444.67	$ 464.32	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 1.92	$ 2.11	5%	5%
304	330	46	$ 240.00	$ 225.06	$ 244.71	$ 465.06	$ 484.71	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 2.12	$ 2.30	5%	6%
331	358	63	$ 240.00	$ 245.45	$ 265.10	$ 485.45	$ 505.10	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 2.31	$ 2.49	6%	6%
359	385	60	$ 240.00	$ 265.84	$ 285.49	$ 505.84	$ 525.49	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 2.50	$ 2.68	6%	6%
386	413	62	$ 240.00	$ 286.23	$ 305.89	$ 526.23	$ 545.89	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 2.69	$ 2.88	6%	6%
414	440	63	$ 240.00	$ 306.63	$ 326.28	$ 546.63	$ 566.28	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 2.88	$ 3.07	6%	7%
441	621	311	$ 240.00	$ 327.02	$ 460.71	$ 567.02	$ 700.71	$ 420.00	$ 183.50	$ 258.53	$ 603.50	$ 678.53	$ 3.04	$ (1.85)	6%	-3%
622	803	166	$ 240.00	$ 461.45	$ 595.15	$ 701.45	$ 835.15	$ 420.00	$ 258.94	$ 333.96	$ 678.94	$ 753.96	$ (1.88)	$ (6.77)	-3%	-10%
804	984	94	$ 240.00	$ 595.89	$ 729.58	$ 835.89	$ 969.58	$ 420.00	$ 334.38	$ 409.40	$ 754.38	$ 829.40	$ (6.79)	$ (11.68)	-10%	-14%
985	1165	63	$ 240.00	$ 730.32	$ 864.01	$ 970.32	$ 1,104.01	$ 420.00	$ 409.82	$ 484.84	$ 829.82	$ 904.84	$ (11.71)	$ (16.60)	-14%	-18%
1,166	1346	35	$ 240.00	$ 864.76	$ 998.45	$ 1,104.76	$ 1,238.45	$ 420.00	$ 485.25	$ 560.27	$ 905.25	$ 980.27	$ (16.63)	$ (21.51)	-18%	-21%
1,347	1528	26	$ 240.00	$ 999.19	$ 1,132.88	$ 1,239.19	$ 1,372.88	$ 420.00	$ 560.69	$ 635.71	$ 980.69	$ 1,055.71	$ (21.54)	$ (26.43)	-21%	-23%
1,529	1709	22	$ 240.00	$ 1,133.62	$ 1,267.32	$ 1,373.62	$ 1,507.32	$ 420.00	$ 636.13	$ 711.15	$ 1,056.13	$ 1,131.15	$ (26.46)	$ (31.35)	-23%	-25%
1,710	1890	12	$ 240.00	$ 1,268.06	$ 1,401.75	$ 1,508.06	$ 1,641.75	$ 420.00	$ 711.56	$ 786.58	$ 1,131.56	$ 1,206.58	$ (31.37)	$ (36.26)	-25%	-27%
1,891	2072	7	$ 240.00	$ 1,402.49	$ 1,536.19	$ 1,642.49	$ 1,776.19	$ 420.00	$ 787.00	$ 862.02	$ 1,207.00	$ 1,282.02	$ (36.29)	$ (41.18)	-27%	-28%
2,073	2253	4	$ 240.00	$ 1,536.93	$ 1,670.62	$ 1,776.93	$ 1,910.62	$ 420.00	$ 862.44	$ 937.46	$ 1,282.44	$ 1,357.46	$ (41.21)	$ (46.10)	-28%	-29%
2,254	2434	1	$ 240.00	$ 1,671.36	$ 1,805.05	$ 1,911.36	$ 2,045.05	$ 420.00	$ 937.87	$ 1,012.89	$ 1,357.87	$ 1,432.89	$ (46.12)	$ (51.01)	-29%	-30%
2,435	2615	5	$ 240.00	$ 1,805.80	$ 1,939.49	$ 2,045.80	$ 2,179.49	$ 420.00	$ 1,013.31	$ 1,088.33	$ 1,433.31	$ 1,508.33	$ (51.04)	$ (55.93)	-30%	-31%
2,616	2797	4	$ 240.00	$ 1,940.23	$ 2,073.92	$ 2,180.23	$ 2,313.92	$ 420.00	$ 1,088.75	$ 1,163.77	$ 1,508.75	$ 1,583.77	$ (55.96)	$ (60.85)	-31%	-32%
2,798	2978	2	$ 240.00	$ 2,074.66	$ 2,208.36	$ 2,314.66	$ 2,448.36	$ 420.00	$ 1,164.18	$ 1,239.20	$ 1,584.18	$ 1,659.20	$ (60.87)	$ (65.76)	-32%	-32%
2,979	3159	1	$ 240.00	$ 2,209.10	$ 2,342.79	$ 2,449.10	$ 2,582.79	$ 420.00	$ 1,239.62	$ 1,314.64	$ 1,659.62	$ 1,734.64	$ (65.79)	$ (70.68)	-32%	-33%

Annual Residential Bill Impacts of WNSA Small/Large Rate Structure in NTSA Incorporated Areas Compared to Traditional Rate Structure

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 20.00	$ 0.74154	$ 0.74154			$ 35.00	$ 0.41611	$ 0.41611	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	28	261	$ 240.00	$ -	$ 20.39	$ 240.00	$ 260.39	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ -	$ 0.19	0%	1%
29	55	143	$ 240.00	$ 21.13	$ 40.78	$ 261.13	$ 280.78	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 0.20	$ 0.38	1%	2%
56	83	231	$ 240.00	$ 41.53	$ 61.18	$ 281.53	$ 301.18	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 0.39	$ 0.58	2%	2%

Residential Bill Impacts New Rates

84	110	263	$ 240.00	$ 61.92	$ 81.57	$ 301.92	$ 321.57	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 0.58	$ 0.77	2%	3%
111	138	342	$ 240.00	$ 82.31	$ 101.96	$ 322.31	$ 341.96	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 0.77	$ 0.96	3%	3%
139	165	337	$ 240.00	$ 102.70	$ 122.35	$ 342.70	$ 362.35	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.97	$ 1.15	3%	4%
166	193	367	$ 240.00	$ 123.10	$ 142.75	$ 363.10	$ 382.75	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.16	$ 1.34	4%	4%
194	220	419	$ 240.00	$ 143.49	$ 163.14	$ 383.49	$ 403.14	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.35	$ 1.53	4%	5%
221	248	413	$ 240.00	$ 163.88	$ 183.53	$ 403.88	$ 423.53	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 1.54	$ 1.73	5%	5%
249	275	498	$ 240.00	$ 184.27	$ 203.92	$ 424.27	$ 443.92	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 1.73	$ 1.92	5%	5%
276	303	515	$ 240.00	$ 204.67	$ 224.32	$ 444.67	$ 464.32	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 1.92	$ 2.11	5%	5%
304	330	581	$ 240.00	$ 225.06	$ 244.71	$ 465.06	$ 484.71	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 2.12	$ 2.30	5%	6%
331	358	623	$ 240.00	$ 245.45	$ 265.10	$ 485.45	$ 505.10	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 2.31	$ 2.49	6%	6%
359	385	637	$ 240.00	$ 265.84	$ 285.49	$ 505.84	$ 525.49	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 2.50	$ 2.68	6%	6%
386	413	643	$ 240.00	$ 286.23	$ 305.89	$ 526.23	$ 545.89	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 2.69	$ 2.88	6%	6%
414	440	576	$ 240.00	$ 306.63	$ 326.28	$ 546.63	$ 566.28	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 2.88	$ 3.07	6%	7%
441	623	3,111	$ 240.00	$ 327.02	$ 461.91	$ 567.02	$ 701.91	$ 420.00	$ 183.50	$ 259.19	$ 603.50	$ 679.19	$ 3.04	$ (1.89)	6%	-3%
624	806	1,386	$ 240.00	$ 462.65	$ 597.53	$ 702.65	$ 837.53	$ 420.00	$ 259.61	$ 335.30	$ 679.61	$ 755.30	$ (1.92)	$ (6.85)	-3%	-10%
807	989	679	$ 240.00	$ 598.27	$ 733.16	$ 838.27	$ 973.16	$ 420.00	$ 335.72	$ 411.41	$ 755.72	$ 831.41	$ (6.88)	$ (11.81)	-10%	-15%
990	1,172	266	$ 240.00	$ 733.90	$ 868.79	$ 973.90	$ 1,108.79	$ 420.00	$ 411.82	$ 487.51	$ 831.82	$ 907.51	$ (11.84)	$ (16.77)	-15%	-18%
1,173	1,354	125	$ 240.00	$ 869.53	$ 1,004.41	$ 1,109.53	$ 1,244.41	$ 420.00	$ 487.93	$ 563.62	$ 907.93	$ 983.62	$ (16.80)	$ (21.73)	-18%	-21%
1,355	1,537	66	$ 240.00	$ 1,005.16	$ 1,140.04	$ 1,245.16	$ 1,380.04	$ 420.00	$ 564.04	$ 639.73	$ 984.04	$ 1,059.73	$ (21.76)	$ (26.69)	-21%	-23%
1,538	1,720	30	$ 240.00	$ 1,140.78	$ 1,275.67	$ 1,380.78	$ 1,515.67	$ 420.00	$ 640.14	$ 715.83	$ 1,060.14	$ 1,135.83	$ (26.72)	$ (31.65)	-23%	-25%
1,721	1,903	18	$ 240.00	$ 1,276.41	$ 1,411.30	$ 1,516.41	$ 1,651.30	$ 420.00	$ 716.25	$ 791.94	$ 1,136.25	$ 1,211.94	$ (31.68)	$ (36.61)	-25%	-27%
1,904	2,086	8	$ 240.00	$ 1,412.04	$ 1,546.92	$ 1,652.04	$ 1,786.92	$ 420.00	$ 792.36	$ 868.05	$ 1,212.36	$ 1,288.05	$ (36.64)	$ (41.57)	-27%	-28%
2,087	2,269	8	$ 240.00	$ 1,547.67	$ 1,682.55	$ 1,787.67	$ 1,922.55	$ 420.00	$ 868.46	$ 944.15	$ 1,288.46	$ 1,364.15	$ (41.60)	$ (46.53)	-28%	-29%
2,270	2,452	2	$ 240.00	$ 1,683.29	$ 1,818.18	$ 1,923.29	$ 2,058.18	$ 420.00	$ 944.57	$ 1,020.26	$ 1,364.57	$ 1,440.26	$ (46.56)	$ (51.49)	-29%	-30%
2,453	2,635	2	$ 240.00	$ 1,818.92	$ 1,953.81	$ 2,058.92	$ 2,193.81	$ 420.00	$ 1,020.67	$ 1,096.37	$ 1,440.67	$ 1,516.37	$ (51.52)	$ (56.45)	-30%	-31%
2,636	2,818	1	$ 240.00	$ 1,954.55	$ 2,089.43	$ 2,194.55	$ 2,329.43	$ 420.00	$ 1,096.78	$ 1,172.47	$ 1,516.78	$ 1,592.47	$ (56.48)	$ (61.41)	-31%	-32%
2,819	3,001	0	$ 240.00	$ 2,090.18	$ 2,225.06	$ 2,330.18	$ 2,465.06	$ 420.00	$ 1,172.89	$ 1,248.58	$ 1,592.89	$ 1,668.58	$ (61.44)	$ (66.37)	-32%	-32%
3,002	7,304	6	$ 240.00	$ 2,225.80	$ 5,416.02	$ 2,465.80	$ 5,656.02	$ 420.00	$ 1,248.99	$ 3,039.16	$ 1,668.99	$ 3,459.16	$ (66.40)	$ (183.07)	-32%	-39%

Annual Residential Bill Impacts of WNSA Small/Large Rate Structure in BSSA Compared to Traditional Rate Structure

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 20.00	$ 0.74154	$ 0.74154			$ 35.00	$ 0.41611	$ 0.41611	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	28	43	$ 240.00	$ -	$ 20.39	$ 240.00	$ 260.39	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ -	$ 0.19	0%	1%
29	55	12	$ 240.00	$ 21.13	$ 40.78	$ 261.13	$ 280.78	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ 0.20	$ 0.38	1%	2%
56	83	34	$ 240.00	$ 41.53	$ 61.18	$ 281.53	$ 301.18	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ 0.39	$ 0.58	2%	2%
84	110	42	$ 240.00	$ 61.92	$ 81.57	$ 301.92	$ 321.57	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ 0.58	$ 0.77	2%	3%
111	138	45	$ 240.00	$ 82.31	$ 101.96	$ 322.31	$ 341.96	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ 0.77	$ 0.96	3%	3%
139	165	75	$ 240.00	$ 102.70	$ 122.35	$ 342.70	$ 362.35	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.97	$ 1.15	3%	4%
166	193	73	$ 240.00	$ 123.10	$ 142.75	$ 363.10	$ 382.75	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.16	$ 1.34	4%	4%
194	220	118	$ 240.00	$ 143.49	$ 163.14	$ 383.49	$ 403.14	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.35	$ 1.53	4%	5%
221	248	131	$ 240.00	$ 163.88	$ 183.53	$ 403.88	$ 423.53	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 1.54	$ 1.73	5%	5%
249	275	156	$ 240.00	$ 184.27	$ 203.92	$ 424.27	$ 443.92	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 1.73	$ 1.92	5%	5%
276	303	180	$ 240.00	$ 204.67	$ 224.32	$ 444.67	$ 464.32	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 1.92	$ 2.11	5%	5%
304	330	203	$ 240.00	$ 225.06	$ 244.71	$ 465.06	$ 484.71	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 2.12	$ 2.30	5%	6%
331	358	195	$ 240.00	$ 245.45	$ 265.10	$ 485.45	$ 505.10	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 2.31	$ 2.49	6%	6%
359	385	196	$ 240.00	$ 265.84	$ 285.49	$ 505.84	$ 525.49	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 2.50	$ 2.68	6%	6%
386	413	211	$ 240.00	$ 286.23	$ 305.89	$ 526.23	$ 545.89	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 2.69	$ 2.88	6%	6%
414	440	224	$ 240.00	$ 306.63	$ 326.28	$ 546.63	$ 566.28	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 2.88	$ 3.07	6%	7%
441	613	1,195	$ 240.00	$ 327.02	$ 454.85	$ 567.02	$ 694.85	$ 420.00	$ 183.50	$ 255.23	$ 603.50	$ 675.23	$ 3.04	$ (1.63)	6%	-3%
614	787	821	$ 240.00	$ 455.59	$ 583.42	$ 695.59	$ 823.42	$ 420.00	$ 255.65	$ 327.38	$ 675.65	$ 747.38	$ (1.66)	$ (6.34)	-3%	-9%
788	960	505	$ 240.00	$ 584.16	$ 711.98	$ 824.16	$ 951.98	$ 420.00	$ 327.80	$ 399.52	$ 747.80	$ 819.52	$ (6.36)	$ (11.04)	-9%	-14%
961	1134	248	$ 240.00	$ 712.73	$ 840.55	$ 952.73	$ 1,080.55	$ 420.00	$ 399.94	$ 471.67	$ 819.94	$ 891.67	$ (11.07)	$ (15.74)	-14%	-17%
1,135	1307	145	$ 240.00	$ 841.29	$ 969.12	$ 1,081.29	$ 1,209.12	$ 420.00	$ 472.09	$ 543.82	$ 892.09	$ 963.82	$ (15.77)	$ (20.44)	-17%	-20%
1,308	1480	76	$ 240.00	$ 969.86	$ 1,097.69	$ 1,209.86	$ 1,337.69	$ 420.00	$ 544.23	$ 615.96	$ 964.23	$ 1,035.96	$ (20.47)	$ (25.14)	-20%	-23%
1,481	1654	40	$ 240.00	$ 1,098.43	$ 1,226.26	$ 1,338.43	$ 1,466.26	$ 420.00	$ 616.38	$ 688.11	$ 1,036.38	$ 1,108.11	$ (25.17)	$ (29.85)	-23%	-24%
1,655	1827	21	$ 240.00	$ 1,227.00	$ 1,354.83	$ 1,467.00	$ 1,594.83	$ 420.00	$ 688.52	$ 760.25	$ 1,108.52	$ 1,180.25	$ (29.87)	$ (34.55)	-24%	-26%
1,828	2000	10	$ 240.00	$ 1,355.57	$ 1,483.40	$ 1,595.57	$ 1,723.40	$ 420.00	$ 760.67	$ 832.40	$ 1,180.67	$ 1,252.40	$ (34.58)	$ (39.25)	-26%	-27%
2,001	2174	8	$ 240.00	$ 1,484.14	$ 1,611.97	$ 1,724.14	$ 1,851.97	$ 420.00	$ 832.81	$ 904.54	$ 1,252.81	$ 1,324.54	$ (39.28)	$ (43.95)	-27%	-28%
2,175	2347	4	$ 240.00	$ 1,612.71	$ 1,740.53	$ 1,852.71	$ 1,980.53	$ 420.00	$ 904.96	$ 976.69	$ 1,324.96	$ 1,396.69	$ (43.98)	$ (48.65)	-28%	-29%
2,348	2521	3	$ 240.00	$ 1,741.28	$ 1,869.10	$ 1,981.28	$ 2,109.10	$ 420.00	$ 977.10	$ 1,048.83	$ 1,397.10	$ 1,468.83	$ (48.68)	$ (53.36)	-29%	-30%
2,522	2694	4	$ 240.00	$ 1,869.84	$ 1,997.67	$ 2,109.84	$ 2,237.67	$ 420.00	$ 1,049.25	$ 1,120.98	$ 1,469.25	$ 1,540.98	$ (53.38)	$ (58.06)	-30%	-31%
2,695	2867	3	$ 240.00	$ 1,998.41	$ 2,126.24	$ 2,238.41	$ 2,366.24	$ 420.00	$ 1,121.40	$ 1,193.13	$ 1,541.40	$ 1,613.13	$ (58.08)	$ (62.76)	-31%	-32%
2,868	7187	6	$ 240.00	$ 2,126.98	$ 5,329.28	$ 2,366.98	$ 5,569.28	$ 420.00	$ 1,193.54	$ 2,990.49	$ 1,613.54	$ 3,410.49	$ (62.79)	$ (179.90)	-32%	-39%

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PROPOSED RESIDENTIAL BILL IMPACTS COMPARED TO EXISTING RATES

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing WTSA Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 23.53	$ 0.49675	$ 0.49675			$ 35.00	$ 0.41611	$ 0.41611	Large					
Consumption					Current Charges					Proposed Charges			Absolute Change		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	28	1,829	$ 282.36	$ -	$ 13.66	$ 282.36	$ 296.02	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ (3.53)	$ (2.78)	-15%	-11%
29	55	1,648	$ 282.36	$ 14.16	$ 27.32	$ 296.52	$ 309.68	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ (2.75)	$ (2.02)	-11%	-8%
56	83	2,377	$ 282.36	$ 27.82	$ 40.98	$ 310.18	$ 323.34	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ (2.00)	$ (1.27)	-8%	-5%
84	110	3,165	$ 282.36	$ 41.48	$ 54.64	$ 323.84	$ 337.00	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ (1.24)	$ (0.52)	-5%	-2%
111	138	4,264	$ 282.36	$ 55.14	$ 68.30	$ 337.50	$ 350.66	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ (0.49)	$ 0.23	-2%	1%
139	165	5,763	$ 282.36	$ 68.80	$ 81.96	$ 351.16	$ 364.32	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ 0.26	$ 0.99	1%	3%
166	193	7,282	$ 282.36	$ 82.46	$ 95.62	$ 364.82	$ 377.98	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ 1.01	$ 1.74	3%	6%
194	220	9,197	$ 282.36	$ 96.12	$ 109.29	$ 378.48	$ 391.65	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ 1.77	$ 2.49	6%	8%
221	248	11,601	$ 282.36	$ 109.78	$ 122.95	$ 392.14	$ 405.31	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ 2.52	$ 3.24	8%	10%
249	275	13,856	$ 282.36	$ 123.44	$ 136.61	$ 405.80	$ 418.97	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ 3.27	$ 4.00	10%	11%
276	303	15,556	$ 282.36	$ 137.10	$ 150.27	$ 419.46	$ 432.63	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ 4.02	$ 4.75	12%	13%
304	330	16,884	$ 282.36	$ 150.76	$ 163.93	$ 433.12	$ 446.29	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ 4.78	$ 5.50	13%	15%
331	358	17,462	$ 282.36	$ 164.42	$ 177.59	$ 446.78	$ 459.95	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ 5.53	$ 6.26	15%	16%
359	385	17,584	$ 282.36	$ 178.08	$ 191.25	$ 460.44	$ 473.61	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ 6.28	$ 7.01	16%	18%
386	413	16,555	$ 282.36	$ 191.75	$ 204.91	$ 474.11	$ 487.27	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ 7.04	$ 7.76	18%	19%
414	440	15,188	$ 282.36	$ 205.41	$ 218.57	$ 487.77	$ 500.93	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ 7.79	$ 8.51	19%	20%
441	1,240	100,529	$ 282.36	$ 219.07	$ 615.97	$ 501.43	$ 898.33	$ 420.00	$ 183.50	$ 515.98	$ 603.50	$ 935.98	$ 8.51	$ 3.14	20%	4%
1,241	2,040	2,807	$ 282.36	$ 616.47	$ 1,013.37	$ 898.83	$ 1,295.73	$ 420.00	$ 516.39	$ 848.86	$ 936.39	$ 1,268.86	$ 3.13	$ (2.24)	4%	-2%
2,041	2,840	548	$ 282.36	$ 1,013.87	$ 1,410.77	$ 1,296.23	$ 1,693.13	$ 420.00	$ 849.28	$ 1,181.75	$ 1,269.28	$ 1,601.75	$ (2.25)	$ (7.61)	-2%	-5%
2,841	3,640	185	$ 282.36	$ 1,411.27	$ 1,808.17	$ 1,693.63	$ 2,090.53	$ 420.00	$ 1,182.17	$ 1,514.64	$ 1,602.17	$ 1,934.64	$ (7.62)	$ (12.99)	-5%	-7%
3,641	4,440	115	$ 282.36	$ 1,808.67	$ 2,205.57	$ 2,091.03	$ 2,487.93	$ 420.00	$ 1,515.06	$ 1,847.53	$ 1,935.06	$ 2,267.53	$ (13.00)	$ (18.37)	-7%	-9%
4,441	5,240	73	$ 282.36	$ 2,206.07	$ 2,602.97	$ 2,488.43	$ 2,885.33	$ 420.00	$ 1,847.94	$ 2,180.42	$ 2,267.94	$ 2,600.42	$ (18.37)	$ (23.74)	-9%	-10%
5,241	6,040	35	$ 282.36	$ 2,603.47	$ 3,000.37	$ 2,885.83	$ 3,282.73	$ 420.00	$ 2,180.83	$ 2,513.30	$ 2,600.83	$ 2,933.30	$ (23.75)	$ (29.12)	-10%	-11%
6,041	6,840	16	$ 282.36	$ 3,000.87	$ 3,397.77	$ 3,283.23	$ 3,680.13	$ 420.00	$ 2,513.72	$ 2,846.19	$ 2,933.72	$ 3,266.19	$ (29.13)	$ (34.49)	-11%	-11%
6,841	7,640	9	$ 282.36	$ 3,398.27	$ 3,795.17	$ 3,680.63	$ 4,077.53	$ 420.00	$ 2,846.61	$ 3,179.08	$ 3,266.61	$ 3,599.08	$ (34.50)	$ (39.87)	-11%	-12%
7,641	8,440	5	$ 282.36	$ 3,795.67	$ 4,192.57	$ 4,078.03	$ 4,474.93	$ 420.00	$ 3,179.50	$ 3,511.97	$ 3,599.50	$ 3,931.97	$ (39.88)	$ (45.25)	-12%	-12%
8,441	9,240	2	$ 282.36	$ 4,193.07	$ 4,589.97	$ 4,475.43	$ 4,872.33	$ 420.00	$ 3,512.38	$ 3,844.86	$ 3,932.38	$ 4,264.86	$ (45.25)	$ (50.62)	-12%	-12%
9,241	10,040	3	$ 282.36	$ 4,590.47	$ 4,987.37	$ 4,872.83	$ 5,269.73	$ 420.00	$ 3,845.27	$ 4,177.74	$ 4,265.27	$ 4,597.74	$ (50.63)	$ (56.00)	-12%	-13%
10,041	10,840	3	$ 282.36	$ 4,987.87	$ 5,384.77	$ 5,270.23	$ 5,667.13	$ 420.00	$ 4,178.16	$ 4,510.63	$ 4,598.16	$ 4,930.63	$ (56.01)	$ (61.37)	-13%	-13%
10,841	11,640	3	$ 282.36	$ 5,385.27	$ 5,782.17	$ 5,667.63	$ 6,064.53	$ 420.00	$ 4,511.05	$ 4,843.52	$ 4,931.05	$ 5,263.52	$ (61.38)	$ (66.75)	-13%	-13%
11,641	59,201	7	$ 282.36	$ 5,782.67	$ 29,408.27	$ 6,065.03	$ 29,690.63	$ 420.00	$ 4,843.94	$ 24,634.27	$ 5,263.94	$ 25,054.27	$ (66.76)	$ (386.36)	-13%	-16%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing NTSA Environs Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 24.50	$ 1.13191	$ 1.13191		0	$ 35.00	$ 0.41611	$ 0.41611	Large					
Consumption					Current Charges					Proposed Charges			Absolute Change		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	28	62	$ 294.00	$ -	$ 31.13	$ 294.00	$ 325.13	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ (4.50)	$ (5.20)	-18%	-19%
29	55	27	$ 294.00	$ 32.26	$ 62.26	$ 326.26	$ 356.26	$ 240.00	$ 23.52	$ 45.39	$ 263.52	$ 285.39	$ (5.23)	$ (5.91)	-19%	-20%
56	83	23	$ 294.00	$ 63.39	$ 93.38	$ 357.39	$ 387.38	$ 240.00	$ 46.21	$ 68.08	$ 286.21	$ 308.08	$ (5.93)	$ (6.61)	-20%	-20%
84	110	28	$ 294.00	$ 94.51	$ 124.51	$ 388.51	$ 418.51	$ 240.00	$ 68.90	$ 90.77	$ 308.90	$ 330.77	$ (6.63)	$ (7.31)	-20%	-21%
111	138	39	$ 294.00	$ 125.64	$ 155.64	$ 419.64	$ 449.64	$ 240.00	$ 91.60	$ 113.47	$ 331.60	$ 353.47	$ (7.34)	$ (8.01)	-21%	-21%
139	165	43	$ 294.00	$ 156.77	$ 186.77	$ 450.77	$ 480.77	$ 240.00	$ 114.29	$ 136.16	$ 354.29	$ 376.16	$ (8.04)	$ (8.72)	-21%	-22%
166	193	42	$ 294.00	$ 187.90	$ 217.89	$ 481.90	$ 511.89	$ 240.00	$ 136.98	$ 158.85	$ 376.98	$ 398.85	$ (8.74)	$ (9.42)	-22%	-22%
194	220	42	$ 294.00	$ 219.02	$ 249.02	$ 513.02	$ 543.02	$ 240.00	$ 159.68	$ 181.54	$ 399.68	$ 421.54	$ (9.45)	$ (10.12)	-22%	-22%
221	248	61	$ 294.00	$ 250.15	$ 280.15	$ 544.15	$ 574.15	$ 240.00	$ 182.37	$ 204.24	$ 422.37	$ 444.24	$ (10.15)	$ (10.83)	-22%	-23%
249	275	52	$ 294.00	$ 281.28	$ 311.28	$ 575.28	$ 605.28	$ 240.00	$ 205.06	$ 226.93	$ 445.06	$ 466.93	$ (10.85)	$ (11.53)	-23%	-23%
276	303	55	$ 294.00	$ 312.41	$ 342.40	$ 606.41	$ 636.40	$ 240.00	$ 227.76	$ 249.62	$ 467.76	$ 489.62	$ (11.55)	$ (12.23)	-23%	-23%
304	330	46	$ 294.00	$ 343.53	$ 373.53	$ 637.53	$ 667.53	$ 240.00	$ 250.45	$ 272.32	$ 490.45	$ 512.32	$ (12.26)	$ (12.93)	-23%	-23%
331	358	63	$ 294.00	$ 374.66	$ 404.66	$ 668.66	$ 698.66	$ 240.00	$ 273.14	$ 295.01	$ 513.14	$ 535.01	$ (12.96)	$ (13.64)	-23%	-23%
359	385	60	$ 294.00	$ 405.79	$ 435.79	$ 699.79	$ 729.79	$ 240.00	$ 295.83	$ 317.70	$ 535.83	$ 557.70	$ (13.66)	$ (14.34)	-23%	-24%
386	413	62	$ 294.00	$ 436.92	$ 466.91	$ 730.92	$ 760.91	$ 240.00	$ 318.53	$ 340.40	$ 558.53	$ 580.40	$ (14.37)	$ (15.04)	-24%	-24%
414	440	63	$ 294.00	$ 468.04	$ 498.04	$ 762.04	$ 792.04	$ 240.00	$ 341.22	$ 363.09	$ 581.22	$ 603.09	$ (15.07)	$ (15.75)	-24%	-24%
441	621	311	$ 294.00	$ 499.17	$ 703.25	$ 793.17	$ 997.25	$ 420.00	$ 183.50	$ 258.53	$ 603.50	$ 678.53	$ (15.81)	$ (26.56)	-24%	-32%
622	803	166	$ 294.00	$ 704.38	$ 908.45	$ 998.38	$ 1,202.45	$ 420.00	$ 258.94	$ 333.96	$ 678.94	$ 753.96	$ (26.62)	$ (37.37)	-32%	-37%
804	984	94	$ 294.00	$ 909.58	$ 1,113.65	$ 1,203.58	$ 1,407.65	$ 420.00	$ 334.38	$ 409.40	$ 754.38	$ 829.40	$ (37.43)	$ (48.19)	-37%	-41%
985	1165	63	$ 294.00	$ 1,114.79	$ 1,318.86	$ 1,408.79	$ 1,612.86	$ 420.00	$ 409.82	$ 484.84	$ 829.82	$ 904.84	$ (48.25)	$ (59.00)	-41%	-44%
1,166	1346	35	$ 294.00	$ 1,319.99	$ 1,524.06	$ 1,613.99	$ 1,818.06	$ 420.00	$ 485.25	$ 560.27	$ 905.25	$ 980.27	$ (59.06)	$ (69.82)	-44%	-46%
1,347	1528	26	$ 294.00	$ 1,525.20	$ 1,729.27	$ 1,819.20	$ 2,023.27	$ 420.00	$ 560.69	$ 635.71	$ 980.69	$ 1,055.71	$ (69.88)	$ (80.63)	-46%	-48%
1,529	1709	22	$ 294.00	$ 1,730.40	$ 1,934.47	$ 2,024.40	$ 2,228.47	$ 420.00	$ 636.13	$ 711.15	$ 1,056.13	$ 1,131.15	$ (80.69)	$ (91.44)	-48%	-49%
1,710	1890	12	$ 294.00	$ 1,935.61	$ 2,139.68	$ 2,229.61	$ 2,433.68	$ 420.00	$ 711.56	$ 786.58	$ 1,131.56	$ 1,206.58	$ (91.50)	$ (102.26)	-49%	-50%
1,891	2072	7	$ 294.00	$ 2,140.81	$ 2,344.88	$ 2,434.81	$ 2,638.88	$ 420.00	$ 787.00	$ 862.02	$ 1,207.00	$ 1,282.02	$ (102.32)	$ (113.07)	-50%	-51%
2,073	2253	4	$ 294.00	$ 2,346.01	$ 2,550.09	$ 2,640.01	$ 2,844.09	$ 420.00	$ 862.44	$ 937.46	$ 1,282.44	$ 1,357.46	$ (113.13)	$ (123.89)	-51%	-52%
2,254	2434	1	$ 294.00	$ 2,551.22	$ 2,755.29	$ 2,845.22	$ 3,049.29	$ 420.00	$ 937.87	$ 1,012.89	$ 1,357.87	$ 1,432.89	$ (123.95)	$ (134.70)	-52%	-53%
2,435	2615	5	$ 294.00	$ 2,756.42	$ 2,960.50	$ 3,050.42	$ 3,254.50	$ 420.00	$ 1,013.31	$ 1,088.33	$ 1,433.31	$ 1,508.33	$ (134.76)	$ (145.51)	-53%	-54%
2,616	2797	4	$ 294.00	$ 2,961.63	$ 3,165.70	$ 3,255.63	$ 3,459.70	$ 420.00	$ 1,088.75	$ 1,163.77	$ 1,508.75	$ 1,583.77	$ (145.57)	$ (156.33)	-54%	-54%
2,798	2978	2	$ 294.00	$ 3,166.83	$ 3,370.91	$ 3,460.83	$ 3,664.91	$ 420.00	$ 1,164.18	$ 1,239.20	$ 1,584.18	$ 1,659.20	$ (156.39)	$ (167.14)	-54%	-55%
2,979	3159	1	$ 294.00	$ 3,372.04	$ 3,576.11	$ 3,666.04	$ 3,870.11	$ 420.00	$ 1,239.62	$ 1,314.64	$ 1,659.62	$ 1,734.64	$ (167.20)	$ (177.96)	-55%	-55%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing NTSA Incorporated Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 15.44	$ 1.20926	$ 1.20926			$ 35.00	$ 0.41611	$ 0.41611	Large					
Consumption					Current Charges					Proposed Charges			Absolute Change		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	28	261	$ 185.28	$ -	$ 33.25	$ 185.28	$ 218.53	$ 240.00	$ -	$ 22.69	$ 240.00	$ 262.69	$ 4.56	$ 3.68	30%	20%

Residential Bill Impacts Existing Rates

29	55	143	185.28	34.46	66.51	219.74	251.79	240.00	23.52	45.39	263.52	285.39	3.65	2.80	20%	13%
56	83	231	185.28	67.72	99.76	253.00	285.04	240.00	46.21	68.08	286.21	308.08	2.77	1.92	13%	8%
84	110	263	185.28	100.97	133.02	286.25	318.30	240.00	68.90	90.77	308.90	330.77	1.89	1.04	8%	4%
111	138	342	185.28	134.23	166.27	319.51	351.55	240.00	91.60	113.47	331.60	353.47	1.01	0.16	4%	1%
139	165	337	185.28	167.48	199.53	352.76	384.81	240.00	114.29	136.16	354.29	376.16	0.13	(0.72)	0%	-2%
166	193	367	185.28	200.74	232.78	386.02	418.06	240.00	136.98	158.85	376.98	398.85	(0.75)	(1.60)	-2%	-5%
194	220	419	185.28	233.99	266.04	419.27	451.32	240.00	159.68	181.54	399.68	421.54	(1.63)	(2.48)	-5%	-7%
221	248	413	185.28	267.25	299.29	452.53	484.57	240.00	182.37	204.24	422.37	444.24	(2.51)	(3.36)	-7%	-8%
249	275	498	185.28	300.50	332.55	485.78	517.83	240.00	205.06	226.93	445.06	466.93	(3.39)	(4.24)	-8%	-10%
276	303	515	185.28	333.76	365.80	519.04	551.08	240.00	227.76	249.62	467.76	489.62	(4.27)	(5.12)	-10%	-11%
304	330	581	185.28	367.01	399.06	552.29	584.34	240.00	250.45	272.32	490.45	512.32	(5.15)	(6.00)	-11%	-12%
331	358	623	185.28	400.27	432.31	585.55	617.59	240.00	273.14	295.01	513.14	535.01	(6.03)	(6.88)	-12%	-13%
359	385	637	185.28	433.52	465.57	618.80	650.85	240.00	295.83	317.70	535.83	557.70	(6.91)	(7.76)	-13%	-14%
386	413	643	185.28	466.77	498.82	652.05	684.10	240.00	318.53	340.40	558.53	580.40	(7.79)	(8.64)	-14%	-15%
414	440	576	185.28	500.03	532.07	685.31	717.35	240.00	341.22	363.09	581.22	603.09	(8.67)	(9.52)	-15%	-16%
441	623	3,111	185.28	533.28	753.25	718.56	938.53	420.00	183.50	259.19	603.50	679.19	(9.59)	(21.61)	-16%	-28%
624	806	1,386	185.28	754.46	974.42	939.74	1,159.70	420.00	259.61	335.30	679.61	755.30	(21.68)	(33.70)	-28%	-35%
807	989	679	185.28	975.63	1,195.59	1,160.91	1,380.87	420.00	335.72	411.41	755.72	831.41	(33.77)	(45.79)	-35%	-40%
990	1172	266	185.28	1,196.80	1,416.77	1,382.08	1,602.05	420.00	411.82	487.51	831.82	907.51	(45.85)	(57.88)	-40%	-43%
1,173	1354	125	185.28	1,417.98	1,637.94	1,603.26	1,823.22	420.00	487.93	563.62	907.93	983.62	(57.94)	(69.97)	-43%	-46%
1,355	1537	66	185.28	1,639.15	1,859.11	1,824.43	2,044.39	420.00	564.04	639.73	984.04	1,059.73	(70.03)	(82.06)	-46%	-48%
1,538	1720	30	185.28	1,860.32	2,080.29	2,045.60	2,265.57	420.00	640.14	715.83	1,060.14	1,135.83	(82.12)	(94.14)	-48%	-50%
1,721	1903	18	185.28	2,081.50	2,301.46	2,266.78	2,486.74	420.00	716.25	791.94	1,136.25	1,211.94	(94.21)	(106.23)	-50%	-51%
1,904	2086	8	185.28	2,302.67	2,522.63	2,487.95	2,707.91	420.00	792.36	868.05	1,212.36	1,288.05	(106.30)	(118.32)	-51%	-52%
2,087	2269	8	185.28	2,523.84	2,743.81	2,709.12	2,929.09	420.00	868.46	944.15	1,288.46	1,364.15	(118.39)	(130.41)	-52%	-53%
2,270	2452	2	185.28	2,745.02	2,964.98	2,930.30	3,150.26	420.00	944.57	1,020.26	1,364.57	1,440.26	(130.48)	(142.50)	-53%	-54%
2,453	2635	2	185.28	2,966.19	3,186.15	3,151.47	3,371.43	420.00	1,020.67	1,096.37	1,440.67	1,516.37	(142.57)	(154.59)	-54%	-55%
2,636	2818	1	185.28	3,187.36	3,407.33	3,372.64	3,592.61	420.00	1,096.78	1,172.47	1,516.78	1,592.47	(154.66)	(166.68)	-55%	-56%
2,819	3001	0	185.28	3,408.54	3,628.50	3,593.82	3,813.78	420.00	1,172.89	1,248.58	1,592.89	1,668.58	(166.74)	(178.77)	-56%	-56%
3,002	7304	6	185.28	3,629.71	8,832.12	3,814.99	9,017.40	420.00	1,248.99	3,039.16	1,668.99	3,459.16	(178.83)	(463.19)	-56%	-62%

Annual Residential Bill Impacts of WNSA Small/Large Rate Relative to Existing BSSA Rates

								$ 20.00	$ 0.82520	$ 0.82520	Small					
			$ 16.00	$ 0.63096	$ 0.63096			$ 35.00	$ 0.41611	$ 0.41611	Large					
Consumption					Current Charges					Proposed Charges			Absolute Change		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	28	43	192.00	-	17.35	192.00	209.35	240.00	-	22.69	240.00	262.69	4.00	4.45	25%	25%
29	55	12	192.00	17.98	34.70	209.98	226.70	240.00	23.52	45.39	263.52	285.39	4.46	4.89	25%	26%
56	83	34	192.00	35.33	52.05	227.33	244.05	240.00	46.21	68.08	286.21	308.08	4.91	5.34	26%	26%
84	110	42	192.00	52.69	69.41	244.69	261.41	240.00	68.90	90.77	308.90	330.77	5.35	5.78	26%	27%
111	138	45	192.00	70.04	86.76	262.04	278.76	240.00	91.60	113.47	331.60	353.47	5.80	6.23	27%	27%
139	165	75	192.00	87.39	104.11	279.39	296.11	240.00	114.29	136.16	354.29	376.16	6.24	6.67	27%	27%
166	193	73	192.00	104.74	121.46	296.74	313.46	240.00	136.98	158.85	376.98	398.85	6.69	7.12	27%	27%
194	220	118	192.00	122.09	138.81	314.09	330.81	240.00	159.68	181.54	399.68	421.54	7.13	7.56	27%	27%
221	248	131	192.00	139.44	156.16	331.44	348.16	240.00	182.37	204.24	422.37	444.24	7.58	8.01	27%	28%
249	275	156	192.00	156.79	173.51	348.79	365.51	240.00	205.06	226.93	445.06	466.93	8.02	8.45	28%	28%
276	303	180	192.00	174.14	190.87	366.14	382.87	240.00	227.76	249.62	467.76	489.62	8.47	8.90	28%	28%
304	330	203	192.00	191.50	208.22	383.50	400.22	240.00	250.45	272.32	490.45	512.32	8.91	9.34	28%	28%
331	358	195	192.00	208.85	225.57	400.85	417.57	240.00	273.14	295.01	513.14	535.01	9.36	9.79	28%	28%
359	385	196	192.00	226.20	242.92	418.20	434.92	240.00	295.83	317.70	535.83	557.70	9.80	10.23	28%	28%
386	413	211	192.00	243.55	260.27	435.55	452.27	240.00	318.53	340.40	558.53	580.40	10.25	10.68	28%	28%
414	440	224	192.00	260.90	277.62	452.90	469.62	240.00	341.22	363.09	581.22	603.09	10.69	11.12	28%	28%
441	613	1,195	192.00	278.25	387.02	470.25	579.02	420.00	183.50	255.23	603.50	675.23	11.10	8.02	28%	17%
614	787	821	192.00	387.65	496.42	579.65	688.42	420.00	255.65	327.38	675.65	747.38	8.00	4.91	17%	9%
788	960	505	192.00	497.05	605.81	689.05	797.81	420.00	327.80	399.52	747.80	819.52	4.90	1.81	9%	3%
961	1134	248	192.00	606.44	715.21	798.44	907.21	420.00	399.94	471.67	819.94	891.67	1.79	(1.29)	3%	-2%
1,135	1307	145	192.00	715.84	824.60	907.84	1,016.60	420.00	472.09	543.82	892.09	963.82	(1.31)	(4.40)	-2%	-5%
1,308	1480	76	192.00	825.24	934.00	1,017.24	1,126.00	420.00	544.23	615.96	964.23	1,035.96	(4.42)	(7.50)	-5%	-8%
1,481	1654	40	192.00	934.63	1,043.40	1,126.63	1,235.40	420.00	616.38	688.11	1,036.38	1,108.11	(7.52)	(10.61)	-8%	-10%
1,655	1827	21	192.00	1,044.03	1,152.79	1,236.03	1,344.79	420.00	688.52	760.25	1,108.52	1,180.25	(10.63)	(13.71)	-10%	-12%
1,828	2000	10	192.00	1,153.42	1,262.19	1,345.42	1,454.19	420.00	760.67	832.40	1,180.67	1,252.40	(13.73)	(16.82)	-12%	-14%
2,001	2174	8	192.00	1,262.82	1,371.59	1,454.82	1,563.59	420.00	832.81	904.54	1,252.81	1,324.54	(16.83)	(19.92)	-14%	-15%
2,175	2347	4	192.00	1,372.22	1,480.98	1,564.22	1,672.98	420.00	904.96	976.69	1,324.96	1,396.69	(19.94)	(23.02)	-15%	-17%
2,348	2521	3	192.00	1,481.61	1,590.38	1,673.61	1,782.38	420.00	977.10	1,048.83	1,397.10	1,468.83	(23.04)	(26.13)	-17%	-18%
2,522	2694	4	192.00	1,591.01	1,699.77	1,783.01	1,891.77	420.00	1,049.25	1,120.98	1,469.25	1,540.98	(26.15)	(29.23)	-18%	-19%
2,695	2867	3	192.00	1,700.41	1,809.17	1,892.41	2,001.17	420.00	1,121.40	1,193.13	1,541.40	1,613.13	(29.25)	(32.34)	-19%	-19%
2,868	7187	6	192.00	1,809.80	4,534.57	2,001.80	4,726.57	420.00	1,193.54	2,990.49	1,613.54	3,410.49	(32.36)	(109.67)	-19%	-28%

Residential

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

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.
			$ 108,996,862		2
		Determinants	Recommended		
Bills		3,403,902	Customer Charge	$	20.00
Volumes		124,726,694	Usage Rate	$	0.32807
			Calculated Revenue	$	108,997,128
			Rounding	$	266
Rates:					
Small	*	2,037,081	Customer Charge	$	20.00
	*	49,102,655	Usage Rate	$	0.41173
		24.10			
Large	*	1,366,821	Customer Charge	$	35.00
	*	75,624,039	Usage Rate	$	0.00264
		$ 55.33			
			Total Calculated Revenue	$	108,997,039
			Rounding	$	177

$ 22,865,615	Revenue Deficiency	9,919,370	benefit dollars taken from the other classes
$ 12,946,245	Target Increase	2,735,711	revenue credits (services fees, irrigation, custom transport)
$ 2,735,711	Revenue Credits	12,655,082	total credits
$ 12,655,082	Total Credits		
$ 50,819	Commodity-Related		
$ 12,604,263	Fixed		

To Implement Small/Large Rates:		
1. Input Small Customer Charge:	$ 20.00	$ 40,741,620
2. Input Large Customer Charge:	$ 35.00	$ 47,838,735
3. Input Initial Large Usage Charge:	$ 0.00500	$ 378,120
Internally Calculated:		
4. Calculate Small Usage Charge:	$ 0.41409	$ 20,332,919
5. Revenue Requirement Adjustment:	$ (0.00236)	$ (294,532)

*Source: Res Usage Summary_WNSA.xlsx

Commercial

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

COMMERCIAL CLASS RATE DESIGN

Select recommended customer charges.

Proposed Revenue	Class Revenue Alloc.
$ 19,445,088	2

	Commercial	Comm. Trans.	Electrical Cogeneration		
Determinants:					
Bills	208,155	240		24	
				Oct - Apr	May - Sep
Volumes	46,755,918	6,717,889	First 5000	35,010	25,000
			Next 95000	665,000	475,000
			Next 300000	240,050	75,420
			Over 400000	0	0
			Customer Charge	424.58	
			First 5000	$0.05696	$0.04695
			Next 95000	$0.04696	$0.03694
			Next 300000	$0.03696	$0.02695
			Over 400000	$0.02696	$0.01694
Recommended					
Customer Charge	$ 75.00	$ 500.00		$ 700.00	
			First 5000	$0.05260	$0.04259
Volumes	$ 0.06808	$ 0.06808	Next 95000	$0.04260	$0.03258
			Next 300000	$0.03260	$0.02259
Calculated Revenue	$ 18,794,736	$ 577,354	Over 400000	$0.02260	$0.01258
			Total	$ 73,040	
				Total Calculated Revenue	$ 19,445,130
				Rounding	$ 42

Add CC Revenue	$ 6,610.08	
CCF Change	$0.00436	
	Keep Cogen Constant	

Industrial

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

INDUSTRIAL CLASS RATE DESIGN

Select recommended customer charges.

	Proposed Revenue	Class Revenue Alloc.
	$ 1,306,864	2

	Industrial	Industrial Trans.	Standby	
Determinants:				
Bills	487	180		0
Volumes	1,370,091	6,561,058		0
Recommended Customer Charge	$ 850.00	$ 1,050.00		$ 666.37
Volumes	$ 0.08875	$ 0.08875	Per Mcf/Hour	$ 20.00
Calculated Revenue	$ 535,546	$ 771,294		$ -
			Total Calculated Revenue	$ 1,306,840
			Rounding	$ (25)

Public Authority

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

PUBLIC AUTHORITY CLASS RATE DESIGN

Select recommended customer charges.

	Proposed Revenue	Class Revenue Alloc.
	$ 4,878,521	2

Determinants:	Public Authority	Public Authority Trans.
Bills	16,237	84
Volumes	12,106,612	2,192,902
Recommended		
Customer Charge	$200.00	$500.00
Volumes	$ 0.11113	$ 0.11113
Calculated Revenue	$ 4,592,837	$ 285,697
	Total Calculated Revenue	$ 4,878,534
	Rounding	$ 14

CNG

TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.
WEST-NORTH SERVICE AREA
TWELVE MONTHS ENDED DECEMBER 31, 2021

CNG CLASS RATE DESIGN

Select recommended customer charges.

	Proposed Revenue	Class Revenue Alloc.
	$ 416,451	2

	CNG	CNG Trans.
Determinants:		
Bills		48
Volumes		5,160,298
Recommended		
Customer Charge	$150.00	$450.00
Volumes	$ 0.07652	$ 0.07652
Calculated Revenue	$ -	$ 416,466

Total Calculated Revenue	$	416,466
Rounding	$	15

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.

Bureau of Labor Statistics

RATE OF RETURN ON EQUITY **Workpaper**

CPI for All Urban Consumers (CPI-U)
Original Data Value

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Series Title: seasonally adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 2011 to 2021

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	220.223	221.309	223.467	224.906	225.964	225.722	225.922	226.545	226.889	226.421	226.230	225.672
2012	226.665	227.663	229.392	230.085	229.815	229.478	229.104	230.379	231.407	231.317	230.221	229.601
2013	230.280	232.166	232.773	232.531	232.945	233.504	233.596	233.877	234.149	233.546	233.069	233.049
2014	233.916	234.781	236.293	237.072	237.900	238.343	238.250	237.852	238.031	237.433	236.151	234.812
2015	233.707	234.722	236.119	236.599	237.805	238.638	238.654	238.316	237.945	237.838	237.336	236.525
2016	236.916	237.111	238.132	239.261	240.229	241.018	240.628	240.849	241.428	241.729	241.353	241.432
2017	242.839	243.603	243.801	244.524	244.733	244.955	244.786	245.519	246.819	246.663	246.669	246.524
2018	247.867	248.991	249.554	250.546	251.588	251.989	252.006	252.146	252.439	252.885	252.038	251.233
2019	251.712	252.776	254.202	255.548	256.092	256.143	256.571	256.558	256.759	257.346	257.208	256.974
2020	257.971	258.678	258.115	256.389	256.394	257.797	259.101	259.918	260.280	260.388	260.229	260.474
2021	261.582	263.014	264.877	267.054	269.195	271.696	273.003	273.567	274.31	276.589	277.948	278.802
2022	281.148	283.716	287.504	289.109	292.296							
2021 Increase in CPI												**7.04%**
21-22 Increase in CPI	7.48%	7.87%	8.54%	8.26%	8.58%							

Source: Bureau of Labor Statistics

TEXAS GAS SERVICE
A Division of ONE Gas, Inc.

ONE GAS, INC. CAPITAL STRUCTURE

	Capital (000s)		Capital Structure Ratios	
	LT Debt	Equity	LT Debt	Equity
December 31, 2021	1,583,378	2,349,532	40.26%	59.74%
December 31, 2020	1,582,428	2,233,311	41.47%	58.53%
December 31, 2019	1,286,064	2,129,390	37.65%	62.35%
December 31, 2018	1,285,483	2,042,656	38.62%	61.38%
December 31, 2017	1,193,257	1,960,209	37.84%	62.16%
December 31, 2016	1,192,453	1,888,280	38.71%	61.29%
December 31, 2015	1,201,312	1,841,555	39.48%	60.52%
December 31, 2014	1,201,317	1,794,037	40.11%	59.89%

Source: ONE Gas, Inc. Forms 10-K.

Unamortized issuance cost balance:

Natural	Description	December 2021 Balance
2240312	LT DEBT ISSUANCE COST 3.61% DUE 2024	596,513.19
2240313	LT DEBT ISSUANCE COST 4.658% DUE 2044	5,381,208.24
2240314	LT DEBT ISSUANCE COST 4.5% DUE 2048	4,019,469.36
2240315	LT DEBT ISSUANCE COST 2.0% DUE 2030	2,420,656.05
		12,417,846.84

Unamortized discount balance:

Natural	Description	December 2021 Balance
2260214	UNAMT DSC LT 4.5% DUE 2048	4,121,762.14
2260215	UNAMT DSC LT 2.0% DUE 2030	1,332,857.35
		5,454,619.49

Debt balances

Natural	Description	December 2021 Balance		Annual Amortization of Loss
1890110	UNAMORT LOSS REACQ DEBT 8.7% D	$ -		
1890118	UNAMORT LOSS REACQ 6 7/8%	$ 2,600,971.61		385,329.12
1890119	UNAMORT LOSS REACQ DEBT 6.125%	$ 2,280,463.46		337,846.11
2240212	LT PRIN DUE 3.61% DUE 2024	$ 300,000,000.00		723,175.23
2240213	LT PRIN DUE 4.658% DUE 2044	$ 600,000,000.00		
2240214	LT PRIN DUE 4.5% DUE 2048	$ 400,000,000.00		
2240215	LT PRIN DUE 2.0% DUE 2030	$ 300,000,000.00		
2240216	LT PRIN DUE 0.85% DUE 2023	$ 1,000,000,000.00	note: winter storm debt to be securitized	
2240217	LT PRIN FLOATING DUE 2023	$ 400,000,000.00	note: winter storm debt to be securitized	
2240218	LT PRIN DUE 1.10% DUE 2024	$ 700,000,000.00	note: winter storm debt to be securitized	

2021 amortization expense:

Natural	Description	Monthly Entry	
2240312	Amortize Debt Discount - January	$ 21,843.04	
2240312	Amortize Debt Discount - February	$ 22,248.16	
2240312	Amortize Debt Discount - March	$ 22,248.16	
2240312	Amortize Debt Discount - April	$ 22,248.16	
2240312	Amortize Debt Discount - May	$ 22,248.16	
2240312	Amortize Debt Discount - June	$ 22,248.16	
2240312	Amortize Debt Discount - July	$ 22,248.16	
2240312	Amortize Debt Discount - August	$ 22,248.16	
2240312	Amortize Debt Discount - September	$ 23,073.44	
2240312	Amortize Debt Discount - October	$ 22,660.80	
2240312	Amortize Debt Discount - November	$ 22,660.80	
2240312	Amortize Debt Discount - December	$ 22,660.80	
		$ 268,636.00	2021 Total
2240313	Amortize Debt Discount - January	$ 10,974.26	
2240313	Amortize Debt Discount - February	$ 11,233.45	
2240313	Amortize Debt Discount - March	$ 11,233.45	
2240313	Amortize Debt Discount - April	$ 11,233.45	
2240313	Amortize Debt Discount - May	$ 11,233.45	
2240313	Amortize Debt Discount - June	$ 11,233.45	
2240313	Amortize Debt Discount - July	$ 11,233.45	
2240313	Amortize Debt Discount - August	$ 11,233.45	
2240313	Amortize Debt Discount - September	$ 11,764.09	
2240313	Amortize Debt Discount - October	$ 11,498.77	
2240313	Amortize Debt Discount - November	$ 11,498.77	
2240313	Amortize Debt Discount - December	$ 11,498.77	
		$ 135,868.81	2021 Total
2240314	Amortize Debt Discount - January	$ 6,084.22	
2240314	Amortize Debt Discount - February	$ 6,084.22	
2240314	Amortize Debt Discount - March	$ 6,084.22	
2240314	Amortize Debt Discount - April	$ 6,084.22	
2240314	Amortize Debt Discount - May	$ 6,225.17	
2240314	Amortize Debt Discount - June	$ 6,225.17	
2240314	Amortize Debt Discount - July	$ 6,225.17	
2240314	Amortize Debt Discount - August	$ 6,225.17	
2240314	Amortize Debt Discount - September	$ 6,225.17	
2240314	Amortize Debt Discount - October	$ 6,225.17	
2240314	Amortize Debt Discount - November	$ 6,369.39	
2240314	Amortize Debt Discount - December	$ 6,369.39	
		$ 74,426.68	2021 Total
2240315	Amortize Debt Discount - January	$ 21,622.43	
2240315	Amortize Debt Discount - February	$ 21,622.43	
2240315	Amortize Debt Discount - March	$ 21,622.43	
2240315	Amortize Debt Discount - April	$ 21,622.43	
2240315	Amortize Debt Discount - May	$ 21,902.67	
2240315	Amortize Debt Discount - June	$ 21,902.67	
2240315	Amortize Debt Discount - July	$ 21,902.67	
2240315	Amortize Debt Discount - August	$ 21,902.67	
2240315	Amortize Debt Discount - September	$ 21,902.67	
2240315	Amortize Debt Discount - October	$ 21,902.67	
2240315	Amortize Debt Discount - November	$ 22,139.88	
2240315	Amortize Debt Discount - December	$ 22,139.88	
		$ 262,185.50	2021 Total
2260214	Amortize Debt Discount - January	$ 6,239.04	
2260214	Amortize Debt Discount - February	$ 6,239.04	
2260214	Amortize Debt Discount - March	$ 6,239.04	
2260214	Amortize Debt Discount - April	$ 6,239.04	
2260214	Amortize Debt Discount - May	$ 6,383.58	
2260214	Amortize Debt Discount - June	$ 6,383.58	
2260214	Amortize Debt Discount - July	$ 6,383.58	
2260214	Amortize Debt Discount - August	$ 6,383.58	
2260214	Amortize Debt Discount - September	$ 6,383.58	
2260214	Amortize Debt Discount - October	$ 6,383.58	
2260214	Amortize Debt Discount - November	$ 6,531.46	
2260214	Amortize Debt Discount - December	$ 6,531.46	
		$ 76,320.56	2021 Total
2260215	Amortize Debt Discount - January	$ 11,930.84	
2260215	Amortize Debt Discount - February	$ 11,930.84	
2260215	Amortize Debt Discount - March	$ 11,930.84	
2260215	Amortize Debt Discount - April	$ 11,930.84	
2260215	Amortize Debt Discount - May	$ 12,060.01	
2260215	Amortize Debt Discount - June	$ 12,060.01	
2260215	Amortize Debt Discount - July	$ 12,060.01	
2260215	Amortize Debt Discount - August	$ 12,060.01	
2260215	Amortize Debt Discount - September	$ 12,060.01	
2260215	Amortize Debt Discount - October	$ 12,060.01	
2260215	Amortize Debt Discount - November	$ 12,190.62	
2260215	Amortize Debt Discount - December	$ 12,190.62	
		$ 144,464.66	2021 Total

Issue	Debt Outstanding 12/31/21	Debt to be Retired at Securitization	Long-term Debt	Unamortized Issuance Costs	Unamortized Debt Discounts	Unamortized Retirement Costs	Annualized Amortization Issuance Costs	Annualized Amortization Debt Discounts
LT PRIN DUE 3.61% DUE 2024	300,000,000		300,000,000	596,513			271,930	
LT PRIN DUE 4.658% DUE 2044	600,000,000		600,000,000	5,381,208			137,985	
LT PRIN DUE 4.5% DUE 2048	400,000,000		400,000,000	4,019,469	4,121,762		76,433	78,378
LT PRIN DUE 2.0% DUE 2030	300,000,000		300,000,000	2,420,656	1,332,857		265,679	146,287
LT PRIN DUE 0.85% DUE 2023	1,000,000,000	(1,000,000,000)	-					
LT PRIN FLOATING DUE 2023	400,000,000	(400,000,000)	-					
LT PRIN DUE 1.10% DUE 2024	700,000,000	(700,000,000)	-					
Unamortized Debt Retirement Costs						4,881,435		
Totals	3,700,000,000	(2,100,000,000)	1,600,000,000	12,417,847	5,454,619	4,881,435	752,026	224,665

Embedded Cost of Debt

Issue	Amount	Interest Rate	Annual Expense
3.61% due 2024	300,000,000	3.61%	10,830,000
4.658% due 2044	600,000,000	4.66%	27,948,000
4.5% due 2048	400,000,000	4.50%	18,000,000
2.0% due 2030	300,000,000	2.00%	6,000,000
Debt issuance expenses	(17,872,466)		976,691
Debt Retirement Costs	(4,881,435)		723,175
Totals	1,577,246,099		64,477,866
Embedded Cost of Debt		**4.088%**	

THE VALUE LINE Investment Survey®

www.valueline.com

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ESPECIALLY NOTEWORTHY:

Subscribers should note a couple of name changes in this week's Issue. HollyFrontier Corp. is now known as ***HF Sinclair*** *(page 508), following a number of transactions, and its stock trades under its new ticker DINO. And, Westlake Chemical now goes by its new moniker* ***Westlake Corp.*** *(page 578). Meanwhile...*

Momentum and conservative income investors may want to consider ***American Tower****. The REIT's expanding cell tower network outside the U.S. should keep revenues and cash flow rising in the coming years. See page 580 for details.*

A strong recovery in oil and gas prices has proven to be a boon for many, including ***CVR Energy.*** *The company's reinstatement of the dividend gives it appeal. Our review is found on page 503.*

MDU Resources *(page 531) stands to gain from growing domestic energy infrastructure needs. The well-diversified company is playing in both the traditional exploration & production and renewables markets.*

Ingevity *seems well positioned to grow market share over the long haul, as the use of high-performance chemicals for various applications increases. Turn to page 565 for our thoughts.*

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★★ Rank 1 (Highest) for Timeliness.
★ Rank 2 (Above Average).

In three parts: Part 1 is the Summary & Index. Part 2 is Selection & Opinion. This is Part 3, Ratings & Reports. Volume LXXVII, No. 42

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THE VALUE LINE Investment Survey®

Part 1
Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

June 3, 2022

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The Median of Estimated **PRICE-EARNINGS RATIOS** of all stocks with earnings

16.1

26 Weeks Ago	Market Low 3-23-20	Market High 1-3-22
18.5	11.0	19.3

The Median of Estimated **DIVIDEND YIELDS** (next 12 months) of all dividend paying stocks

2.1%

26 Weeks Ago	Market Low 3-23-20	Market High 1-3-22
1.7%	3.7%	1.7%

The Median Estimated **THREE-TO-FIVE YEAR PRICE APPRECIATION POTENTIAL** of all stocks in the VL Universe

70%

26 Weeks Ago	Market Low 3-23-20	Market High 1-3-22
35%	145%	35%

The Median Estimated **18-MONTH APPRECIATION POTENTIAL TO TARGET PRICE RANGE** of all stocks in the VL Universe

32%

26 Weeks Ago	Market Low 3-23-20	Market High 1-3-22
11%	72%	13%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

	PAGE		PAGE		PAGE		PAGE
Advertising (88)	2384	Electric Util. (Central) (68)	901	Investment Co. (–)	1196	R.E.I.T. (73)	1511
*Aerospace/Defense (39)	701	Electric Utility (East) (71)	132	Investment Co.(Foreign) (–)	410	Recreation (67)	2301
Air Transport (78)	301	Electric Utility (West) (81)	2200	Machinery (56)	1701	Reinsurance (45)	2009
Apparel (83)	2101	Electronics (41)	1319	Maritime (42)	329	Restaurant (57)	346
Asset Management (63)	2212	Engineering & Const (54)	1012	*Medical Services (27)	783	Retail Automotive (49)	2116
Automotive (6)	101	Entertainment (19)	2331	Med Supp Invasive (69)	161	Retail Building Supply (47)	1139
Auto Parts (50)	959	Entertainment Tech (23)	2000	Med Supp Non-Invasive (33)	190	Retail (Hardlines) (38)	2163
Bank (35)	2501	Environmental (76)	401	*Metal Fabricating (43)	725	Retail (Softlines) (74)	2185
*Bank (Midwest) (72)	769	Financial Svcs. (Div.) (26)	2534	Metals & Mining (Div.) (31)	1579	Retail Store (34)	2133
Beverage (75)	1962	Food Processing (82)	1901	Natural Gas Utility (86)	538	Retail/Wholesale Food (25)	1943
*Biotechnology (15)	819	Foreign Electronics (70)	1977	Natural Gas (Div.) (65)	522	Semiconductor (7)	1346
Brokers & Exchanges (10)	1789	Furn/Home Furnishings (53)	1147	Office Equip/Supplies (95)	1404	Semiconductor Equip (11)	1377
Building Materials (40)	1101	*Healthcare Information (84)	810	Oil/Gas Distribution (64)	592	Shoe (46)	2153
Cable TV (59)	996	Heavy Truck & Equip (79)	144	Oilfield Svcs/Equip. (96)	2408	*Steel (28)	734
Chemical (Basic) (13)	1596	Homebuilding (36)	1126	Packaging & Container (8)	1168	Telecom. Equipment (58)	937
Chemical (Diversified) (29)	2425	Hotel/Gaming (9)	2353	Paper/Forest Products (62)	1160	Telecom. Services (66)	916
Chemical (Specialty) (51)	549	Household Products (92)	1184	Petroleum (Integrated) (61)	501	Telecom. Utility (90)	1007
Computers/Peripherals (52)	1391	Human Resources (20)	1634	Petroleum (Producing) (37)	2392	Thrift (93)	1501
Computer Software (4)	2572	Industrial Services (60)	369	Pipeline MLPs (85)	604	Tobacco (91)	1985
Cyber Security (5)	2018	Information Services (17)	417	Power (48)	1207	Toiletries/Cosmetics (32)	987
Diversified Co. (77)	1742	IT Services (24)	2604	Precious Metals (94)	1564	Trucking (12)	315
Drug (16)	1606	Insurance (Life) (87)	1552	Precision Instrument (44)	110	Water Utility (22)	1781
E-Commerce (2)	1805	*Insurance (Prop/Cas.) (30)	747	Public/Private Equity (1)	2436	Wireless Networking (55)	579
Educational Services (18)	1991	Internet (3)	2628	Publishing (89)	2377		
Electrical Equipment (80)	1301	Investment Banking (21)	1798	Railroad (14)	336		

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXXVII, No. 43.

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PAGE NUMBERS
Bold type refers to full report.
The number on the left signifies a Supplement (if available).

Suppl.	Page	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 12-31-22	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	1582	Arconic Corp.	ARNC	27.65	–	3	–	NMF	55- 85 (100-205%)	9.9	NIL	2.80	NIL	31	3/31	.39	.46	3/31	NIL	NIL	YES
	2216	Ares Management	ARES	68.19	2	3	3	1.35	90- 135 (30-100%)	22.4	3.6	3.05	2.44	63	3/31	.24	.32	6/30	.61	.47	YES
	2010	Argo Group Int'l	ARGO	41.54	1	3	5	.95	55- 85 (30-105%)	9.5	3.0	4.35	1.24	45	3/31	d.11	.78	6/30	.31	.31	
	1807	Arista Networks	ANET	102.30	3	3	2	1.10	110- 165 (10- 60%)	31.0	NIL	3.30	NIL	2	3/31	.85	.57	3/31	NIL	NIL	YES
	1105	Armstrong World Inds.	AWI	82.09	3	3	4	1.20	90- 135 (10- 65%)	18.0	1.1	4.55	.92	40	3/31	.94	.78	6/30	.231	.21	YES
	1323	Arrow Electronics	ARW	118.70	▲1	3	3	1.20	175- 260 (45-120%)	6.2	NIL	19.10	NIL	41	3/31	5.43	2.84	3/31	NIL	NIL	YES
	2031	Artivion, Inc.	AORT						SEE FINAL SUPPLEMENT												
	2118	Asbury Automotive	ABG	166.33	2	3	3	1.30	210- 315 (25- 90%)	4.9	NIL	33.75	NIL	49	3/31	9.27	4.68	3/31	NIL	NIL	YES
	552	Ashland Global Hldgs.	ASH	100.79	3	[illegible]	3	1.25	125- 185 (25- 85%)	18.9	1.3	5.32	1.33	51	3/31	1.50	.40	3/31	.30	.275	YES
620	2577	Aspen Technology	AZPN.D						SEE FINAL SUPPLEMENT												
	770	Assoc. Banc-Corp	ASB	20.02	4	3	2	1.15	30- 40 (50-100%)	10.8	4.0	1.85	.80	72	3/31	.47	.58	6/30	.20	.18	YES
	2539	Assurant Inc.	AIZ	178.49	4	2	[illegible]	.90	215- 295 (20- 65%)	14.9	1.7	12.00	3.05	26	3/31	2.59	2.41	6/30	.68	.66	YES
	2011	Assured Guaranty	AGO	57.07	▼3	3	[illegible]	1.50	55- 80 (N- 40%)	16.1	1.8	3.55	1.03	45	3/31	.98	.14	6/30	.25	.22	YES
	146	Astec Inds. (NDQ)	ASTE	44.71	4	3	[illegible]	1.15	70- 105 (55-135%)	24.8	1.1	1.80	.48	79	3/31	.41	.41	6/30	.12	.11	YES
	1609	AstraZeneca PLC (ADS)(NDQ)	AZN	66.41	2	2	3	.75	70- 90 (5- 35%)	NMF	2.2	.50	1.45	16	3/31	.13	.59	3/31	▲.985	.95	YES
	726	Atkore, Inc.	ATKR	102.92	4	3	[illegible]	1.55	115- 175 (10- 70%)	5.7	NIL	▲17.98	NIL	43	3/31	5.08	2.58	3/31	NIL	NIL	YES
	305	Atlas Air Worldwide (NDQ)	AAWW	66.96	3	3	3	.75	85- 125 (25- 85%)	4.3	NIL	15.50	NIL	78	3/31	2.99	2.45	3/31	NIL	NIL	YES
	539	Atmos Energy	ATO	113.67	3	1	1	.80	130- 160 (15- 40%)	20.1	2.5	5.66	2.87	86	3/31	2.37	2.30	6/30	.68	.625	YES
	940	AudioCodes Ltd. (NDQ)	AUDC	22.01	3	3	4	.95	45- 65 (105-195%)	14.2	1.6	1.55	.36	58	3/31	.33	.37	3/31	▲.18	.16	YES
219	1411	Aurora Cannabis	ACB						SEE FINAL SUPPLEMENT												
	2578	Autodesk, Inc. (NDQ)	ADSK	183.51	2	3	[illegible]	1.00	250- 375 (35-105%)	45.9	NIL	4.00	NIL	4	1/31	.40	4.10	3/31	NIL	NIL	YES
	964	Autoliv, Inc.	ALV	76.25	3	3	[illegible]	1.30	115- 175 (50-130%)	13.3	3.4	5.75	2.56	50	3/31	.45	1.79	6/30	.64	.62	YES
	2608	Automatic Data Proc. (NDQ)	ADP	212.96	3	1	[illegible]	1.05	240- 295 (15- 40%)	29.8	2.1	7.15	4.52	24	3/31	2.21	1.90	9/30	1.04	.93	YES
	2119	AutoNation, Inc.	AN	107.41	▼4	3	3	1.05	165- 250 (55-135%)	5.0	NIL	21.35	NIL	49	3/31	5.78	2.79	3/31	NIL	NIL	YES
	2120	AutoZone Inc.	AZO	1805.22	4	3	2	.95	1960-2940 (10- 65%)	15.8	NIL	114.21	NIL	49	5/31	♦29.03	26.48	3/31	NIL	NIL	YES
	1808	Avalara, Inc.	AVLR	80.58	2	3	4	.90	95- 140 (20- 75%)	NMF	NIL	d.80	NIL	2	3/31	d.37	d.35	3/31	NIL	NIL	YES
	1515	AvalonBay Communities	AVB	204.19	▼3	3	1	1.10	225- 340 (10- 65%)	30.3	3.2	6.75	6.47	73	3/31	1.87	1.02	9/30	♦1.59	1.59	YES
	133	AVANGRID, Inc.	AGR	47.65	4	2	4	.85	40- 55 (N- 15%)	20.7	3.7	2.30	1.76	71	3/31	1.15	1.08	9/30	.44	.44	YES
	195	Avanos Medical	AVNS	27.71	3	3	4	1.15	60- 90 (115-225%)	16.8	NIL	1.65	NIL	33	3/31	.26	.23	3/31	NIL	NIL	YES
	553	Avantor, Inc.	AVTR	31.53	▼2	3	4	.95	35- 55 (10- 75%)	30.0	NIL	1.05	NIL	51	3/31	.28	.25	3/31	NIL	NIL	YES
	941	Avaya Holdings	AVYA	4.11	3	4	3	.90	20- 35 (385-750%)	NMF	NIL	d.71	NIL	58	3/31	d.02	d.70	3/31	NIL	NIL	YES
	554	Avery Dennison	AVY	166.70	3	2	4	1.20	175- 240 (5- 45%)	17.3	1.8	9.65	3.07	51	3/31	2.39	2.49	6/30	▲.75	.68	YES
	555	Avient Corp.	AVNT	47.70	3	3	3	1.30	50- 80 (5- 70%)	13.6	2.0	3.50	.95	51	3/31	.91	.86	9/30	.238	.213	YES
	2164	Avis Budget Group (NDQ)	CAR	184.60	1	4	1	1.70	185- 305 (N- 65%)	8.2	NIL	22.50	NIL	38	3/31	9.99	d.46	3/31	NIL	NIL	YES
	2201	Avista Corp.	AVA	43.41	4	2	2	.90	45- 65 (5- 50%)	21.7	4.1	2.00	1.78	81	3/31	.99	.98	6/30	.44	.422	YES
	1324	Avnet, Inc. (NDQ)	AVT	46.23	3	2	4	1.10	80- 110 (75-140%)	7.9	2.2	5.87	1.04	41	3/31	2.15	.74	3/31	▲.26	.21	YES
	556	Axalta Coating	AXTA	25.93	2	3	4	1.30	30- 45 (15- 75%)	24.7	NIL	1.05	NIL	51	3/31	.18	.06	3/31	NIL	NIL	YES
	1381	Axcelis Technologies (NDQ)	ACLS	57.05	3	3	3	1.40	55- 85 (N- 50%)	13.9	NIL	4.10	NIL	11	3/31	1.22	.48	3/31	NIL	NIL	YES
	2012	AXIS Capital Hldgs.	AXS	56.52	4	2	2	1.00	70- 95 (25- 70%)	9.5	3.0	5.95	1.72	45	3/31	1.65	.97	9/30	.43	.42	YES
	704	Axon Enterprise (NDQ)	AXON	94.74	3	3	4	1.00	105- 160 (10- 70%)	48.6	NIL	1.95	NIL	39	3/31	.45	.34	3/31	NIL	NIL	YES
	1502	Axos Financial	AX	36.65	4	3	3	1.25	50- 75 (35-105%)	8.7	NIL	4.21	NIL	93	3/31	1.05	.89	3/31	NIL	NIL	YES
2652	1610	Axsome Therapeutics (NDQ)	AXSM	28.16	4	4	4	1.10	55- 95 (95-235%)	NMF	NIL	d4.10	NIL	16	3/31	d1.03	d.78	3/31	NIL	NIL	YES
	1106	AZEK (The) Company	AZEK	19.46	–	3	–	NMF	30- 50 (55-155%)	16.4	NIL	1.19	NIL	40	3/31	.23	.14	3/31	NIL	NIL	YES
	1707	Azenta, Inc. (NDQ)	AZTA	70.77	–	3	–	1.35	75- 115 (5- 60%)	68.7	NIL	1.03	NIL	56	3/31	.12	d.10	3/31	▼NIL	.10	YES
	1903	**B&G Foods**	BGS	22.17	5	[illegible]	4	.45	45- 65 (105-195%)	12.7	8.6	1.75	1.90	82	3/31	.34	.52	9/30	♦.475	.475	YES
	1008	BCE Inc.	BCE	53.35	3	2	2	.90	45- 60 (N- 10%)	20.1	5.5	2.65	2.91	90	3/31	.70	.61	9/30	.727	.696	YES
★★	1583	BHP Group Ltd. ADR	BHP	68.70	–	3	–	1.00	90- 135 (30- 95%)	11.2	7.3	6.16	5.00(h)	31	12/31	3.34(p)	1.53(p)	3/31	3.00	2.02	YES
	347	BJ's Restaurants (NDQ)	BJRI	23.10	4	4	[illegible]	1.80	45- 75 (95-225%)	30.8	NIL	.75	NIL	57	3/31	.06	d.14	3/31	NIL	NIL	YES
1227	2134	BJ's Wholesale Club	BJ	54.57	4	3	[illegible]	.50	75- 110 (35-100%)	16.8	NIL	3.25	NIL	34	4/30	♦.82	.59	3/31	NIL	NIL	YES
	771	BOK Financial (NDQ)	BOKF	83.28	4	3		1.30	95- 140 (15- 70%)	13.9	2.5	▼6.00	2.12	72	3/31	.91	2.10	6/30	.53	.52	YES
1028	502	BP PLC ADR	BP	32.11	▼4	3	3	1.30	50- 75 (55-135%)	NMF	4.1	d3.65	1.31	61	3/31	d6.27	1.37	6/30	.328	.315	YES
	1209	BWX Technologies	BWXT	49.61	4	3	[illegible]	.85	50- 80 (N- 60%)	18.4	1.8	2.70	.88	48	3/31	.64	.73	6/30	▲.22	.21	YES
	112	Badger Meter	BMI	77.55	2	3	3	1.10	85- 130 (10- 70%)	35.3	1.0	2.20	.80	44	3/31	.49	.47	6/30	.20	.18	YES
	1831	Baidu, Inc.	BIDU						SEE FINAL SUPPLEMENT												
	2410	Baker Hughes	BKR	35.71	▲4	3	3	.25	40- 55 (10- 55%)	28.6	2.0	1.25	.72	96	3/31	.15	.12	6/30	♦.18	.18	YES
	557	Balchem Corp. (NDQ)	BCPC	121.79	2	2	[illegible]	.70	155- 205 (25- 70%)	37.5	0.5	3.25	.64	51	3/31	.89	.72	3/31	▲.64	.58	YES
	1171	Ball Corp.	BALL	70.81	3	2	[illegible]	.95	165- 225 (135-220%)	18.9	1.1	3.75	.80	8	3/31	1.37	.60	6/30	.20	.15	YES
	2355	Bally's Corp.	BALY	24.87	–	5	–	2.05	45- 85 (80-240%)	NMF	NIL	d.10	NIL	9	3/31	.03	d.30	3/31	NIL	NIL	YES
1026	920	Bandwidth Inc. (NDQ)	BAND	20.93	3	4	[illegible]	.75	70- 110 (235-425%)	NMF	NIL	.05	NIL	66	3/31	.09	.30	3/31	NIL	NIL	YES
	2503	Bank of America	BAC	35.87	2	3	2	1.25	45- 70 (25- 95%)	11.0	2.4	3.25	.86	35	3/31	.80	.86	6/30	.21	.18	YES
	2504	Bank of Hawaii	BOH	76.91	4	3	3	1.10	90- 135 (15- 75%)	14.4	3.6	5.35	2.80	35	3/31	1.32	1.50	6/30	.70	.67	YES
	2505	Bank of Montreal (TSE)	BMO.TO	130.92b	▼2	2	1	1.00	170- 230 (30- 75%)	8.0	4.2	16.45	5.56	35	1/31	4.43(b)	3.03(b)	6/30	1.33(b)	1.06(b)	YES
	2506	Bank of New York Mellon	BK	44.68	2	2	3	1.10	70- 95 (55-115%)	9.9	3.0	4.50	1.36	35	3/31	.86	.97	6/30	.34	.31	YES
	2507	Bank of Nova Scotia (TSE)	BNS.TO	80.24b	3	1	2	.90	90- 115 (10- 45%)	9.1	5.1	8.85	4.12	35	1/31	2.15(b)	1.88(b)	6/30	1.00(b)	.90(b)	YES
	1747	Barnes Group	B	34.56	4	3	4	1.25	65- 95 (90-175%)	15.0	1.9	2.30	.64	77	3/31	.41	.38	6/30	.16	.16	YES
620	1637	Barrett Business Serv.	BBSI						SEE FINAL SUPPLEMENT												
	1568	Barrick Gold	GOLD	20.73	4	3	1	.55	20- 30 (N- 45%)	18.8	4.8	1.10	1.00	94	3/31	.26	.29	6/30	.10	.09	YES
	2165	Bath & Body Works	BBWI	38.53	–	4	–	1.55	60- 100 (55-160%)	8.6	2.1	4.50	.80	38	4/30	♦.64	.97	6/30	.20	.15	YES
436	1611	Bausch Health	BHC	9.79	–	5	–	1.40	30- 60 (205-515%)	2.1	NIL	4.70	NIL	16	3/31	.72	1.04	3/31	NIL	NIL	YES
	163	Baxter Int'l Inc.	BAX	73.37	3	1	4	.75	110- 135 (50- 85%)	17.1	1.6	4.30	1.16	69	3/31	.93	.76	9/30	▲.29	.28	YES
	1107	Beacon Roofing (NDQ)	BECN	59.82	3	3	3	1.55	90- 135 (50-125%)	11.2	NIL	5.35	NIL	40	3/31	.61	d.24	3/31	NIL	NIL	YES
620	1127	Beazer Homes USA	BZH						SEE FINAL SUPPLEMENT												
	164	Becton, Dickinson	BDX	257.00	3	1	2	.75	290- 350 (15- 35%)	21.7	1.4	11.86	3.60	69	3/31	3.18	3.19	6/30	.87	.83	YES
1227	2166	Bed Bath & Beyond (NDQ)	BBBY	8.33	–	5	–	1.45	20- 35 (140-320%)	NMF	NIL	d1.44	NIL	38	2/28	d1.79	.08	3/31	NIL	NIL	YES
	1304	Belden Inc.	BDC	54.43	4	3	3	1.30	80- 120 (45-120%)	12.8	0.4	4.25	.20	80	3/31	.79	.64	6/30	.05	.05	YES
	752	Berkley (W.R.)	WRB	67.84	5	2	3	1.05	75- 100 (10- 45%)	17.0	0.5	▼4.00	.35	30	3/31	1.10	.72	3/31	.087	.08	YES
1649	753	Berkshire Hathaway 'B'	BRKB	310.20	1	1	1	.95	360- 440 (15- 40%)	28.9	NIL	10.75	NIL	30	3/31	3.18	3.05	3/31	NIL	NIL	YES
	1172	Berry Global Group	BERY	56.25	2	3	4	1.00	100- 150 (80-165%)	7.5	NIL	7.50	NIL	8	3/31	1.93	1.59	3/31	NIL	NIL	YES
1227	2167	Best Buy Co.	BBY	72.59	3	3	3	1.10	130- 200 (80-175%)	8.1	4.8	9.00	3.52	38	4/30	♦1.57	2.23	9/30	♦.88	.70	YES
620	1904	Beyond Meat (NDQ)	BYND	24.67	3	4	3	1.35	140- 235 (465-855%)	NMF	NIL	d2.85	NIL	82	3/31	d1.58	d.43	3/31	NIL	NIL	YES
	2135	Big Lots Inc.	BIG	27.09	5	3	4	1.15	70- 105 (160-290%)	5.4	4.6	5.00	1.25	34	1/31	1.63	2.59	6/30	.30	.60	YES
	196	Bio-Rad Labs. 'A'	BIO	520.75	3	2	4	.80	550- 745 (5- 45%)	38.9	NIL	13.40	NIL	33	3/31	4.94	5.21	3/31	NIL	NIL	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 12-31-22, the arrow indicates a change since the preceding week. When a diamond ♦ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to full report.
The number on the left signifies a Supplement (if available).

Supp.	Page	NAME OF STOCK	Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 12-31-22	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	338	Can. National Railway	CNI	112.66	4	1	2	.85	150- 185 (35- 65%)	20.5	2.1	5.50	2.32	14	3/31	1.03	.97	6/30	.579	.467	YES
	2396	Can. Natural Res.	(TSE) CNQ.TO	79.33b	▲3	3	2	1.50	85- 130 (5- 65%)	6.6	3.8	12.00	3.00	37	3/31	2.86(b)	1.03(b)	9/30	.75(b)	.47(b)	YES
	339	Can. Pacific Railway	CP	69.49	3	2	2	.95	90- 125 (30- 80%)	23.2	0.8	3.00	.58	14	3/31	.50	.71	6/30	.144	.144	YES
	2138	Canadian Tire 'A'	(TSE) CTCA.TO	161.80b	▲2	3	2	1.10	210- 315 (30- 95%)	8.6	4.0	18.80	6.50	34	3/31	3.03(b)	2.47(b)	9/30	1.625(b)	1.175(b)	YES
	1976	Canon Inc. ADR(g)	CAJ	25.23	4	2	4	.75	35- 45 (40- 80%)	12.3	3.3	2.05	.82	70	3/31	.38	.37	6/30	.449	.36	YES
219	1412	Canopy Growth Corp.	CGC					SEE FINAL SUPPLEMENT													
	2542	Capital One Fin'l	COF	118.80	3	3	3	1.45	110- 160 (N- 35%)	6.0	2.0	19.65	2.40	26	3/31	5.62	7.03	6/30	.60	.40	YES
	1503	Capitol Fed. Fin'l	(NDQ) CFFN	9.89	4	3	3	.80	11- 16 (10- 60%)	19.0	3.4	.52	.34	93	3/31	.16	.15	6/30	.085	.085	YES
	2103	Capri Holdings Ltd.	CPRI	42.14	2	4	3	1.85	70- 120 (65-185%)	6.9	NIL	6.13	NIL	83	12/31	2.11	1.18	3/31	NIL	NIL	YES
	197	Cardinal Health	CAH	56.96	3	3	1	1.00	90- 135 (60-135%)	10.2	3.5	5.59	1.98	33	3/31	1.45	1.53	9/30	▲.496	.491	YES
	1750	Carlisle Cos.	CSL	248.86	4	2	3	1.10	230- 315 (N- 25%)	20.7	0.9	12.00	2.16	77	3/31	3.67	.97	6/30	.54	.525	YES
	2439	Carlyle Group	(NDQ) CG	36.68	3	3	3	.20	65- 100 (75-175%)	10.5	3.5	3.50	1.30	1	3/31	1.57	2.41	6/30	▲.325	.25	YES
	2122	CarMax, Inc.	KMX	90.89	1	3	5	1.20	160- 240 (75-165%)	14.5	NIL	6.28	NIL	49	2/28	.98	1.27	3/31	NIL	NIL	YES
	2305	Carnival Corp.	CCL	13.11	3	5	3	1.75	35- 60 (165-360%)	NMF	NIL	d1.20	NIL	67	2/28	d1.66	d1.82	3/31	NIL	NIL	YES
	736	Carpenter Technology	CRS	33.36	3	3		1.50	35- 55 (5- 65%)	71.0	2.4	.47	.80	28	3/31	d.16	d.54	6/30	.20	.20	YES
	1708	Carrier Global	CARR	38.27	–	3		NMF	65- 100 (70-160%)	16.6	1.6	2.30	.60	56	3/31	.54	.48	6/30	.15	.12	YES
1029	2104	Carter's Inc.	CRI	75.37	4	3	4	.95	120- 180 (60-140%)	8.5	4.0	8.85	3.00	83	3/31	1.66	1.98	6/30	◆.75	.40	YES
621	2123	Carvana Co.	CVNA	30.24	1	5	3	1.75	175- 330 (480-990%)	NMF	NIL	d2.42	NIL	49	3/31	d1.02	d.46	3/31	NIL	NIL	YES
	402	Casella Waste Sys.	(NDQ) CWST	69.85	1	3	[illegible]	.85	70- 105 (N- 50%)	63.5	NIL	1.10	NIL	76	3/31	.08	.08	3/31	NIL	NIL	YES
	1946	Casey's Gen'l Stores	(NDQ) CASY	199.57	▼3	3	2	.90	195- 295 (N- 50%)	22.0	0.7	9.06	1.43	25	1/31	1.71	1.04	6/30	.35	.34	YES
	166	Catalent, Inc.	CTLT	98.54	3	3	4	1.00	135- 205 (35-110%)	33.0	NIL	2.99	NIL	69	3/31	.78	.48	3/31	NIL	NIL	YES
	148	Caterpillar Inc.	CAT	204.15	3	2	2	1.10	215- 290 (5- 40%)	16.7	2.2	12.20	4.44	79	3/31	2.88	2.87	6/30	1.11	1.03	YES
	2306	Cedar Fair L.P.	FUN	43.84	5	4	[illegible]	1.30	70- 115 (60-160%)	12.5	NIL	3.50	NIL	67	3/31	d1.56	d1.95	3/31	NIL	NIL	YES
	2429	Celanese Corp.	CE	151.79	▼3	3	[illegible]	1.15	160- 240 (5- 60%)	9.8	1.9	15.50	2.90	29	3/31	5.54	3.46	6/30	.68	.68	YES
	1966	Celsius Holdings	(NDQ) CELH	62.62	▲4	3	[illegible]	1.15	30- 50 (N- N%)	NMF	NIL	.30	NIL	75	3/31	.09	.01	3/31	NIL	NIL	YES
	1110	CEMEX ADS	CX	4.36	4	4	3	1.45	7- 12 (60-175%)	5.1	NIL	.85	NIL	40	3/31	.13	.42	3/31	NIL	NIL	YES
	504	Cenovus Energy	(TSE) CVE.TO	27.41b	▲2	4	3	1.55	14- 25 (N- N%)	7.5	1.5	3.65	.42	61	3/31	.79(b)	.10(b)	6/30	▲.105(b)	.018(b)	YES
	786	Centene Corp.	CNC	86.04	2	3	3	1.00	95- 145 (10- 70%)	15.8	NIL	5.45	NIL	27	3/31	1.83	1.63	3/31	NIL	NIL	YES
	907	CenterPoint Energy	CNP	30.84	3	3	2	1.15	25- 35 (N- 15%)	24.7	2.3	1.25	.71	68	3/31	.52	.41	6/30	.17	.16	YES
1029	412	Central & East. Europe	CEE	10.50	–	5	–	1.25	10- 18 (N- 70%)	NMF	0.5	NMF	.05	–	4/30	7.27(q)	28.62(q)	3/31	.953	.919	
	1185	Central Garden & Pet	(NDQ) CENT	42.72	3	3	5	.80	70- 100 (65-135%)	13.6	NIL	3.14	NIL	92	3/31	1.27	1.32	3/31	NIL	NIL	YES
	1585	Century Aluminum	(NDQ) CENX	12.49	▼3	5	1	1.60	35- 60 (180-380%)	3.0	NIL	4.20	NIL	31	3/31	.59	d.54	3/31	NIL	NIL	YES
	812	Cerner Corp.	(NDQ) CERN	94.10	–	2	–	.85	95- 130 (N- 40%)	25.4	1.2	3.70	1.12	84	3/31	.89	.76	6/30	.27	.22	YES
	198	Charles River	CRL	231.24	2	3	3	1.20	250- 375 (10- 60%)	26.1	NIL	8.85	NIL	33	3/31	1.81	1.20	3/31	NIL	NIL	YES
	727	Chart Industries	(NDQ) GTLS	177.47	3	3	3	1.75	▲ 165- 250 (N- 40%)	33.2	NIL	5.35	NIL	43	3/31	.65	.74	3/31	NIL	NIL	YES
	999	Charter Communic.	(NDQ) CHTR	473.67	1	2	4	.85	820-1110 (75-135%)	15.3	NIL	31.00	NIL	59	3/31	6.90	4.11	3/31	NIL	NIL	YES
	2019	Check Point Software	(NDQ) CHKP	124.12	3	1	2	.75	150- 180 (20- 45%)	16.8	NIL	7.40	NIL	5	3/31	1.57	1.54	3/31	NIL	NIL	YES
	350	Cheesecake Factory	(NDQ) CAKE	29.08	4	3	4	1.40	60- 85 (105-190%)	10.0	3.7	2.90	1.08	57	3/31	.47	.20	6/30	▲.27	NIL	YES
	1947	Chefs' Warehouse	(NDQ) CHEF	33.47	3	4	3	2.10	30- 50 (N- 50%)	47.8	NIL	.70	NIL	25	3/31	.04	d.49	3/31	NIL	NIL	YES
220	1994	Chegg, Inc.	CHGG	18.42	2	3	3	.75	75- 115 (305-525%)	14.7	NIL	1.25	NIL	18	3/31	.32	.28	3/31	NIL	NIL	YES
	1751	Chemed Corp.	CHE	491.94	▼3	2	3	.80	520- 700 (5- 40%)	25.4	0.3	19.35	1.44	77	3/31	4.79	4.44	6/30	.36	.34	YES
	559	Chemours Co. (The)	CC	41.35	2	3	3	1.55	45- 65 (10- 55%)	8.7	2.7	4.75	1.10	51	3/31	1.43	.55	6/30	.25	.25	YES
	594	Cheniere Energy Inc.	(ASE) LNG	131.11	1	3	2	1.05	115- 175 (N- 35%)	65.6	1.0	2.00	1.32	64	3/31	d3.41	1.54	6/30	.33	NIL	YES
	605	Cheniere Energy Part.	CQP	52.11	3	3	3	.90	50- 75 (N- 45%)	23.2	6.2	2.25	3.23	85	3/31	d.11	.64	6/30	▲.775	.66	YES
	540	Chesapeake Utilities	CPK	133.28	2	2	2	.75	125- 170 (N- 30%)	26.7	1.6	5.00	2.18	86	3/31	2.06	1.96	9/30	▲.535	.48	YES
	505	Chevron Corp.	CVX	171.72	4	3	3	1.25	125- 190 (N- 10%)	11.2	3.3	15.40	5.71	61	3/31	3.22	.72	6/30	1.42	1.34	YES
	2635	Chewy, Inc.	CHWY	24.80	3	4	3	.75	65- 110 (160-340%)	NMF	NIL	.05	NIL	3	1/31	d.15	.05	3/31	NIL	NIL	YES
	2189	Children's Place	(NDQ) PLCE	43.95	4	4	4	.65	100- 165 (130-275%)	4.6	NIL	9.55	NIL	74	4/30	◆1.05	3.25	3/31	NIL	NIL	YES
	1831	China Fund (The)	CHN					SEE FINAL SUPPLEMENT													
	351	Chipotle Mex. Grill	CMG	1289.79	2	3	3	.95	1390-2085 (10- 60%)	41.9	NIL	30.80	NIL	57	3/31	5.59	5.22	3/31	NIL	NIL	YES
	2357	Choice Hotels Int'l	CHH	123.27	1	3		1.20	110- 170 (N- 40%)	25.4	0.8	4.85	.95	9	3/31	1.20	.40	6/30	.238	NIL	YES
	755	Chubb Ltd.	CB	207.31	3	1	[illegible]	1.10	235- 285 (15- 35%)	13.6	1.6	15.25	3.32	30	3/31	3.82	2.52	9/30	▲.83	.80	YES
	1186	Church & Dwight	CHD	89.45	5	1	3	.60	90- 110 (N- 25%)	25.9	1.2	3.45	1.05	92	3/31	.83	.88	6/30	.263	.253	YES
	2358	Churchill Downs	(NDQ) CHDN	185.51	2	3	3	1.40	260- 390 (40-110%)	20.8	0.4	8.90	.67	9	3/31	1.08	.91	3/31	▲.667	.622	YES
	943	Ciena Corp.	CIEN	50.19	3	3	3	.95	80- 120 (60-140%)	15.4	NIL	3.25	NIL	58	1/31	.47	.52	3/31	NIL	NIL	YES
	787	Cigna Corp.	CI	263.37	2	3	3	1.25	305- 460 (15- 75%)	11.7	1.7	22.60	4.48	27	3/31	6.01	4.73	6/30	▲1.12	1.00	YES
	2378	Cimpress plc	(NDQ) CMPR	43.53	5	3	3	1.30	90- 135 (105-210%)	16.2	NIL	2.68	NIL	89	3/31	d2.75	d1.50	3/31	NIL	NIL	YES
	756	Cincinnati Financial	(NDQ) CINF	125.34	2	3	2	1.10	▼ 135- 200 (10- 60%)	21.8	2.2	5.75	2.76	30	3/31	1.58	1.37	9/30	.69	.63	YES
	2307	Cinemark Hldgs.	CNK	15.61	4	5	3	1.25	25- 45 (60-190%)	44.6	NIL	.35	NIL	67	3/31	d.62	d1.75	3/31	NIL	NIL	YES
	376	Cintas Corp.	(NDQ) CTAS	370.28	▲2	2	[illegible]	1.15	370- 505 (N- 35%)	32.5	1.0	11.38	3.80	60	2/28	2.69	2.37	6/30	.95	.75	YES
	1352	Cirrus Logic	(NDQ) CRUS	78.87	2	3	3	.95	115- 175 (45-120%)	12.1	NIL	6.50	NIL	7	3/31	2.01	.66	3/31	NIL	NIL	YES
★★	944	Cisco Systems	(NDQ) CSCO	43.35	3	1	3	.90	70- 90 (60-110%)	12.1	3.5	3.59	1.52	58	4/30	◆.87	.83	6/30	▲.38	.37	YES
	2190	Citi Trends	(NDQ) CTRN	25.73	▼3	3	4	1.35	90- 140 (250-445%)	5.8	NIL	4.40	NIL	74	4/30	◆3.59	3.23	3/31	NIL	NIL	YES
	2510	Citigroup Inc.	C	52.77	2	3	4	1.40	75- 115 (40-120%)	7.8	4.0	6.75	2.09	35	3/31	2.02	3.62	6/30	.51	.51	YES
	2511	Citizens Fin'l Group	CFG	39.05	3	3	2	1.45	55- 85 (40-120%)	9.2	4.0	4.25	1.58	35	3/31	.93	1.37	6/30	.39	.39	YES
	2581	Citrix Sys.	(NDQ) CTXS	99.78	–	3	–	.60	150- 230 (50-130%)	19.2	NIL	5.20	NIL	4	3/31	1.46	1.42	3/31	▼NIL	.37	YES
1416	420	Clarivate Plc	CLVT	14.66	2	3	4	.90	17- 25 (15- 70%)	NMF	NIL	d.15	NIL	17	3/31	d.06	d.17	3/31	NIL	NIL	YES
	595	Clean Energy Fuels	(NDQ) CLNE	4.87	4	5	2	1.35	6- 11 (25-125%)	NMF	NIL	d.15	NIL	64	3/31	d.11	d.04	3/31	NIL	NIL	YES
	403	Clean Harbors	CLH	91.10	▲3	3	2	1.30	105- 155 (15- 70%)	19.8	NIL	4.60	NIL	76	3/31	.83	.39	3/31	NIL	NIL	YES
	737	Cleveland-Cliffs Inc.	CLF	23.01	3	5	1	1.60	40- 70 (75-205%)	3.7	NIL	6.20	NIL	28	3/31	1.50	.07	3/31	NIL	NIL	YES
	1187	Clorox Co.	CLX	139.59	4	1	5	.40	185- 225 (35- 60%)	28.3	3.3	4.93	4.64	92	3/31	1.31	1.62	6/30	1.16	1.11	YES
438	2582	Cloudflare, Inc.	NET	56.75	▼2	4	2	.85	120- 205 (110-260%)	NMF	NIL	d.30	NIL	4	3/31	d.13	d.13	3/31	NIL	NIL	YES
	1967	Coca-Cola	KO	62.86	3	1	3	.90	60- 75 (N- 20%)	25.7	2.8	2.45	1.76	75	3/31	.64	.54	9/30	.44	.42	YES
	1649	Coca-Cola Consol.	COKE					SEE FINAL SUPPLEMENT													
	1649	Coca-Cola Euro. Part.	CCEP					SEE FINAL SUPPLEMENT													
	1569	Coeur Mining	CDE	3.66	5	4	2	.80	11- 18 (200-390%)	NMF	NIL	NIL	NIL	94	3/31	d.05	.06	3/31	NIL	NIL	YES
	1000	Cogeco Communic.	(TSE) CCA.TO	102.92b	3	2	3	.55	120- 165 (15- 60%)	11.2	2.7	9.18	2.82	59	2/28	2.38(b)	2.14(b)	6/30	.705(b)	.64(b)	YES
	114	Cognex Corp.	(NDQ) CGNX	47.79	[illegible]	3	3	1.05	75- 110 (55-130%)	27.3	0.5	1.75	.26	44	3/31	.38	.39	6/30	.065	.06	YES
	2612	Cognizant Technology	(NDQ) CTSH	71.84	▲4	2	2	1.00	95- 130 (30- 80%)	16.0	1.5	4.50	1.08	24	3/31	1.08	.97	6/30	.27	.24	YES
	115	Coherent, Inc.	(NDQ) COHR	266.99	–	3	–	1.15	180- 270 (N- N%)	47.4	NIL	5.63	NIL	44	3/31	1.35	.86	3/31	NIL	NIL	YES
	1752	Colfax Corp.	CFX					SEE FINAL REPORT													
	1188	Colgate-Palmolive	CL	76.52	4	1	4	.65	80- 100 (5- 30%)	26.8	2.5	2.85	1.88	92	3/31	.66	.80	6/30	▲.47	.45	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter.

For Ti. eliness, 3-5 year Target Price Range, or Estimated Earni ,s 12 months to 12-31-22, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a ne figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to full report.
The number on the left signifies a Supplement (if available).

Supplement	Page	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range and % appreciation potential		Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 12-31-22	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	831	Neurocrine Biosci. (NDQ)	NBIX	86.49	3	3	3	.85	100- 150	(15- 75%)	48.1	NIL	▼1.80	NIL	15	3/31	.14	.33	3/31	NIL	NIL	YES
	181	Nevro Corp.	NVRO	45.56	4	4	3	1.30	120- 200	(165-340%)	NMF	NIL	d2.70	NIL	69	3/31	d.98	d.85	3/31	NIL	NIL	YES
	533	New Fortress Energy (NDQ)	NFE	43.84	3	4	2	1.25	50- 85	(15- 95%)	15.4	0.9	2.85	.40	65	3/31	1.13	d.21	6/30	.10	.10	YES
	416	New Germany Fund	GF	9.59	–	3	–	1.05	13- 19	(35-100%)	NMF	1.0	NMF	.10	–	12/31	16.58(q)	21.87(q)	3/31	.064	NIL	
	541	New Jersey Resources	NJR	45.36	4	2	3	.95	40- 55	(N- 20%)	19.4	3.2	2.34	1.45	86	3/31	1.36	1.77	9/30	.363	.333	YES
	1817	New Relic, Inc.	NEWR	48.13	1	3	3	.95	85- 130	(75-170%)	NMF	NIL	d3.17	NIL	2	3/31	d.84	d.98	3/31	NIL	NIL	YES
	1506	New York Community	NYCB	9.50	3	3	4	.80	14- 20	(45-110%)	7.3	7.2	1.30	.68	93	3/31	.31	.29	6/30	.17	.17	YES
	2380	New York Times	NYT	34.28	1	3	3	.75	50- 75	(45-120%)	24.5	1.1	1.40	.36	89	3/31	.03	.24	6/30	▲.09	.07	YES
	1192	Newell Brands (NDQ)	NWL	19.59	3	3	5	1.20	50- 75	(155-285%)	15.1	4.7	1.30	.92	92	3/31	.55	.21	6/30	.23	.23	YES
	573	NewMarket Corp.	NEU	333.09	5	1	4	.75	270- 330	(N- N%)	15.2	2.5	21.85	8.40	51	3/31	5.75	6.38	9/30	2.10	1.90	YES
	1573	Newmont Corp.	NEM	67.43	3	3	[illegible]	.55	65- 95	(N- 40%)	18.5	3.3	3.65	2.20	94	3/31	.69	.74	6/30	.55	.55	YES
	2361	News Corp. 'A' (NDQ)	NWSA	17.42	2	3		1.10	45- 65	(160-275%)	16.3	1.1	1.07	.20	89	3/31	.14	.13	6/30	.10	.10	YES
	2343	Nexstar Media Group (NDQ)	NXST	175.36	▲1	3	3	1.50	305- 460	(75-160%)	8.9	2.1	19.75	3.60	19	3/31	5.99	4.42	6/30	.90	.70	YES
	140	NextEra Energy	NEE	72.55	2	1	2	.90	85- 100	(15- 40%)	33.7	2.4	2.15	1.74	71	3/31	.08	.84	6/30	◆.425	.385	YES
	1217	NextEra Energy Part.	NEP	66.64	3	3	3	1.05	95- 145	(45-120%)	19.8	4.4	3.37	2.93	48	3/31	1.72	2.66	6/30	▲.733	.638	YES
	2023	NICE Ltd. ADR (NDQ)	NICE	192.79	2	2	4	.75	305- 415	(60-115%)	26.8	NIL	7.20	NIL	5	3/31	1.80	1.54	3/31	NIL	NIL	YES
1651	431	Nielsen Hldgs. plc	NLSN	25.65	–	[illegible]	–	1.00	25- 40	(N- 55%)	13.9	0.9	1.85	.24	17	3/31	.45	.47	6/30	.06	.06	YES
1650	2160	NIKE, Inc. 'B'	NKE	108.63	2	1	4	1.15	170- 210	(55- 95%)	26.1	1.1	4.16	1.22	46	2/28	.87	.90	9/30	.305	.275	YES
1834	155	Nikola Corp. (NDQ)	NKLA	6.25	–	4	–	1.65	11- 19	(75-205%)	NMF	NIL	d1.10	NIL	79	3/31	d.37	d.14	3/31	NIL	NIL	YES
	542	NiSource Inc.	NI	30.75	4	3	[illegible]	.85	35- 50	(15- 65%)	21.2	3.1	1.45	.94	86	3/31	.75	.77	6/30	.235	.22	YES
	107	Nissan Motor ADR(g) (PNK)	NSANY	7.81	▲3	3	1	.95	16- 25	(105-220%)	7.3	NIL	1.07	NIL	6	3/31	.06	d.36	3/31	NIL	NIL	
	955	Nokia Corp. ADR	NOK	4.93	3	3	3	.95	7- 10	(40-105%)	11.0	NIL	.45	NIL	58	3/31	.08	.08	3/31	NIL	NIL	YES
	1726	Nordson Corp. (NDQ)	NDSN	205.90	3	3	3	1.15	250- 375	(20- 80%)	22.6	1.0	9.13	2.10	56	4/30	◆2.43	2.12	6/30	.51	.39	YES
	2146	Nordstrom, Inc.	JWN	21.45	4	4	3	1.45	40- 65	(85-205%)	6.5	3.5	3.30	.76	34	4/30	◆.13	d.64	6/30	▲.19	NIL	YES
	342	Norfolk Southern	NSC	232.79	3	2	2	1.05	305- 415	(30- 80%)	16.9	2.1	13.80	4.96	14	3/31	2.93	2.66	6/30	1.24	.99	YES
	778	Northern Trust Corp. (NDQ)	NTRS	106.18	3	3	2	1.15	130- 200	(20- 90%)	13.5	2.6	7.85	2.80	72	3/31	1.77	1.70	9/30	.70	.70	YES
	1218	Northland Power (TSE)	NPI.TO	39.39b	3	3	3	.85	55- 80	(40-105%)	25.4	3.0	1.55	1.20	48	3/31	.99(b)	.52(b)	6/30	.30(b)	.30(b)	YES
	718	Northrop Grumman	NOC	456.77	3	1	2	.80	495- 605	(10- 30%)	18.3	1.5	24.90	6.92	39	3/31	6.10	6.57	6/30	▲1.73	1.57	YES
	1507	Northwest Bancshares (NDQ)	NWBI	12.58	5	3	3	.90	14- 20	(10- 60%)	14.0	6.4	.90	.80	93	3/31	.22	.32	6/30	.20	.20	YES
	543	Northwest Natural	NWN	52.48	4	3	5	.80	55- 85	(5- 60%)	20.6	3.7	2.55	1.93	86	3/31	1.80	1.94	6/30	.483	.48	YES
	2206	NorthWestern Corp.	NWE	60.93	5	2	4	.95	55- 80	(N- 30%)	18.5	4.2	3.30	2.53	81	3/31	1.08	1.24	6/30	.63	.62	YES
	2024	NortonLifeLock Inc. (NDQ)	NLOK	24.65	–	3	–	NMF	30- 45	(20- 85%)	13.2	2.0	1.87	.50	5	3/31	.46	.40	6/30	.125	.125	YES
	2316	Norwegian Cruise Line	NCLH	15.10	3	5	3	1.90	35- 60	(130-295%)	NMF	NIL	d1.00	NIL	67	3/31	d2.35	d3.76	3/31	NIL	NIL	YES
	124	Novanta Inc. (NDQ)	NOVT	123.72	3	3	4	1.00	95- 140	(N- 15%)	72.8	NIL	1.70	NIL	44	3/31	.53	.32	3/31	NIL	NIL	YES
	1625	Novartis AG ADR	NVS	90.71	4	1	3	.75	115- 140	(25- 55%)	19.5	3.7	4.65	3.36	16	3/31	1.00	.91	3/31	3.357	3.199	YES
	1626	Novo Nordisk ADR(g)	NVO	107.84	▼3	1	2	.80	110- 135	(N- 25%)	33.2	1.4	3.25	1.52	16	3/31	.94	.83	6/30	1.022	.922	YES
	211	NovoCure Limited (NDQ)	NVCR	77.08	4	4	4	1.25	150- 250	(95-225%)	NMF	NIL	d.20	NIL	33	3/31	d.04	d.04	3/31	NIL	NIL	YES
	993	Nu Skin Enterprises	NUS	44.96	3	3	4	1.00	85- 130	(90-190%)	10.7	3.4	4.20	1.54	32	3/31	.76	.91	6/30	.385	.38	YES
	1226	Nuance Communic.	NUAN	SEE FINAL SUPPLEMENT																		
	740	Nucor Corp.	NUE	126.31	1	3	1	1.20	130- 190	(5- 50%)	5.3	1.6	▲24.00	2.00	28	3/31	7.67	3.20	6/30	.50	.405	YES
	613	NuStar Energy L.P.	NS	15.34	4	4	3	1.25	25- 40	(65-160%)	15.3	10.4	1.00	1.60-1.20	85	3/31	d.22	.05	6/30	.40	.40	YES
	1818	Nutanix, Inc. (NDQ)	NTNX	21.72	2	4	4	1.25	60- 100	(175-360%)	NMF	NIL	d1.02	NIL	2	1/31	d.53	d1.42	3/31	NIL	NIL	YES
	1604	Nutrien Ltd.	NTR	101.48	▲2	3	2	1.05	130- 190	(30- 85%)	10.1	1.9	10.00	1.94	13	3/31	2.49	.22	9/30	◆.48	.46	YES
	182	NuVasive, Inc. (NDQ)	NUVA	54.64	5	3	4	1.10	85- 125	(55-130%)	64.3	NIL	.85	NIL	69	3/31	.31	d.15	3/31	NIL	NIL	YES
	1204	Nuveen Muni Value Fund	NUV	8.85	–	1	–	.60	9- 12	(N- 35%)	NMF	4.0	NMF	.35	–	10/31	10.62(q)	10.48(q)	3/31	.056	.062	
	1313	nVent Electric plc	NVT	34.62	3	3	3	1.30	40- 60	(15- 75%)	15.7	2.0	2.20	.70	80	3/31	.50	.43	9/30	.175	.175	YES
	1362	NVIDIA Corp. (NDQ)	NVDA	168.98	1	3		1.25	200- 300	(20- 80%)	33.8	0.1	5.00	.16	7	1/31	1.18	.58	3/31	.04	.04	YES
	1177	**O-I Glass**	OI	14.53	3	4		1.45	16- 25	(10- 70%)	8.1	NIL	1.80	NIL	8	3/31	.55	d.62	3/31	NIL	NIL	YES
	1407	ODP Corp. (NDQ)	ODP	38.94	–	5	–	1.35	40- 80	(5-105%)	9.3	NIL	4.20	NIL	95	3/31	1.27	1.21	3/31	NIL	NIL	YES
	913	OGE Energy	OGE	40.20	3	2	2	1.00	40- 55	(N- 35%)	16.1	4.1	2.50	1.66	68	3/31	.33	.26	9/30	◆.41	.402	YES
	125	OSI Systems (NDQ)	OSIS	82.60	▲3	3	5	.90	115- 170	(40-105%)	13.1	NIL	6.32	NIL	44	3/31	2.41	1.03	3/31	NIL	NIL	YES
	803	Oak Street Health	OSH	17.70	–	3	–	NMF	70- 105	(295-495%)	NMF	NIL	▼d1.75	NIL	27	3/31	d.43	d.29	3/31	NIL	NIL	YES
	513	Occidental Petroleum	OXY	65.42	3	4	3	1.60	55- 95	(N- 45%)	7.7	0.9	8.50	.59	61	3/31	2.12	d.15	9/30	.13	.01	YES
	2419	Oceaneering Int'l	OII	11.77	5	5	2	1.95	18- 35	(55-195%)	26.2	NIL	.45	NIL	96	3/31	d.06	.03	3/31	NIL	NIL	YES
	2025	Okta, Inc. (NDQ)	OKTA	83.51	2	3	[illegible]	.75	250- 380	(200-355%)	66.8	NIL	1.25	NIL	5	1/31	d.18	.06	3/31	NIL	NIL	YES
	323	Old Dominion Freight (NDQ)	ODFL	250.06	4	1	[illegible]	.95	260- 315	(5- 25%)	21.7	0.5	11.50	1.23	12	3/31	2.60	1.70	6/30	◆.30	.20	YES
	779	Old Nat'l Bancorp (NDQ)	ONB	15.55	▲3	3	1	.95	20- 35	(30-125%)	9.4	3.6	1.65	.56	72	3/31	.40	.52	6/30	◆.14	.14	YES
	764	Old Republic	ORI	22.92	▼4	3	3	1.15	50- 70	(120-205%)	9.2	4.0	2.50	.92	30	3/31	.63	.69	6/30	◆.23	.22	YES
	1605	Olin Corp.	OLN	63.62	2	3	3	1.30	140- 210	(120-230%)	6.3	1.3	10.10	.80	13	3/31	2.50	1.05	6/30	.20	.20	YES
	2147	Ollie's Bargain Outlet (NDQ)	OLLI	43.19	▲4	3	4	1.00	85- 130	(95-200%)	19.6	NIL	2.20	NIL	34	1/31	.69	.97	3/31	NIL	NIL	YES
	212	Omnicell, Inc. (NDQ)	OMCL	110.92	3	3	4	.95	180- 275	(60-150%)	28.4	NIL	3.90	NIL	33	3/31	.83	.83	3/31	NIL	NIL	YES
	2388	Omnicom Group	OMC	75.86	4	3	3	1.00	95- 145	(25- 90%)	12.6	4.0	6.04	3.00	88	3/31	1.39	1.33	9/30	.70	.70	YES
	1363	ON Semiconductor (NDQ)	ON	55.89	2	3	3	1.45	75- 115	(35-105%)	13.0	NIL	4.30	NIL	7	3/31	1.22	.35	3/31	NIL	NIL	YES
	544	ONE Gas, Inc.	OGS	86.65	3	2	2	.80	105- 145	(20- 65%)	21.4	3.0	4.05	2.56	86	3/31	1.83	1.79	6/30	.62	.58	YES
	2031	1-800-FLOWERS.COM	FLWS	SEE FINAL SUPPLEMENT																		
	815	1Life Healthcare (NDQ)	ONEM	8.79	–	4	–	.75 ▼	20- 35	(130-300%)	NMF	NIL	▼d1.75	NIL	84	3/31	d.47	d.29	3/31	NIL	NIL	YES
	599	ONEOK Inc.	OKE	63.56	3	3	2	1.50	95- 140	(50-120%)	16.7	5.9	3.80	3.74-1.95	64	3/31	.87	.86	6/30	.935	.935	YES
	1388	Onto Innovation	ONTO	74.38	3	3	3	1.20	100- 150	(35-100%)	15.3	NIL	4.85	NIL	11	3/31	1.31	.73	3/31	NIL	NIL	YES
	926	Ooma, Inc.	OOMA	13.67	3	4	3	1.15	15- 25	(10- 85%)	NMF	NIL	NIL	NIL	66	4/30	◆d.03	d.04	3/31	NIL	NIL	YES
	1819	Open Text Corp. (NDQ)	OTEX	39.16	4	2	4	.95	65- 90	(65-130%)	17.4	2.2	2.25	.88	2	3/31	.28	.33	6/30	.221	.201	YES
	1627	Opko Health (NDQ)	OPK	3.10	3	5	3	.95	6- 11	(95-255%)	62.0	NIL	.05	NIL	16	3/31	d.08	.05	3/31	NIL	NIL	YES
	2590	Oracle Corp.	ORCL	70.04	3	1	3	.80	110- 135	(55- 95%)	14.0	1.8	4.99	1.28	4	2/28	1.13	1.16	6/30	.32	.32	YES
	2129	O'Reilly Automotive (NDQ)	ORLY	579.11	▲2	3	2	.95	770-1155	(35-100%)	17.3	NIL	33.40	NIL	49	3/31	7.17	7.06	3/31	NIL	NIL	YES
	1219	Ormat Technologies	ORA	78.14	3	3	2	.70	100- 150	(30- 90%)	11.8	0.6	6.60	.48	48	3/31	.33	.27	6/30	.12	.12	YES
	156	Oshkosh Corp.	OSK	90.22	4	3	4	1.30	145- 215	(60-140%)	15.4	1.6	5.85	1.48	79	3/31	.24	1.48	6/30	.37	.33	YES
	1727	Otis Worldwide	OTIS	73.87	–	3	–	NMF	100- 150	(35-105%)	22.4	1.6	3.30	1.16	56	3/31	.77	.72	6/30	▲.29	.24	YES
	914	Otter Tail Corp. (NDQ)	OTTR	63.34	▲1	2	3	.85	55- 70	(N- 10%)	16.0	2.7	3.95	1.68	68	3/31	1.72	.73	6/30	.413	.39	YES
	2389	OUTFRONT Media	OUT	20.24	2	4	1	1.85	30- 50	(50-145%)	23.8	6.2	.85	1.25	88	3/31	d.04	d.49	6/30	.30	NIL	YES
	534	Ovintiv Inc.	OVV	49.83	3	5	2	1.65	85- 160	(70-220%)	6.7	2.0	7.45	1.00	65	3/31	d.94	1.10	6/30	▲.25	.094	YES
	1118	Owens Corning	OC	92.75	3	3	3	1.30	95- 140	(N- 50%)	11.9	1.5	7.80	1.40	40	3/31	3.03	1.98	6/30	.35	.26	YES
	2111	Oxford Inds.	OXM	83.43	5	3	3	1.40	145- 215	(75-160%)	9.3	2.6	8.95	2.20	83	1/31	1.68	.13	6/30	▲.55	.42	YES
	514	**PBF Energy**	PBF	30.44	4	5	3	1.95	30- 60	(N- 95%)	15.2	NIL	2.00	NIL	61	3/31	d.18	d.34	3/31	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Dollars.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

PAGE NUMBERS
Bold type refers to full report.
The number on the left signifies a Supplement (if available).

Supplement	Page	NAME OF STOCK	Exch.	Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	% appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 12-31-22	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	2132	Sonic Automotive		SAH	43.16	3	3	4	1.60	70- 105	(60-145%)	4.3	2.3	10.15	1.00	49	3/31	2.33	1.23	9/30	.25	.12	YES
	1182	Sonoco Products		SON	57.24	3	2	3	.95	85- 115	(50-100%)	10.0	3.4	5.75	1.96	8	3/31	1.85	.90	6/30	▲.49	.45	YES
622	1339	Sonos, Inc.	(NDQ)	SONO	20.96	2	4	3	1.05	55- 95	(160-355%)	17.0	NIL	1.23	NIL	41	3/31	.06	.12	3/31	NIL	NIL	YES
	1984	Sony Group ADR(g)		SONY	89.77	3	[illegible]	4	.85	120- 160	(35- 80%)	15.8	0.7	5.69	.61	70	3/31	.77	.38	3/31	NIL	NIL	YES
1027	545	South Jersey Inds.		SJI	34.44	–	3	–	1.00	35- 50	(N- 45%)	19.7	3.6	1.75	1.25	86	3/31	1.25	1.19	9/30	.31	.303	YES
	143	Southern Co.		SO	74.15	4	2	3	.90	65- 80	(N- 20%)	20.9	3.7	3.55	2.72	71	3/31	.97	1.09	6/30	▲.68	.66	YES
	1593	Southern Copper		SCCO	60.46	2	3	1	1.15	70- 105	(15- 75%)	14.4	8.3	4.20	5.00	31	3/31	1.02	.99	6/30	▲1.25	.70	YES
	311	Southwest Airlines		LUV	43.38	3	3	4	1.05	60- 90	(40-105%)	18.9	NIL	2.30	NIL	78	3/31	d.32	d1.72	3/31	NIL	NIL	YES
	546	Southwest Gas		SWX	92.89	–	3	–	.90	85- 130	(N- 40%)	21.9	2.7	4.25	2.51	86	3/31	1.58	2.03	9/30	.62	.595	YES
	536	Southwestern Energy		SWN	7.68	4	5	2	.70	20- 40	(160-420%)	5.3	NIL	1.45	NIL	65	3/31	.40	.29	3/31	NIL	NIL	YES
	1955	SpartanNash Co.	(NDQ)	SPTN	32.22	4	4	3	.45	30- 50	(N- 55%)	15.0	2.6	2.15	.84	25	12/31	.63	.34	3/31	▲.21	.20	YES
	1773	Spectrum Brands		SPB	85.45	–	3	–	1.40	75- 110	(N- 30%)	22.8	2.0	3.75	1.68	77	3/31	.39	.86	6/30	.42	.42	YES
	547	Spire Inc.		SR	75.51	4	2	3	.80	95- 130	(25- 70%)	17.6	3.7	4.29	2.80	86	3/31	3.27	3.55	9/30	.685	.65	YES
	721	Spirit AeroSystems		SPR	30.32	2	3	2	1.75	105- 155	(245-410%)	NMF	0.1	▲d.10	.04	39	3/31	.03	d1.65	9/30	.01	.01	YES
	312	Spirit Airlines		SAVE	19.36	–	4	–	1.85	40- 65	(105-235%)	NMF	NIL	d2.50	NIL	78	3/31	d1.60	d2.51	3/31	NIL	NIL	YES
	1826	Splunk Inc.	(NDQ)	SPLK	98.20	–	3	–	.95	180- 265	(85-170%)	NMF	NIL	d3.95	NIL	2	1/31	d.88	d.86	3/31	NIL	NIL	YES
	2349	Spotify Tech. S.A.		SPOT	109.07	2	3	4	.90	335- 500	(205-360%)	NMF	NIL	d.25	NIL	19	3/31	.23	d.30	3/31	NIL	NIL	YES
	1956	Sprouts Farmers Market	(NDQ)	SFM	23.62	3	3		.50	40- 55	(70-135%)	11.0	NIL	2.15	NIL	25	3/31	.79	.70	3/31	NIL	NIL	YES
2225	981	Standard Motor Prod.		SMP	SEE FINAL SUPPLEMENT																		
	1774	Standex Int'l		SXI	92.12	3	3	3	1.10	115- 175	(25- 90%)	15.3	1.1	6.01	1.04	77	3/31	1.54	1.19	6/30	.26	.24	YES
	1734	Stanley Black & Decker		SWK	117.72	4	3	4	1.45	190- 290	(60-145%)	9.8	3.1	12.00	3.63	56	3/31	2.10	3.13	6/30	.79	.70	YES
	1024	Stantec Inc.	(TSE)	STN.TO	56.99b	2	2	1	.70	60- 85	(5- 50%)	19.0	1.3	3.00	.72	54	3/31	.61(b)	.50(b)	9/30	.18(b)	.165(b)	YES
	363	Starbucks Corp.	(NDQ)	SBUX	73.42	2	1	4	1.05	135- 165	(85-125%)	24.2	2.8	3.03	2.04	57	3/31	.59	.62	6/30	.49	.45	YES
	2527	State Street Corp.		STT	69.73	3	3	3	1.30	110- 160	(60-130%)	8.7	3.5	8.00	2.43	35	3/31	1.57	1.37	9/30	◆.57	.52	YES
	744	Steel Dynamics	(NDQ)	STLD	78.13	3	3	2	1.25	85- 125	(10- 60%)	4.3	1.7	▲18.00	1.36	28	3/31	5.71	2.08	9/30	.34	.26	YES
	1158	Steelcase, Inc. 'A'		SCS	11.74	5	3	[illegible]	1.15	20- 30	(70-155%)	27.3	4.9	.43	.58	53	2/28	d.02	.06	6/30	.145	.10	YES
	576	Stepan Company		SCL	107.01	3	3	[illegible]	.75	130- 195	(20- 80%)	16.5	1.3	6.50	1.43	51	3/31	1.93	1.74	6/30	.335	.305	YES
	406	Stericycle Inc.	(NDQ)	SRCL	48.68	5	3	[illegible]	1.10	55- 85	(15- 75%)	23.7	NIL	2.05	NIL	76	3/31	.32	.71	3/31	NIL	NIL	YES
	185	STERIS plc		STE	227.54	4	2	2	1.05	255- 340	(10- 50%)	27.2	0.8	8.38	1.72	69	3/31	2.04	1.63	6/30	.43	.40	YES
	1804	Stifel Financial Corp.		SF	62.16	4	3	3	1.35	105- 155	(70-150%)	8.6	1.9	7.20	1.20	21	3/31	1.49	1.50	6/30	.30	.15	YES
	2645	Stitch Fix	(NDQ)	SFIX	8.39	3	4	5	1.05	40- 70	(375-735%)	NMF	NIL	d.31	NIL	3	1/31	d.28	d.20	3/31	NIL	NIL	YES
	1370	STMicroelectronics		STM	39.32	2	3	3	1.25	70- 100	(80-155%)	12.1	0.6	3.24	.24	7	3/31	.79	.39	6/30	.06	.06	YES
2225	982	Stoneridge, Inc.		SRI	SEE FINAL SUPPLEMENT																		
	1340	Stratasys Ltd.	(NDQ)	SSYS	18.41	3	4	4	1.00	35- 55	(90-200%)	NMF	NIL	d.50	NIL	41	3/31	d.32	d.32	3/31	NIL	NIL	YES
	1998	Strategic Education	(NDQ)	STRA	63.04	4	3	4	.95	85- 125	(35-100%)	18.0	3.8	3.50	2.40	18	3/31	.54	1.53	6/30	.60	.60	YES
	1999	Stride, Inc.		LRN	36.89	2	3	3	.85	60- 90	(65-145%)	13.8	NIL	2.67	NIL	18	3/31	1.02	.57	3/31	NIL	NIL	YES
	186	Stryker Corp.		SYK	233.05	3	1	2	1.20	305- 370	(30- 60%)	24.3	1.2	9.60	2.78	69	3/31	1.97	1.93	9/30	.695	.63	YES
	2325	Sturm, Ruger & Co.		RGR	63.70	5	3	3	.60	70- 110	(10- 75%)	10.6	3.8	6.00	2.40	67	3/31	1.70	2.16	6/30	.68	.86	YES
	618	Suburban Propane		SPH	16.71	3	3	3	1.05	30- 50	(80-200%)	6.8	7.8	2.46	1.30	85	3/31	2.74	2.02	6/30	.325	.30	YES
	1121	Summit Materials		SUM	26.24	5	[illegible]	3	1.60	40- 55	(50-110%)	17.5	NIL	1.50	NIL	40	3/31	d.29	d.20	3/31	NIL	NIL	YES
	2565	Sun Life Fin'l Svcs.	(TSE)	SLF.TO	61.56b	3	2	1	1.05	80- 110	(30- 80%)	9.3	4.5	6.60	2.76	26	3/31	1.46(b)	1.59(b)	6/30	▲.69(b)	.55(b)	YES
	519	Suncor Energy	(TSE)	SU.TO	48.87b	3	3	3	1.35	90- 135	(85-175%)	11.0	3.8	4.45	1.88	61	3/31	2.06(b)	.54(b)	6/30	▲.47(b)	.21(b)	YES
	2180	Sunoco LP		SUN	40.37	3	3	2	1.15	40- 60	(N- 50%)	8.4	8.2	4.60	3.30	38	3/31	2.32	1.60	6/30	.826	.826	YES
	1222	SunPower Corp.	(NDQ)	SPWR	16.58	4	5	4	1.10	25- 45	(50-170%)	33.2	NIL	.50	NIL	48	3/31	d.01	d.28	3/31	NIL	NIL	YES
	1223	Sunrun Inc.	(NDQ)	RUN	23.31	3	4	5	1.50	40- 65	(70-180%)	NMF	NIL	d.30	NIL	48	3/31	d.42	d.11	3/31	NIL	NIL	YES
439	957	Switch, Inc.		SWCH	33.37	–	3	–	.85	30- 40	(N- 20%)	NMF	0.6	.20	.21	58	3/31	.04	.06	6/30	.053	.05	YES
	958	Synaptics	(NDQ)	SYNA	137.36	3	3	3	1.20	265- 395	(95-190%)	12.6	NIL	10.92	NIL	58	3/31	2.71	1.19	3/31	NIL	NIL	YES
	2566	Synchrony Financial		SYF	34.10	3	3	4	1.55	60- 85	(75-150%)	5.9	2.6	5.75	.88	26	3/31	1.77	1.73	6/30	.22	.22	YES
	806	Syneos Health	(NDQ)	SYNH	71.47	3	4	3	1.30	115- 190	(60-165%)	13.9	NIL	5.15	NIL	27	3/31	1.01	.79	3/31	NIL	NIL	YES
★★	2599	Synopsys, Inc.	(NDQ)	SNPS	306.98	▲2	1	3	1.00	310- 380	(N- 25%)	38.4	NIL	8.00	NIL	4	4/30	◆2.50	1.70	3/31	NIL	NIL	YES
	2528	Synovus Financial		SNV	40.70	2	3	2	1.55	60- 90	(45-120%)	8.7	3.3	4.70	1.36	35	3/31	1.11	1.19	6/30	▲.34	.33	YES
	1957	Sysco Corp.		SYY	78.59	4	3	3	1.30	85- 125	(10- 60%)	22.1	2.5	3.55	1.96	25	3/31	.71	.22	9/30	▲.49	.47	YES
	928	**T-Mobile US**	(NDQ)	TMUS	129.89	1	3	2	.75	145- 215	(10- 65%)	29.5	NIL	4.40	NIL	66	3/31	.57	.74	3/31	NIL	NIL	YES
	601	TC Energy Corp.		TRP	57.78	4	3		1.05	70- 105	(20- 80%)	19.3	4.9	3.00	2.86	64	3/31	.29	d.87	9/30	.711	.705	YES
	396	TD SYNNEX Corp.		SNX	98.38	–	3		NMF	155- 235	(60-140%)	8.6	1.2	11.40	1.20	60	2/28	3.03	1.89	6/30	.30	.20	YES
	1341	TE Connectivity		TEL	123.65	2	2	4	1.15	170- 230	(35- 85%)	17.0	1.8	7.29	2.24	41	3/31	1.81	1.57	6/30	▲.56	.48	YES
	2197	TJX Companies		TJX	60.31	2	3	4	1.15	75- 110	(25- 80%)	19.1	2.0	3.15	1.18	74	4/30	◆.49	.44	6/30	▲.295	.26	YES
620	1224	TPI Composites		TPIC	SEE FINAL SUPPLEMENT																		
	1136	TRI Pointe Homes		TPH	20.35	2	3	5	1.40	35- 50	(70-145%)	5.2	NIL	3.95	NIL	36	3/31	.81	.59	3/31	NIL	NIL	YES
	397	TTEC Holdings	(NDQ)	TTEC	63.12	▼5	3	3	1.10	110- 165	(75-160%)	17.5	1.6	3.60	1.00	60	3/31	.71	1.06	6/30	▲.50	.43	YES
	1371	TTM Technologies	(NDQ)	TTMI	13.92	3	3	3	1.00	20- 30	(45-115%)	11.1	NIL	1.25	NIL	7	3/31	.24	.23	3/31	NIL	NIL	YES
	1831	Taiwan Fund		TWN	SEE FINAL SUPPLEMENT																		
	1372	Taiwan Semic. ADR		TSM	91.50	3	1	[illegible]	.90	135- 185	(50-100%)	16.0	2.2	5.71	2.00	7	3/31	1.40	.96	6/30	.476	.44	YES
	2005	Take-Two Interactive	(NDQ)	TTWO	123.62	2	3	[illegible]	.60	180- 270	(45-120%)	29.3	NIL	4.22	NIL	23	3/31	.95	1.37	3/31	NIL	NIL	YES
	187	Tandem Diabetes Care	(NDQ)	TNDM	71.14	2	4	2	1.00	135- 225	(90-215%)	NMF	NIL	.45	NIL	69	3/31	d.23	d.08	3/31	NIL	NIL	YES
623	2181	Tapestry Inc.		TPR	31.30	3	3	4	1.50	50- 75	(60-140%)	9.9	3.2	3.16	1.00	38	3/31	.51	.51	6/30	.25	NIL	YES
	537	Targa Resources		TRGP	69.26	3	4	1	1.60	80- 135	(15- 95%)	27.7	2.2	2.50	1.50	65	3/31	.06	.53	6/30	.35	.10	YES
1027	2150	Target Corp.		TGT	153.90	3	2	2	.70	255- 345	(65-125%)	10.5	2.3	14.60	3.60	34	4/30	◆2.19	3.69	6/30	.90	.68	YES
	1026	Tata Motors ADR		TTM	SEE FINAL SUPPLEMENT																		
	1137	Taylor Morrison Home		TMHC	27.17	3	3	3	1.60	40- 60	(45-120%)	5.8	NIL	4.65	NIL	36	3/31	1.44	.75	3/31	NIL	NIL	YES
	2424	TechnipFMC plc		FTI	7.99	–	4	–	NMF	14- 25	(75-215%)	40.0	NIL	.20	NIL	96	3/31	d.03	d.03	3/31	NIL	NIL	YES
	1594	Teck Resources 'B'	(TSE)	TECKB.TO	51.71b	▲2	3	2	1.05	55- 80	(5- 55%)	12.2	1.0	4.25	.50	31	3/31	2.87(b)	.57(b)	6/30	.125(b)	.05(b)	YES
	2350	TEGNA Inc.		TGNA	21.42	–	3	–	.85	35- 50	(65-135%)	7.4	1.8	2.90	.38	19	3/31	.60	.50	9/30	.095	.095	YES
221	817	Teladoc Health		TDOC	32.99	4	4	4	.65	▼ 115- 190	(250-475%)	NMF	NIL	▼d2.05	NIL	84	3/31	d.46	d1.27	3/31	NIL	NIL	YES
	722	Teledyne Technologies		TDY	393.42	4	2	1	1.10	530- 720	(35- 85%)	21.9	NIL	18.00	NIL	39	3/31	4.27	3.19	3/31	NIL	NIL	YES
	188	Teleflex Inc.		TFX	289.36	4	[illegible]	4	1.15	385- 575	(35-100%)	31.5	0.5	9.20	1.36	69	3/31	1.63	1.58	6/30	.34	.34	YES
	1011	Telefonica SA ADR(g)		TEF	5.09	▲4	4	2	.85	6- 10	(20- 95%)	9.3	6.9	.55	.35	90	3/31	.14	.17	3/31	NIL	.238	YES
	929	Telephone & Data		TDS	17.78	5	3	3	.95	35- 55	(95-210%)	16.2	4.0	1.10	.72	66	3/31	.37	.48	6/30	◆.18	.175	YES
	930	TELUS Corporation	(TSE)	T.TO	31.10b	3	2	2	.70	35- 45	(15- 45%)	29.6	4.4	1.05	1.37	66	3/31	.28(b)	.25(b)	9/30	▲.339(b)	.316(b)	YES
	1831	Templeton Emerg'g		EMF	SEE FINAL SUPPLEMENT																		
	1159	Tempur Sealy Int'l		TPX	24.91	2	4	4	1.45	70- 115	(180-360%)	6.6	1.6	3.75	.40	53	3/31	.69	.62	6/30	.10	.07	YES
	732	Tenaris S.A. ADS		TS	32.94	3	3	3	1.20	▲ 45- 65	(35- 95%)	11.0	1.7	▲3.00	.56	43	3/31	.85	.18	6/30	.56	.28	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Dollars.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

STOCK PRICES

Workpapers
Page 1 of 1

May

2012	32.74	27.99	21.50	9.81	45.93		23.89	42.13	38.67
2017	81.48	72.61	40.63	24.67	59.75	69.04	35.81	80.11	69.53
2022	113.91	129.25	44.74	30.24	51.10	85.98	34.09	91.24	75.60

Date	ATO	CPK	NJR	NI	NWN	OGS	SJI	SWX	SR
5/1/2012	32.84	27.66	21.71	9.95	45.68		24.62	42.29	39.58
5/2/2012	32.54	27.30	21.58	9.84	45.71		24.35	41.97	39.39
5/3/2012	32.74	27.71	21.61	9.73	45.31		24.22	41.63	39.14
5/4/2012	32.43	27.54	21.41	9.79	45.40		23.98	41.45	39.01
5/7/2012	32.40	27.69	21.59	9.75	46.28		23.72	42.38	39.17
5/8/2012	32.69	27.85	21.76	9.77	46.30		23.88	42.84	39.06
5/9/2012	32.59	27.82	21.66	9.80	45.88		23.90	42.62	38.95
5/10/2012	32.84	28.39	22.00	9.93	46.43		24.06	43.17	39.04
5/11/2012	32.89	28.41	21.76	9.92	46.08		23.95	42.66	38.86
5/14/2012	32.65	28.11	21.50	9.87	45.60		23.65	42.42	38.68
5/15/2012	32.69	28.14	21.82	9.86	45.79		23.71	42.41	38.79
5/16/2012	32.85	28.20	21.95	9.84	45.93		23.83	42.36	38.80
5/17/2012	33.12	28.41	21.75	9.69	45.61		23.77	42.08	38.54
5/18/2012	32.68	28.16	21.45	9.60	45.61		23.67	41.74	38.53
5/21/2012	32.74	28.27	21.37	9.75	46.12		23.76	41.88	38.43
5/22/2012	33.02	28.37	21.24	9.73	45.87		23.73	41.94	38.23
5/23/2012	32.38	27.74	21.06	9.72	45.70		23.46	41.58	38.07
5/24/2012	32.91	28.11	21.29	9.81	46.31		23.67	41.91	38.29
5/25/2012	32.67	28.15	21.29	9.84	46.19		23.75	41.79	38.16
5/29/2012	32.90	27.98	21.31	9.93	46.38		23.98	42.01	38.19
5/30/2012	32.52	27.53	20.90	9.84	45.93		23.80	41.74	37.73
5/31/2012	33.14	28.17	20.99	9.86	46.35		24.21	41.98	38.11
5/1/2017	80.71	73.00	40.10	24.09	59.50	68.83	37.23	83.63	68.25
5/2/2017	80.72	73.15	40.10	24.24	59.70	69.52	37.23	83.93	68.05
5/3/2017	80.11	71.80	39.50	24.01	59.00	68.63	36.82	83.14	68.30
5/4/2017	81.38	71.80	39.75	24.28	59.10	68.85	36.61	83.54	68.51
5/5/2017	82.17	71.75	40.65	24.53	59.20	69.34	36.88	84.11	69.40
5/8/2017	81.91	72.60	40.70	24.38	58.85	69.15	36.69	83.22	69.80
5/9/2017	80.55	71.25	39.85	24.10	58.90	67.82	35.52	80.46	68.70
5/10/2017	80.89	71.85	39.80	24.14	59.50	68.28	35.20	80.82	69.30
5/11/2017	80.79	71.85	40.05	24.14	59.35	67.95	35.21	79.56	69.65
5/12/2017	81.34	72.20	40.45	24.30	59.65	68.71	35.37	79.57	69.90
5/15/2017	81.36	72.45	41.00	24.52	59.75	69.03	35.45	79.59	70.00
5/16/2017	80.33	71.55	40.20	24.21	59.05	67.83	34.80	78.06	68.90
5/17/2017	80.55	71.50	40.45	24.25	58.95	67.70	34.80	77.84	69.00
5/18/2017	80.36	71.75	40.25	24.50	59.65	68.12	34.67	77.18	69.20
5/19/2017	81.08	71.75	40.40	24.70	59.40	68.55	34.78	77.44	69.40
5/22/2017	81.53	72.60	40.85	25.01	59.70	69.10	35.07	77.29	70.15
5/23/2017	82.09	73.35	41.20	25.14	60.10	69.50	35.34	77.16	70.05
5/24/2017	82.16	73.70	41.35	25.22	60.45	69.61	35.54	77.74	70.35
5/25/2017	83.10	74.75	41.85	25.53	61.15	70.52	36.09	79.52	70.90
5/26/2017	82.85	74.20	41.75	25.56	61.15	70.67	35.98	79.35	70.40
5/30/2017	83.19	74.40	41.70	25.82	61.20	70.47	36.14	79.59	70.60
5/31/2017	83.31	74.25	41.90	26.07	61.25	70.65	36.41	79.57	70.85
5/2/2022	111.76	122.00	42.79	28.73	47.29	82.63	34.16	87.13	72.79
5/3/2022	112.61	122.09	43.83	28.96	47.27	82.99	34.10	87.01	72.14
5/4/2022	115.31	130.36	44.60	29.67	49.16	85.82	34.44	88.74	74.35
5/5/2022	115.04	128.53	43.19	29.31	49.02	84.79	34.18	87.36	73.52
5/6/2022	114.90	127.56	43.76	29.49	49.34	85.13	34.31	87.66	73.95
5/9/2022	113.63	127.66	44.21	29.44	49.54	85.42	33.59	90.71	75.55
5/10/2022	113.11	125.57	43.85	29.32	49.24	84.68	33.90	89.84	74.45
5/11/2022	112.62	127.66	43.77	29.67	49.82	84.59	33.39	90.70	74.13
5/12/2022	112.09	127.01	43.66	29.61	50.14	85.34	33.58	92.16	74.75
5/13/2022	112.96	126.57	44.02	30.32	50.63	84.90	33.40	91.16	74.50
5/16/2022	113.16	127.45	44.63	30.43	50.78	85.96	33.38	91.65	75.39
5/17/2022	113.75	127.84	45.40	30.75	51.10	87.55	33.68	93.24	77.02
5/18/2022	111.85	128.47	45.54	30.56	51.07	87.37	34.10	91.70	76.72
5/19/2022	111.37	128.84	45.51	30.31	51.52	86.14	34.07	92.07	75.84
5/20/2022	111.70	131.13	44.91	30.28	51.78	85.69	34.28	93.97	75.36
5/23/2022	113.67	133.28	45.36	30.75	52.48	86.65	34.44	92.89	75.51
5/24/2022	116.03	133.94	46.03	31.24	55.11	88.63	34.40	94.14	77.93
5/25/2022	115.92	133.53	46.18	31.44	54.54	88.15	34.58	93.10	78.18
5/26/2022	116.74	135.69	46.19	31.54	54.73	88.21	34.50	93.39	78.32
5/27/2022	117.64	135.55	46.28	31.76	54.25	88.00	34.60	94.12	78.84
5/31/2022	116.31	133.57	45.92	31.45	54.29	87.02	34.85	93.13	78.30

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 113.16 | P/E RATIO 20.0 (Trailing: 21.0; Median: 20.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Raised 2/18/22
SAFETY 1 Raised 6/6/14
TECHNICAL 1 Raised 5/20/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$83-$128	$106 (-5%)

2025-27 PROJECTIONS

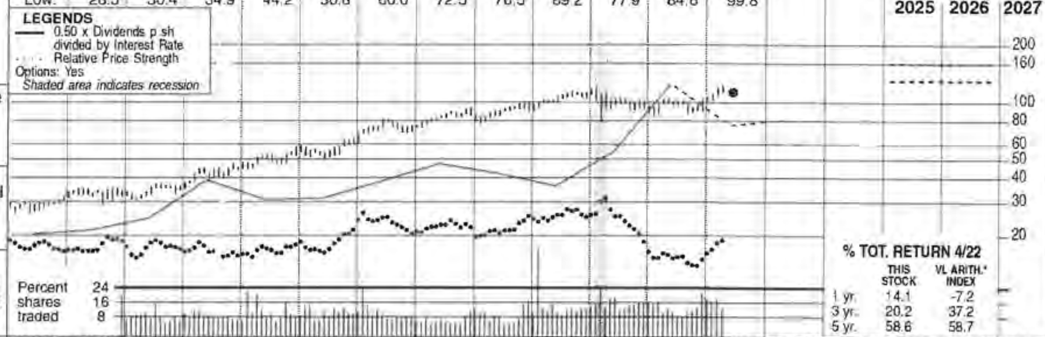
	Price	Gain	Ann'l Total Return
High	160	(+40%)	11%
Low	130	(+15%)	6%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	256	247	262
to Sell	258	223	217
Hld's(000)	107920	109549	114371

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	35.6	37.3	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0
Low:	28.5	30.4	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	99.8

Target Price Range
2025 2026 2027



% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.1	-7.2
3 yr.	20.2	37.2
5 yr.	58.6	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
75.27	66.03	79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	**27.45**	**28.75**	Revenues per sh A	*35.50*
4.26	4.14	4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	**9.05**	**9.75**	"Cash Flow" per sh	*11.95*
2.00	1.94	2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	**5.50**	**5.90**	Earnings per sh AB	*7.30*
1.26	1.28	1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	**2.72**	**2.92**	Div'ds Decl'd per sh C■	*3.50*
5.20	4.39	5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	**17.25**	**17.10**	Cap'l Spending per sh	*18.00*
20.16	22.01	22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	**64.25**	**68.20**	Book Value per sh	*82.85*
81.74	89.33	90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	**142.00**	**146.00**	Common Shs Outst'g D	*155.00*
13.5	15.9	13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.73	.84	.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.00	*Value Line*		Relative P/E Ratio	*1.10*
4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	*estimates*		Avg Ann'l Div'd Yield	*2.4%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $7959.0 mill. **Due in 5 Yrs** $2410.0 mill.
LT Debt $5757.6 mill. **LT Interest** $85.0 mill.
(LT interest earned: 10.8x; total interest coverage: 10.8x)
Leases, Uncapitalized Annual rentals $41.8 mill.

Pfd Stock None

Pension Assets-9/21 $596.8 mill.
Oblig. $596.0 mill

Common Stock 139,015,012 shs.
as of 4/29/22

MARKET CAP: $15.7 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
3438.5	3886.3	4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	**3900**	**4200**	Revenues ($mill) A	*6000*
192.2	230.7	289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	**760**	**860**	Net Profit ($mill)	*1130*
33.8%	38.2%	39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	**8.5%**	**17.5%**	Income Tax Rate	*25.0%*
5.6%	5.9%	5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	**19.5%**	**20.5%**	Net Profit Margin	*18.8%*
45.3%	48.8%	44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	**40.0%**	**40.0%**	Long-Term Debt Ratio	*40.0%*
54.7%	51.2	55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	**60.0%**	**60.0%**	Common Equity Ratio	*60.0%*
4315.5	503[illegible]	5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	**15200**	**16600**	Total Capital ($mill)	*21400*
5475.6	6030.7	6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	**16500**	**18000**	Net Plant ($mill)	*23000*
6.1%	5.9%	6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	**6.0%**	**6.5%**	Return on Total Cap'l	*6.5%*
8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	**8.5%**	**8.5%**	Return on Shr. Equity	*9.0%*
8.1%	8.9%	9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	**8.5%**	**8.5%**	Return on Com Equity	*9.0%*
2.8%	4.0%	4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	**4.0%**	**4.5%**	Retained to Com Eq	*4.5%*
65%	56%	50%	51%	50%	50%	48%	48%	49%	49%	**51%**	**50%**	All Div'ds to Net Prof	*48%*

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	20.8	116.7	582.5
Other	450.5	2722.0	2946.5
Current Assets	471.3	2838.7	3529.0
Accts Payable	235.8	423.2	354.0
Debt Due	2	2400.5	2201.4
Other	546.4	686.7	653.0
Current Liab.	782.4	3510.4	3208.4
Fix. Chg. Cov.	1306%	1457%	1445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-7.5%	-10.0%	*6.5%*
"Cash Flow"	6.0%	7.0%	*7.0%*
Earnings	8.5%	8.5%	*7.5%*
Dividends	5.5%	8.0%	*7.0%*
Book Value	8.5%	11.0%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	877.8	1094.6	485.7	443.7	2901.8
2020	875.6	977.6	493.0	474.9	2821.1
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	**640**	**597.4**	**3900**
2023	**1060**	**1720**	**730**	**690**	**4200**

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.38	1.82	.68	.49	4.35
2020	1.47	1.95	.79	.53	4.72
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	**.82**	**.45**	**5.50**
2023	**2.02**	**2.43**	**.91**	**.54**	**5.90**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.485	.485	.485	.525	1.98
2019	.525	.525	.525	.575	2.15
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2021: 67.9%, residential; 26.8%, commercial; 3.6%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .9% of common stock (12/21 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy had a decent showing through the first half of fiscal 2022 (which ended last March 31st). Share net rose 5.5%, to $4.23, compared to $4.01 for the same period in fiscal 2021. That was brought about partly by the distribution unit, helped by favorable rate case outcomes and an expanded customer base. A substantially diminished effective income tax rate also benefited the company. But the performance of the pipeline and storage division was held back a bit by heightened operating expenses. Nevertheless, assuming that the second half goes fairly well for Atmos, full-year earnings stand to increase around 7%, to $5.50 a share, relative to fiscal 2021's $5.12 total. Regarding next year, share net might grow at a similar percentage rate, to $5.90, as operating margins widen further.

The Financial Strength rating is A+. When the second quarter concluded, cash and equivalents resided at $582.5 million. Also, long-term debt was manageable (roughly 40% of total capital) and short-term commitments did not appear to be a major obstacle. Furthermore, $2.2 billion in common stock and/or debt securities remained available for issuance (out of $5 billion) under a shelf registration statement expiring in June, 2024. Lastly, Atmos can access four revolving credit facilities aggregating $2.5 billion plus a $1.5 billion commercial paper program. So, there seems to be ample liquidity to satisfy working capital needs, capital expenditures, and other obligations for some time.

Prospects out to 2025-2027 appear encouraging. The company ranks as one of the nation's largest natural gas-only distributors, with more than three million customers across several states, including Texas, Louisiana, and Mississippi. Moreover, we think the pipeline and storage segment has promising overall growth opportunities, given that it operates in one of the most-active drilling regions in the world. The healthy balance sheet is another positive.

That said, these top-quality shares hold unimpressive long-term total return potential. Capital appreciation possibilities aren't exciting. Also, the dividend yield is below the average of *Value Line's* Natural Gas Utility group.

Frederick L. Harris, III *May 27, 2022*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next egs. rpt. due early Aug.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	100

CHESAPEAKE UTIL. NYSE-CPK

RECENT PRICE 127.45 | P/E RATIO 25.5 (Trailing: 26.3 / Median: 21.0) | RELATIVE P/E RATIO 1.57 | DIV'D YLD 1.7% | VALUE LINE

TIMELINESS 2 Raised 5/13/22
SAFETY 2 New 6/5/15
TECHNICAL 1 Raised 5/20/22
BETA .75 (1.00 = Market)

High: 29.7 32.6 40.8 52.7 61.1 70.0 86.4 93.4 98.6 111.4 146.1 146.3
Low: 24.0 26.6 30.6 37.5 44.4 52.3 63.0 66.4 77.6 69.5 99.6 121.0

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$105-$176	$141 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	170	(+35%)	9%
Low	125	(Nil)	2%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	95	91	84
to Sell	96	93	93
Hld's(000)	13167	13128	13078

Target Price Range 2025 2026 2027: 200, 160, 100, 80, 60, 50, 40, 30, 20

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.0	-7.2
3 yr.	41.9	37.2
5 yr.	85.6	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
23.05	25.41	28.46	19.07	29.93	29.13	27.26	30.73	34.19	30.07	30.60	37.79	43.81	29.24	27.96	32.28	*35.95*	*39.45*	Revenues per sh	*61.70*
2.18	2.52	2.50	2.15	3.50	3.69	3.95	4.35	4.73	5.05	5.16	5.42	6.47	6.50	7.37	8.28	*9.50*	*10.35*	"Cash Flow" per sh	*12.55*
1.15	1.29	1.39	1.43	1.82	1.91	1.99	2.26	2.47	2.68	2.86	2.68	3.45	3.72	4.21	4.73	*5.00*	*5.25*	Earnings per sh A	*6.50*
.77	.78	.81	.83	.87	.91	.96	1.01	1.07	1.12	1.19	1.26	1.39	1.55	1.69	1.84	*2.03*	*2.22*	Div'ds Decl'd per sh B■	*2.75*
4.87	3.08	3.00	1.89	3.18	3.28	5.00	6.72	6.66	9.47	10.42	10.73	16.47	11.26	9.48	10.59	*11.35*	*11.60*	Cap'l Spending per sh	*13.50*
11.08	11.76	12.02	14.89	15.84	16.78	17.82	19.28	20.59	23.45	27.36	29.75	31.65	34.23	39.92	43.85	*47.15*	*50.10*	Book Value per sh	*56.15*
10.03	10.17	10.24	14.09	14.29	14.35	14.40	[illegible]	14.59	15.27	16.30	16.34	16.38	16.40	17.46	17.66	*18.50*	*19.00*	Common Shs Outst'g C	*23.50*
17.9	16.7	14.2	14.2	12.2	14.2	14.8	[illegible]	17.7	19.1	21.8	27.8	22.9	24.7	21.6	25.6	Bold figures are	Value Line	Avg Ann'l P/E Ratio	*22.5*
.97	.89	.85	.95	.78	.89	.94	.88	.93	.96	1.14	1.40	1.24	1.32	1.11	1.39	estimates		Relative P/E Ratio	*1.25*
3.8%	3.6%	4.1%	4.1%	3.9%	3.4%	3.3%	2.9%	2.4%	2.2%	1.9%	1.7%	1.8%	1.7%	1.9%	1.5%			Avg Ann'l Div'd Yield	*1.9%*

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
392.5	444.3	498.8	459.2	498.9	617.6	717.5	479.6	488.2	570.0	*665*	*750*	Revenues ($mill)	*1450*
28.9	32.8	36.1	40.2	44.7	43.8	56.6	61.1	70.6	83.5	*92.0*	*100*	Net Profit ($mill)	*155*
40.1%	40.2%	39.9%	39.5%	38.6%	39.5%	27.1%	25.6%	25.0%	25.9%	*26.0%*	*26.5%*	Income Tax Rate	*29.0%*
7.4%	7.4%	7.2%	8.8%	9.0%	7.1%	7.9%	12.7%	14.5%	14.6%	*13.8%*	*13.3%*	Net Profit Margin	*10.7%*
28.4%	29.7%	34.5%	29.4%	23.5%	28.9%	37.9%	43.9%	42.2%	41.5%	*43.0%*	*43.0%*	Long-Term Debt Ratio	*40.0%*
71.6%	70.3%	65.5%	70.6%	76.5%	71.1%	62.1%	56.1%	57.8%	58.5%	*57.0%*	*57.0%*	Common Equity Ratio	*60.0%*
358.5	396.4	458.8	507.5	583.0	683.7	834.5	1001.7	1205.6	1324.0	*1530*	*1670*	Total Capital ($mill)	*2200*
541.8	631.2	689.8	855.0	986.7	1126.0	1384.0	1463.8	1601.2	1744.9	*1900*	*2100*	Net Plant ($mill)	*2700*
8.8%	8.8%	8.5%	8.9%	8.6%	7.3%	7.8%	7.2%	6.8%	7.1%	*6.0%*	*7.5%*	Return on Total Cap'l	*8.0%*
11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.5%*
11.2%	11.8%	12.0%	11.2%	10.0%	9.0%	10.9%	10.9%	10.1%	10.8%	*10.5%*	*10.5%*	Return on Com Equity	*11.5%*
6.4%	7.1%	7.4%	6.8%	6.1%	4.9%	6.7%	6.5%	6.2%	6.7%	*6.0%*	*6.0%*	Retained to Com Eq	*7.0%*
43%	40%	38%	40%	39%	45%	39%	40%	38%	38%	*41%*	*42%*	All Div'ds to Net Prof	*42%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $758.5 mill. **Due in 5 Yrs** $340.0 mill.
LT Debt $597.9 mill. **LT Interest** $27.0 mill.
(LT interest earned: 6.6x; total interest coverage: 6.6x) (43% of Cap'l)
Leases, Uncapitalized Annual rentals $2.0 mill.
Pfd Stock None
Pension Assets-12/21 $58.7 mill. **Oblig.** $69.1 mill.
Common Stock 17,727,326 shs. as of 4/29/22

MARKET CAP: $2.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	3.5	5.0	5.2
Other	132.9	168.1	147.8
Current Assets	136.4	173.1	153.0
Accts Payable	60.3	52.6	30.3
Debt Due	189.2	239.6	160.6
Other	79.5	84.2	88.8
Current Liab.	329.0	376.4	279.7
Fix. Chg. Cov.	618%	771%	780%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	1.5%	-1.0%	13.0%
"Cash Flow"	9.0%	8.0%	9.5%
Earnings	9.5%	9.5%	7.5%
Dividends	7.0%	8.5%	8.5%
Book Value	9.5%	10.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	160.5	94.5	92.6	132.0	479.6
2020	152.7	97.1	101.4	137.0	488.2
2021	191.2	111.1	107.3	160.4	570.0
2022	222.9	*140*	*132.1*	*170*	*665*
2023	*240*	*165*	*160*	*185*	*750*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.75	.54	.38	1.04	3.72
2020	1.77	.64	.56	1.24	4.21
2021	1.96	.78	.71	1.28	4.73
2022	2.08	*.86*	*.75*	*1.31*	*5.00*
2023	*2.15*	*.95*	*.80*	*1.35*	*5.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.325	.325	.37	.37	1.39
2019	.37	.37	.405	.405	1.55
2020	.405	.405	.44	.44	1.69
2021	.44	.44	.48	.48	1.84
2022	.48	.48	.535		

BUSINESS: Chesapeake Utilities Corporation consists of two main units. The Regulated Energy segment distributes natural gas in Delaware, Maryland, and Florida; distributes electricity in Florida; and transmits natural gas on the Delmarva Peninsula and in Florida. The Unregulated Energy operation wholesales and distributes propanr markets natural gas; and provides other unregulated energy services, including midstream services in Ohio. Revenue breakdown for 2021: Regulated Energy, 67.4%; Unregulated Energy, 36.3%; Other, d3.7%. Officers and directors own 2.6% of common stock; BlackRock, 15.1% (3/22 Proxy). CEO: Jeffry M. Householder. Inc.: DE. Address: 909 Silver Lake Boulevard, Dover, DE 19904. Tel.: (302) 734-6799. Internet: www.chpk.com.

Chesapeake Utilities Corporation had a respectable performance in the opening quarter of 2022. Share net of $2.08 was 6% higher than the year-ago total of $1.96. One contributor was the Regulated Energy unit, aided by continued pipeline expansions by the Eastern Shore and Per,nsula Pipeline operations, organic growth in the natural gas distribution businesses, plus incremental benefits from the acquisition of Escambia Meter Station in 2021. Moreover, results of the Unregulated Energy division got a boost from last year's purchase of Diversified Energy Company, higher rates for the Aspire Energy segment, and increased propane margins per gallon and service fees. Although inflationary pressures persist, full-year earnings might advance around 6%, to $5.00 a share, relative to 2021's $4.73 figure. Regarding 2023, the bottom line ought to rise at a similar percentage rate, to $5.25 a share, as operating margins expand further.

Corporate finances are sound. When the first quarter ended, cash and equivalents resided at $5.2 million. Too, there was $256.3 million available under a revolving credit facility. Meanwhile, Chesapeake's long-term debt seemed manageable (43% of total capital), and we believe that short-term commitments of $160.6 million were not a major stumbling block. Lastly, additional debt and/or equity securities can be issued if necessary. All things considered, the company ought to continue to satisfy its obligations with little trouble.

The quarterly common stock dividend was just increased 11.5%, to $0.535 a share. What's more, our projections out to 2025-2027 indicate that additional steady hikes in the distribution will probably take place. The payout ratio over that span ought to be in the neighborhood of 40%, which is reasonable.

Chesapeake shares, although favorably ranked for Timeliness, have unenticing total return potential during the 2025-2027 period. Capital gains possibilities are nothing to write home about. Also, the current dividend yield of 1.7% is not spectacular when stacked against the average of *Value Line's* Natural Gas Utility Industry.

Frederick L. Harris, III *May 27, 2022*

(A) Diluted shrs. Excludes nonrecurring items: '08, d7¢; '15, 6¢; '17, 87¢. Excludes discontinued operations: '19, 24¢; '20, 5¢. Quarters for 2019 don't equal total because of rounding. Next earnings report due early Aug.
(B) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan. Direct stock purchase plan available.
(C) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	90
Earnings Predictability	95

NEW JERSEY RES. NYSE-NJR

RECENT PRICE 44.63 | P/E RATIO 19.1 (Trailing: 22.7 Median: 17.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 4 Lowered 5/20/22
SAFETY 2 Lowered 4/17/20
TECHNICAL 3 Lowered 5/27/22
BETA .95 (1.00 = Market)

18-Month Target Price Range
Low-High: $29-$55 | Midpoint (% to Mid): $42 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	8%
Low	40	(-10%)	1%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	105	102	109
to Sell	139	130	121
Hld's(000)	68468	68609	66131

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High	25.2	25.1	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	47.5	
Low	19.8	19.3	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	

LEGENDS
— 0.40 x Dividends p sh divided by Interest Rate
···· Relative Price Strength
2-for-1 split 3/15
Options: Yes
Shaded area indicates recession

Target Price Range 2025 | 2026 | 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.2	-7.2
3 yr.	-4.6	37.2
5 yr.	24.6	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
39.81	36.31	45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	25.50	25.95	Revenues per sh A	28.10
1.37	1.22	1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.65	3.75	"Cash Flow" per sh	4.25
.93	.78	1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.30	2.40	Earnings per sh B	2.80
.48	.51	.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.49	Div'ds Decl'd per sh C■	1.70
.64	.73	.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	5.35	5.30	Cap'l Spending per sh	5.50
7.50	7.75	8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	18.70	19.85	Book Value per sh D	23.15
82.88	83.22	84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	98.00	99.00	Common Shs Outst'g E	100.00
16.1	21.6	12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	Bold figures are		Avg Ann'l P/E Ratio	17.0
.87	1.15	.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	Value Line		Relative P/E Ratio	.95
3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	estimates		Avg Ann'l Div'd Yield	4.0%

CAPITAL STRUCTURE as of 3/31/22
Total Debt $2646.1 mill. Due in 5 Yrs $442.8 mill.
LT Debt $2319.4 mill. LT Interest $78.6 mill.
Incl. $6.0 mill. capitalized leases.
(LT interest earned: 5.0x; total interest coverage: 5.0x)
Pension Assets-9/21 $469.5 mill. Oblig. $640.2 mill.
Pfd Stock None
Common Stock 96,152,712 shs. as of 5/2/22
MARKET CAP: $4.3 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
2248.9	3198.1	3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2500	2570	Revenues ($mill) A	2810
112.4	113.7	176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	225	240	Net Profit ($mill)	280
7.1%	25.4%	30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	10.5%	10.5%	Income Tax Rate	10.5%
5.0%	3.6%	4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	9.1%	10.0%	Net Profit Margin	10.0%
39.2%	36.6%	38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.5%	57.0%	Long-Term Debt Ratio	56.5%
60.8%	63.4%	61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.5%	43.0%	Common Equity Ratio	43.5%
1339.0	1400.3	1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4335	4565	Total Capital ($mill)	5310
1484.9	1643.1	1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4145	4225	Net Plant ($mill)	4485
9.2%	9.[illegible]	12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	6.5%	6.5%	Return on Total Cap'l	6.5%
13.8%	12.[illegible]	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	12.5%	12.0%	Return on Shr. Equity	12.0%
13.8%	12.8%	18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	12.5%	12.0%	Return on Com Equity	12.0%
6.2%	5.2%	11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	4.5%	4.5%	Retained to Com Eq	4.5%
55%	59%	40%	50%	60%	59%	40%	59%	60%	56%	63%	62%	All Div'ds to Net Prof	61%

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	117.0	4.7	13.9
Other	505.3	629.6	542.1
Current Assets	622.3	634.3	556.0
Accts Payable	270.1	429.6	301.6
Debt Due	152.6	450.1	326.7
Other	111.0	171.7	253.8
Current Liab.	533.7	1051.4	882.1
Fix. Chg. Cov.	545%	545%	550%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	-6.0%	2.5%
"Cash Flow"	7.0%	4.5%	5.0%
Earnings	5.0%	2.5%	5.0%
Dividends	6.5%	6.5%	5.0%
Book Value	7.5%	7.0%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	811.8	866.2	434.9	479.1	2592.0
2020	615.0	639.6	299.0	400.1	1953.7
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	430	481.9	2500
2023	695	930	450	495	2570

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	.61	1.27	d.20	.29	1.96
2020	.44	1.12	d.06	.57	2.07
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.10	.35	2.30
2023	.73	1.38	d.08	.37	2.40

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.273	.273	.273	.2925	1.11
2019	.2925	.2925	.2925	.3125	1.19
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625			

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 564,000 cust. at 9/30/21. Fiscal 2021 volume: 112 bill. cu. ft. (20% interruptible, 61% residential, commercial & firm transportation, 19% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2021 dep. rate: 2.4%. Has 1,251 empls. Off./dir. own less than 1% of common; BlackRock, 15.3%; Vanguard, 10.6% (12/21 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

Since our February review, shares of New Jersey Resources have continued to trend higher. In fact, the stock's price advanced another 9.5%. In comparison, the S&P 500 Index registered a downturn of nearly 10% for this same period.

Meanwhile, the retail and wholesale energy provider posted mixed March-quarter results. To that point, revenues advanced 13.7%, to $912.3 million, besting our call for $855 million. This reflected an impressive 49% spike in utility volumes, partially offset by a 9% downturn in non-utility volumes. On the margin front, total expenses increased 990 basis points, as a percentage of the top line. That margin compression completely offset the top-line growth, and after factoring in the dilutive effects of stock issuances, NJR's fiscal second-quarter (ended March 31, 2022) earnings declined 23%, to $1.36 a share. This fell short of our outlook of $1.70.

We have left our fiscal 2022 (ends September 30th) bottom-line estimate unchanged at this time. Despite the lower-than-expected second-quarter earnings, management recently raised its guidance range from $2.20-$2.30, to $2.30-$2.40 per share. Our call of $2.30 represents a year-over-year advance of about 6.5%. Share net should be driven by an estimated uptick in the top line of approximately 16%. This ought to be supported by the addition of more than 3,575 new customer accounts over the first half of the year. At the same time, steady contributions from the Storage & Transportation arm will likely be nicely complementary this year. Alternatively, the Energy Services segment has been hurt by the increased volatility in energy prices over the past year. This will likely present some headwinds for the company as the year progresses.

At the recent quotation, these untimely shares have already realized the bulk of the earnings growth potential that we envision for the pull to 2025-2027. Due to this, the stock offers below-average capital appreciation potential over that time frame. That said, conservative investors will likely find the Above-Average Safety rank and high Price Stability mark attractive features, given the recent market volatility. The attractive dividend yield is also a plus.

Bryan J. Fong — *May 27, 2022*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due early Aug.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2021: $522.1 million, $5.49/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A+
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	55

NISOURCE INC. NYSE-NI

RECENT PRICE 30.43 | P/E RATIO 21.0 (Trailing: 22.1 Median: 21.0) | RELATIVE P/E RATIO 1.30 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 4 Raised 3/11/22
SAFETY 3 Lowered 3/19/21
TECHNICAL 2 Raised 5/13/22
BETA .85 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$28-$39 $34 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+65%)	16%
Low	35	(+15%)	7%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	252	256	230
to Sell	188	197	208
Hld's(000)	361696	367884	376481

High:	24.0	26.2	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6
Low:	17.7	22.3	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	26.4

LEGENDS
— 0.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession

Target Price Range 2025 2026 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.2	-7.2
3 yr.	15.3	37.2
5 yr.	40.2	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
27.37	28.96	32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	**13.65**	**14.70**	Revenues per sh	**17.55**
3.18	3.20	3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	**3.20**	**3.50**	"Cash Flow" per sh	**4.35**
1.14	1.14	1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	**1.45**	**1.60**	Earnings per sh A	**2.30**
.92	.92	.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	**.94**	**.98**	Div'd Decl'd per sh B ■	**1.08**
2.33	2.88	3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	**4.45**	**4.45**	Cap'l Spending per sh	**4.35**
18.32	18.52	17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.66	13.33	**13.80**	**14.35**	Book Value per sh C	**17.40**
273.65	274.18	274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	**405.00**	**405.00**	Common Shs Outst'g D	**415.00**
19.2	18.8	12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	64.4	19.3	21.3	18.7	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	**19.0**
1.04	1.00	.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	3.24	1.04	1.13	.96	.99	*Value Line*		Relative P/E Ratio	**1.05**
4.2%	4.3%	5.7%	7.6%	5.7%	4.5%	3.8%	3.3	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	*estimates*		Avg Ann'l Div'd Yield	**2.5%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $9757.7 mill. **Due in 5 Yrs** $1318 mill.
LT Debt $9179.8 mill. **LT Interest** $341 mill.
(Interest cov. earned: 2.2x) (58% of Cap'l)

Leases, Uncapitalized Annual rentals $32.7 mill.
Pension Assets-12/21 $1.9 bill. **Oblig.** $2.0 bill.

Pfd Stock $1547 mill. **Pfd Div'd** $55.1 mill.

Common Stock 407,798,111 shs.
as of 4/26/22
MARKET CAP: $12.4 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
5061.2	565. 3	6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	**5600**	**5950**	Revenues ($mill)	**7290**
410.6	490.9	530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	**605**	**670**	Net Profit ($mill)	**990**
34.4%	34.8%	36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	**19.0%**	**19.0%**	Income Tax Rate	**19.0%**
--	--	--	--	--	--	--	--	2.9%	2.0%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
55.1%	56.3%	56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.2%	56.9%	**56.5%**	**56.0%**	Long-Term Debt Ratio	**52.0%**
44.9%	43.7%	43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.9%	33.5%	**34.0%**	**35.0%**	Common Equity Ratio	**39.5%**
12373	13460	14331	9792.0	10129	11832	12856	13843	15058	16131	**16435**	**16700**	Total Capital ($mill)	**18225**
12916	14315	16017	12112	13068	14360	15543	16912	16620	17882	**18000**	**19000**	Net Plant ($mill)	**22000**
5.0%	5.2%	5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	**3.5%**	**4.0%**	Return on Total Cap'l	**5.5%**
7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.6%	9.0%	**8.5%**	**9.0%**	Return on Shr. Equity	**11.5%**
7.4%	8.3%	8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.2%	10.6%	**8.5%**	**9.0%**	Return on Com Equity	**11.5%**
2.5%	3.1%	3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.7%	4.2%	**2.5%**	**3.0%**	Retained to Com Eq	**5.5%**
67%	62%	61%	NMF	63%	NMF	60%	64%	67%	64%	**72%**	**68%**	All Div'ds to Net Prof	**51%**

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	116.5	85.2	114.5
Other	1542.9	1835.6	1757.4
Current Assets	1659.4	1920.8	1871.9
Accts Payable	589.0	697.8	628.5
Debt Due	526.3	618.1	577.9
Other	1164.1	1430.3	1388.2
Current Liab.	2279.4	2746.2	2594.6
Fix. Chg. Cov.	250%	250%	255%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-6.0%	-5.0%	*5.5%*
"Cash Flow"	.5%	2.0%	*5.5%*
Earnings	3.0%	4.0%	*9.5%*
Dividends	-1.0%	--	*4.5%*
Book Value	-3.0%	-2.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1869.8	1010.4	931.5	1397.2	5208.9
2020	1605.5	962.7	902.5	1211.0	4681.7
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	**1085**	**1035**	**1606.7**	**5600**
2023	**1960**	**1170**	**1120**	**1700**	**5950**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.05	--	.45	1.31
2020	.76	.13	.09	.34	1.32
2021	.77	.13	.11	.39	1.37
2022	.75	**.17**	**.15**	**.38**	**1.45**
2023	**.80**	**.20**	**.20**	**.40**	**1.60**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.195	.195	.195	.195	.78
2019	.200	.200	.200	.200	.80
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235			

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 479,185 electric in Indiana, 3,200,000 million gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2021: electrical, 31%; gas, 69%; other, less than 1%. Generating sources, coal, 69.4%; purchased & other, 30.6%. 2021 reported depreciation rates: 2.9% electric, 2.2% gas. Has 7,304 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

Since our February review, shares of NiSource have continued on their upward trajectory. In fact, over that time frame, the stock's price advanced another roughly 7%. In comparison, the S&P 500 Index underwent a correction of approximately 10% over that same period.

Meantime, the supplier of electricity and gas to northern Indiana is off to a mixed start this year. To that point, revenues advanced 21.2%, to $1.873 billion, thanks to a solid, double-digit increase in customer revenues, partially offset by a modest decline in other volumes. This handily bested our call for $1.645 billion. On the profitability front, total expenses declined 402 basis points, as a percentage of the top line. After accounting for the dilutive effects of a 13.3 million spike in the number of shares outstanding, NI's first-quarter share net fell 2.6%, to $0.75. This was modestly below our call for $0.80.

As a result, we have sliced a nickel off our 2022 and 2023 earnings estimates, bringing those figures to $1.45 and $1.60, respectively. In the current year, our revised call would still represent a roughly 6% annual increase. This figure also coincides with management's recently reiterated guidance range of $1.42 to $1.48. This ought to reflect an estimated revenue advance of more than 14%, to $5.6 billion. NiSource has roughly $10 billion in capital growth projects on deck and planned to come into service through 2024. It is also transitioning away from coal-fired generation and toward greener alternatives. Finally, the company has filed for roughly $475 million in proposed rate-case increases across its various service territories. Those efforts ought to help the company recoup some of its already invested capital and offset growth costs.

This stock offers an above-average dividend yield when viewed against the Value Line median, which may appeal to income-oriented investors. That said, the stock's upside potential for the pull to 2025-2027 is below the *Value Line* median. What's more, momentum accounts would probably be better served elsewhere. Our Timeliness Ranking System has NiSource pegged to lag the broader market averages in the coming six to 12 months (Timeliness: 4).

Bryan J. Fong *May 27, 2022*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '06, (11¢); '07, 3¢; '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due late July. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '21: $1485.9 million, $3.68/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15).

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	20
Earnings Predictability	50

N.W. NATURAL NYSE-NWN

RECENT PRICE 50.78 | P/E RATIO 19.9 (Trailing: 21.0 Median: 24.0) | RELATIVE P/E RATIO 1.23 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 4 Raised 4/29/22
SAFETY 3 Lowered 3/19/21
TECHNICAL 4 Lowered 5/27/22
BETA .80 (1.00 = Market)

18-Month Target Price Range
Low-High Midpoint (% to Mid)
$41-$67 $54 (5%)

2025-27 PROJECTIONS

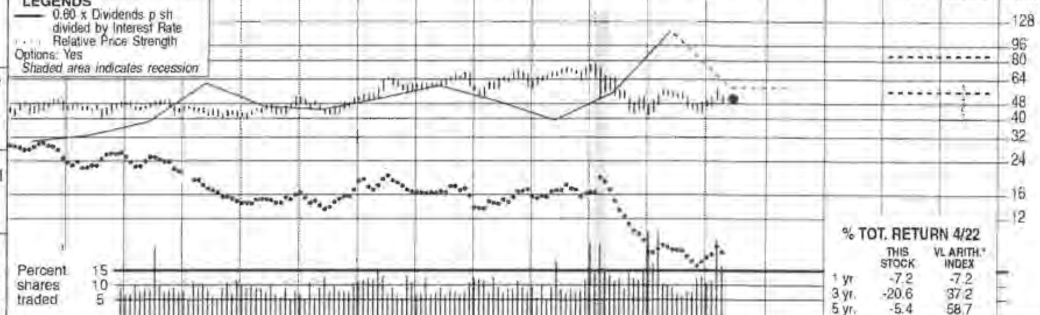
	Price	Gain	Ann'l Total Return
High	85	(+65%)	16%
Low	55	(+10%)	6%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	103	114	95
to Sell	89	81	95
Hld's(000)	21451	21444	21597

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	49.0	50.8	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6
Low:	39.6	41.0	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	45.8

LEGENDS
— 0.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2025 2026 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.2	-7.2
3 yr.	-20.6	37.2
5 yr.	-5.4	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
37.20	39.13	39.16	38.17	30.56	31.72	27.14	28.[illegible]	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	*28.50*	*29.45*	Revenues per sh	*33.55*
4.76	5.41	5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	*6.20*	*6.65*	"Cash Flow" per sh	*7.65*
2.35	2.76	2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	*2.55*	*2.85*	Earnings per sh A	*3.45*
1.39	1.44	1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	*1.93*	*1.94*	Div'ds Decl'd per sh B■	*1.96*
3.56	4.48	3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	*8.65*	*8.90*	Cap'l Spending per sh	*9.40*
22.01	22.52	23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.65	26.41	28.42	29.05	30.04	*29.25*	*30.25*	Book Value per sh D	*37.20*
27.24	26.41	26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	*31.25*	*31.50*	Common Shs Outst'g C	*32.00*
15.9	16.7	18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	--	26.6	30.9	25.0	19.5	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*20.0*
.86	.89	1.09	1.01	1.08	1.19	1.34	1.19	1.09	1.19	1.41	--	1.44	1.65	1.28	1.06			Relative P/E Ratio	*1.10*
3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%			Avg Ann'l Div'd Yield	*2.6%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $1434.4 mill. Due in 5 Yrs $175.3 mill.
LT Debt $1044.6 mill. LT Interest $44.5 mill.

(Total interest coverage: 3.1x)

Pension Assets-12/21 $399.2 mill. Oblig. $569.8 mill.

Pfd Stock None

Common Stock 30,730,274 shares as of 10/27/21

MARKET CAP $1.6 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
730.6	758.5	754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	*890*	*925*	Revenues ($mill)	*1075*
59.9	60.5	58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	*80.0*	*90.0*	Net Profit ($mill)	*135*
42.4%	40.8%	41.5%	40.0%	40.9%	--	26.4%	16.2%	23.1%	25.8%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
8.2%	8.0%	7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	*8.9%*	*9.7%*	Net Profit Margin	*10.3%*
48.5%	47.6%	44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	*52.0%*	*51.0%*	Long-Term Debt Ratio	*48.0%*
51.5%	52.4%	55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	*48.0%*	*49.5%*	Common Equity Ratio	*52.0%*
1424.7	1433.6	1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	*1915*	*1955*	Total Capital ($mill)	*2290*
1973.6	2062.9	2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	*3105*	*3360*	Net Plant ($mill)	*4250*
5.7%	5.8%	5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	*4.0%*	*4.5%*	Return on Total Cap'l	*5.0%*
8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	*8.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
8.2%	8.1%	7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	*8.5%*	*9.5%*	Return on Com Equity	*9.5%*
1.6%	1.5%	1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	*2.0%*	*3.0%*	Retained to Com Eq	*4.0%*
80%	81%	85%	92%	87%	NMF	76%	82%	79%	71%	*76%*	*68%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	30.2	18.6	24.3
Other	293.0	418.7	367.1
Current Assets	323.2	437.3	391.4
Accts Payable	97.9	133.5	130.6
Debt Due	399.9	389.8	332.8
Other	129.3	201.5	194.9
Current Liab.	627.1	724.8	658.3
Fix. Chg. Cov.	335%	335%	312%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	--	*4.5%*
"Cash Flow"	1.0%	2.5%	*5.0%*
Earnings	-1.0%	2.5%	*6.5%*
Dividends	1.5%	.5%	*.5%*
Book Value	1.0%	.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	285.4	123.4	90.3	247.3	746.4
2020	285.2	135.0	93.3	260.2	773.7
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	*150*	*110*	*279.7*	*890*
2023	*355*	*160*	*120*	*290*	*925*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.50	.07	d.61	1.26	2.19
2020	1.58	d.17	d.61	1.50	2.30
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	*.01*	*d.56*	*1.30*	*2.55*
2023	*2.00*	*.05*	*d.55*	*1.35*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4725	.4725	.4725	.475	1.89
2019	.475	.475	.475	.4775	1.90
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483			

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 775,000 customers, in Oregon (89% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 37%; commercial, 22%; industrial, gas transportation, 41%. Employs 1,167. BlackRock Inc. owns 17.2% of shares; Vanguard, 11.8%; Off./Dir., .92% (4/22 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Since our February review, shares of Northwest Natural Holding Co. have ticked modestly higher. In fact, the stock's price advanced nearly 7%. In comparison, the S&P 500 Index logged a correction of nearly 10% for that same period.
Meantime, the distributor of natural gas posted mixed financial results for the March quarter. On the upside, revenues increased 10.9%, to $350.3 million, thanks to incremental volumes associated with the 10,800 natural gas meters added over the past 12 months. Additional benefits stemmed from a rate increase in Washington state. On the profitability front, total costs rose 498 basis points, as a percentage of the top line. After accounting for a drop in other expenses and an increase in common stock outstanding, NWN's share net declined about 7%, to $1.80, versus the prior year. This was well below our call for $1.96 per share.
Consequently, we have sliced $0.15 off our bottom-line outlook for this year, to $2.55 a share. Our revised figure would represent a less-than-1% year-over-year earnings decline. This ought to reflect an estimated revenue advance of about 3.5%, to $890 million, as Northwest Natural continues to focus its efforts on growing its renewal operations, and moving its existing rate cases forward. In mid-December, it filed for a more-than-$365 million hike with the Oregon Public Utility Commission, which is anticipated to go into effect around November 1st. The purpose of the higher rate is to support long-term investments in safety, reliability, and technology upgrades. That said, we look for costs to remain elevated as the year progresses. This will likely offset the top-line gains and keep a lid on bottom-line growth until next year.
These shares have improved one notch in Timeliness since our last report. Still, they are ranked a 4, suggesting NWN will lag the broader market averages in the year ahead. Meanwhile, the stock offers worthwhile capital appreciation potential for the pull to 2025-2027, even after reducing our 3- to 5-year P/E multiple to 20 from 24. Additionally, NWN offers a dividend yield that is well above the *Value Line* median, which may appeal to yield-seeking investors.
Bryan J. Fong *May 27, 2022*

(A) Diluted earnings per share. Excludes non-recurring items: '06, ($0.06); '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in early Aug.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2021: $70.6 million, $2.27/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	10

ONE GAS, INC. NYSE-OGS

RECENT PRICE 85.96 | P/E RATIO 21.2 (Trailing: 22.1 Median: NMF) | RELATIVE P/E RATIO 1.31 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Raised 5/13/22
SAFETY 2 New 6/2/17
TECHNICAL 1 Raised 5/20/22
BETA .80 (1.00 = Market)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
High	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3
Low	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	73.4

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$69-$110	$90 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	145	(+70%)	16%
Low	105	(+20%)	8%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	127	111	135
to Sell	144	140	122
Hld's(000)	42395	43179	42681

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.4	-7.2
3 yr.	4.2	37.2
5 yr.	40.6	58.7

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
--	--	34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	**42.80**	**45.35**	Revenues per sh	**57.45**
--	--	4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	**8.25**	**8.70**	"Cash Flow" per sh	**10.55**
--	--	2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	**4.05**	**4.25**	Earnings per sh A	**5.30**
--	--	.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	**2.48**	**2.64**	Div'ds Decl'd per sh B■	**3.12**
--	--	5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	**9.40**	**9.55**	Cap'l Spending per sh	**9.85**
--	--	34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	**59.70**	**60.65**	Book Value per sh	**71.60**
--	--	52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	**54.00**	**54.00**	Common Shs Outst'g C	**57.00**
--	--	17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	**23.5**
--	--	.94	1.00	1.19	1.18	1.25	1.35	1.11	1.03	*Value Line*		Relative P/E Ratio	**1.30**
--	--	2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	*estimates*		Avg Ann'l Div'd Yield	**2.5%**
--	--	1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	**2310**	**2450**	Revenues ($mill)	**3275**
--	--	109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	**218**	**230**	Net Profit ($mill)	**300**
--	--	38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	**18.0%**	**18.5%**	Income Tax Rate	**22.0%**
--	--	6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	**9.4%**	**9.4%**	Net Profit Margin	**9.2%**
--	--	40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.0%	**48.0%**	**49.0%**	Long-Term Debt Ratio	**52.0%**
--	--	59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	39.0%	**52.0%**	**51.0%**	Common Equity Ratio	**48.0%**
--	--	2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	**6200**	**6420**	Total Capital ($mill)	**8500**
--	--	3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	**5500**	**5800**	Net Plant ($mill)	**6750**
--	--	4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	**5.0%**	**5.0%**	Return on Total Cap'l	**5.0%**
--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	**7.0%**	**7.0%**	Return on Shr. Equity	**7.5%**
--	--	6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	**7.0%**	**7.0%**	Return on Com Equity	**7.5%**
--	--	3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	**2.5%**	**2.5%**	Retained to Com Eq	**3.0%**
--	--	40%	53%	52%	55%	56%	56%	58%	60%	**61%**	**62%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 3/31/22
Total Debt $4188.8 mill. **Due in 5 Yrs** $2900.0 mill.
LT Debt $2283.6 mill. **LT Interest** $140.0 mill.
(LT interest earned: 5.1x; total interest coverage: 5.1x)
Leases, Uncapitalized Annual rentals $7.5 mill.
Pfd Stock None
Pension Assets-12/21 $1245.2 mill. **Oblig.** $1272.8 mill.
Common Stock 54,089,905 shs. as of 4/25/22
MARKET CAP: $4.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	8.0	8.9	12.4
Other	531.9	2215.7	2262.1
Current Assets	539.9	2224.6	2274.5
Accts Payable	152.3	258.6	209.8
Debt Due	418.2	494.0	1905.2
Other	226.6	227.9	253.8
Current Liab.	797.1	980.5	2368.8
Fix. Chg. Cov.	587%	625%	632%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	.5%	10.5%
"Cash Flow"	--	8.5%	6.5%
Earnings	--	9.5%	6.5%
Dividends	--	13.5%	6.5%
Book Value	--	3.5%	9.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	661.0	290.6	248.6	452.5	1652.7
2020	528.2	273.3	244.6	484.2	1530.3
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	*400*	*323.5*	*615*	*2310*
2023	*1009*	*450*	*346*	*645*	*2450*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.76	.46	.33	.96	3.51
2020	1.72	.48	.39	1.09	3.68
2021	1.79	.56	.38	1.12	3.85
2022	1.83	*.62*	*.45*	*1.15*	*4.05*
2023	*1.90*	*.67*	*.50*	*1.18*	*4.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.46	.46	.46	.46	1.84
2019	.50	.50	.50	.50	2.00
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62			

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 164 Bcf of natural gas supply in 2021, compared to 153 Bcf in 2020. Total volumes delivered by customer (fiscal 2021): transportation, 59.3%; residential, 30.4%; commercial & industrial, 9.7%; other, .6%. ONE Gas has around 3,600 employees. BlackRock owns 12.2% of common stock. The Vanguard Group, 10.9%; American Century Investment, 8.0%; officers and directors, 1.5% (4/22 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas' first-quarter 2022 results showed some improvement. Share net of $1.83 was several pennies higher than last year's $1.79 figure. That stemmed partially from benefits from new rates. Also, there was a rise in residential sales due to net customer growth. Bad-debt expense decreased, too. So, assuming that the business climate continues to be generally favorable over the course of the year, we believe that 2022 share net will increase around 5%, to $4.05, compared to the 2021 tally of $3.85. Regarding next year, the company's bottom line might advance at a similar percentage rate, to $4.25 a share, as operating margins expand further.

Prospects over the 2025-2027 period appear promising. ONE Gas remains the top natural gas distributor (as measured by customer count) in both Oklahoma and Kansas, and holds the number-three position in Texas. Moreover, we think these markets have decent growth possibilities and are located in one of the most active drilling regions in the United States. Too, thanks to healthy finances, the company should continue to satisfy its working capital requirements, capital expenditures, and other commitments with little difficulty.

There are risks to bear in mind, though. ONE Gas' lack of geographic diversification leaves it somewhat more vulnerable to regional economic downturns and regulations. Also, there's competition from other energy suppliers, which include electric companies and propane dealers. Lastly, pipeline ruptures, leaks, and other unfortunate occurrences can take a big bite out of corporate profits if not adequately covered by insurance.

The good-quality stock has climbed roughly 15% in value since our last full-page report in February. It seems that can be traced, to some extent, to expectations of decent earnings for the energy provider in 2022. But the price action has dampened 3- to 5-year capital appreciation potential. Too, the dividend yield does not stand out from the average yield in *Value Line's* Natural Gas Utility group. Lastly, these shares are ranked to just approximate the market over the coming six to 12 months.

Frederick L. Harris, III — *May 27, 2022*

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Aug.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 33.38 | P/E RATIO 19.1 (Trailing: 19.9 Median: 19.0) | RELATIVE P/E RATIO 1.18 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS — Suspended 3/11/22
SAFETY 3 Lowered 8/28/20
TECHNICAL — Suspended 3/11/22
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$12-$44	$28 (-15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+50%)	14%
Low	35	(+5%)	6%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	141	132	125
to Sell	89	106	90
Hld's(000)	102245	105367	102702

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	29.0	29.0	31.1	30.6	30.4	34.8	38.4	36.7	34.5	33.4	29.2	35.3
Low:	21.4	22.9	25.3	25.9	21.2	22.1	30.8	26.0	26.6	18.2	20.8	23.1

LEGENDS
— 0.70 x Dividends p sh divided by Interest Rate
····· Relative Price Strength
2-for-1 split 5/15
Options: Yes
Shaded area indicates recession

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	44.1	-7.2
3 yr.	19.4	37.2
5 yr.	9.6	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
15.88	16.15	16.18	14.19	15.48	13.71	11.16	11.18	12.98	13.52	13.04	15.63	19.20	17.63	15.32	16.98	*18.50*	*19.05*	Revenues per sh	*21.60*
1.75	1.60	1.74	1.86	2.10	2.23	2.34	[illegible]	2.67	2.42	2.67	2.79	2.91	2.56	3.32	3.32	*2.90*	*3.25*	"Cash Flow" per sh	*4.25*
1.23	1.05	1.14	1.19	1.35	1.45	1.52	[illegible]	1.57	1.44	1.34	1.23	1.38	1.12	1.68	1.62	*1.75*	*1.95*	Earnings per sh A	*2.70*
.46	.51	.56	.61	.68	.75	.83	.90	.96	1.02	1.06	1.10	1.13	1.16	1.19	1.22	*1.25*	*1.28*	Div'ds Decl'd per sh B ■	*1.50*
1.26	.94	1.04	1.83	2.79	3.20	4.01	4.84	5.01	4.87	3.50	3.43	3.99	5.46	4.84	4.53	*5.65*	*6.35*	Cap'l Spending per sh	*8.00*
7.55	8.12	8.67	9.12	9.54	10.33	11.63	12.64	13.65	14.62	16.22	14.99	14.82	15.41	16.51	16.95	*20.85*	*22.45*	Book Value per sh C	*24.80*
58.65	59.22	59.46	59.59	59.75	60.43	63.31	65.43	68.33	70.97	79.48	79.55	85.51	92.39	100.59	117.34	*115.00*	*118.00*	Common Shs Outst'g D	*125.00*
11.9	17.2	15.9	15.0	16.8	18.4	16.9	16.9	18.0	17.9	21.7	27.9	22.6	28.3	14.9	15.1	Bold figures are		Avg Ann'l P/E Ratio	*16.0*
.64	.91	.96	1.00	1.07	1.15	1.08	[illegible]	.95	.90	1.14	1.40	1.22	1.51	.77	.82	Value Line		Relative P/E Ratio	*.90*
3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	3.2%	3.1%	3.4%	3.9%	3.6%	3.2%	3.6%	3.7%	4.8%	5.0%	estimates		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $3344.3 mill. **Due in 5 Yrs** $278.5 mill.
LT Debt $3187.6 mill. **LT Interest** $120.0 mill.

Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/21 $331 mill. **Oblig.** $351.6 mill.

Pfd Stock None

Common Stock 122,407,427 shs. as of 2/15/22

MARKET CAP: $4.1 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
706.3	731.4	887.0	959.6	1036.5	1243.1	1641.3	1628.6	1541.4	1992.0	*2125*	*2250*	Revenues ($mill)	*2700*
93.3	97.1	104.0	99.0	102.8	98.1	116.2	103.0	163.0	178.0	*195*	*225*	Net Profit ($mill)	*330*
10.6%	--	--	5.9%	42.0%	--	--	--	9.9%	22.0%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
13.2%	13.3%	11.7%	10.3%	9.9%	7.9%	7.1%	6.3%	10.6%	8.9%	*9.2%*	*10.0%*	Net Profit Margin	*12.2%*
45.0%	45.1%	48.0%	49.2%	38.5%	48.5%	62.4%	59.2%	62.6%	61.6%	*58.5%*	*57.5%*	Long-Term Debt Ratio	*57.0%*
55.0%	54.9%	52.0%	50.8%	61.5%	51.5%	37.6%	40.8%	37.4%	38.4%	*41.5%*	*42.5%*	Common Equity Ratio	*43.0%*
1337.6	1507.4	1791.9	2043.9	2097.2	2315.4	3373.9	3493.9	4437.3	5178.2	*5800*	*6250*	Total Capital ($mill)	*7250*
1578.0	1859.1	2134.1	2448.1	2623.8	2700.2	3653.5	4073.5	4464.2	4912.3	*5200*	*5600*	Net Plant ($mill)	*6500*
7.4%	6.8%	6.4%	5.4%	5.4%	5.1%	4.4%	4.0%	4.8%	4.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	9.0%	*8.0%*	*8.5%*	Return on Shr. Equity	*10.5%*
12.7%	11.7%	11.2%	9.5%	8.0%	8.2%	9.2%	7.2%	9.8%	9.0%	*8.0%*	*8.5%*	Return on Com Equity	*10.5%*
5.8%	4.8%	4.3%	2.8%	1.6%	.9%	1.7%	NMF	2.9%	2.2%	*2.0%*	*3.0%*	Retained to Com Eq	*4.5%*
55%	59%	61%	71%	80%	89%	82%	NMF	70%	75%	*74%*	*67%*	All Div'ds to Net Prof	*57%*

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	34.0	28.8	32.5
Other	472.8	610.2	644.9
Current Assets	506.8	639.0	677.4
Accts Payable	256.6	330.2	358.6
Debt Due	739.2	400.1	156.8
Other	167.8	225.4	293.4
Current Liab.	1163.6	955.7	808.8
Fix. Chg. Cov.	238%	275%	276%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	1.5%	5.0%	*4.5%*
"Cash Flow"	4.0%	3.5%	*5.5%*
Earnings	1.0%	.5%	*10.5%*
Dividends	6.0%	3.5%	*4.0%*
Book Value	5.5%	2.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	637.3	266.9	261.2	463.2	1628.6
2020	534.1	260.0	261.5	485.8	1541.4
2021	674.3	311.8	365.6	640.3	1992.0
2022	824.6	*335*	*380*	*585.4*	*2125*
2023	*850*	*360*	*415*	*625*	*2250*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.09	d.13	d.30	.46	1.12
2020	1.15	d.01	d.06	.62	1.68
2021	1.19	.02	d.17	.58	1.62
2022	1.25	*.02*	*d.12*	*.58*	*1.75*
2023	*1.35*	*.04*	*d.06*	*.62*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	--	.280	.280	.567	1.13
2019	--	.287	.287	.582	1.16
2020	--	.295	.295	.598	1.19
2021	--	.303	.303	.613	1.22
2022	--	.310			

BUSINESS: South Jersey Industries, Inc. is a holding company. The company distributes natural gas in New Jersey and Maryland. South Jersey Gas rev. mix '21: residential, 48%; commercial, 23%; cogen. and electric gen., 9%; industrial, 20%. Acq. Elizabethtown Gas and Elkton Gas, 7/18. Nonutil. oper. incl. South Jersey Energy, South Jersey Resources Group, South Jersey Exploration, Marina Energy, South Jersey Energy Service Plus, and SJI Midstream. Has about 1,173 empl. Off./dir. own less than 1% of common; BlackRock, 14.4%; State Street Corporation, 13.9%; The Vanguard Group, 10.8% (3/21 proxy). Pres. & CEO: Michael J. Renna. Chairman: Joseph M. Rigby. Inc.: NJ. Addr.: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Web: www.sjindustries.com.

South Jersey Industries has agreed to be acquired by Infrastructure Investments Fund for $36.00 per share in cash. This represents an enterprise value of about $8.1 billion. The transaction was unanimously approved by the company's board of directors, and is expected to close in the fourth quarter of this year, subject to customary conditions.

Assuming completion, the company will become a private entity and its shares will no longer trade on the New York Stock Exchange. Following its acquisition, South Jersey is expected to remain at its present location and be run by the current management team.

Revenue advanced at a strong pace for the March quarter. Utility South Jersey Gas benefited from growth in the customer base and infrastructure replacement programs. On the nonutility side, results at the Energy Management line were supported by more robust asset optimization opportunities and improved contributions from consulting activities and appliance service contract fees. However, operating expenses also increased considerably, and bottom-line results were less impressive for the recent period. Looking forward, top-line comparisons ought to remain positive in the second and third quarters. The company's utility operations should be able to capitalize on the popularity of natural gas within its service territories. Earnings will probably remain roughly flat in the June period, but we anticipate that the deficit will narrow in the September quarter, assuming a measure of cost control. Infrastructure modernization, as well as clean energy and decarbonization initiatives, should also provide support. We envision solid performance from the nonutility side going forward.

This stock is unranked for year-ahead relative price performance, due to the aforementioned merger. On its own, the issue offers uninspiring long-term total return potential. The stock is now trading fairly close to the price that Infrastructure Investments Fund will probably pay to acquire the company. Moreover, should the deal fall through, then these shares would most likely decline significantly in price. Stockholders should consider selling their position, in our view.

Michael Napoli, CFA *May 27, 2022*

(A) Based on economic egs. from 2007. GAAP EPS: '12, $1.49; '13, $1.28; '14, $1.46; '15, $1.52; '16, $1.56; '17, ($0.04); '18, $0.21; '19, $0.84; '20, $1.62; '21, $0.81. Excl. nonrecur. gain (loss): '12, ($0.03); '13, ($0.24); '14, ($0.11); '15, $0.08; '16, $0.22; '17, ($1.27); '18, ($1.17); '19, ($0.28); '20, ($0.06); '21, ($0.81). Totals may not sum due to rounding. Next egs. rpt. due early Aug. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2021: $672.4 mill., $5.73 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	50
Price Growth Persistence	15
Earnings Predictability	70

SOUTHWEST GAS NYSE-SWX

RECENT PRICE **91.85** | P/E RATIO **21.6** (Trailing: 30.9; Median: 19.0) | RELATIVE P/E RATIO **1.33** | DIV'D YLD **2.7%** | VALUE LINE

TIMELINESS — Suspended 10/29/21
SAFETY 3 Lowered 1/4/91
TECHNICAL — Suspended 10/29/21
BETA .90 (1.00 = Market)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
High:	43.2	46.[illegible]	56.0	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	92.4
Low:	32.1	39.0	42.0	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	62.6

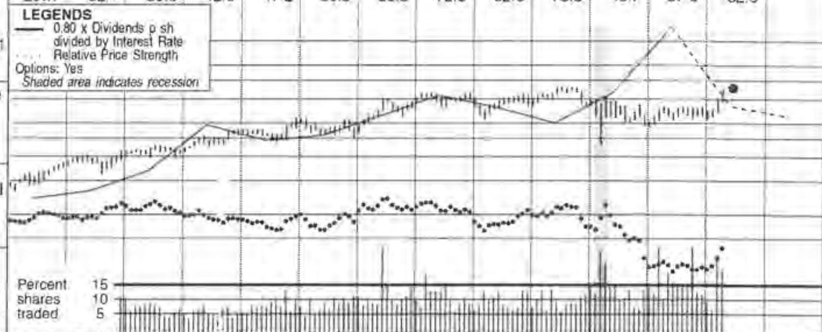
18-Month Target Price Range
Low-High Midpoint (% to Mid)
$62-$109 $86 (-5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+40%)	11%
Low	85	(-5%)	1%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	144	125	121
to Sell	132	137	122
Hld's(000)	48499	48501	52325



Target Price Range
2025 | 2026 | 2027
160
120
100
80
60
50
40
30
20
15

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.3	-7.2
3 yr.	16.1	37.2
5 yr.	21.5	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
48.47	50.28	48.53	42.00	40.18	41.07	41.77	42.18	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	*66.20*	*67.85*	Revenues per sh	*82.65*
5.97	6.21	5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	*11.05*	*12.15*	"Cash Flow" per sh	*15.75*
1.98	1.95	1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	*4.25*	*4.90*	Earnings per sh A	*6.75*
.82	.86	.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	*2.48*	*2.60*	Div'ds Decl'd per sh B■†	*3.10*
8.27	7.96	6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	*11.05*	*12.85*	Cap'l Spending per sh	*20.00*
21.58	22.98	23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	*52.95*	*56.45*	Book Value per sh	*72.00*
41.77	42.81	44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	*68.00*	*70.00*	Common Shs Outst'g C	*75.00*
15.9	17.3	20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.86	.92	1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	*Value Line*		Relative P/E Ratio	*.90*
2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*2.9%*

CAPITAL STRUCTURE as of 3/31/22
Total Debt $6324.8 mill. **Due in 5 Yrs** $1765 mill.
LT Debt $4559.8 mill. **LT Interest** $80.0 mill.
(Total interest coverage: 2.5x) (56% of Cap'l)
Leases, Uncapitalized Annual rentals $15.2 mill.
Pension Assets-12/21 $1418.2 mill.
Oblig. $1615.4 mill.
Pfd Stock None

Common Stock 66,852,050 shs.
as of 4/29/22

MARKET CAP: $6.1 billion (Large Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
1927.8	1950.8	2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	*4500*	*4750*	Revenues ($mill)	*6200*
133.3	145.3	141.1	138.3	152.0	173.8	182.3	213.9	232.3	200.8	*272*	*325*	Net Profit ($mill)	*480*
36.2%	35.0%	35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.8%	16.1%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
6.9%	7.4%	6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	*6.0%*	*6.8%*	Net Profit Margin	*7.7%*
49.2%	49.4%	52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	*56.5%*	*56.0%*	Long-Term Debt Ratio	*52.5%*
50.8%	50.6%	47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	*43.5%*	*44.0%*	Common Equity Ratio	*47.5%*
2576.9	2793.7	3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	*8300*	*8950*	Total Capital ($mill)	*11400*
3343.8	3486.1	3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	*8000*	*8400*	Net Plant ($mill)	*10000*
6.4%	6.3%	5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.4%	*4.0%*	*4.0%*	Return on Total Cap'l	*4.5%*
10.2%	10.3%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	*7.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
10.2%	10.2%	9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	*7.5%*	*8.0%*	Return on Com Equity	*9.0%*
6.1%	6.1	5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	*3.0%*	*3.5%*	Retained to Com Eq	*4.5%*
40%	4[illegible]	47%	54%	55%	53%	55%	54%	54%	69%	*62%*	*56%*	All Div'ds to Net Prof	*48%*

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	83.4	222.7	624.7
Other	787.6	1392.1	1421.9
Current Assets	871.0	1614.8	1392.6
Accts Payable	231.3	353.4	256.6
Debt Due	147.4	2206.3	1765.0
Other	533.3	552.3	608.6
Current Liab.	912.0	3112.0	2630.2
Fix. Chg. Cov.	379%	310%	254%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	3.5%	3.0%	*6.0%*
"Cash Flow"	4.0%	1.5%	*8.5%*
Earnings	5.5%	4.5%	*10.0%*
Dividends	8.5%	7.0%	*5.5%*
Book Value	6.5%	7.0%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	833.6	713.0	725.2	848.1	3119.9
2020	836.3	757.2	791.2	914.2	3298.9
2021	885.9	821.4	888.7	1084.5	3680.5
2022	1267.4	*1040*	*1050*	*1142.6*	*4500*
2023	*1310*	*1100*	*1100*	*1240*	*4750*

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.77	.41	.10	1.67	3.94
2020	1.31	.68	.32	1.82	4.14
2021	2.03	.43	d.19	1.15	3.39
2022	1.58	*.55*	*.32*	*1.80*	*4.25*
2023	*1.85*	*.65*	*.40*	*2.00*	*4.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.495	.520	.520	.520	2.06
2019	.520	.545	.545	.545	2.16
2020	.545	.570	.570	.570	2.26
2021	.570	.595	.595	.595	2.36
2022	.595	.620			

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas and Centuri Group. Southwest Gas is a regulated gas distributor serving 2.2 million customers in Arizona, Nevada, and California. Centuri provides construction services. 2021 margin mix: residential and small commercial, 85%; large commercial and industrial, 4%; transportation, 11%. Total through-put: 2.2 billion therms. Has 12,973 employees. Off. & dir. own .9% of common; BlackRock, 15.3%; The Vanguard Group, 9.9%; T. Rowe Price Associates, 5.6% (3/22 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Shares of Southwest Gas have increased dramatically in price over the past three months. The company has announced a settlement with activist investor Carl Icahn. Mr. Icahn had previously made tender offers to purchase a stake in the company, and was also looking to replace its board. As part of the agreement, three to four new directors will join the company's board. Mr. Icahn has since withdrawn his litigation against the company. The board will continue to review strategic alternatives to maximize shareholder value, including a possible sale of the company. This news followed the announcement that Southwest plans to separate its utility infrastructure services business, Centuri. This is expected to occur in the first quarter of 2023. Assuming completion, the separation should enhance shareholder value and allow both businesses to increase their focus on core operations. As a stand-alone independent company, unregulated Centuri will be an industry leader well positioned to benefit from the ongoing trend of infrastructure modernization. Southwest Gas will be a fully regulated natural gas operation with service areas in Arizona, Nevada, California, and the Rocky Mountain region.

The company has announced a changing of the guard. Following the retirement of John P. Hester, the board has appointed Karen S. Haller, as president and chief executive officer. Ms. Haller has worked at Southwest Gas for 25 years, and has served as executive vice president and chief legal and administrative officer of the company since May of 2018.

Long-term capital gains potential is limited, following the aforementioned run-up in the share price. The dividend yield does not stand out for a utility, either. At this juncture, investors can probably find more-suitable choices elsewhere. That said, a pullback in the stock price some time in the future may present patient subscribers with a more-attractive entry point. We expect that the company will report solid growth in revenues, earnings, and dividends in the coming years. Southwest Gas earns good marks for Financial Strength, Price Stability, and Earnings Predictability. Volatility is subdued, as well.

Michael Napoli, CFA *May 27, 2022*

(A) Diluted earnings. Excl. nonrec. gains (losses): '06, 7¢. Next egs. report due early August. (B) Dividends historically paid early March, June, September, and December.
■† Div'd reinvestment and stock purchase plan avail. (C) In millions.
(D) Totals may not sum due to rounding.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	40
Earnings Predictability	90

SPIRE INC. NYSE-SR

RECENT PRICE 75.39 | P/E RATIO 17.6 (Trailing: 18.6; Median: 19.0) | RELATIVE P/E RATIO 1.09 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 8/20/21
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 5/20/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

Low-High Midpoint (% to Mid)
$51-$84 $68 (-10%)

2025-27 PROJECTIONS

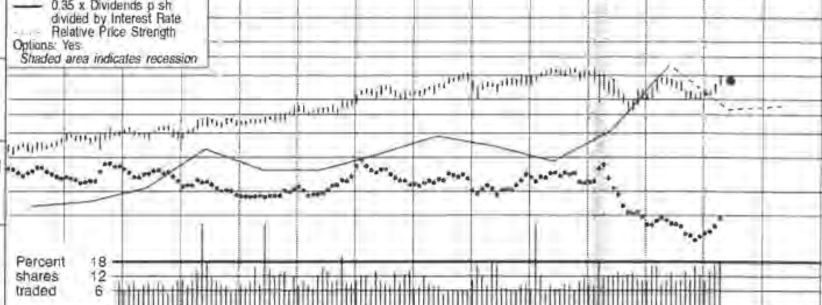
	Price	Gain	Ann'l Total Return
High	130	(+70%)	17%
Low	95	(+25%)	10%

Institutional Decisions

	1Q2021	2Q2021	3Q2021
to Buy	124	112	125
to Sell	139	126	113
Hld's(000)	42475	42992	42729

High:	42.8	44.0	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2
Low:	32.9	36.5	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.9

LEGENDS
— 0.35 x Dividends p sh divided by Interest Rate
···· Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2025 2026 2027

% TOT. RETURN 4/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.8	-7.2
3 yr.	-2.4	37.2
5 yr.	27.3	58.7

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB, LLC	25-27
93.51	93.40	100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	***38.95***	***40.75***	Revenues per sh A	***63.65***
3.81	3.87	4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	***8.40***	***9.10***	"Cash Flow" per sh	***10.90***
2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	***3.90***	***4.35***	Earnings per sh A B	***5.50***
1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	***2.74***	***2.86***	Div'ds Decl'd per sh C■	***3.30***
2.97	2.72	2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	***10.40***	***11.10***	Cap'l Spending per sh	***11.50***
18.85	19.79	22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	***51.90***	***56.55***	Book Value per sh D	***67.10***
21.36	21.65	21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	***52.00***	***52.50***	Common Shs Outst'g E	***55.00***
13.6	14.2	14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	NMF	13.6	*Bold figures are*		Avg Ann'l P/E Ratio	***20.5***
.73	.75	.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	NMF	.73	*Value Line*		Relative P/E Ratio	***1.15***
4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%	4.0	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	*estimates*		Avg Ann'l Div'd Yield	***3.0%***

CAPITAL STRUCTURE as of 3/31/22
Total Debt $3845.6 mill. **Due in 5 Yrs** $1520.0 mill.
LT Debt $3207.3 mill. **LT Interest** $145.0 mill.
(Total interest coverage: 4.2x)

Leases, Uncapitalized Annual rentals $8.8 mill.
Pension Assets-9/21 $945.7 mill. **Oblig.** $1318.0 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 52,121,977 shs. as of 5/1/22

MARKET CAP: $3.9 billion (Mid Cap)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023		25-27
1125.5	101[illegible]	1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	***2025***	***2140***	Revenues ($mill) A	***3500***
62.6	52.8	84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	***205***	***230***	Net Profit ($mill)	***300***
29.6%	25.0%	27.6%	31.2%	32.5%	32.4%	NMF	15.7%	12.3%	20.1%	***21.0%***	***22.0%***	Income Tax Rate	***25.0%***
5.6%	5.2%	5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	***10.1%***	***10.7%***	Net Profit Margin	***8.6%***
36.1%	46.6%	55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	***53.0%***	***52.0%***	Long-Term Debt Ratio	***51.0%***
63.9%	53.4%	44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	***43.0%***	***44.0%***	Common Equity Ratio	***45.0%***
941.0	1959.0	3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	***6275***	***6750***	Total Capital ($mill)	***8200***
1019.3	1776.6	2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	***5400***	***5715***	Net Plant ($mill)	***7100***
7.9%	3.5%	3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.0%***
10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	***7.5%***	***7.5%***	Return on Shr. Equity	***8.0%***
10.4%	5.0%	5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	***7.5%***	***7.5%***	Return on Com Equity	***8.0%***
4.3%	1.0%	1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	***2.0%***	***2.0%***	Retained to Com Eq	***3.0%***
59%	81%	73%	58%	59%	60%	51%	66%	NMF	54%	***77%***	***72%***	All Div'ds to Net Prof	***65%***

CURRENT POSITION ($MILL.)	2020	2021	3/31/22
Cash Assets	4.1	4.3	8.3
Other	586.5	1312.2	1081.0
Current Assets	590.6	1316.5	1089.3
Accts Payable	243.3	409.9	367.5
Debt Due	708.4	727.8	638.3
Other	497.5	470.6	390.0
Current Liab.	1449.2	1608.3	1395.8
Fix. Chg. Cov.	373%	448%	435%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-6.5%	--	*8.5%*
"Cash Flow"	5.0%	6.0%	*7.5%*
Earnings	2.0%	2.5%	*9.0%*
Dividends	4.5%	6.0%	*5.0%*
Book Value	6.5%	4.5%	*7.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	602.0	803.5	321.3	225.6	1952.4
2020	566.9	715.5	321.1	251.9	1855.4
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	***330***	***258.7***	***2025***
2023	***580***	***950***	***340***	***270***	***2140***

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2019	1.32	3.04	d.09	d.74	3.52
2020	1.24	2.54	d1.87	d.45	1.44
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	***.06***	***d.44***	***3.90***
2023	***1.40***	***3.36***	***.07***	***d.48***	***4.35***

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.5625	.5625	.5625	.5625	2.25
2019	.5925	.5925	.5925	.5925	2.37
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685			

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2021: 3.3 bill. Revenue mix for regulated operations: residential, 58%; commercial and industrial, 28%; transportation, 6%; other, 8%. Has about 3,710 employees. Officers and directors own 3.0% of common shares; BlackRock, 11.5% (1/22 proxy). Chairman: Edward Glotzbach; CEO: Suzanne Sitherwood, Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

It's been a difficult year, thus far, for Spire Inc. (Fiscal 2022 ends on September 30th.) In fact, first-half share net of $4.28 plummeted about 18%, compared to the prior-year tally of $5.20. This stemmed partially from substantially lower profits from the Gas Marketing unit, as fiscal 2021's results enjoyed very favorable market conditions created by extreme weather associated with Winter Storm Uri. Moreover, the Gas Utility division was held back, to a certain extent, by higher operating expenses. So, right now, it seems that full-year share net will plunge more than 20%, to $3.90, relative to fiscal 2021's $4.96 figure. Please be aware that our fiscal 2023 estimate of $4.35 a share is a bit tentative, in part, because of a pending rate case in Missouri. Too, the company is authorized by the Federal Energy Regulatory Commission to operate the key Spire STL Pipeline, temporarily, while it reviews whether permanent approval should be granted. (Leadership expects the process to continue into calendar 2023.)

The Financial Strength rating is B++. When the March period concluded, cash and equivalents resided at $8.3 million. Furthermore, there was $975 million available through a revolving credit facility maturing in October, 2023. Elsewhere, long-term debt was a manageable 53% of total capital, and short-term borrowings were not a major stumbling block. So, Spire ought to be able to meet its various obligations for a while.

We are optimistic about the company's performance out to 2025-2027. The gas utilities boast 1.7 million customers in Mississippi, Alabama, and Missouri, providing a measure of regional diversity. Also, the other businesses, especially pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere should aid Spire, as well. Finally, acquisitions are plausible, supported by the decent balance sheet.

These good-quality shares offer a solid dividend yield. Steady hikes in the payout appear to be in store during the 3- to 5-year period, too. But recent price strength has diminished long-term capital appreciation potential. Meanwhile, the stock is untimely.

Frederick L. Harris, III *May 27, 2022*

(A) Fiscal year ends Sept. 30th. (B) Based on diluted shares outstanding. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late July. (C) Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '21: $1,171.6 mill., $22.66/sh. (E) In millions. (F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	45

REFINITIV STOCK REPORTS PLUS

ATMOS ENERGY CORP (ATO-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT
Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
117.64 (USD)	**1.1M**	**122.96**	**21.9**	**2.72**	**8.6%**	**8.6%**	**1.4%**
2022 May 27 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	16.4B	**85.80**	**20.7**	**2.3%**	**3.8B**	**92.8%**	**7.8%**

VERUS OPINION

Hold

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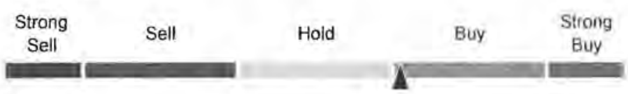
I/B/E/S MEAN

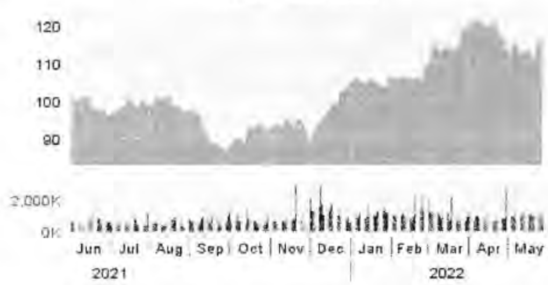
Buy
12 Analysts

Mean recommendation from all analysts covering the company on a standardized 5-point scale.

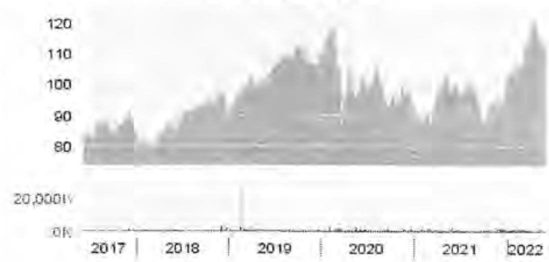


PRICE AND VOLUME CHARTS

1-Year Return: 18.6%



5-Year Return: 42.0%



BUSINESS SUMMARY

Atmos Energy Corporation is a natural-gas-only distributor that delivers natural gas through regulated sales and transportation arrangements to residential, commercial, public authority and industrial customers. The Company also operates intrastate pipelines in Texas based on miles of pipe. The Company operates through two segments: Distribution and Pipeline and Storage. The Distribution segment comprises of regulated natural gas distribution and related sales operations in eight states. The Pipeline and Storage segment consists of the pipeline and storage operations of its Atmos Pipeline-Texas (APT) division and its natural gas transmission operations in Louisiana. APT provides transportation and storage services to its Mid-Tex Division, other third-party local distribution companies, industrial and electric generation customers, marketers and producers. APT owns and operates five underground storage reservoirs in Texas.

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REFINITIV STOCK REPORTS PLUS

CHESAPEAKE UTILITIES CORP (CPK-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT
Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
135.55 (USD)	**63,439**	**146.30**	**28.0**	**2.14**	**11.2%**	**--**	**4.6%**
2022 May 27	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
NEW YORK Exchange	**2.4B**	**113.49**	**26.0**	**1.6%**	**602M**	**75.6%**	**2.7%**

VERUS OPINION

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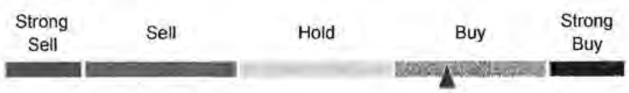
I/B/E/S MEAN

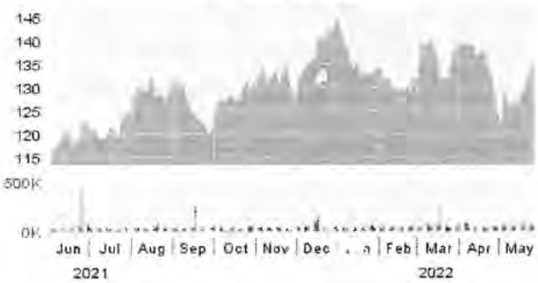
Buy
7 Analysts

Mean recommendation from all analysts covering the company on a standardized 5-point scale.

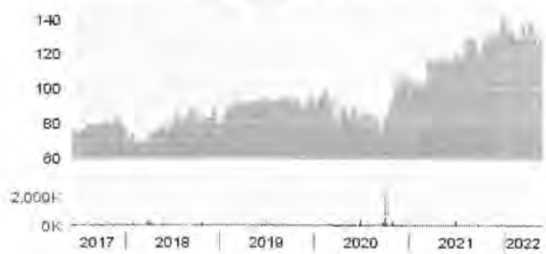


PRICE AND VOLUME CHARTS

1-Year Return: 17.2%



5-Year Return: 82.7%



BUSINESS SUMMARY

Chesapeake Utilities Corporation is an energy delivery company. The Company is engaged in the distribution of natural gas, electricity, and propane; the transmission of natural gas; the generation of electricity and steam; and in providing related services to its customers. The Company's segments include regulated energy and unregulated energy. The Regulated Energy segment includes energy distribution and transmission services, such as natural gas distribution, natural gas transmission, and electric distribution operations. The Unregulated Energy segment includes energy transmission, energy generation, propane operations, mobile compressed natural gas distribution, and pipeline solutions operations. This segment also includes other unregulated energy services, such as energy-related merchandise sales and heating, ventilation, and air conditioning, plumbing, and electrical services. It operates primarily on the Delmarva Peninsula and in Florida, Pennsylvania, and Ohio.

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NEW JERSEY RESOURCES CORP (NJR-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT
Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
46.28 (USD)	**461,633**	**47.50**	**46.8**	**1.45**	**5.2%**	**6.0%**	**5.0%**
2022 May 27 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	4.5B	**34.41**	**18.7**	**3.1%**	**2.5B**	**75.8%**	**6.4%**

VERUS OPINION

Hold

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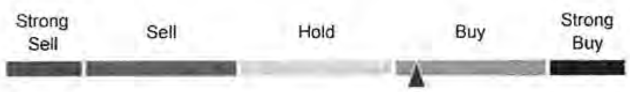
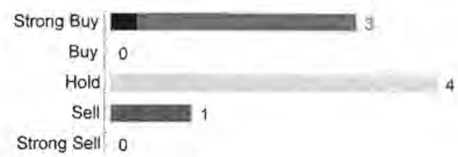
verus analytics

I/B/E/S MEAN

Buy
8 Analysts

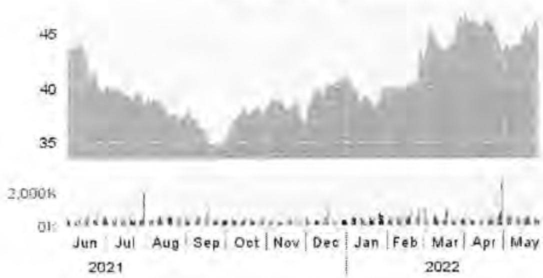
Mean recommendation from all analysts covering the company on a standardized 5-point scale.



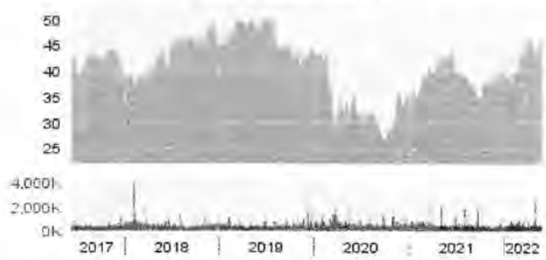


PRICE AND VOLUME CHARTS

1-Year Return: 8.8%



5-Year Return: 10.9%



BUSINESS SUMMARY

New Jersey Resources Corporation is a diversified energy services holding company. The Company's business is the distribution of natural gas through a regulated utility, which provides other retail and wholesale energy services to customers and investing in clean energy projects and midstream assets. The Company's segments include Natural Gas Distribution, Energy Services, Clean Energy Ventures and Storage and Transportation. The Natural Gas Distribution segment consists of regulated natural gas services, off-system sales, capacity and storage management operations. The Energy Services segment consists of unregulated wholesale and retail energy operations, as well as energy management services. The Clean Energy Ventures segment consists of capital investments in clean energy projects. The Storage and Transportation segment consists of investments in the natural gas storage and transportation markets, such as natural gas storage and transportation facilities.

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REFINITIV® STOCK REPORTS PLUS

NISOURCE INC (NI-N)

Utilities / Multiline Utilities / Multiline Utilities

COMPANY IN CONTEXT REPORT

Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
31.76 (USD)	**4.4M**	**32.59**	**20.8**	**0.94**	**13.4%**	**7.2%**	**5.5%**
2022 May 27	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
NEW YORK Exchange	**12.9B**	**23.65**	**20.5**	**3.0%**	**5.2B**	**95.2%**	**9.6%**

VERUS OPINION

Hold

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I/B/E/S MEAN

Buy

14 Analysts

Mean recommendation from all analysts covering the company on a standardized 5-point scale.

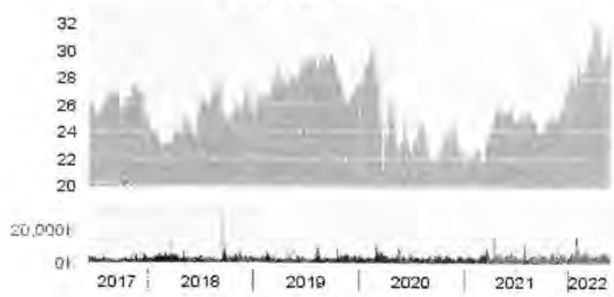
Strong Sell | Sell | Hold | Buy | Strong Buy

Strong Buy	4
Buy	7
Hold	3
Sell	0
Strong Sell	0

PRICE AND VOLUME CHARTS

1-Year Return: 24.5%

5-Year Return: 24.3%



BUSINESS SUMMARY

NiSource Inc. is an energy holding company that operates through Gas Distribution Operations and Electric Operations segments. Gas Distribution operations owns five distribution subsidiaries that provide natural gas to approximately 2.4 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. In addition, the Company distribute natural gas to approximately 853,000 customers in northern Indiana. The Company operates approximately 54,600 miles of distribution main pipeline plus the associated individual customer service lines and approximately 1,000 miles of transmission main pipeline located in its service areas. Electric Operations generates, transmits and distributes electricity to approximately 483,000 customers in 20 counties in the northern part of Indiana and also engaged in wholesale electric and transmission transactions. The Company owns and operates sources of generation as well as source power.

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NORTHWEST NATURAL HOLDING CO (NWN-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT

Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
54.25 (USD)	**280,083**	**5[illegible].63**	**22.4**	**1.93**	**7.8%**	**5.9%**	**10.3%**
2022 May 27 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	1.9B	**43.07**	**19.3**	**3.6%**	**895M**	**74.1%**	**9.2%**

VERUS OPINION

Hold

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verus analytics

I/B/E/S MEAN

Buy

7 Analysts

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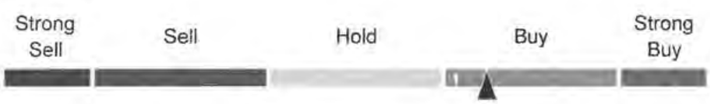
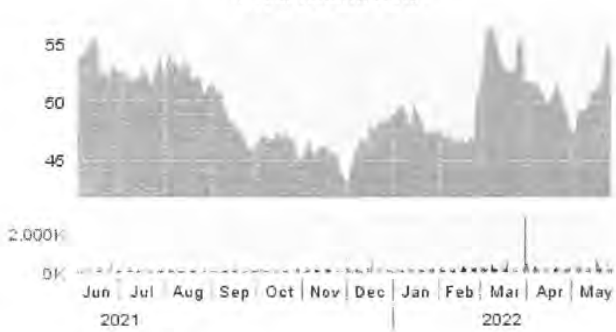
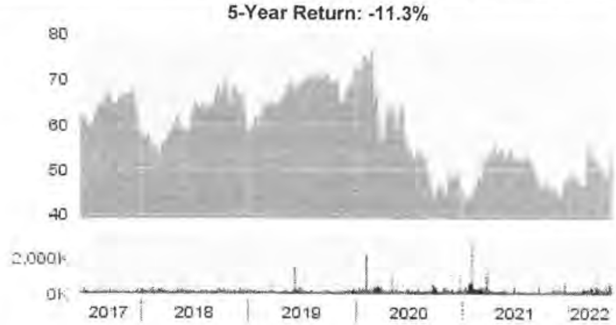


PRICE AND VOLUME CHARTS

1-Year Return: 2.5%



5-Year Return: -11.3%



BUSINESS SUMMARY

Northwest Natural Holding Company is a holding company. The Company operates through its subsidiaries as a provider of natural gas services. Its subsidiary Northwest Natural Gas Company (NW Natural) distributes natural gas to residential, commercial, and industrial customers in Oregon and southwest Washington. The Company operates through the Natural Gas Distribution (NGD) segment. The NGD segment provides natural gas service through over 786,000 meters in Oregon and southwest Washington. The NGD segment serves residential, commercial and industrial customers. Its other business activities include certain gas storage activities, water businesses, and non-regulated renewable natural gas activities. it has a diverse portfolio of short, medium and long-term firm gas supply contracts and a variety of contract types, including firm and interruptible supplies, as well as supplemental supplies from gas storage facilities. Its storage facility is located near Chehalis, Washington.

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REFINITIV STOCK REPORTS PLUS

ONE GAS INC (OGS-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT
Report Date: 2022-May-31

Last Close **88.00** (USD)	Avg Daily Vol **262,850**	52-Week High **92.26**	Trailing PE **22.6**	Annual Div **2.48**	ROE **8.8%**	LTG Forecast **5.0%**	1-Mo Return **0.7%**
2022 May 27 NEW YORK Exchange	Market Cap **4.8B**	52-Week Low **62.52**	Forward PE **20.9**	Dividend Yield **2.8%**	Annual Rev **2.2B**	Inst Own **84.0%**	3-Mo Return **8.4%**

VERUS OPINION

Hold

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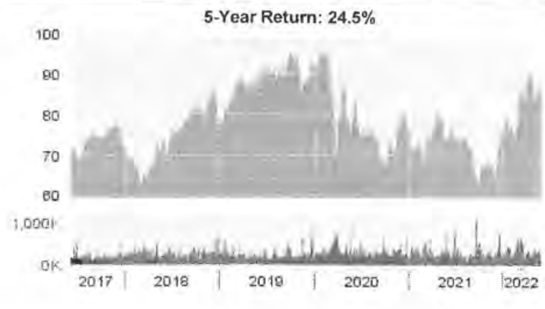
verus analytics

I/B/E/S MEAN

Buy
7 Analysts

Mean recommendation from all analysts covering the company on a standardized 5-point scale.

PRICE AND VOLUME CHARTS



BUSINESS SUMMARY

ONE Gas, Inc. is a regulated natural gas distribution utility in the United States. The Company provides natural gas distribution services through its divisions in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service. The Company serves residential, commercial and transportation customers. The Company's natural gas distribution markets in terms of customers are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita and Topeka, Kansas; and Austin and El Paso, Texas. Its three divisions, Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, distribute natural gas to approximately 88%, 72% and 13% of the natural gas distribution customers in Oklahoma, Kansas and Texas, respectively.

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SOUTH JERSEY INDUSTRIES INC (SJI-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT

Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
34.60 (USD)	**1.2M**	**35.32**	**49.4**	**1.24**	**4.5%**	**--**	**1.3%**
2022 May 27 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	4.2B	**20.75**	**20.4**	**3.6%**	**2.1B**	**89.5%**	**4.5%**

VERUS OPINION

Hold

The Verus Opinion, provided by Verus Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, hold, and sell opinions. To develop a rating, the quantitative system analyzes a company's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the firm's management and directors (i.e. insiders).

The Verus Opinion covers 4546 companies, with 16.7% rated Buy, 62.3% rated Hold, and 21.0% rated Sell as of 2022-05-27. Verus Analytics Inc is a private independent research firm, unaffiliated with Refinitiv, that specializes in engineering institutional ratings systems.

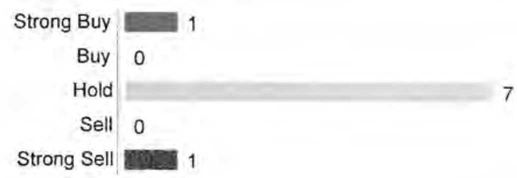
verus analytics

I/B/E/S MEAN

Hold

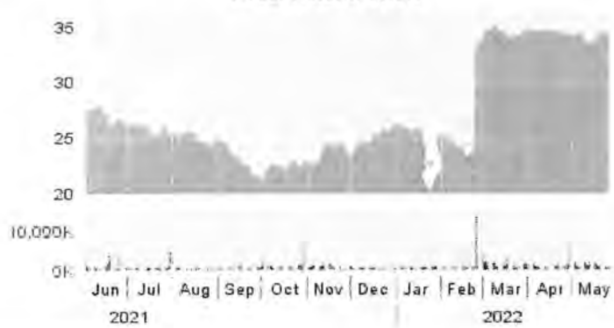
9 Analysts

Mean recommendation from all analysts covering the company on a standardized 5-point scale.

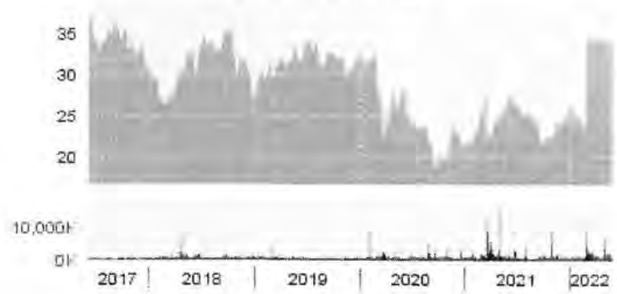


PRICE AND VOLUME CHARTS

1-Year Return: 31.[illegible]%



5-Year Return: -3.8%



BUSINESS SUMMARY

South Jersey Industries, Inc. is an energy services holding company. The Company's segments include South Jersey Gas Company (SJG) utility operations, which consist of natural gas distribution in southern New Jersey; Elizabethtown Gas Company (ETG) utility operations consist of natural gas distribution in northern and central New Jersey; Wholesale energy operations include the activities of South Jersey Resources Group, LLC (SJRG) and South Jersey Exploration, LLC (SJEX); Retail services operations includes the activities of South Jersey Energy Company (SJE), South Jersey Energy Service Plus, LLC (SJESP) and SJI Energy Investments, LLC (SJEI); Renewables consists of the Catamaran joint venture, which owns Annadale Community Clean Energy Projects LLC (Annadale) and Bronx Midco, LLC (Bronx Midco), along with a solar project; Decarbonization consists of SJI Renewables Energy Ventures, LLC and SJI RNG Devco, LLC, and Midstream invests in infrastructure and other midstream projects.

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SOUTHWEST GAS HOLDINGS INC (SWX-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

COMPANY IN CONTEXT REPORT
Report Date: 2022-May-31

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
94.12 (USD)	**655,461**	**95.62**	**31.7**	**2.48**	**5.7%**	**4.0%**	**6.2%**
2022 May 27 NEW YORK Exchange	Market Cap **6.3B**	52 Week Low **6...54**	Forward PE **20.4**	Dividend Yield **2.6%**	Annual Rev **4.1B**	Inst Own **89.0%**	3-Mo Return **36.4%**

VERUS OPINION

Buy

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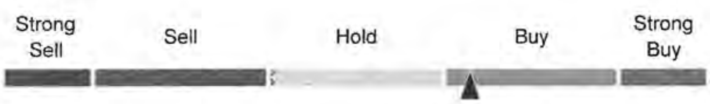
I/B/E/S MEAN

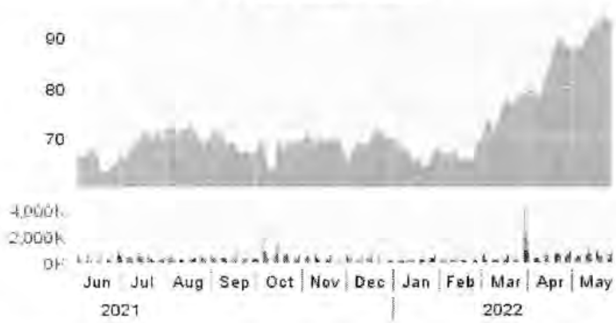
Buy
6 Analysts

Mean recommendation from all analysts covering the company on a standardized 5-point scale.

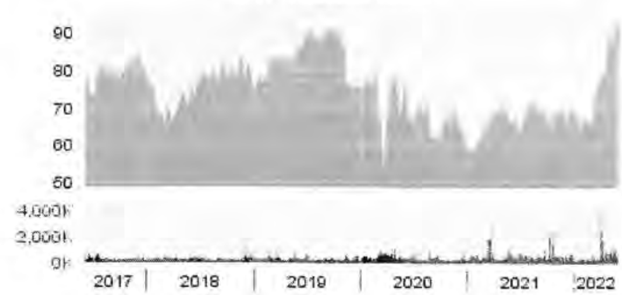


PRICE AND VOLUME CHARTS

1-Year Return: 42.8%



5-Year Return: 18.6%



BUSINESS SUMMARY

Southwest Gas Holdings, Inc. is a holding company. The Company conducts its operations through its subsidiaries, Southwest Gas Corporation (Southwest) and Centuri Group, Inc. (Centuri). The Company operates through two segments: Natural Gas Operations and Utility Infrastructure Services. Southwest provides regulated natural gas delivery services. Southwest is engaged in the business of purchasing, distributing, and transporting natural gas for customers in portions of Arizona, Nevada, and California. Centuri is a utility infrastructure services enterprise that delivers a diverse array of solutions to North America's gas and electric providers. Centuri is also engaged in the installation, replacement, repair, and maintenance of energy distribution systems. The primary focus of Centuri operations is replacement of natural gas distribution pipe and electric service lines, as well as new infrastructure installations.

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COMPANY IN CONTEXT REPORT

Report Date: 2022-May-31

SPIRE INC (SR-N)

Utilities / Natural Gas Utilities / Natural Gas Utilities

Last Close	Avg Daily Vol	52-Week High	Trailing PE	Annual Div	ROE	LTG Forecast	1-Mo Return
78.84 (USD)	**393,156**	**79.24**	**19.5**	**2.74**	**8.8%**	**4.3%**	**5.6%**
2022 May 27 NEW YORK Exchange	Market Cap	52-Week Low	Forward PE	Dividend Yield	Annual Rev	Inst Own	3-Mo Return
	4.1B	**59.60**	**20.2**	**3.5%**	**2.1B**	**88.4%**	**19.1%**

VERUS OPINION

The Verus Opinion, provided by Verus Analytics Inc, is an empirically-derived and historically back-tested stock rating system with buy, hold, and sell opinions. To develop a rating, the quantitative system analyzes a company's earnings quality, balance sheet, and income statement, conducts technical and valuation analysis and evaluates the transactions made by the firm's management and directors (i.e. insiders).

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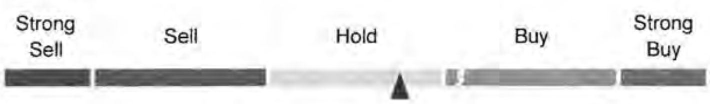
verus analytics

I/B/E/S MEAN

Hold

9 Analysts

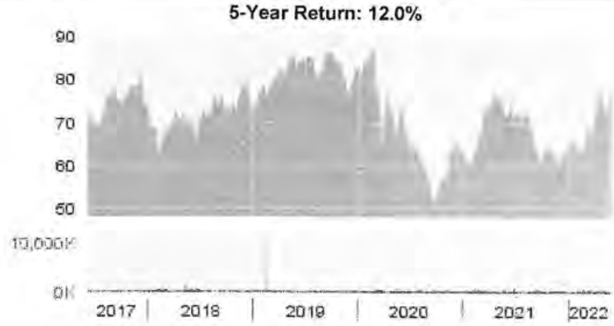
Mean recommendation from all analysts covering the company on a standardized 5-point scale.



PRICE AND VOLUME CHARTS

1-Year Return: 9.9%

5-Year Return: 12.0%



BUSINESS SUMMARY

Spire Inc. is the holding company for Spire Missouri Inc. (Spire Missouri), Spire Alabama Inc. (Spire Alabama), other gas utilities, and gas-related businesses. The Company, through its subsidiaries engaged in the purchase, retail distribution, and sale of natural gas, principally in central and northern, St. Louis, Missouri, and south-central Mississippi. The Company's segments include Gas Utility and Gas Marketing. The Gas Utility segment includes the regulated operations of Spire Missouri, Spire Alabama, Spire Gulf Inc. (Spire Gulf), and Spire Mississippi Inc. The Gas Marketing segment includes Spire Marketing Inc. (Spire Marketing), which is a wholly owned subsidiary providing natural gas marketing services. The Company's natural gas-related businesses include Spire Marketing, Spire STL Pipeline, and Spire Storage.

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Atmos Energy (ATO)
(Real Time Quote from BATS)
$115.29 USD
-1.02 (-0.88%)
Updated Jun 1, 2022 10:22 AM ET

Add to portfolio

Zacks Rank:
3-Hold 3
Style Scores:
D Value | F Growth | B Momentum | F VGM
Industry Rank:
Bottom 37% (159 out of 252)
Industry: Utility - Gas Distribution

View All Zacks #1 Ranked Stocks
Atmos Energy (ATO) Quote Overview » Estimates » Atmos Energy (ATO) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	**8/3/22**	Earnings ESP	**0.00%**
Current Quarter	**0.84**	Current Year	**5.52**
EPS Last Quarter	**2.37**	Next Year	**5.92**
Last EPS Surprise	-0.84%	EPS (TTM)	**5.38**
ABR	**1.81**	P/E (F1)	**21.07**

Growth Estimates	**ATO**	**IND**	**S&P**
Current Qtr (06/2022)	7.69	12.92	17.52
Next Qtr (09/2022)	32.43	-1.41	13.35
Current Year (09/2022)	7.81	5.20	8.93
Next Year (09/2023)	7.25	9.40	14.64
Past 5 Years	8.80	4.60	13.40
Next 5 Years	7.30	6.30	NA
PE	21.07	15.60	18.22
PEG Ratio	2.89	2.48	NA

Learn More About Estimate Research
See Brokerage Recommendations
See Earnings Report Transcript

Premium Research for ATO

Zacks Rank	**Hold 3**
Zacks Industry Rank	Bottom 37% (159 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	**D Value | F Growth | B Momentum | F VGM**
Earnings ESP	0.00%
Research Reports for ATO	Analyst | Snapshot

(= Change in last 30 days)
View All Zacks Rank #1 Strong Buys

More Premium Research » »

Research for ATO

Price and EPS Surprise Chart

1 Month | 3 Months | YTD

Chesapeake Utilities (CPK)
(Real Time Quote from BATS)

$132.73 USD

-0.84 (-0.63%)

Updated Jun 1, 2022 10:23 AM ET

Add to portfolio

Zacks Rank: 3-Hold 3

Style Scores: C Value | A Growth | C Momentum | B VGM

Industry Rank: Bottom 37% (159 out of 252)

Industry: Utility - Gas Distribution

View All Zacks #1 Ranked Stocks

Chesapeake Utilities (CPK) Quote Overview » Estimates » Chesapeake Utilities (CPK) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	8/3/22	Earnings ESP	0.00%
Current Quarter	0.81	Current Year	4.99
EPS Last Quarter	2.08	Next Year	5.46
Last EPS Surprise	0.97%	EPS (TTM)	4.85
ABR	1.00	P/E (F1)	26.77

Growth Estimates	CPK	IND	S&P
Current Qtr (06/2022)	3.85	12.92	17.52
Next Qtr (09/2022)	7.04	-1.41	13.35
Current Year (12/2022)	5.50	5.20	8.93
Next Year (12/2023)	9.42	9.40	14.64
Past 5 Years	10.20	4.60	13.40
Next 5 Years	NA	6.30	NA
PE	26.77	15.60	18.22
PEG Ratio	NA	2.48	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for CPK

Zacks Rank	Hold 3
Zacks Industry Rank	Bottom 37% (159 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	C Value | A Growth | C Momentum | B VGM
Earnings ESP	0.00%
Research Report for CPK	Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

More Premium Research » »

Research for CPK

Price and EPS Surprise Chart

1 Month 3 Months YTD

NewJersey Resources (NJR)
(Real Time Quote from BATS)
$45.43 USD
-0.49 (-1.07%)
Updated Jun 1, 2022 10:23 AM ET

Add to portfolio

Zacks Rank:
3-Hold 3
Style Scores:
B Value | B Growth | C Momentum | B VGM
Industry Rank:
Bottom 37% (159 out of 252)
Industry: Utility - Gas Distribution

View All Zacks #1 Ranked Stocks
NewJersey Resources (NJR) Quote Overview » Estimates » NewJersey Resources (NJR) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	**8/4/22**	Earnings ESP	240.00%
Current Quarter	**0.05**	Current Year	**2.33**
EPS Last Quarter	**1.36**	Next Year	**2.44**
Last EPS Surprise	7.09%	EPS (TTM)	**1.97**
ABR	**2.75**	P/E (F1)	**19.71**

Growth Estimates	**NJR**	**IND**	**S&P**
Current Qtr (06/2022)	133.33	12.92	17.52
Next Qtr (09/2022)	271.43	-1.41	13.35
Current Year (09/2022)	7.87	5.20	8.93
Next Year (09/2023)	4.72	9.40	14.64
Past 5 Years	4.80	4.60	13.40
Next 5 Years	6.00	6.30	NA
PE	19.71	15.60	18.22
PEG Ratio	3.28	2.48	NA

Learn More About Estimate Research
See Brokerage Recommendations
See Earnings Report Transcript

Premium Research for NJR

Zacks Rank	Hold 3
Zacks Industry Rank	Bottom 37% (159 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	B Value | B Growth | C Momentum | B VGM
Earnings ESP	240.00%
Research Report for NJR	Snapshot

(= Change in last 30 days)
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More Premium Research » »

Research for NJR

Price and EPS Surprise Chart

1 Month 3 Months YTD

NiSource (NI)
(Real Time Quote from BATS)

$31.20 USD

-0.25 (-0.80%)

Updated Jun 1, 2022 10:26 AM ET

Add to portfolio

Zacks Rank:
3-Hold 3

Style Scores:
C Value | C Growth | F Momentum | C VGM

Industry Rank:
Bottom 27% (184 out of 252)

Industry: Utility - Electric Power

View All Zacks #1 Ranked Stocks

NiSource (NI) Quote Overview » Estimates » NiSource (NI) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	**8/3/22**	Earnings ESP	**0.00%**
Current Quarter	**0.15**	Current Year	**1.45**
EPS Last Quarter	**0.75**	Next Year	**1.54**
Last EPS Surprise	**-1.32%**	EPS (TTM)	**1.38**
ABR	**1.80**	P/E (F1)	**21.74**

Growth Estimates	**NI**	**IND**	**S&P**
Current Qtr (06/2022)	15.38	-1.70	17.52
Next Qtr (09/2022)	27.27	10.64	13.35
Current Year (12/2022)	5.84	4.80	8.93
Next Year (12/2023)	6.21	5.90	14.64
Past 5 Years	4.90	5.50	13.40
Next 5 Years	7.20	6.80	NA
PE	21.74	13.80	18.22
PEG Ratio	3.02	2.03	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for NI

Zacks Rank	**Hold 3**
Zacks Industry Rank	Bottom 27% (184 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	**C Value | C Growth | F Momentum | C VGM**
Earnings ESP	0.00%
Research Reports for NI	Analyst | Snapshot

(▲ ▼ = Change in last 30 days)

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Research for NI

Price and EPS Surprise Chart

1 Month 3 Months YTD

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Northwest Natural (NWN)
(Real Time Quote from BATS)

$54.12 USD

-0.17 (-0.31%)

Updated Jun 1, 2022 10:26 AM ET

Add to portfolio

Zacks Rank:
4-Sell 4

Style Scores:
B Value | B Growth | C Momentum | B VGM

Industry Rank:
Bottom 37% (159 out of 252)

~~Industry: Utility - Gas Distribution~~

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Northwest Natural (NWN) Quote Overview » Estimates » Northwest Natural (NWN) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	8/4/22	Earnings ESP	-84.62%
Current Quarter	-0.07	Current Year	2.53
EPS Last Quarter	1.80	Next Year	2.69
Last EPS Surprise	-5.26%	EPS (TTM)	2.42
ABR	2.20	P/E (F1)	21.50

Growth Estimates	NWN	IND	S&P
Current Qtr (06/2022)	-250.00	12.92	17.52
Next Qtr (09/2022)	14.93	-1.41	13.35
Current Year (12/2022)	-1.17	5.20	8.93
Next Year (12/2023)	6.32	9.40	14.64
Past 5 Years	2.70	4.60	13.40
Next 5 Years	4.70	6.30	NA

ONE Gas (OGS)
(Real Time Quote from BATS)
$86.05 USD
-0.97 (-1.12%)
Updated Jun 1, 2022 10:23 AM ET

Add to portfolio

Zacks Rank:
3-Hold 3
Style Scores:
D Value | F Growth | D Momentum | F VGM
Industry Rank:
Bottom 37% (159 out of 252)
Industry: Utility - Gas Distribution

View All Zacks #1 Ranked Stocks
ONE Gas (OGS) Quote Overview » Estimates » ONE Gas (OGS) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	**8/1/22**	Earnings ESP	-5.95%
Current Quarter	**0.62**	Current Year	**4.08**
EPS Last Quarter	**1.83**	Next Year	**4.36**
Last EPS Surprise	-6.15%	EPS (TTM)	**3.89**
ABR	**2.00**	P/E (F1)	**21.32**

Growth Estimates	OGS	IND	S&P
Current Qtr (06/2022)	10.71	12.92	17.52
Next Qtr (09/2022)	36.84	-1.41	13.35
Current Year (12/2022)	5.97	5.20	8.93
Next Year (12/2023)	6.86	9.40	14.64
Past 5 Years	8.00	4.60	13.40
Next 5 Years	5.00	6.30	NA
PE	21.32	15.60	18.22
PEG Ratio	4.26	2.48	NA

Learn More About Estimate Research
See Brokerage Recommendations
See Earnings Report Transcript

Premium Research for OGS

Zacks Rank	**Hold** 3
Zacks Industry Rank	Bottom 37% (159 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	**D Value | F Growth | D Momentum | F VGM**
Earnings ESP	-5.95%
Research Reports for OGS	Analyst | Snapshot

(= Change in last 30 days)
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More Premium Research » »

Research for OGS

Price and EPS Surprise Chart

1 Month | 3 Months | YTD

South Jersey Industries (SJI)
(Real Time Quote from BATS)

$34.52 USD

-0.33 (-0.95%)

Updated Jun 1, 2022 10:26 AM ET

Add to portfolio

Zacks Rank:
2-Buy 2

Style Scores:
B Value | **B** Growth | **F** Momentum | **C** VGM

Industry Rank:
Bottom 37% (159 out of 252)

~~Industry: Utility - Gas Distribution~~

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South Jersey Industries (SJI) Quote Overview » Estimates » South Jersey Industries (SJI) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	**8/3/22**	Earnings ESP	100.00%
Current Quarter	**0.00**	Current Year	**1.69**
EPS Last Quarter	**1.08**	Next Year	**1.79**
Last EPS Surprise	**-6.09%**	EPS (TTM)	**1.73**
ABR	**2.71**	P/E (F1)	**20.65**

Growth Estimates	**SJI**	**IND**	**S&P**
Current Qtr (06/2022)	-100.00	12.92	17.52
Next Qtr (09/2022)	11.76	-1.41	13.35
Current Year (12/2022)	4.32	5.20	8.93
Next Year (12/2023)	5.92	9.40	14.64
Past 5 Years	3.90	4.60	13.40
Next 5 Years	NA	6.30	NA
PE	20.65	15.60	18.22
PEG Ratio	NA	2.48	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for SJI

Zacks Rank	**Buy** 2
Zacks Industry Rank	Bottom 37% (159 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	**B** Value | **B** Growth | **F** Momentum | **C** VGM
Earnings ESP	100.00%
Research Report for SJI	Snapshot

(= Change in last 30 days)

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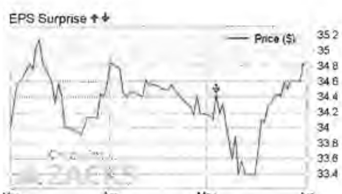
Trades from $1

Research for SJI

Price and EPS Surprise Chart

1 Month 3 Months YTD



Southwest Gas (SWX)
(Real Time Quote from BATS)

$92.52 USD

-0.61 (-0.66%)

Updated Jun 1, 2022 10:28 AM ET

Add to portfolio

Zacks Rank:
3-Hold 3
Style Scores:
C Value | F Growth | C Momentum | D VGM
Industry Rank:
Bottom 37% (159 out of 252)
Industry: Utility - Gas Distribution

View All Zacks #1 Ranked Stocks

Southwest Gas (SWX) Quote Overview » Estimates » Southwest Gas (SWX) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	**8/4/22**	Earnings ESP	**0.00%**
Current Quarter	**0.63**	Current Year	**4.57**
EPS Last Quarter	**1.74**	Next Year	**4.87**
Last EPS Surprise	**-13.86%**	EPS (TTM)	**3.83**
ABR	**2.00**	P/E (F1)	**20.39**

Growth Estimates	**SWX**	**IND**	**S&P**
Current Qtr (06/2022)	46.51	12.92	17.52
Next Qtr (09/2022)	1,040.00	-1.41	13.35
Current Year (12/2022)	9.59	5.20	8.93
Next Year (12/2023)	6.56	9.40	14.64
Past 5 Years	5.20	4.60	13.40
Next 5 Years	5.00	6.30	NA
PE	20.39	15.60	18.22
PEG Ratio	4.08	2.48	NA

Learn More About Estimate Research

See Brokerage Recommendations

See Earnings Report Transcript

Premium Research for SWX

Zacks Rank	**Hold 3**
Zacks Industry Rank	Bottom 37% (159 out of 252)
Zacks Sector Rank	Bottom 19% (13 out of 16)
Style Scores	**C Value | F Growth | C Momentum | D VGM**
Earnings ESP	0.00%
Research Reports for SWX	Analyst | Snapshot

(= Change in last 30 days)

View All Zacks Rank #1 Strong Buys

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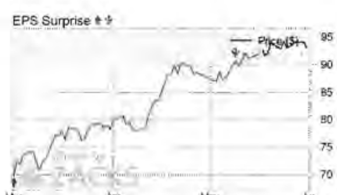
Research for SWX

Price and EPS Surprise Chart

1 Month 3 Months YTD



Spire (SR)
(Real Time Quote from BATS)

$77.31 USD

-0.99 (-1.26%)

Updated Jun 1, 2022 10:26 AM ET

Add to portfolio

Zacks Rank:
3-Hold 3

Style Scores:
B Value | D Growth | D Momentum | C VGM

Industry Rank:
Bottom 37% (159 out of 252)

Industry: Utility - Gas Distribution

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Spire (SR) Quote Overview » Estimates » Spire (SR) Detailed Earnings Estimates

Detailed Estimates

Enter Symbol

Estimates

Exp Earnings Date	8/4/22	Earnings ESP	-142.86%
Current Quarter	0.02	Current Year	3.93
EPS Last Quarter	3.42	Next Year	4.39
Last EPS Surprise	11.04%	EPS (TTM)	4.30
ABR	2.75	P/E (F1)	19.91

Growth Estimates	SR	IND	S&P
Current Qtr (06/2022)	-66.67	12.92	17.52
Next Qtr (09/2022)	-68.75	-1.41	13.35
Current Year (09/2022)	-19.14	5.20	8.93
Next Year (09/2023)	11.70	9.40	14.64
Past 5 Years	7.40	4.60	13.40
Next 5 Years	5.00	6.30	NA
PE	19.91	15.60	18.22

Atmos Energy Corp.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULA IDENTIF
Local Currency LT	A- Regulatory Disclosures	22-Feb-2021	15-Feb-2022	EE|UKE
Local Currency ST	A-2 Regulatory Disclosures	22-Feb-2021	15-Feb-2022	EE|UKE
Foreign Currency LT	A- Regulatory Disclosure	22-Feb-2021	15-Feb-2022	EE|UKE
Foreign Currency ST	A-2 Regulatory Disclosures	22-Feb-2021	15-Feb-2022	EE|UKE

RESEARCH AND INSIGHTS ENTITY

Found 0 results for "chesapeake utilities"

RESEARCH AND INSIGHTS   ENTITY

Found 0 results for "new jersey resources"

RESEARCH AND INSIGHTS ENTITY

Found 0 results for "new jersey natural gas"

NiSource Inc.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULA IDENTIF
Local Currency LT	BBB+ Regulatory Disclosures	18-Jun-2015	17-Feb-2022	EE|UKE
Local Currency ST	A-2 Regulatory Disclosures	18-Jun-2015	17-Feb-2022	EE|UKE
Foreign Currency LT	BBB+ Regulatory Disclosures	18-Jun-2015	17-Feb-2022	EE|UKE
Foreign Currency ST	A-2 Regulatory Disclosures	18-Jun-2015	17-Feb-2022	EE|UKE

Northwest Natural Gas Co.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULA IDENTIF
Local Currency LT	A+ Regulatory Disclosures	25-Jan-2010	26-May-2022	EE|UKE
Local Currency ST	A-1 Regulatory Disclosures	25-Jan-2010	26-May-2022	EE|UKE
Foreign Currency LT	A+ Regulatory Disclosures	25-Jan-2010	26-May-2022	EE|UKE
Foreign Currency ST	A-1 Regulatory Disclosures	25-Jan-2010	26-May-2022	EE|UKE

South Jersey Industries Inc.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULA IDENTIF
Local Currency LT	**BBB** Regulatory Disclosures	02-Jul-2018	25-Feb-2022	EE|UKE
Foreign Currency LT	**BBB** Regulatory Disclosures	02-Jul-2018	25-Feb-2022	EE|UKE

VIEW RATINGS DEFINITIONS DEBT TYPES ∨ TIMEZONE: EDT

Related Credit News and Research

Southwest Gas Holdings Inc.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGUL/ IDENTIF
Local Currency LT	BBB- Regulatory Disclosures	27-Aug-2021	26-Apr-2022	EE|UKE
Foreign Currency LT	BBB- Regulatory Disclosures	27-Aug-2021	26-Apr-2022	EE|UKE

VIEW RATINGS DEFINITIONS

TIMEZONE: EDT

Related Credit News and Research

Spire Inc.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULA IDENTIF
Local Currency LT	A- Regulatory Disclosures	19-Jul-2013	24-Jun-2021	EE|UKE
Local Currency ST	A-2 Regulatory Disclosures	22-Dec-2016	24-Jun-2021	EE|UKE
Foreign Currency LT	A- Regulatory Disclosures	19-Jul-2013	24-Jun-2021	EE|UKE
Foreign Currency ST	A-2 Regulatory Disclosures	22-Dec-2016	24-Jun-2021	EE|UKE

Atmos Energy Corporation

CONTACT ANALYST
EDNA MARINELARENA

SUMMARY
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METHODOLOGIES & FRAMEWORKS

TOOLS:
PEER COMPARISON
SCORECARD

REFERENCE:
SECTOR
RATINGS DEFINITIONS
TEAR SHEET

Reports

FILTER BY Rating Action, Announcement +2 | Region | Series | SYNOPSIS
Topics / Credit Foundations | Date Range

DATE	TYPE	TITLE | 33 DOCUMENTS
10 Mar 2022	Credit Opinion	**Atmos Energy Corporation: Update following rating affirmation** MOODY'S INVESTORS SERVICE
22 Feb 2022	Rating Action	**Moody's revises Atmos' outlook to stable; affirms ratings** MOODY'S INVESTORS SERVICE
16 Sep 2021	Announcement of Periodic Review	**Moody's announces completion of a periodic review of ratings of Atmos Energy Corporation** MOODY'S INVESTORS SERVICE
02 Mar 2021	Credit Opinion	**Atmos Energy Corporation: Update following change in outlook to negative** MOODY'S INVESTORS SERVICE
25 Feb 2021	Rating Action	**Moody's changes outlook of Atmos to negative** MOODY'S INVESTORS SERVICE
11 Dec 2020	Credit Opinion	**Atmos Energy Corporation: Update to credit analysis** MOODY'S INVESTORS SERVICE
16 Oct 2020	Announcement of Periodic Review	**Moody's announces completion of a periodic review of ratings of Atmos Energy Corporation** MOODY'S INVESTORS SERVICE
18 Dec 2019	Credit Opinion	**Atmos Energy Corporation: Update to credit analysis following upgrade to A1** MOODY'S INVESTORS SERVICE
16 Dec 2019	Rating Action	**Moody's upgrades Atmos Energy Corporation's rating to A1, outlook changed to stable.** MOODY'S INVESTORS SERVICE
05 Nov 2019	Announcement of Periodic Review	**Moody's announces completion of a periodic review of ratings of Atmos Energy Corporation** MOODY'S INVESTORS SERVICE
18 Dec 2018	Credit Opinion	**Atmos Energy Corporation: Update to credit analysis following positive outlook** MOODY'S INVESTORS SERVICE
14 Dec 2018	Rating Action	**Moody's affirms Atmos Energy rating at A2, outlook changed to positive** MOODY'S INVESTORS SERVICE
14 Dec 2017	Credit Opinion	**Atmos Energy Corporation: Update to Credit Analysis** MOODY'S INVESTORS SERVICE
14 Dec 2016	Credit Opinion	**Atmos Energy Corporation: Regulated local gas distribution company** MOODY'S INVESTORS SERVICE
17 Dec 2015	Credit Opinion	**Atmos Energy Corporation** MOODY'S INVESTORS SERVICE
30 Jan 2014	Rating Action	**Moody's upgrades Atmos Energy; Outlook stable** MOODY'S INVESTORS SERVICE
08 Nov 2013	Rating Action	**Moody's places ratings of most US regulated utilities on review for upgrade** MOODY'S INVESTORS SERVICE

RATINGS VIEW ALL

LONG TERM RATING
A1
Senior Unsecured - Dom Curr
22 FEB 2022
Not on Watch

SHORT TERM RATING
P-1
Commercial Paper - Dom Curr
22 FEB 2022
Not on Watch

OUTLOOK
Stable
22 FEB 2022

OTHER DEBTS ON WATCH?
No

Source: Moody's Investors Service

ESG Scores

from Moody's Investors Service

ESG CREDIT IMPACT SCORE (CIS)
CIS-3
Moderately Negative
06 DEC 2021

ESG ISSUER PROFILE SCORES (IPS)
06 DEC 2021

ENVIRONMENTAL	SOCIAL	GOVERNANCE
E-3	S-3	G-2
Moderately Negative	Moderately Negative	Neutral-to-Low

Methodology

Source: Moody's Investors Service

Ticker
ATO

LEI
QVLWEGTD2S8GJMO8D383

Moody's Org Id
600020375

Market Segment
Infrastructure & Project Finance

Industry
ENERGY: GAS - DISTRIBUTION

Peer Group
Regulated Electric and Gas Utilities

Domicile
UNITED STATES

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chesapeake utilities

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4568 Results NEED HELP?

Oil & Gas - North America: E&P capital spending xpands in 2022, but production will grow only modestly

06 JUN 2022 | SECTOR IN-DEPTH | MOODY'S INVESTORS SERVICE

North American oil and gas producers are poised to boost their capital spending significantly in 2022, but rampant production growth amid higher prices is still unlikely through 2023.

Ports America Chesapeake, LLC: Update to credit analysis following upgrade

02 JUN 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of this issuer reflects its status as a container terminal monopoly at Port of Baltimore, constrained by its demand risk profile.

Moody's announces completion of a periodic review for a group of Ports issuers

20 MAY 2022 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE

New York, May 20, 2022 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings -and other ratings that are associated with the same analytical units for the rated entity(entities) listed below. The review

Queen Anne's (County of) MD: Update to credit analysis

18 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of Queen Anne's County MD reflecting a diverse, growing tax base with strong resident income indices, improved financial p

Time to Worry About the Consumer? (Capital Market Research) (Weekly Market Outlook)

02 JUN 2022 | MARKET OUTLOOK |

This Weekly Market Outlook titled, "Time to Worry Abot t the Consumer?," has credit market commentary and analysis from Ryan Sweet a

US Public Finance: US municipal bond defaults and recoveries, 1970-2021

21 APR 2022 | DEFAULT REPORT | MOODY'S INVESTORS SERVICE

This study updates our findings concerning the default, loss and rating transition experience of US municipal bond issuers from 1970 to 2021.

Baltimore (City of) MD Sewer Enterprise: Update following assignment of negative outlook

01 MAR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of Baltimore sewer reflecting a sizeable system with adequate debt service coverage, sound liquidity supported by annual rate increases, and an elevated growing debt burden

Maryland Water Quality Financing Administration: Update to credit analysis after downgrade

31 JAN 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of this issuer reflects a the strengths of a statewide fee tied to water consumption, short maturity of 15 years, and vulnera

CSX Corporation: Key facts and statistics - F 'E 2021

24 MAR 2022 | ISSUER PROFILE | MOODY'S INVESTORS SERVICE

A summary company profile, detailing CSX Corporation's business operations and financial highlights.

Moody's upgrades Chesapeake (City of) VA Water and Sewer Enterprise's revenue bonds to Aa1; outlook stable

09 APR 2020 | RATING ACTION | MOODY'S INVESTORS SERVICE

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new jersey resources

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7301 Results

Local government - New Jersey: Shared services agreements save local governments money and resources

11 DEC 2019 | SECTOR IN-DEPTH | MOODY'S INVESTORS SERVICE

New Jersey local governments will continue to curb expense growth and save money through shared services agreements in an environment of rising costs and declining appetite for tax hikes.

Moody's takes various actions in conjunction with publication of updated methodology for US states and territories

22 MAR 2022 | RATING ACTION | MOODY'S INVESTORS SERVICE

> NOTE: On March 29, 2022, the press release was corrected as follows: In the List of Affected Ratings accessible via hyperlink from this press release, the sale descriptions were changed for Sale IDs 907605859, 907605990, 9076C

New Jersey Natural Gas Company: Natural gas LDC of New Jersey Resources

04 OCT 2016 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

NJNG's Aa2 senior secured rating applies to its first mortgage bonds. The rating is supported by the LDC's low business risk profile and constructive relationship with its regulators.

Local Government - US: Government enterprises offer resources for grappling with pension challenges

01 JUN 2022 | SECTOR COMMENT | MOODY'S INVESTORS SERVICE

Despite accounting and operational separation, governments have numerous mechanisms through which they can harness the **resources** of their enterprises to help address pension challenges.

Moody's announces completion of a periodic review of ratings of New Jersey Natural Gas Company

30 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE

New York, September 30, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **New Jersey** Natural Gas Company and other ratings that are associated with the same analytical unit. The rev

Popular, Inc.: Update to credit analysis following initiation of review for upgrade

27 MAY 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of Popular, reflecting its high capitalization and strong liquidity, offset by its sectoral and geographic lending concentrations.

UBS Group AG: Update following annual results

31 MAY 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of the issuer reflects its superior business mix generating a high proportion of predictable and stable earnings, its solid liquidity.

US Public Finance Credit Outlook: June 1, 2022

01 JUN 2022 | COMPILATION | *US Public Finance Credit Outlook* | MOODY'S INVESTORS SERVICE

This edition highlights how governments are leveraging enterprises to ease pension challenges, and medians data for cities and counties, school districts, and water and sewer utilities.

Princeton University, NJ: Update to credit analysis

04 MAY 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of this issuer reflects high wealth, strong operating performance and an exceptional reputation offset by high reliance on enc new jersey natural gas

All Organizations Reports

3320 Results

New Jersey Natural Gas Company
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | NJR
Headquartered in Wall, **New Jersey**, **New Jersey Natural Gas** Company (NJNG) provides **natural gas** and related services to approximately 561,500 residential and commercial customers. Its service territory is comprised of 105 n

Natural Gas Pipelines - New Jersey
SECTOR & REGION
Find the latest ratings, research, and analytics on **Na**

Moody's announces completion of a periodic review of ratings of New Jersey Natural Gas Company
30 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, September 30, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **New Jersey Natural Gas** Company and other ratings that are associated with the same analytical unit. The rev

New Jersey Natural Gas Company: Update to credit analysis
11 MAY 2021 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of NJNG reflects low business risk and supportive regulation, offset by high debt levels.

Moody's announces completion of a periodic review of ratings of New Jersey Natural Gas Company
16 OCT 2020 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, October 16, 2020 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **New Jersey Natural Gas** Company and other ratings that are associated with the same analytical unit. The rev

New Jersey Natural Gas Company: Update following downgrade
20 MAR 2020 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **New Jersey Natural Gas** Company reflects its declining credit measures, low business risk profile as a **natural gas** utility and credit supportive regulatory rate construct.

Moody's downgrades New Jersey Natural Gas' senior secured rating to A1, outlook is stable.
18 MAR 2020 | RATING ACTION | MOODY'S INVESTORS SERVICE
Approximately $133 million of debt securities affected **New** York, March 18, 2020 -- Moody's Investors Service, ("Moody's") today downgraded the senior secured **New Jersey** Economic Development Authority revenue bond rating of **New**

Moody's announces completion of a periodic review of ratings of New Jersey Natural Gas Company
07 NOV 2019 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, November 07, 2019 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **New Jersey Natural Gas** Company and other ratings that are associated with the same analytical unit. The rev

New Jersey Economic Development Authority, Natural Gas Facilities Revenue Bonds, 1998C, (New Jersey Natural Gas Company Project), $18MM
Find the latest ratings, research, and analytics on **New Jersey** Economic Development Authority, **Natural Gas** Facilities Revenue Bonds, 1998C, (**New Jersey Natural Gas** Company Project), $18MM.

New Jersey Economic Development Authority, Natural Gas Fac. Ref. Revenue Bonds, 1997A, (New Jersey Natural Gas Company Project), $13.5MM
Find the latest ratings, research, and analytics on **New Jersey** Economic Development Authority, **Natural Gas** Fac. Ref. Revenue Bonds, 1997A, (**New Jersey Natural Gas** Company Project), $13.5MM.

New Jersey Natural Gas Company
INFRASTRUCTURE & PROJECT FINANCE

MIS RATING SUMMARY

LONG TERM RATING	SHORT TERM RATING
A1 18 MAR 2020 Not on Watch	P-2 18 MAR 2020 Not on Watch
OUTLOOK Stable 18 MAR 2020	OTHER DEBTS ON WATCH? No

Ticker: NJR
Domicile: UNITED STATES
Industry: ENERGY: GAS - DISTRIBUTION

nisource

All Organizations Reports

364 Results

NiSource Inc.
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | NI
NiSource Inc. is a utility holding company with a portfolio of fully regulated utility subsidiaries totaling about $13.6 billion in rate base. **NiSource** owns one of the largest LDC systems in the US, with operations in Ohio, Indiana, I

NiSource Inc.: Update to credit analysis
27 JUL 2021 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **NiSource** reflects the credit supportiveness and diversity of its regulated utility operations, offset by a highly levered financial

Moody's announces completion of a periodic review of ratings of NiSource Inc.
20 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, September 20, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **NiSource** Inc. and other ratings that are associated with the same analytical unit. The review was conducted thro

NiSource Finance Corporation
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | NI
Find the latest ratings, research, and analytics on **Ni**

NiSource Capital Trust I
CORPORATES | UNITED STATES
Find the latest ratings, research, and analytics on **Ni**

NiSource Capital Markets, Inc.
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | NI
Find the latest ratings, research, and analytics on **Ni**

NiSource Inc.: Equity units issuance helps maintain credit quality but with little financial flexibility over the near-term
28 APR 2021 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE
NiSource's new equity units, which will receive Basket E (100% equity) treatment by Moody's will help the company to maintain appropriate y financial metrics but with little flexibility.

NiSource Inc.: Update to credit analysis
29 JUL 2020 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **NiSource** reflects the credit supportiveness and diversity of its regulated utility operations, offset by a highly levered profile.

Moody's announces completion of a periodic review of ratings of NiSource Inc.
07 OCT 2020 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, October 07, 2020 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **NiSource** Inc. and other ratings that are associated with the same analytical unit. The review was conducted thro

NiSource Inc.: Update to credit analysis
11 JUL 2019 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **NiSource** reflects the credit supportiveness and diversity of its regulated utility operations, offset by weak financial ratios and

NiSource Inc.: Sale of Bay State Gas removes Massachusetts regulatory risk overhang
27 FEB 2020 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE
NiSource's planned sale of Bay State Gas Company removes Massachusetts regulatory and operational risks and has limited impact on credit m

NiSource Inc.
INFRASTRUCTURE & PROJECT FINANCE

MIS RATING SUMMARY

LONG TERM RATING	SHORT TERM RATING
Baa2 28 FEB 2018 Not on Watch	P-2 28 FEB 2018 Not on Watch
OUTLOOK	OTHER DEBTS ON WATCH?
Stable 28 FEB 2018	No

Ticker: NI
Domicile: UNITED STATES
Industry: UTILITY: REG - ELECTR - INTEGRATED - HOLDCO

northwest natural gas

All Organizations Reports

4138 Results

Northwest Natural Gas Company
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | NWN
Northwest Natural Gas Company (NW **Natural**) is a **natural gas** local distribution company (LDC), serving over 770,000 customers in Oregon (about 90% of utility margins) and Washington (about 10% of utility margins). NW

Moody's announces completion of a periodic review of ratings of Northwest Natural Gas Company
15 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, September 15, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **Northwest Natural Gas** Company and other ratings that are associated with the same analytical unit. The rev

Northwest Natural Gas Company: Update to credit analysis
01 JUN 2021 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of this issuer reflects its status as a low business risk local **gas** distribution company, constrained by its financial metrics.

Northwest Natural Gas Finance NV
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES
Find the latest ratings, research, and analytics on **No**

Moody's announces completion of a periodic review of ratings of Northwest Natural Gas Company
08 OCT 2020 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, October 08, 2020 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **Northwest Natural Gas** ompany and other ratings that are associated with the same analytical unit. The rev

Northwest Natural Gas Company: Update to credit analysis
29 MAY 2020 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
NW **Natural**'s credit profile reflects low business risk LDC operations, supported by constructive regulatory decisions that provide clarity

Moody's announces completion of a periodic review of ratings of Northwest Natural Gas Company
08 NOV 2019 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, November 08, 2019 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **Northwest Natural Gas** Company and other ratings that are associated with the same analytical unit. The rev

Northwest Natural Gas Company: Update following downgrade to Baa1
24 MAY 2019 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
NW **Natural**'s credit profile reflects low business risk LDC operations, supported by constructive regulatory decisions that provide clarity

Northwest Natural Gas Company: Update to credit opinion
10 JAN 2019 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
NW Natrual's credit reflects its low business risk operations, regulatory support and weak financial metrics.

Moody's downgrades Northwest Natural Gas to (P)Baa1; rating outlook changed to stable from negative
17 MAY 2019 | RATING ACTION | MOODY'S INVESTORS SERVICE
Approximately $1.0 billion of debt affected New York, Ma 17, 2019 -- Moody's Investors Service ("Moody's") has today downgraded the ratings c **Northwest Natural Gas** Company (NW **Natural**) by one notch to (P)Baa1 senior unsecu

Northwest Natural Gas Company: Update following negative outlook

Northwest Natural Gas Company

INFRASTRUCTURE & PROJECT FINANCE

MIS RATING SUMMARY

LONG TERM RATING	SHORT TERM RATING
(P)Baa1 17 MAY 2019 Not on Watch	P-2 17 MAY 2019 Not on Watch
OUTLOOK	OTHER DEBTS ON WATCH?
Stable 17 MAY 2019	No

Ticker: NWN
Domicile: UNITED STATES
Industry: ENERGY: GAS - DISTRIBUTION

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ONE Gas, Inc

CONTACT ANALYST
NANA HAMILTON

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MARKET SIGNALS
METHODOLOGIES & FRAMEWORKS

TOOLS:
PEER COMPARISON
SCORECARD

REFERENCE:
SECTOR
RATINGS DEFINITIONS
TEAR SHEET

Reports

FILTERED BY Rating Action, Credit Opinion Region Series SYNOPSIS
Topics / Credit Foundations Date Range

DATE	TYPE	TITLE | 19 DOCUMENTS
22 Feb 2022	Credit Opinion	ONE Gas, Inc: Update following rating affirmation MOODY'S INVESTORS SERVICE
15 Feb 2022	Rating Action	Moody's revises ONE Gas outlook to stable, affirms ratings MOODY'S INVESTORS SERVICE
20 Sep 2021	Announcement of Periodic Review	Moody's announces completion of a periodic review of ratings of ONE Gas, Inc MOODY'S INVESTORS SERVICE
25 Feb 2021	Credit Opinion	ONE Gas, Inc: Update following downgrade to A3, negative outlook MOODY'S INVESTORS SERVICE
23 Feb 2021	Rating Action	Moody's downgrades ONE Gas to A3 from A2; outlook negative MOODY'S INVESTORS SERVICE
06 Jan 2021	Credit Opinion	ONE Gas, Inc: Update to credit analysis MOODY'S INVESTORS SERVICE
07 Oct 2020	Announcement of Periodic Review	Moody's announces completion of a periodic review of ratings of ONE Gas, Inc MOODY'S INVESTORS SERVICE
14 Jan 2020	Credit Opinion	ONE Gas, Inc: Update to credit analysis MOODY'S INVESTORS SERVICE
05 Nov 2019	Announcement of Periodic Review	Moody's announces completion of a periodic review of ratings of ONE Gas, Inc MOODY'S INVESTORS SERVICE
29 Jan 2019	Credit Opinion	ONE Gas, Inc: Update following outlook change to stable MOODY'S INVESTORS SERVICE
28 Jan 2019	Rating Action	Moody's affirms ONE Gas at A2, revises outlook to stable from negative MOODY'S INVESTORS SERVICE
31 Jan 2018	Credit Opinion	ONE Gas, Inc: Update following outlook change to negative MOODY'S INVESTORS SERVICE
19 Jan 2018	Rating Action	Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform MOODY'S INVESTORS SERVICE
08 Jan 2018	Credit Opinion	ONE Gas, Inc: Update to credit analysis MOODY'S INVESTORS SERVICE
09 Jan 2017	Credit Opinion	ONE Gas, Inc: Regulated Natural Gas Local Distribution Holding Company MOODY'S INVESTORS SERVICE
14 Jan 2016	Credit Opinion	ONE Gas, Inc: A Regulated Local Distribution Utility Holding Company MOODY'S INVESTORS SERVICE
13 Jan 2015	Credit Opinion	ONE Gas, Inc MOODY'S INVESTORS SERVICE

RATINGS VIEW ALL

LONG TERM RATING
A3
Senior Unsecured - Dom Curr
15 FEB 2022
Not on Watch

SHORT TERM RATING
P-2
Commercial Paper - Dom Curr
15 FEB 2022
Not on Watch

OUTLOOK
Stable
15 FEB 2022

OTHER DEBTS ON WATCH?
No

Source: Moody's Investors Service

ESG Scores

from Moody's Investors Service

ESG CREDIT IMPACT SCORE (CIS)
CIS-3
Moderately Negative
06 DEC 2021

ESG ISSUER PROFILE SCORES (IPS)
06 DEC 2021

ENVIRONMENTAL	SOCIAL	GOVERNANCE
E-3	S-3	G-2
Moderately Negative	Moderately Negative	Neutral-to-Low

Methodology

Source: Moody's Investors Service

LEI
549300HXDWI0LATTX840

Moody's Org Id
823501127

Market Segment
Infrastructure & Project Finance

Industry
ENERGY: GAS - DISTRIBUTION

Peer Group
Regulated Electric and Gas Utilities

Domicile
UNITED STATES

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South Jersey Gas Company: Announced acquisition by Infrastructure Investments Fund has no immediate credit impact

25 FEB 2022 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE

The sale of **South Jersey Industries** to Infrastructure Investments Fund has no immediate impact on **South Jersey** Gas' credit profile.

Moody's announces completion of a periodic re\ ·w of ratings of South Jersey Gas Company

29 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE

New York, September 29, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **South Jersey** Gas Company and other ratings that are associated with the same analytical unit. The review

South Jersey Gas Company: Update to credit ana.ysis

14 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of SJG reflects its low business risk profile as a natural gas utility and credit supportive regulatory rate construct.

CD&R Firefly 4 Limited: Update to credit opinion

30 MAY 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of this issuer reflects its exposure to the inherently low profit margin associated with fuel retail operations.

Moody's affirms South Jersey Gas at A3; revises outlook to stable from negative

01 FEB 2021 | RATING ACTION | MOODY'S INVESTORS SERVICE

Approximately $50 million of debt securities affected New York, February 01, 2021 -- Moody's Investors Service, ("Moody's") affirmed **South Jersey** Gas Company's (SJG) ratings including its A3 Issuer rating, A1 senior secur

Township of Mantua, NJ: Annual Comment on Mantua Township

26 APR 2022 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE

Mantua Township's credit position is high quality. Its Aa3 rating is level with the US cities median of Aa3.

Verizon Communications Inc.: Key facts and statistics - 2021

06 MAY 2022 | ISSUER PROFILE | MOODY'S INVESTORS SERVICE

A summary company profile, detailing Verizon Communications Inc.'s business operations and financial highlights.

Selective Insurance Group, Inc.: Strong regional fı anchise supports profitable commercial lines business

12 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of this issuer reflects its strong regional franchise and profitability offset by geographic concentration.

NVR Inc.: Update to Credit Analysis

28 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of NVR reflects the resiliency of its business model, against a track record of significant share repurchasing activity

Chemours Company, (The): Update to credit analysis

28 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE

Our credit view of this issuer reflects its competitive asset base in TiO2 and its strong TiO2 margins vs peer group, offset by its highly cyclical

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South Jersey Gas Company: Update to credit analysis
14 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of SJG reflects its low business risk profile as a natural **gas** utility and credit supportive regulatory rate **construct**.

South Jersey Gas Company
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | SJI
South Jersey Gas Company is a regulated natural **gas** local distribution **co**mpany (LDC) serving approximately 411,300 customers in117 mu..icipalities in **south**ern New **Jersey**. Approximately 93% of these customers are residenti

South Jersey Gas Company: Announced acquisition by Infrastructure Investments Fund has no immediate credit impact
25 FEB 2022 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE
The sale of **South Jersey** Industries to Infrastructure Invstments Fund has no immediate impact on **South Jersey Gas**' credit profile.

Moody's announces completion of a periodic review of ratings of South Jersey Gas Company
29 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, September 29, 2021 -- Moody's Investors Service ("Moody's") has **co**mpleted a periodic review of the ratings of **South Jersey Gas Co**mpany and other ratings that are associated with the same analytical unit. The review

South Jersey Gas Company: Update to credit analysis
04 FEB 2021 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **South Jersey Gas** reflects low business risk and supportive regulation, offset by high environmental remediation **co**sts and

Moody's announces completion of a periodic review of ratings of South Jersey Gas Company
07 OCT 2020 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, October 07, 2020 -- Moody's Investors Service ("Moody's") has **co**mpleted a periodic review of the ratings of **South Jersey Gas Co**mpany and other ratings that are associated with the same analytical unit. The review

South Jersey Gas Company: Update to credit analysis
16 JUL 2020 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
South Jersey Gas' credit profile **co**nsiders its low risk LDC operations and weak credit metrics.

New Jersey Economic Development Authority, Natural Gas Facilities Revenue Bonds (South Jersey Gas Company Project), Series 20
Find the latest ratings, research, and analytics on New Je..ey Economic Development Authority, Natural **Gas** Facilities Revenue Bonds (**South** ..ersey **Gas Co**mpany Project), Series 20.

Moody's affirms South Jersey Gas at A3; revises outlook to stable from negative
01 FEB 2021 | RATING ACTION | MOODY'S INVESTORS SERVICE
Approximately $50 million of debt securities affected New York, February 01, 2021 -- Moody's Investors Service, ("Moody's") affirmed **South ..ersey Gas Co**mpany's (SJG) ratings including its A3 Issuer rating, A1 senior secur

Moody's announces completion of a periodic review of ratings of South Jersey Gas Company
05 NOV 2019 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, November 05, 2019 -- Moody's Investors Service ("Moody's") has **co**mpleted a periodic review of the ratings of **South Jersey Gas Co**mpany and other ratings that are associated with the same analytical unit. The review

South Jersey Gas Company
INFRASTRUCTURE & PROJECT FINANCE

MIS RATING SUMMARY

LONG TERM RATING	SHORT TERM RATING
A3 01 FEB 2021 Not on Watch	P-2 01 FEB 2021 Not on Watch
OUTLOOK Stable 01 FEB 2021	OTHER DEBTS ON WATCH? No

Ticker: SJI
Domicile: UNITED STATES
Industry: ENERGY: GAS - DISTRIBUTION

southwest gas

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Southwest Gas Corporation: Update to credit analysis
11 MAR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of this issuer reflects its low-risk LDC op ations with stable cash flow, balanced against sustained high capital expenditures an some degree of regulatory lag in Arizona.

Southwest Gas Corporation
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | SWX
Southwest Gas Corporation is a natural **gas** local distribution company (LDC) subsidiary of **Southwest Gas** Holdings, Inc., serving over two million c stomers in central and southern Arizona, northern and southern Nevada (including th

Southwest Gas Holdings, Inc.: Update to credit analysis
11 MAR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our view reflects **Southwest** Holdings' reduced exposure to higher risk non-utility operations, balanced against its interstate pipeline acquisition, regulatory lag and declining metrics.

Southwest Gas Holdings, Inc.
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES
Southwest Gas Holdings, Inc. (**Southwest** Holdings, Baa2 stable) is a diversified utility holding company, conducting business through regulated natural **gas** utility operations and unregulated utility infrastructure services. Its princip

Moody's announces completion of a periodic review of ratings of Southwest Gas Holdings, Inc.
29 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, September 29, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **Southwest Gas** Holdings, Inc. and other ratings that are associated with the same analytical unit. The review

Southwest Gas Holdings, Inc.: Acquisition of Dor .nion's Questar Pipeline will have minimal impact on credit quality
07 OCT 2021 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE
The acquisition of Questar Pipeline is credit neutral for **Southwest Gas** as it increases scale and diversity, offsetting higher business risk, with ba

Moody's downgrades Southwest Gas Corporatior. and Southwest Gas Holdings; outlooks stable
29 JAN 2021 | RATING ACTION | MOODY'S INVESTORS SERVICE
Approximately $2.0 billion of debt securities affected New York, January 29, 2021 -- Moody's Investors Service, ("Moody's") downgraded the senior unsecured rating of **Southwest Gas** Corporation (**Southwest Gas**) to Ba

Southwest Gas Capital I
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | SWX
Find the latest ratings, research, and analytics on **So**

Moody's places Aa2 on watch for upgrade for Clark (County of) NV, Industrial Development Revenue Bonds, (Southwest Gas Corporation Project), Series 2008A
01 OCT 2021 | RATING ACTION | MOODY'S INVESTORS SERVICE
New York, October 01, 2021 -- Moody's Investors Service (Moody's) has placed on review for upgrade the Aa2 rating of Clark (County of) NV, Industrial Development Revenue Bonds, (**Southwest Gas** Corporation Project), Series 2008A

Southwest Gas Capital II
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES
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Southwest Gas Corporation
INFRASTRUCTURE & PROJECT FINANCE

MIS RATING SUMMARY View All

LONG TERM RATING	OUTLOOK
Baa1	Stable
29 JAN 2021	29 JAN 2021
Not on Watch	

OTHER DEBTS ON WATCH?
No

Ticker: SWX
Domicile: UNITED STATES
Industry: ENERGY: GAS - DISTRIBUTION

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Spire Inc.: Update to credit analysis
26 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **Spire** reflects its low LDC business risk and historically credit supportive regulation, constrained by a recent adverse Missouri

Spire Inc.
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | SR
Spire Inc. is a utility holding company based in St. Louis, Missouri. **Spire**'s principal operating subsidiary is **Spire** Missouri Inc., (A1 senior secured, negative) a regulated natural gas local distribution company serving almost 1.7 mi

Spire Alabama Inc.: Update to credit analysis
26 APR 2022 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **Spire** Alabama reflects its low business risk gas distribution operations in a credit supportive regulatory environment offset b

Spire Missouri Inc.: Update following outlook change to negative
01 DEC 2021 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **Spire** Missouri reflects its low business risk profile as an LDC operating in a potentially less supportive regulatory environment

Moody's changes Spire Missouri's outlook to negative; affirms A1 senior secured rating
29 NOV 2021 | RATING ACTION | MOODY'S INVESTORS SERVICE
Approximately $865 million of rated debt outstanding New York, November 29, 2021 -- Moody's Investors Service (Moody's) affirmed **Spire** Missouri Inc.'s A1 senior secured rating and changed the outlook to negative from stable. RA

Moody's announces completion of a periodic review of ratings of Spire Inc.
15 SEP 2021 | ANNOUNCEMENT OF PERIODIC REVIEW | MOODY'S INVESTORS SERVICE
New York, September 15, 2021 -- Moody's Investors Service ("Moody's") has completed a periodic review of the ratings of **Spire** Inc. and other ratings that are associated with the same analytical unit. The review was conducted thro

Spire Missouri Inc.: State regulator rate case order includes inconsistent and less transparent cost recovery provisions, a credit negative
17 NOV 2021 | ISSUER COMMENT | MOODY'S INVESTORS SERVICE
Recent rate order included certain provisions that could delay cost recovery and pressure the company's credit metrics.

Spire Missouri Inc.
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES
Spire Missouri is a regulated natural gas local distribution company serving almost 1.2 million customers, primarily residential, in Missouri, including the cities of St. Louis and Kansas City. The company is composed of two utility

Spire Inc.: Update to credit analysis
01 APR 2021 | CREDIT OPINION | MOODY'S INVESTORS SERVICE
Our credit view of **Spire** reflects the low business risk of its LDCs that operate in credit supportive regulatory environments; and a stable financ profile with substantial parent debt.

Spire Alabama Inc.
INFRASTRUCTURE & PROJECT FINANCE | UNITED STATES | EGN
Spire Alabama is the second largest utility subsidiary of **Spire** Inc. It is the largest regulated natural gas local distribution company in Alabama serving over 428,400 primarily residential customers throughout the state including

Spire Alabama Inc.: Update to credit analysis

Spire Inc.
INFRASTRUCTURE & PROJECT FINANCE

MIS RATING SUMMARY

LONG TERM RATING	SHORT TERM RATING
Baa2	P-2
12 AUG 2014	22 DEC 2016
Not on Watch	Not on Watch

OUTLOOK	OTHER DEBTS ON WATCH?
Stable	No
22 JUL 2014	

Ticker: SR
Domicile: UNITED STATES
Industry: ENERGY: GAS - DISTRIBUTION - HOLDCO

Summary Statistics of Annual Total Returns, Income Returns, and Capital Appreciation Returns of Basic U.S. Asset Classes

1926–2021	Geometric Mean Returns (%)	Arithmetic Mean Returns (%)	Standard Deviation of Returns (%)
Large Company Stocks			
Total Return	10.5	12.3	19.6
Income Return	3.9	3.9	1.6
Capital Appreciation Return	6.4	8.2	19.0
Small Company Stocks			
Total Return	12.1	16.3	31.2
Mid-cap Stocks (Decile 3-5)			
Total Return	11.2	13.9	23.9
Income Return	3.6	3.7	1.8
Capital Appreciation Return	7.4	10.0	23.3
Low-cap Stocks (Decile 6-8)			
Total Return	11.6	15.2	28.1
Income Return	3.3	3.3	2.0
Capital Appreciation Return	8.1	11.7	27.5
Micro-cap Stocks (Decile 9-10)			
Total Return	12.3	17.9	37.9
Income Return	2.4	2.4	1.7
Capital Appreciation Return	9.8	15.4	37.1
Long-term Corporate Bonds			
Total Return	6.1	6.4	8.5
Long-term Government Bonds			
Total Return	5.5	6.0	9.8
Income Return	4.8	4.9	2.6
Capital Appreciation Return	0.5	0.9	8.9
Intermediate-term Government Bonds			
Total Return	5.0	5.2	5.6
Income Return	4.3	4.3	2.9
Capital Appreciation Return	0.6	0.7	4.4
US Treasury Bills			
Total Return	3.3	3.3	3.1
Inflation	2.9	3.0	4.0

FRED Graph Observations
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Economic Research Division
Federal Reserve Bank of St. Louis

DGS30 30-Year Treasury Constant Maturity Rate, Percent, Daily, Not Seasonally Adju

Frequency: Daily

observation_date	DGS30
2022-05-02	3.07
2022-05-03	3.03
2022-05-04	3.01
2022-05-05	3.15
2022-05-06	3.23
2022-05-09	3.19
2022-05-10	3.12
2022-05-11	3.05
2022-05-12	3.00
2022-05-13	3.10
2022-05-16	3.09
2022-05-17	3.17
2022-05-18	3.07
2022-05-19	3.05
2022-05-20	2.99
2022-05-23	3.08
2022-05-24	2.98
2022-05-25	2.97
2022-05-26	2.99
2022-05-27	2.97
2022-05-31	3.07
Average	**3.07**

	Company	Ticker	Price	Quarterly Dividend	Est'd Div'd next 12 mos.	Projected Dividend Yield	EPS Growth Rates (Screened) IBES Refinitiv	Value Line	Zacks	Shares Outstanding ($Millions)	Market Cap ($Billions)	Weighted Dividend Yield Weight	Product	Weighted IBES (Refinitiv) Growth Mkt. Cap.	Weight	Product	Weighted Value Line Growth Mkt. Cap.	Weight	Product	Weighted Zacks Growth Mkt. Cap.	Weight	Product
	(a)	(a)	(a)		(b)	(c)	(a)	(b)	(d)	(a)	(e)											
1	Agilent Technologies Inc	A	$127.56		$0.84	0.66%	15.00%	11.50%	10.00%	299.000	38.140	0.001340	0.000009	38.140	0.001701	0.000255	38.14	0.001537	0.000177	38.14	0.001500	0.000150
2	Advance Auto Parts Inc	AAP	$189.86		$6.00	3.16%	15.30%	16.00%	12.74%	60.640	11.513	0.000405	0.000013	11.513	0.000514	0.000079	11.51	0.000464	0.000074	11.51	0.000453	0.000058
3	Apple Inc	AAPL	$148.84		$0.92	0.62%	9.92%	14.00%	12.50%	16,185.181	2,409.002	0.084663	0.000523	2,409.002	0.107455	0.010654	2,409.00	0.097107	0.013595	2,409.00	0.094746	0.011843
4	AbbVie Inc	ABBV	$147.37		$5.64	3.83%	2.13%	6.50%	2.54%	1,767.110	260.419	0.009152	0.000350	260.419	0.011616	0.000246	260.42	0.010497	0.000682	260.42	0.010242	0.000260
5	AMERISOURCEBERGEN CORPORATION	ABC	$154.79		$1.88	1.21%	9.99%	8.50%	8.37%	209.464	32.423	0.001139	0.000014	32.423	0.001446	0.000144	32.42	0.001307	0.000111	32.42	0.001275	0.000107
6	Abbott Laboratories	ABT	$117.46		$1.88	1.60%	11.53%	8.00%	7.83%	1,750.942	205.666	0.007228	0.000116	205.666	0.009174	0.001058	205.67	0.008290	0.000663	205.67	0.008089	0.000633
7	Accenture PLC	ACN	$298.46		$4.12	1.38%	12.69%	12.50%	10.00%	662.434	197.710	0.006948	0.000096	197.710	0.008819	0.001119	197.71	0.007970	0.000996	197.71	0.007776	0.000778
8	Analog Devices Inc	ADI	$168.40		$3.04	1.81%	18.71%	14.00%	12.25%	519.806	87.535	0.003076	0.000056	87.535	0.003905	0.000731	87.54	0.003529	0.000494	87.54	0.003443	0.000422
9	Archer-Daniels-Midland Co	ADM	$90.82		$1.60	1.76%	7.35%	13.00%	6.39%	562.708	51.105	0.001796	0.000032	51.105	0.002280	0.000168	51.11	0.002060	0.000268	51.11	0.002010	0.000128
10	Automatic Data Processing Inc	ADP	$222.94		$4.32	2.03%	14.50%	9.00%	12.00%	417.747	93.133	0.003273	0.000066	93.133	0.004154	0.000602	93.13	0.003754	0.000338	93.13	0.003663	0.000440
11	Ameren Corporation	AEE	$95.19		$2.40	2.52%	6.46%	6.50%	7.20%	258.227	24.581	0.000864	0.000022	24.581	0.001096	0.000071	24.58	0.000991	0.000064	24.58	0.000967	0.000070
12	American Electric Power Co Inc	AEP	$102.03		$3.22	3.16%	6.21%	6.50%	6.20%	513.544	52.397	0.001841	0.000058	52.397	0.002337	0.000145	52.40	0.002112	0.000137	52.40	0.002061	0.000128
13	AES Corp (The)	AES	$22.04		$0.63	2.86%	8.40%	14.00%	7.11%	667.860	14.720	0.000517	0.000015	14.720	0.000657	0.000055	14.72	0.000593	0.000083	14.72	0.000579	0.000041
14	AFLAC Inc	AFL	$60.57		$1.65	2.72%	n/a	9.00%	5.00%	644.165	39.017	0.001371	0.000037	--			39.02	0.001573	0.000142	39.02	0.001535	0.000077
15	American International Group Inc	AIG	$58.68		$1.28	2.18%	n/a	NMF	10.00%	792.192	46.486	0.001634	0.000036							46.49	0.001828	0.000183
16	Assurant Inc	AIZ	$176.69		$3.05	1.73%	17.20%	14.00%	17.19%	54.085	9.556	0.000336	0.000006	9.556	0.000426	0.000073	9.56	0.000385	0.000054	9.56	0.000376	0.000065
17	Arthur J. Gallagher & Co.	AJG	$161.94		$2.04	1.26%	10.40%	16.00%	10.43%	210.068	34.018	0.001196	0.000015	34.018	0.001517	0.000158	34.02	0.001371	0.000219	34.02	0.001338	0.000140
18	Albemarle Corp	ALB	$260.42		$1.58	0.61%	NMF	15.00%	NMF	117.113	30.499	0.001072	0.000007				30.50	0.001229	0.000184	--		
19	The Allstate Corporation	ALL	$136.69		$3.40	2.49%	5.57%	2.50%	5.43%	274.983	37.587	0.001321	0.000033	37.587	0.001677	0.000093	37.59	0.001515	0.000038	37.59	0.001478	0.000080
20	Allegion Plc	ALLE	$111.65		$1.64	1.47%	8.87%	10.50%	8.99%	87.805	9.803	0.000345	0.000005	9.803	0.000437	0.000039	9.80	0.000395	0.000041	9.80	0.000386	0.000035
21	Applied Materials Inc	AMAT	$117.29		$1.04	0.89%	14.17%	14.50%	8.89%	869.947	102.036	0.003586	0.000032	102.036	0.004551	0.000645	102.04	0.004113	0.000596	102.04	0.004013	0.000357
22	Amcor Plc	AMCR	$13.10		$0.48	3.66%	7.67%	13.50%	9.82%	1,502.767	19.686	0.000692	0.000025	19.686	0.000878	0.000067	19.69	0.000794	0.000107	19.69	0.000774	0.000076
23	AMETEK Inc	AME	$121.47		$0.88	0.72%	n/a	10.00%	9.39%	230.910	28.049	0.000986	0.000007				28.05	0.001131	0.000113	28.05	0.001103	0.000104
24	Amgen Inc	AMGN	$256.74		$8.18	3.19%	7.07%	5.50%	6.66%	534.200	137.151	0.004820	0.000154	137.151	0.006118	0.000432	137.15	0.005529	0.000304	137.15	0.005394	0.000359
25	Ameriprise Financial Inc	AMP	$276.27		$5.00	1.81%	NMF	12.00%	n/a	109.904	30.363	0.001067	0.000019				30.36	0.001224	0.000147			
26	American Tower Corp	AMT	$256.13		$5.98	2.33%	13.24%	9.00%	10.26%	456.283	116.868	0.004107	0.000096	116.868	0.005213	0.000690	116.87	0.004711	0.000424	116.87	0.004596	0.000472
27	ANTHEM INC	ANTM	$509.61		$5.12	1.00%	12.57%	12.50%	12.46%	241.085	122.859	0.004318	0.000043	122.859	0.005480	0.000689	122.86	0.004952	0.000619	122.86	0.004832	0.000602
28	Aon plc	AON	$275.67		$2.24	0.81%	n/a	7.50%	n/a	212.384	58.548	0.002058	0.000017				58.55	0.002360	0.000177	--		
29	A. O. Smith Corp	AOS	$60.12		$1.12	1.86%	n/a	11.50%	9.00%	156.007	9.379	0.000330	0.000006				9.38	0.000378	0.000043	9.38	0.000369	0.000033
30	APA Corporation	APA	$47.01		$0.61	1.30%	NMF	NMF	NMF	338.232	15.900	0.000559	0.000007									
31	Air Products and Chemicals Inc	APD	$246.16		$6.48	2.63%	12.13%	11.00%	13.07%	221.773	54.592	0.001919	0.000051	54.592	0.002435	0.000295	54.59	0.002201	0.000242	54.59	0.002147	0.000281
32	Amphenol Corp	APH	$70.86		$0.80	1.13%	9.80%	12.50%	10.90%	597.139	42.313	0.001487	0.000017	42.313	0.001887	0.000185	42.31	0.001706	0.000213	42.31	0.001664	0.000181
33	Alexandria Real Estate Equities Inc	ARE	$165.95		$4.60	2.77%	n/a	9.00%	7.72%	163.218	27.086	0.000952	0.000026				27.09	0.001092	0.000098	27.09	0.001065	0.000082
34	Atmos Energy Corp	ATO	$116.31		$2.87	2.47%	8.61%	7.50%	7.28%	139.015	16.169	0.000568	0.000014	16.169	0.000721	0.000062	16.17	0.000652	0.000049	16.17	0.000636	0.000046
35	Activision Blizzard Inc	ATVI	$77.88		$0.47	0.60%	10.19%	14.00%	14.50%	781.881	60.893	0.002140	0.000013	60.893	0.002716	0.000277	60.89	0.002455	0.000344	60.89	0.002395	0.000347
36	AvalonBay Communities Inc	AVB	$207.96		$6.47	3.11%	n/a	6.50%	6.17%	139.818	29.077	0.001022	0.000032				29.08	0.001172	0.000076	29.08	0.001144	0.000071
37	Broadcom Inc	AVGO	$580.13		$16.40	2.83%	n/a	NMF	15.00%	403.818	234.267	0.008233	0.000233							234.27	0.009214	0.001382
38	Avery Dennison Corp	AVY	$172.56		$3.07	1.78%	7.15%	12.00%	7.00%	81.714	14.101	0.000496	0.000009	14.101	0.000629	0.000045	14.10	0.000568	0.000068	14.10	0.000555	0.000039
39	American Water Works Company Inc	AWK	$151.25		$2.62	1.73%	8.30%	3.00%	8.08%	181.753	27.490	0.000966	0.000017	27.490	0.001226	0.000102	27.49	0.001108	0.000033	27.49	0.001081	0.000087
40	American Express Co	AXP	$168.82		$2.08	1.23%	n/a	10.00%	12.71%	753.091	127.132	0.004468	0.000055				127.13	0.005125	0.000512	127.13	0.005000	0.000636
41	Bank of America Corp	BAC	$37.20		$0.86	2.31%	15.40%	9.50%	7.00%	8,056.881	299.716	0.010533	0.000244	299.716	0.013369	0.002059	299.72	0.012082	0.001148	299.72	0.011788	0.000825
42	BALL CORPORATION	BALL	$70.89		$0.80	1.13%	14.33%	NMF	5.00%	319.789	22.670	0.000797	0.000009	22.670	0.001011	0.000145				22.67	0.000892	0.000045
43	Baxter International Inc	BAX	$76.03		$1.16	1.53%	12.77%	10.00%	10.96%	503.529	38.293	0.001346	0.000021	38.293	0.001708	0.000218	38.29	0.001544	0.000154	38.29	0.001506	0.000165
44	Bath & Body Works Inc	BBWI	$41.02		$0.80	1.95%	19.33%	NMF	8.28%	238.490	9.783	0.000344	0.000007	9.783	0.000436	0.000084				9.78	0.000385	0.000032
45	Best Buy Co Inc	BBY	$82.06		$3.52	4.29%	8.90%	9.50%	9.62%	224.968	18.461	0.000649	0.000028	18.461	0.000823	0.000073	18.46	0.000744	0.000071	18.46	0.000726	0.000070
46	Becton Dickinson and Co	BDX	$255.80		$3.60	1.41%	4.85%	5.50%	5.41%	285.065	72.920	0.002563	0.000036	72.920	0.003253	0.000158	72.92	0.002939	0.000162	72.92	0.002868	0.000155
47	Franklin Resources Inc	BEN	$27.08		$1.16	4.28%	NMF	9.00%	1.58%	499.924	13.538	0.000476	0.000020				13.54	0.000546	0.000049	13.54	0.000532	0.000008
48	Brown-Forman Corp	BF/B	$66.12		$0.75	1.13%	7.01%	12.00%	n/a	309.793	20.484	0.000720	0.000008	20.484	0.000914	0.000064	20.48	0.000826	0.000099			
49	Bank of New York Mellon Corp (The)	BK	$46.61		$1.36	2.92%	6.34%	6.50%	6.00%	807.798	37.651	0.001323	0.000039	37.651	0.001679	0.000106	37.65	0.001518	0.000099	37.65	0.001481	0.000089
50	Baker Hughes a GE Co	BKR	$35.98		$0.72	2.00%	NMF	n/a	n/a	1,025.167	36.886	0.001296	0.000026									
51	Blackrock Inc	BLK	$669.08		$19.91	2.98%	6.43%	10.00%	8.14%	151.503	101.368	0.003563	0.000106	101.368	0.004522	0.000291	101.37	0.004086	0.000409	101.37	0.003987	0.000325
52	Bristol-Myers Squibb Co	BMY	$75.45		$2.16	2.86%	4.43%	NMF	6.24%	2,129.064	160.638	0.005646	0.000162	160.638	0.007165	0.000318				160.64	0.006318	0.000394
53	Broadridge Financial Solutions Inc	BR	$146.22		$2.56	1.75%	n/a	9.00%	n/a	117.227	17.141	0.000602	0.000011				17.14	0.000691	0.000062			
54	Brown & Brown Inc	BRO	$59.37		$0.41	0.69%	n/a	8.00%	n/a	282.273	16.759	0.000589	0.000004				16.76	0.000676	0.000054			
55	BorgWarner Inc	BWA	$40.32		$0.68	1.69%	18.91%	9.50%	NMF	239.575	9.660	0.000339	0.000006	9.660	0.000431	0.000081	9.56	0.000389	0.000037			
56	Boston Properties Inc	BXP	$111.18		$3.94	3.54%	n/a	NMF	5.74%	156.712	17.423	0.000612	0.000022							17.42	0.000685	0.000039
57	Citigroup Inc	C	$53.41		$2.04	3.91%	NMF	5.50%	11.19%	1,941.921	103.718	0.003645	0.000143				103.72	0.004181	0.000230	103.72	0.004079	0.000456
58	Conagra Brands Inc	CAG	$32.89		$1.32	4.01%	0.87%	4.00%	7.00%	479.873	15.783	0.000555	0.000022	15.783	0.000704	0.000006	15.78	0.000636	0.000025	15.78	0.000621	0.000043
59	Cardinal Health Inc	CAH	$56.32		$1.98	3.52%	3.67%	5.00%	1.62%	272.427	15.343	0.000539	0.000019	15.343	0.000684	0.000025	15.34	0.000618	0.000031	15.34	0.000603	0.000010
60	Carrier Global Corp	CARR	$39.31		$0.60	1.53%	11.31%	n/a	8.57%	848.242	33.344	0.001172	0.000018	33.344	0.001487	0.000168				33.34	0.001311	0.000112
61	Caterpillar Inc	CAT	$215.85		$4.44	2.06%	NMF	10.00%	12.00%	533.374	115.129	0.004046	0.000083				115.13	0.004641	0.000464	115.13	0.004528	0.000543
62	Chubb Ltd	CB	$211.29		$3.32	1.57%	13.45%	12.50%	10.00%	423.711	89.526	0.003146	0.000049	89.526	0.003993	0.000537	89.53	0.003609	0.000451	89.53	0.003521	0.000352
63	Cboe Global Markets Inc	CBOE	$112.31		$1.92	1.71%	4.32%	10.00%	n/a	106.189	11.926	0.000419	0.000007	11.926	0.000532	0.000023	11.93	0.000481	0.000048	--		
64	Crown Castle International Corp	CCI	$189.65		$6.00	3.16%	13.60%	12.00%	n/a	433.032	82.125	0.002886	0.000091	82.125	0.003663	0.000476	82.12	0.003310	0.000397			
65	CDW Corp	CDW	$169.86		$2.00	1.18%	13.10%	8.50%	13.10%	135.116	22.951	0.000807	0.000009	22.951	0.001024	0.000134	22.95	0.000925	0.000079	22.95	0.000903	0.000118
66	Celanese Corp	CE	$156.52		$2.90	1.85%	NMF	9.50%	n/a	108.309	16.953	0.000596	0.000011				16.95	0.000683	0.000065			
67	Constellation Energy Corp	CEG	$62.08		n/a	n/a	n/a	n/a	2.00%	326.699	20.281	0.000713										
68	Cerner Corp	CERN	$94.65		$1.12	1.18%	13.30%	10.00%	12.77%	294.109	27.895	0.000980	0.000012	27.895	0.001244	0.000165	27.90	0.001124	0.000112	27.90	0.001097	0.000140
69	CF Industries Holdings Inc	CF	$98.77		$1.60	1.62%	n/a	NMF	6.00%	208.602	20.604	0.000724	0.000012							20.60	0.000810	0.000049
70	Citizens Financial Group Inc	CFG	$41.38		$1.58	3.82%	n/a	9.00%	n/a	495.446	20.502	0.000721	0.000028				20.50	0.000826	0.000074			
71	Church & Dwight Co Inc	CHD	$90.06		$1.05	1.17%	7.24%	6.00%	8.00%	242.771	21.864	0.000768	0.000009	21.864	0.000975	0.000071	21.86	0.000881	0.000053	21.86	0.000860	0.000069
72	C.H. Robinson Worldwide Inc	CHRW	$108.51		$2.20	2.03%	7.24%	8.00%	9.00%	127.266	13.810	0.000485	0.000010	13.810	0.000616	0.000045	13.81	0.000557	0.000045	13.81	0.000543	0.000049
73	Cigna Corp	CI	$268.29		$4.48	1.67%	11.23%	9.50%	11.10%	317.273	85.121	0.002992	0.000050	85.121	0.003797	0.000426	85.12	0.003431	0.000326	85.12	0.003348	0.000372
74	Cincinnati Financial Corp	CINF	$127.86		$2.76	2.16%	n/a	13.00%	n/a	160.355	20.503	0.000721	0.000016				20.50	0.000826	0.000107			
75	Colgate-Palmolive Co	CL	$78.81		$1.88	2.39%	3.96%	6.00%	4.85%	837.942	66.038	0.002321	0.000055	66.038	0.002946	0.000117	66.04	0.002662	0.000160	66.04	0.002597	0.000126
76	Clorox Co (The)	CLX	$145.36		$4.64	3.19%	NMF	4.50%	7.00%	123.080	17.891	0.000629	0.000020				17.89	0.000721	0.000032	17.89	0.000704	0.000049
77	Comerica Incorporated	CMA	$83.21		$2.72	3.27%	n/a	6.00%	6.20%	130.760	10.881	0.000382	0.000012				10.88	0.000439	0.000026	10.88	0.000428	0.000027
78	Comcast Corp	CMCSA	$44.28		$1.08	2.44%	13.48%	9.50%	13.29%	4,480.015	198.375	0.006972	0.000170	198.375	0.008849	0.001193	198.38	0.007996	0.000760	198.38	0.007802	0.001037
79	CME Group Inc	CME	$198.83		$4.00	2.01%	7.36%	7.50%	6.14%	359.418	71.463	0.002512	0.000051	71.463	0.003188	0.000234	71.46	0.002881	0.000216	71.46	0.002811	0.000173
80	Cummins Inc	CMI	$209.12		$5.80	2.77%	8.15%	8.50%	8.84%	141.099	29.506	0.001037	0.000029	29.506	0.001316	0.000107	29.51	0.001189	0.000101	29.51	0.001160	0.000103

81	CMS Energy Corp	CMS	$71.04	$1.87	2.63%	8.48%	6.50%	8.41%	290.129	20.611	0.000724	0.000019	20.611	0.000819	0.000078	20.61	0.000831	0.000054	20.61	0.000811	0.000088
82	CenterPoint Energy Inc	CNP	$32.05	$0.71	2.22%	NMF	5.00%	3.89%	629.449	20.174	0.000709	0.000016	–			20.17	0.000813	0.000041	20.17	0.000793	0.000031
83	Capital One Financial Corp	COF	$127.86	$2.40	1.88%	NMF	NMF	17.22%	393.051	50.256	0.001766	0.000033							50.26	0.001977	0.000340
84	Cooper Cos Inc (The)	COO	$350.74	$0.06	0.02%	n/a	18.50%	11.00%	49.302	17.292	0.000608	0.000000				17.29	0.000697	0.000179	17.29	0.000680	0.000075
85	Conocophillips	COP	$112.36	$1.84	1.64%	15.28%	20.00%	19.13%	1,293.450	145.332	0.005108	0.000084	145.332	0.006483	0.000990	145.33	0.005858	0.001172	145.33	0.005716	0.001092
86	Costco Wholesale Corp	COST	$466.22	$3.60	0.77%	11.64%	10.50%	9.09%	443.029	206.549	0.007259	0.000056	206.549	0.009213	0.001073	206.55	0.008326	0.000874	206.55	0.008124	0.000738
87	Campbell Soup Co	CPB	$47.91	$1.48	3.09%	0.84%	5.00%	1.61%	301.704	14.455	0.000508	0.000016	14.455	0.000645	0.000005	14.45	0.000583	0.000029	14.45	0.000569	0.000009
88	Camden Property Trust	CPT	$143.49	$3.84	2.68%	n/a	2.50%	5.47%	106.521	15.285	0.000537	0.000014				15.28	0.000616	0.000015	15.28	0.000601	0.000033
89	Cisco Systems Inc	CSCO	$45.03	$1.52	3.37%	6.47%	8.00%	6.50%	4,140.964	186.550	0.006556	0.000221	186.550	0.008321	0.000539	186.55	0.007520	0.000602	186.55	0.007337	0.000477
90	CSX Corp	CSX	$31.79	$0.40	1.26%	13.95%	10.50%	10.15%	2,174.260	69.120	0.002429	0.000031	69.120	0.003083	0.000430	69.12	0.002786	0.000293	69.12	0.002718	0.000276
91	Cintas Corp	CTAS	$398.33	$3.80	0.95%	11.90%	13.50%	10.75%	102.325	40.759	0.001432	0.000014	40.759	0.001818	0.000216	40.76	0.001643	0.000222	40.76	0.001603	0.000172
92	Coterra Energy Inc	CTRA	$34.33	n/a	n/a	4.83%	n/a	NMF	805.805	27.663	0.000972	–									
93	Cognizant Technology Solutions Corp	CTSH	$74.70	$1.08	1.45%	10.49%	7.50%	12.00%	521.174	38.932	0.001368	0.000020	38.932	0.001737	0.000182	38.93	0.001569	0.000118	38.93	0.001531	0.000184
94	Corteva Inc	CTVA	$62.62	$0.59	0.94%	17.55%	16.50%	13.38%	723.700	45.318	0.001593	0.000015	45.318	0.002021	0.000355	45.32	0.001827	0.000301	45.32	0.001782	0.000238
95	Citrix Systems Inc	CTXS	$100.69	n/a	n/a	n/a	9.00%	n/a	126.580	12.745	0.000448	–									
96	CVS Health Corp	CVS	$96.75	$2.20	2.27%	5.74%	6.00%	7.60%	1,311.309	126.869	0.004459	0.000101	126.869	0.005659	0.000325	126.87	0.005114	0.000302	126.87	0.004990	0.000379
97	Chevron Corp	CVX	$174.66	$5.71	3.27%	17.78%	NMF	11.55%	1,964.813	343.174	0.012061	0.000394	343.174	0.015308	0.002722	–			343.17	0.013497	0.001559
98	Dominion Energy Inc	D	$84.22	$2.71	3.22%	6.50%	14.00%	6.30%	811.270	68.325	0.002401	0.000077	68.325	0.003048	0.000198	68.33	0.002754	0.000386	68.33	0.002687	0.000169
99	DuPont De Nemours Inc	DD	$67.85	$1.34	1.97%	n/a	11.50%	9.27%	508.527	34.504	0.001213	0.000024				34.50	0.001391	0.000160	34.50	0.001357	0.000126
100	DEERE & COMPANY	DE	$357.78	$4.20	1.17%	15.45%	15.00%	13.05%	305.636	109.350	0.003843	0.000045	109.350	0.004878	0.000753	109.35	0.004408	0.000661	109.35	0.004301	0.000561
101	Discover Financial Services	DFS	$113.49	$2.40	2.11%	NMF	8.50%	NMF	280.965	31.887	0.001121	0.000024				31.89	0.001285	0.000109	–		
102	Dollar General Corporation	DG	$220.34	$2.20	1.00%	10.61%	10.00%	11.49%	226.997	50.017	0.001758	0.000018	50.017	0.002231	0.000237	50.02	0.002016	0.000202	50.02	0.001967	0.000226
103	Quest Diagnostics Inc	DGX	$141.02	$2.64	1.87%	NMF	3.50%	n/a	117.365	16.551	0.000582	0.000011				16.55	0.000667	0.000023			
104	D.R. Horton Inc	DHI	$75.15	$0.93	1.24%	9.84%	11.00%	8.37%	352.030	26.455	0.000930	0.000012	26.455	0.001180	0.000116	26.46	0.001066	0.000117	26.46	0.001040	0.000087
105	Danaher Corp	DHR	$263.82	$1.00	0.38%	11.05%	16.50%	8.73%	727.077	191.817	0.006741	0.000026	191.817	0.008556	0.000945	191.82	0.007732	0.001276	191.82	0.007544	0.000659
106	Digital Realty Trust Inc	DLR	$139.59	$4.93	3.53%	NMF	NMF	6.80%	284.672	39.737	0.001397	0.000050				–			39.74	0.001563	0.000106
107	Dover Corp	DOV	$133.91	$2.00	1.49%	12.95%	8.00%	14.00%	144.163	19.305	0.000678	0.000010	19.305	0.000861	0.000112	19.30	0.000778	0.000062	19.30	0.000759	0.000106
108	Dow Inc	DOW	$67.98	$2.85	4.19%	NMF	15.00%	NMF	728.102	49.496	0.001740	0.000073				49.50	0.001995	0.000299			
109	Domino's Pizza Inc	DPZ	$363.17	$4.55	1.25%	10.01%	16.00%	11.65%	36.045	13.090	0.000460	0.000006	13.090	0.000584	0.000058	13.09	0.000528	0.000084	13.09	0.000515	0.000060
110	Duke Realty Corp	DRE	$52.83	$1.16	2.20%	n/a	2.50%	7.74%	384.455	20.311	0.000714	0.000016				20.31	0.000819	0.000020	20.31	0.000799	0.000062
111	Darden Restaurants Inc	DRI	$125.00	$4.40	3.52%	NMF	19.50%	10.00%	124.734	15.592	0.000548	0.000019				15.59	0.000629	0.000123	15.59	0.000613	0.000061
112	DTE Energy Co	DTE	$132.71	$3.54	2.67%	3.96%	4.50%	6.00%	193.749	25.711	0.000904	0.000024	25.711	0.001147	0.000045	25.71	0.001036	0.000047	25.71	0.001011	0.000061
113	Duke Energy Corp	DUK	$112.52	$4.00	3.55%	5.94%	6.00%	6.11%	769.900	86.629	0.003045	0.000108	86.629	0.003864	0.000230	86.63	0.003492	0.000210	86.63	0.003407	0.000208
114	Devon Energy Corp	DVN	$74.90	$0.64	0.85%	19.89%	NMF	n/a	660.000	49.434	0.001737	0.000015	49.434	0.002205	0.000439	–					
115	Electronic Arts Inc	EA	$138.65	$0.76	0.55%	13.01%	9.00%	11.18%	279.894	38.807	0.001364	0.000007	38.807	0.001731	0.000225	38.81	0.001564	0.000141	38.81	0.001526	0.000171
116	eBay Inc	EBAY	$48.67	$0.88	1.81%	9.73%	15.50%	9.46%	559.842	27.248	0.000958	0.000017	27.248	0.001215	0.000118	27.25	0.001098	0.000170	27.25	0.001072	0.000101
117	Ecolab Inc	ECL	$163.91	$2.04	1.24%	13.07%	10.50%	12.67%	285.655	46.822	0.001646	0.000020	46.822	0.002089	0.000273	46.82	0.001887	0.000198	46.82	0.001842	0.000233
118	Consolidated Edison Inc	ED	$99.26	$3.18	3.20%	5.16%	4.50%	2.00%	354.295	35.167	0.001236	0.000040	35.167	0.001569	0.000081	35.17	0.001418	0.000064	35.17	0.001383	0.000028
119	Equifax Inc	EFX	$202.58	$1.56	0.77%	14.40%	10.00%	14.36%	122.335	24.783	0.000871	0.000007	24.783	0.001105	0.000159	24.78	0.000999	0.000100	24.78	0.000975	0.000140
120	Edison International	EIX	$69.91	$2.88	4.12%	4.50%	15.00%	3.90%	381.200	26.650	0.000937	0.000039	26.650	0.001189	0.000053	26.65	0.001074	0.000161	26.65	0.001048	0.000041
121	Estee Lauder Cos Inc (The)	EL	$254.65	$2.52	0.99%	12.41%	14.00%	10.81%	357.347	90.998	0.003198	0.000032	90.998	0.004059	0.000504	91.00	0.003668	0.000514	91.00	0.003579	0.000387
122	Eastman Chemical Co	EMN	$110.16	$3.04	2.76%	8.92%	9.50%	9.40%	128.882	14.198	0.000499	0.000014	14.198	0.000633	0.000056	14.20	0.000572	0.000054	14.20	0.000558	0.000052
123	Emerson Electric Co	EMR	$88.66	$2.06	2.32%	10.33%	10.00%	8.79%	594.000	52.664	0.001851	0.000043	52.664	0.002349	0.000243	52.66	0.002123	0.000212	52.66	0.002071	0.000182
124	EOG Resources Inc	EOG	$136.96	$3.25	2.37%	13.24%	NMF	NMF	585.713	80.219	0.002819	0.000067	80.219	0.003578	0.000474	–					
125	Equinix Inc	EQIX	$687.09	$12.65	1.84%	NMF	15.00%	8.20%	91.022	62.540	0.002198	0.000040				62.54	0.002521	0.000378	62.54	0.002460	0.000202
126	Equity Residential	EQR	$76.83	$2.50	3.25%	n/a	NMF	6.59%	376.042	28.891	0.001015	0.000033							28.89	0.001136	0.000075
127	Eversource Energy	ES	$92.32	$2.59	2.81%	6.58%	6.00%	6.21%	344.878	31.839	0.001119	0.000031	31.839	0.001420	0.000093	31.84	0.001283	0.000077	31.84	0.001252	0.000078
128	Essex Property Trust Inc	ESS	$283.85	$8.93	3.15%	n/a	NMF	6.10%	65.333	18.545	0.000652	0.000021	–						18.54	0.000729	0.000044
129	Eaton Corp Plc	ETN	$138.60	$3.24	2.34%	15.55%	12.00%	11.00%	399.000	55.301	0.001944	0.000045	55.301	0.002467	0.000383	55.30	0.002229	0.000268	55.30	0.002175	0.000239
130	Entergy corporation	ETR	$120.32	$4.14	3.44%	6.02%	3.00%	6.07%	203.374	24.470	0.000860	0.000030	24.470	0.001091	0.000066	24.47	0.000986	0.000030	24.47	0.000962	0.000058
131	EVERGY INC	EVRG	$69.94	$2.37	3.39%	4.96%	7.50%	6.08%	229.478	16.050	0.000564	0.000019	16.050	0.000716	0.000035	16.05	0.000647	0.000049	16.05	0.000631	0.000038
132	Exelon Corp	EXC	$49.15	$1.38	2.81%	n/a	3.50%	6.20%	980.210	48.177	0.001693	0.000048				48.18	0.001942	0.000068	48.18	0.001895	0.000117
133	Expeditors International of Washington Inc.	EXPD	$108.84	$1.34	1.23%	NMF	6.50%	n/a	167.734	18.258	0.000642	0.000008				18.26	0.000736	0.000048			
134	Extra Space Storage Inc	EXR	$178.20	$6.00	3.37%	n/a	6.00%	7.67%	134.280	23.929	0.000841	0.000028				23.93	0.000965	0.000058	23.93	0.000941	0.000072
135	Ford Motor Co	F	$13.68	$0.40	2.92%	NMF	NMF	3.00%	4,019.765	54.990	0.001933	0.000057				–			54.99	0.002163	0.000065
136	Diamondback Energy Inc	FANG	$152.10	$2.80	1.84%	16.41%	n/a	NMF	177.493	26.982	0.000948	0.000017	26.982	0.001204	0.000197	–					
137	Fastenal Co	FAST	$53.56	$1.24	2.32%	n/a	8.50%	9.00%	575.606	30.829	0.001083	0.000025	–			30.83	0.001243	0.000106	30.83	0.001213	0.000109
138	Fortune Brands Home & Security Inc	FBHS	$69.35	$1.12	1.61%	8.14%	10.00%	7.67%	130.807	9.071	0.000319	0.000005	9.071	0.000405	0.000033	9.07	0.000366	0.000037	9.07	0.000357	0.000027
139	Freeport-McMoRan Inc	FCX	$39.08	$0.60	1.54%	NMF	NMF	NMF	1,449.262	56.637	0.001990	0.000031	–			–					
140	FactSet Research Systems Inc.	FDS	$381.78	$3.56	0.93%	15.10%	10.00%	10.00%	37.897	14.468	0.000508	0.000005	14.468	0.000645	0.000097	14.47	0.000583	0.000058	14.47	0.000569	0.000057
141	FedEx Corp	FDX	$224.38	$3.00	1.34%	19.33%	10.50%	12.00%	259.178	58.206	0.002046	0.000027	58.206	0.002596	0.000502	58.21	0.002346	0.000246	58.21	0.002289	0.000275
142	FirstEnergy Corp.	FE	$42.96	$1.58	3.68%	NMF	7.50%	6.36%	570.912	24.527	0.000862	0.000032	–			24.53	0.000989	0.000074	24.53	0.000965	0.000061
143	Fidelity National Information Services Inc	FIS	$104.50	$1.96	1.88%	14.00%	NMF	13.58%	610.771	63.826	0.002243	0.000042	63.826	0.002847	0.000399	–			63.83	0.002510	0.000341
144	Fifth Third Bancorp	FITB	$39.43	$1.29	3.27%	5.62%	11.00%	8.25%	686.087	27.052	0.000951	0.000031	27.052	0.001207	0.000068	27.05	0.001090	0.000120	27.05	0.001064	0.000088
145	FMC Corp	FMC	$122.58	$2.16	1.76%	9.58%	11.00%	11.00%	125.939	15.438	0.000543	0.000010	15.438	0.000689	0.000066	15.44	0.000622	0.000068	15.44	0.000607	0.000067
146	Fox Corp	FOX	$32.71	n/a	n/a	n/a	n/a	12.27%	245.063	8.016	0.000282		–								
147	Fox Corp	FOXA	$35.31	$0.48	1.35%	8.10%	11.00%	12.27%	311.684	11.068	0.000389	0.000005	11.068	0.000494	0.000040	11.07	0.000446	0.000049	11.07	0.000435	0.000053
148	First Republic Bank	FRC	$155.03	$1.11	0.72%	14.43%	11.00%	12.27%	179.647	27.851	0.000979	0.000007	27.851	0.001242	0.000179	27.85	0.001123	0.000123	27.85	0.001095	0.000134
149	Federal Realty Investment Trust	FRT	$114.97	$4.32	3.76%	n/a	2.50%	5.82%	79.420	9.131	0.000321	0.000012				9.13	0.000368	0.000009	9.13	0.000359	0.000021
150	Fortive Corp	FTV	$61.77	$0.28	0.45%	NMF	11.50%	10.40%	358.448	22.141	0.000778	0.000004				22.14	0.000893	0.000103	22.14	0.000871	0.000091
151	General Dynamics Corp	GD	$224.91	$5.04	2.24%	11.75%	8.50%	9.82%	277.703	62.459	0.002195	0.000049	62.459	0.002786	0.000327	62.46	0.002518	0.000214	62.46	0.002457	0.000241
152	General Electric Co	GE	$78.29	$0.32	0.41%	NMF	13.50%	7.00%	1,100.665	86.171	0.003028	0.000012				86.17	0.003474	0.000469	86.17	0.003389	0.000237
153	Gilead Sciences Inc	GILD	$64.85	$2.92	4.50%	NMF	13.50%	15.00%	1,254.313	81.342	0.002859	0.000129				81.34	0.003279	0.000443	81.34	0.003199	0.000480
154	General Mills Inc	GIS	$69.85	$2.07	2.96%	4.13%	4.00%	7.50%	602.212	42.065	0.001478	0.000044	42.065	0.001876	0.000077	42.06	0.001696	0.000068	42.06	0.001654	0.000124
155	Globe Life Inc	GL	$97.57	$0.83	0.85%	14.72%	7.50%	n/a	98.600	9.620	0.000338	0.000003	9.620	0.000429	0.000063	9.62	0.000388	0.000029	–		
156	Corning Inc	GLW	$35.82	$1.08	3.02%	NMF	16.00%	6.21%	844.612	30.254	0.001063	0.000032				30.25	0.001220	0.000195	30.25	0.001190	0.000074
157	Genuine Parts Co	GPC	$136.73	$3.58	2.62%	n/a	8.50%	5.57%	141.595	19.360	0.000680	0.000018				19.36	0.000780	0.000066	19.36	0.000761	0.000042
158	GLOBAL PAYMENTS INC	GPN	$131.04	$1.00	0.76%	17.97%	17.00%	17.34%	281.540	36.893	0.001297	0.000010	36.893	0.001646	0.000296	36.89	0.001487	0.000253	36.89	0.001451	0.000252
159	Garmin Ltd	GRMN	$105.62	$2.92	2.76%	5.60%	8.00%	5.60%	193.125	20.398	0.000717	0.000020	20.398	0.000910	0.000051	20.40	0.000822	0.000066	20.40	0.000802	0.000045
160	Goldman Sachs Group Inc (The)	GS	$326.85	$8.00	2.43%	NMF	5.00%	12.80%	343.447	112.256	0.003945	0.000097	–			112.26	0.004525	0.000226	112.26	0.004415	0.000565
161	Grainger (W.W.) Inc	GWW	$487.07	$6.88	1.41%	n/a	7.00%	13.00%	51.102	24.890	0.000875	0.000012	–			24.89	0.001003	0.000070	24.89	0.000979	0.000127
162	Halliburton Co	HAL	$40.50	$0.32	1.28%	NMF	NMF	n/a	901.976	36.530	0.001284	0.000016	–			–					
163	Hasbro Inc	HAS	$89.75	$2.80	3.12%	n/a	9.00%	n/a	139.442	12.515	0.000440	0.000014	–			12.51	0.000504	0.000045	–		
164	Huntington Bancshares Inc	HBAN	$13.88	$0.64	4.61%	n/a	12.50%	n/a	1,439.175	19.976	0.000702	0.000032	–			19.98	0.000805	0.000101	–		

ONE Gas Inc.

Issuer Credit Rating

RATING TYPE	RATING	RATING DATE	LAST REVIEW DATE	REGULA IDENTIF
Local Currency LT	BBB+ Regulatory Disclosures	23-Feb-2021	11-May-2022	EE|UKE
Local Currency ST	A-2 Regulatory Disclosures	23-Feb-2021	11-May-2022	EE|UKE
Foreign Currency LT	BBB+ Regulatory Disclosures	23-Feb-2021	11-May-2022	EE|UKE
Foreign Currency ST	A-2 Regulatory Disclosures	23-Feb-2021	11-May-2022	EE|UKE

165	HCA Healthcare Inc	HCA	$210.40	$2.24	1.06%	7.38%	11.00%	9.13%	295.484	62.170	0.002185	0.000023	62.170	0.002773	0.000205	62.17	0.002506	0.000276	62.17	0.002445	0.000223
166	Home Depot Inc (The)	HD	$302.75	$7.60	2.51%	14.60%	10.00%	10.12%	1,027.755	311.153	0.010935	0.000775	311.153	0.013879	0.002026	311.15	0.012543	0.001254	311.15	0.012238	0.001238
167	Hess Corp	HES	$123.07	$1.50	1.22%	NMF	n/a	n/a	311.263	38.307	0.001346	0.000016									
168	Hartford Financial Services Group Inc. (The)	HIG	$72.51	$1.54	2.12%	11.48%	8.50%	7.00%	328.865	23.846	0.000838	0.000018	23.846	0.001064	0.000122	23.85	0.000961	0.000082	23.85	0.000938	0.000066
169	Huntington Ingalls Industries Inc	HII	$210.46	$4.72	2.24%	13.60%	10.00%	n/a	40.047	8.428	0.000296	0.000007	8.428	0.000376	0.000051	8.43	0.000340	0.000034			
170	Hilton Worldwide Holdings Inc	HLT	$140.86	$0.60	0.43%	NMF	NMF	n/a	278.332	39.206	0.001378	0.000006									
171	Honeywell International Inc	HON	$193.62	$3.92	2.02%	10.60%	11.00%	9.65%	680.733	131.804	0.004632	0.000094	131.804	0.005879	0.000623	131.80	0.005313	0.000584	131.80	0.005184	0.000500
172	Hewlett Packard Enterprise Co	HPE	$15.60	$0.48	3.08%	6.16%	7.50%	3.98%	1,300.176	20.282	0.000713	0.000022	20.282	0.000905	0.000056	20.28	0.000818	0.000061	20.28	0.000798	0.000032
173	HP Inc	HPQ	$38.84	$1.00	2.57%	3.51%	12.50%	4.00%	1,053.366	40.913	0.001438	0.000037	40.913	0.001825	0.000064	40.91	0.001649	0.000206	40.91	0.001609	0.000064
174	Hormel Foods Corp	HRL	$48.67	$1.04	2.14%	8.50%	8.50%	7.96%	544.998	26.525	0.000932	0.000020	26.525	0.001183	0.000101	26.53	0.001069	0.000091	26.53	0.001043	0.000083
175	Host Hotels & Resorts Inc	HST	$19.99	$0.24	1.20%	n/a	8.50%	n/a	714.777	14.288	0.000502	0.000006				14.29	0.000576	0.000049			
176	Hershey Co (The)	HSY	$211.71	$3.60	1.70%	9.51%	6.50%	7.67%	205.605	43.529	0.001530	0.000026	43.529	0.001942	0.000185	43.53	0.001755	0.000114	43.53	0.001712	0.000131
177	Humana Inc.	HUM	$454.23	$3.15	0.69%	14.01%	10.50%	14.07%	126.493	57.457	0.002019	0.000014	57.457	0.002563	0.000359	57.46	0.002316	0.000243	57.46	0.002260	0.000318
178	Howmet Aerospace Inc	HWM	$35.77	$0.08	0.22%	NMF	17.00%	n/a	417.914	14.949	0.000525	0.000001				14.95	0.000603	0.000102			
179	International Business Machines Corp	IBM	$138.84	$6.60	4.75%	13.00%	0.50%	9.02%	899.435	124.878	0.004389	0.000209	124.878	0.005570	0.000724	124.88	0.005034	0.000025	124.88	0.004911	0.000443
180	Intercontinental Exchange Inc	ICE	$102.39	$1.52	1.48%	7.62%	6.50%	9.27%	558.266	57.161	0.002009	0.000030	57.161	0.002550	0.000194	57.16	0.002304	0.000150	57.16	0.002248	0.000208
181	IDEX Corp	IEX	$191.55	$2.40	1.25%	12.00%	10.00%	12.00%	76.006	14.559	0.000512	0.000006	14.559	0.000649	0.000078	14.56	0.000587	0.000059	14.56	0.000573	0.000069
182	International Flavors & Fragrances Inc	IFF	$132.17	$3.16	2.39%	3.70%	7.50%	10.19%	254.838	33.682	0.001184	0.000028	33.682	0.001502	0.000056	33.68	0.001358	0.000102	33.68	0.001325	0.000135
183	Intel Corp	INTC	$44.42	$1.46	3.29%	3.28%	6.00%	7.50%	4,089.000	181.633	0.006383	0.000210	181.633	0.008102	0.000266	181.63	0.007322	0.000439	181.63	0.007144	0.000536
184	Intuit Inc	INTU	$414.46	$2.72	0.66%	17.47%	17.50%	15.69%	282.077	116.910	0.004109	0.000027	116.910	0.005215	0.000911	116.91	0.004713	0.000825	116.91	0.004598	0.000721
185	International Paper Co	IP	$48.45	$1.85	3.82%	19.20%	12.50%	n/a	370.629	17.957	0.000631	0.000024	17.957	0.000801	0.000154	17.96	0.000724	0.000090			
186	Interpublic Group of Cos Inc (The)	IPG	$32.23	$1.18	3.66%	5.60%	10.00%	4.38%	393.664	12.688	0.000446	0.000016	12.688	0.000566	0.000032	12.69	0.000511	0.000051	12.69	0.000499	0.000022
187	Ingersoll Rand Inc	IR	$47.15	$0.08	0.17%	15.78%	n/a	n/a	405.930	19.140	0.000673	0.000001	19.140	0.000854	0.000135						
188	Iron Mountain Inc	IRM	$53.90	$2.48	4.60%	n/a	11.00%	4.00%	290.562	15.661	0.000550	0.000025				15.66	0.000631	0.000069	15.66	0.000616	0.000025
189	Illinois Tool Works Inc	ITW	$208.07	$4.88	2.35%	10.68%	11.00%	10.00%	311.443	64.802	0.002277	0.000053	64.802	0.002891	0.000309	64.80	0.002612	0.000287	64.80	0.002549	0.000255
190	Invesco Ltd	IVZ	$19.34	$0.80	4.14%	0.70%	14.00%	6.00%	455.025	8.800	0.000309	0.000013	8.800	0.000393	0.000003	8.80	0.000355	0.000050	8.80	0.000346	0.000021
191	Jacobs Engineering Group Inc	J	$140.09	$0.92	0.66%	13.76%	12.00%	12.05%	128.627	18.019	0.000633	0.000004	18.019	0.000804	0.000111	18.02	0.000726	0.000087	18.02	0.000709	0.000085
192	J.B. Hunt Transport Services Inc.	JBHT	$172.58	$1.63	0.94%	NMF	11.50%	15.00%	104.783	18.083	0.000636	0.000006				18.08	0.000729	0.000084	18.08	0.000711	0.000107
193	Johnson Controls International Plc	JCI	$54.51	$1.40	2.57%	17.41%	12.50%	15.01%	695.669	37.921	0.001333	0.000034	37.921	0.001691	0.000295	37.92	0.001529	0.000191	37.92	0.001491	0.000224
194	Henry (Jack) & Associates Inc	JKHY	$188.12	$1.96	1.04%	n/a	9.00%	9.00%	72.862	13.707	0.000482	0.000005				13.71	0.000553	0.000050	13.71	0.000539	0.000049
195	Johnson & Johnson	JNJ	$179.55	$4.52	2.52%	4.63%	6.00%	4.94%	2,631.402	472.416	0.016603	0.000418	472.416	0.021072	0.000976	472.42	0.019043	0.001523	472.42	0.018580	0.000918
196	Juniper Networks Inc	JNPR	$30.68	$0.84	2.74%	13.86%	9.00%	7.97%	323.095	9.913	0.000348	0.000010	9.913	0.000442	0.000061	9.91	0.000400	0.000036	9.91	0.000390	0.000031
197	JPMorgan Chase & Co	JPM	$132.25	$4.30	3.25%	7.21%	7.00%	5.00%	2,937.050	388.366	0.013649	0.000444	388.366	0.017323	0.001249	388.37	0.015655	0.001096	388.37	0.015274	0.000764
198	Kellogg Co	K	$69.74	$2.35	3.37%	2.57%	4.00%	3.79%	337.873	23.563	0.000828	0.000028	23.563	0.001051	0.000027	23.56	0.000950	0.000038	23.56	0.000977	0.000035
199	KeyCorp	KEY	$19.96	$0.78	3.91%	0.53%	9.00%	18.24%	932.471	18.612	0.000654	0.000026	18.612	0.000830	0.000004	18.61	0.000750	0.000068	18.61	0.000732	0.000134
200	The Kraft Heinz Co	KHC	$37.83	$1.60	4.23%	NMF	3.00%	5.00%	1,223.952	46.302	0.001627	0.000069				46.30	0.001866	0.000056	46.30	0.001821	0.000091
201	Kimco Realty Corp	KIM	$23.65	$0.80	3.39%	n/a	8.50%	6.83%	618.007	14.616	0.000514	0.000017				14.62	0.000589	0.000050	14.62	0.000575	0.000039
202	KLA Corp	KLAC	$364.85	$4.20	1.15%	NMF	NMF	19.39%	149.235	54.448	0.001914	0.000022							54.45	0.002141	0.000415
203	Kimberly-Clark Corp	KMB	$133.02	$4.64	3.49%	5.41%	5.50%	5.00%	336.925	44.818	0.001575	0.000055	44.818	0.001999	0.000108	44.82	0.001807	0.000099	44.82	0.001763	0.000088
204	Kinder Morgan Inc	KMI	$19.69	$1.11	5.64%	NMF	19.00%	3.00%	2,267.473	44.647	0.001569	0.000088				44.65	0.001800	0.000342	44.65	0.001756	0.000053
205	Coca-Cola Co (The)	KO	$63.38	$1.76	2.78%	6.58%	7.50%	6.99%	4,335.029	274.754	0.009656	0.000268	274.754	0.012256	0.000806	274.75	0.011075	0.000831	274.75	0.010806	0.000755
206	Kroger Co. (The)	KR	$52.97	$0.93	1.76%	5.53%	5.50%	9.88%	727.753	38.549	0.001355	0.000024	38.549	0.001720	0.000095	38.55	0.001554	0.000085	38.55	0.001516	0.000150
207	Loews Corp	L	$65.49	$0.25	0.38%	n/a	16.00%	n/a	246.108	16.118	0.000566	0.000002				16.12	0.000650	0.000104			
208	Leidos Holdings Inc	LDOS	$104.50	$1.44	1.38%	7.50%	9.00%	6.92%	136.662	14.281	0.000502	0.000007	14.281	0.000637	0.000048	14.28	0.000576	0.000052	14.28	0.000562	0.000039
209	Lennar Corp	LEN	$80.25	$1.53	1.91%	n/a	8.50%	1.02%	258.621	20.754	0.000729	0.000014				20.75	0.000837	0.000071	20.75	0.000816	0.000008
210	Laboratory Corp of America Holdings	LH	$246.73	$2.88	1.17%	NMF	1.50%	n/a	92.700	22.871	0.000804	0.000009				22.87	0.000922	0.000014			
211	L3Harris Technologies Inc	LHX	$240.90	$4.48	1.86%	6.20%	18.50%	4.39%	192.875	46.464	0.001633	0.000030	46.464	0.002073	0.000128	46.46	0.001873	0.000346	46.46	0.001627	0.000060
212	Linde Plc	LIN	$324.68	$4.68	1.44%	10.69%	12.00%	10.00%	502.725	163.225	0.005736	0.000083	163.225	0.007281	0.000778	163.22	0.006580	0.000790	163.22	0.006420	0.000842
213	LKQ Corporation	LKQ	$51.39	$1.00	1.95%	n/a	13.00%	n/a	282.835	14.535	0.000511	0.000010				14.53	0.000586	0.000076			
214	Eli Lilly and Co	LLY	$313.44	$3.92	1.25%	14.48%	11.50%	15.32%	950.160	297.818	0.010467	0.000131	297.818	0.013284	0.001923	297.82	0.012005	0.001381	297.82	0.011713	0.001794
215	Lockheed Martin Corp	LMT	$340.11	$11.60	2.64%	8.20%	7.00%	5.68%	266.107	117.116	0.004116	0.000108	117.116	0.005224	0.000428	117.12	0.004721	0.000330	117.12	0.004606	0.000262
216	Lincoln National Corp	LNC	$57.93	$1.86	3.21%	NMF	11.50%	18.95%	171.947	9.961	0.000350	0.000011				9.96	0.000402	0.000046	9.96	0.000392	0.000074
217	Alliant Energy Corporation	LNT	$63.82	$1.74	2.73%	5.40%	4.50%	5.72%	250.814	16.007	0.000563	0.000015	16.007	0.000714	0.000039	16.01	0.000645	0.000029	16.01	0.000630	0.000036
218	Lowe's Cos Inc	LOW	$195.30	$3.50	1.79%	15.05%	15.50%	12.56%	639.129	124.822	0.004387	0.000079	124.822	0.005568	0.000838	124.82	0.005032	0.000780	124.82	0.004909	0.000617
219	Lam Research Corp	LRCX	$520.03	$6.00	1.15%	13.95%	17.00%	15.48%	138.715	72.136	0.002535	0.000029	72.136	0.003218	0.000449	72.14	0.002908	0.000494	72.14	0.002837	0.000439
220	Lumen Technologies Inc	LUMN	$12.24	$1.00	8.17%	NMF	1.50%	7.98%	1,033.055	12.645	0.000444	0.000036				12.64	0.000510	0.000008	12.64	0.000497	0.000040
221	Lamb Weston Holdings Inc	LW	$67.58	$0.99	1.46%	14.75%	5.00%	14.00%	144.447	9.762	0.000343	0.000005	9.762	0.000435	0.000064	9.76	0.000393	0.000020	9.76	0.000384	0.000054
222	LyondellBasell Industries NV	LYB	$114.25	$4.52	3.96%	3.32%	3.50%	8.00%	327.622	37.431	0.001315	0.000052	37.431	0.001670	0.000055	37.43	0.001509	0.000053	37.43	0.001472	0.000118
223	Mastercard Inc	MA	$357.87	$1.96	0.55%	NMF	13.50%	NMF	972.645	348.080	0.012233	0.000067				348.08	0.014031	0.001894			
224	Mid-America Apartment Communities Inc	MAA	$181.07	$5.00	2.76%	n/a	8.50%	2.00%	115.428	20.892	0.000734	0.000020				20.89	0.000842	0.000072	20.89	0.000822	0.000016
225	Marriott International Inc	MAR	$171.58	$1.20	0.70%	NMF	NMF	n/a	327.298	56.158	0.001974	0.000014									
226	Masco Corporation	MAS	$56.69	$1.12	1.98%	n/a	9.00%	11.59%	235.940	13.375	0.000470	0.000009				13.38	0.000539	0.000049	13.38	0.000526	0.000061
227	McDonald's Corp	MCD	$252.21	$5.68	2.25%	7.70%	10.50%	8.02%	739.547	186.521	0.006555	0.000148	186.521	0.008320	0.000640	186.52	0.007519	0.000789	186.52	0.007336	0.000588
228	Microchip Technology Inc	MCHP	$72.63	$1.01	1.39%	NMF	10.00%	NMF	554.501	40.284	0.001416	0.000020				40.28	0.001624	0.000162			
229	McKesson Corp	MCK	$328.01	$1.88	0.57%	13.59%	11.50%	9.42%	145.365	47.780	0.001679	0.000010	47.780	0.002131	0.000290	47.78	0.001926	0.000221	47.78	0.001879	0.000177
230	Moody's Corp	MCO	$301.57	$2.80	0.93%	5.30%	8.00%	11.00%	184.500	55.640	0.001955	0.000018	55.640	0.002482	0.000132	55.64	0.002243	0.000179	55.64	0.002188	0.000241
231	Mondelez International Inc	MDLZ	$63.56	$1.40	2.20%	6.93%	8.00%	6.80%	1,383.924	87.962	0.003091	0.000068	87.962	0.003924	0.000272	87.96	0.003546	0.000284	87.96	0.003460	0.000235
232	Medtronic PLC	MDT	$100.15	$2.72	2.72%	12.66%	6.00%	7.56%	1,330.743	133.274	0.004684	0.000127	133.274	0.005945	0.000753	133.27	0.005372	0.000430	133.27	0.005242	0.000396
233	Metlife Inc	MET	$67.39	$2.00	2.97%	9.18%	5.00%	7.41%	813.206	54.802	0.001926	0.000057	54.802	0.002444	0.000224	54.80	0.002209	0.000110	54.80	0.002155	0.000160
234	MGM Resorts International	MGM	$34.97	$0.01	0.03%	n/a	n/a	n/a	426.052	14.899	0.000524	0.000000									
235	McCormick & Co Inc	MKC	$92.72	$1.50	1.62%	6.95%	6.00%	6.09%	250.226	23.201	0.000815	0.000013	23.201	0.001035	0.000072	23.20	0.000935	0.000056	23.20	0.000912	0.000056
236	MarketAxess Holdings Inc	MKTX	$281.68	$2.80	0.99%	11.07%	11.50%	n/a	37.742	10.631	0.000374	0.000004	10.631	0.000474	0.000052	10.63	0.000429	0.000049			
237	Martin Marietta Materials Inc	MLM	$339.38	$2.46	0.72%	16.80%	8.50%	16.88%	62.365	21.165	0.000744	0.000005	21.165	0.000944	0.000159	21.17	0.000853	0.000073	21.17	0.000832	0.000141
238	Marsh & McLennan Companies Inc	MMC	$159.95	$2.14	1.34%	8.60%	11.50%	8.63%	501.914	80.281	0.002821	0.000038	80.281	0.003581	0.000308	80.28	0.003236	0.000372	80.28	0.003157	0.000272
239	3M Co	MMM	$149.29	$5.96	3.99%	6.58%	5.50%	9.50%	569.059	84.955	0.002986	0.000119	84.955	0.003789	0.000249	84.95	0.003425	0.000188	84.95	0.003341	0.000317
240	Altria Group Inc	MO	$54.09	$3.60	6.66%	5.51%	3.50%	4.00%	1,810.557	97.933	0.003442	0.000229	97.933	0.004368	0.000241	97.93	0.003948	0.000217	97.93	0.003852	0.000154
241	Mosaic Company (The)	MOS	$62.65	$0.64	1.02%	n/a	NMF	7.00%	361.993	22.679	0.000797	0.000008							22.68	0.000892	0.000062
242	Marathon Petroleum Corp	MPC	$101.79	$2.32	2.28%	NMF	n/a	18.54%	540.995	55.068	0.001935	0.000044							55.07	0.002166	0.000402
243	Monolithic Power Systems Inc	MPWR	$450.39	$3.00	0.67%	NMF	18.00%	NMF	46.643	21.008	0.000738	0.000005				21.01	0.000847	0.000152			
244	Merck & Co Inc	MRK	$92.03	$2.76	3.00%	11.63%	8.50%	[illegible]	2,528.805	232.726	0.008179	0.000245	232.726	0.010381	0.001207	232.73	0.009381	0.000797	232.73	0.009153	0.000927
245	Marathon Oil Corp	MRO	$31.43	$0.39	1.24%	10.65%	NMF	14.38%	707.691	22.243	0.000782	0.000010	22.243	0.000992	0.000106				22.24	0.000875	0.000126
246	Morgan Stanley	MS	$86.14	$2.80	3.25%	5.55%	9.00%	8.00%	1,749.284	150.683	0.005296	0.000172	150.683	0.006721	0.000373	150.68	0.006074	0.000547	150.68	0.005926	0.000474
247	MSCI Inc	MSCI	$442.35	$4.55	1.03%	15.20%	14.50%	n/a	81.125	35.885	0.001261	0.000013	35.885	0.001601	0.000243	35.88	0.001447	0.000210			
248	Microsoft Corp	MSFT	$271.87	$2.52	0.93%	16.23%	16.50%	12.63%	7,479.033	2,033.325	0.071460	0.000662	2,033.325	0.090698	0.014723	2,033.32	0.081963	0.013524	2,033.32	0.079971	0.010100

249	Motorola Solutions Inc	MSI	$219.74	$3.16	1.44%	14.28%	8.00%	9.00%	167.297	36.762	0.001292	0.000019	36.762	0.001640	0.000234	36.76	0.001482	0.000119	36.76	0.001446	0.000130
250	M&T Bank Corp	MTB	$179.97	$5.00	2.78%	5.69%	8.00%	12.29%	179.417	32.290	0.001135	0.000032	32.290	0.001440	0.000082	32.29	0.001302	0.000104	32.29	0.001270	0.000156
251	Micron Technology Inc	MU	$73.84	$0.40	0.54%	NMF	NMF	NMF	1,116.667	82.455	0.002898	0.000016									
252	Nasdaq Inc	NDAQ	$155.25	$2.40	1.55%	7.95%	6.00%	9.82%	164.678	25.568	0.000899	0.000014	25.568	0.001140	0.000091	25.57	0.001031	0.000062	25.57	0.001006	0.000099
253	Nordson Corp	NDSN	$217.88	$2.10	0.96%	13.00%	12.00%	13.00%	57.941	12.624	0.000444	0.000004	12.624	0.000563	0.000073	12.62	0.000509	0.000061	12.62	0.000497	0.000065
254	NextEra Energy Inc	NEE	$75.69	$1.74	2.30%	9.31%	12.50%	8.82%	1,964.500	148.693	0.005226	0.000120	148.693	0.006633	0.000618	148.69	0.005994	0.000749	148.69	0.005848	0.000516
255	Newmont Corporation	NEM	$67.85	$2.20	3.24%	NMF	9.50%	n/a	793.651	53.849	0.001892	0.000061				53.85	0.002171	0.000206			
256	NiSource Inc	NI	$31.45	$0.94	2.99%	7.18%	9.50%	7.19%	405.798	12.762	0.000449	0.000013	12.762	0.000569	0.000041	12.76	0.000514	0.000049	12.76	0.000502	0.000036
257	Nike Inc	NKE	$118.85	$1.22	1.03%	15.34%	NMF	14.00%	1,573.767	187.042	0.006573	0.000067	187.042	0.008343	0.001280				187.04	0.007356	0.001030
258	NortonLifeLock Inc	NLOK	$24.34	$0.50	2.05%	8.10%	9.50%	n/a	580.064	14.119	0.000496	0.000010	14.119	0.000630	0.000051	14.12	0.000569	0.000054			
259	Nielsen Holdings plc	NLSN	$25.56	$0.24	0.94%	n/a	NMF	n/a	359.693	9.194	0.000323	0.000003									
260	Northrop Grumman Corp	NOC	$467.97	$6.92	1.48%	6.10%	6.50%	6.10%	155.445	72.744	0.002557	0.000038	72.744	0.003245	0.000198	72.74	0.002932	0.000191	72.74	0.002861	0.000175
261	NRG Energy Inc	NRG	$46.04	$1.40	3.04%	NMF	NMF	10.51%	237.284	10.925	0.000384	0.000012							10.92	0.000430	0.000045
262	Norfolk Southern Corp	NSC	$239.66	$4.96	2.07%	11.15%	10.50%	10.48%	238.333	57.119	0.002007	0.000042	57.119	0.002548	0.000284	57.12	0.002302	0.000242	57.12	0.002246	0.000235
263	NetApp Inc	NTAP	$71.95	$2.00	2.78%	8.80%	8.00%	8.79%	222.536	16.011	0.000563	0.000016	16.011	0.000714	0.000063	16.01	0.000645	0.000052	16.01	0.000630	0.000055
264	Northern Trust Corp	NTRS	$111.75	$2.80	2.51%	8.65%	8.00%	n/a	208.380	23.286	0.000818	0.000021	23.286	0.001039	0.000090	23.29	0.000939	0.000075			
265	Nucor Corp	NUE	$132.46	$2.00	1.51%	NMF	NMF	n/a	266.062	35.243	0.001239	0.000019									
266	NVIDIA Corporation	NVDA	$186.72	$0.16	0.09%	NMF	NMF	16.40%	2,504.014	467.549	0.016432	0.000014							467.55	0.018389	0.003016
267	Newell Brands Inc	NWL	$21.44	$0.92	4.29%	4.61%	n/a	n/a	413.500	8.865	0.000312	0.000013	8.865	0.000395	0.000018						
268	News Corp	NWS	$17.58	n/a	n/a	n/a	n/a	n/a	197.272	3.468	0.000122										
269	News Corp	NWSA	$17.40	$0.20	1.15%	19.14%	n/a	n/a	388.469	6.759	0.000238	0.000003	6.759	0.000302	0.000058						
270	NXP Semiconductors NV	NXPI	$189.76	$3.38	1.78%	11.06%	12.00%	NMF	262.565	49.824	0.001751	0.000031	49.824	0.002222	0.000246	49.82	0.002006	0.000241			
271	Realty Income Corp	O	$68.22	$2.97	4.35%	n/a	3.50%	3.54%	601.398	41.041	0.001442	0.000063				41.04	0.001654	0.000058	41.04	0.001614	0.000057
272	Old Dominion Freight Line Inc	ODFL	$258.24	$1.23	0.48%	NMF	10.50%	17.31%	113.354	29.273	0.001029	0.000005				29.27	0.001180	0.000124	29.27	0.001151	0.000199
273	Organon & Co	OGN	$37.96	n/a	n/a	NMF	n/a	n/a	253.637	9.628	0.000338										
274	ONEOK Inc	OKE	$65.85	$3.74	5.68%	10.87%	11.50%	8.37%	446.616	29.410	0.001034	0.000059	29.410	0.001312	0.000143	29.41	0.001186	0.000136	29.41	0.001157	0.000097
275	Omnicom Group Inc	OMC	$74.61	$3.00	4.02%	10.60%	6.50%	5.32%	205.733	15.350	0.000539	0.000022	15.350	0.000685	0.000073	15.35	0.000619	0.000040	15.35	0.000604	0.000032
276	Oracle Corp	ORCL	$71.92	$1.28	1.78%	10.25%	9.00%	8.00%	2,668.157	191.894	0.006744	0.000120	191.894	0.008560	0.000877	191.89	0.007735	0.000696	191.89	0.007547	0.000604
277	Otis Worldwide Corp	OTIS	$74.40	$1.16	1.56%	9.20%	n/a	n/a	422.794	31.456	0.001105	0.000017	31.456	0.001403	0.000129						
278	Occidental Petroleum Corp	OXY	$69.31	$0.59	0.85%	NMF	n/a	NMF	937.191	64.957	0.002283	0.000019									
279	Paramount Global	PARA	$34.33	$0.96	2.80%	NMF	4.50%	6.15%	608.395	20.886	0.000734	0.000021				20.89	0.000842	0.000038	20.89	0.000821	0.000067
280	Paychex Inc	PAYX	$123.83	$3.16	2.55%	13.32%	9.50%	7.50%	361.000	44.703	0.001571	0.000040	44.703	0.001994	0.000266	44.70	0.001802	0.000171	44.70	0.001758	0.000132
281	PACCAR Inc	PCAR	$86.84	$2.86	3.29%	8.28%	9.50%	10.00%	347.683	30.193	0.001061	0.000035	30.193	0.001347	0.000111	30.19	0.001217	0.000115	30.19	0.001187	0.000119
282	Healthpeak Properties Inc	PEAK	$29.69	$1.20	4.04%	n/a	NMF	5.31%	539.557	16.019	0.000563	0.000023							16.02	0.000630	0.000033
283	Public Service Enterprise Group Inc	PEG	$68.54	$2.19	3.20%	6.49%	4.00%	3.79%	499.259	34.219	0.001203	0.000038	34.219	0.001526	0.000099	34.22	0.001379	0.000055	34.22	0.001346	0.000078
284	PepsiCo Inc	PEP	$167.75	$4.40	2.62%	7.48%	6.00%	7.57%	1,382.684	231.945	0.008152	0.000214	231.945	0.010346	0.000774	231.95	0.009350	0.000561	231.95	0.009122	0.000691
285	Pfizer Inc	PFE	$53.04	$1.60	3.02%	NMF	6.50%	12.47%	5,610.896	297.602	0.010459	0.000316				297.60	0.011996	0.000780	297.60	0.011705	0.001460
286	Principal Financial Group Inc	PFG	$72.93	$2.56	3.51%	13.66%	6.50%	8.09%	252.684	18.428	0.000648	0.000023	18.428	0.000822	0.000112	18.43	0.000743	0.000048	18.43	0.000725	0.000059
287	Procter & Gamble Co (The)	PG	$147.88	$3.65	2.47%	5.76%	6.50%	6.05%	2,399.297	354.808	0.012470	0.000308	354.808	0.015826	0.000911	354.81	0.014302	0.000930	354.81	0.013955	0.000844
288	Progressive Corp (The)	PGR	$119.38	$0.40	0.34%	NMF	6.50%	17.27%	584.900	69.825	0.002454	0.000008				69.83	0.002815	0.000183	69.83	0.002746	0.000474
289	Parker-Hannifin Corp	PH	$272.17	$5.32	1.95%	10.62%	12.50%	9.00%	128.372	34.939	0.001228	0.000024	34.939	0.001558	0.000165	34.94	0.001408	0.000176	34.94	0.001374	0.000124
290	PulteGroup Inc	PHM	$45.26	$0.62	1.37%	n/a	9.50%	5.02%	237.627	10.755	0.000378	0.000005				10.75	0.000434	0.000041	10.75	0.000423	0.000021
291	Packaging Corp Of America	PKG	$157.28	$5.00	3.18%	9.71%	9.50%	5.00%	93.701	14.737	0.000518	0.000016	14.737	0.000657	0.000064	14.74	0.000594	0.000056	14.74	0.000580	0.000029
292	PerkinElmer Inc	PKI	$149.67	$0.28	0.19%	n/a	5.00%	NMF	126.148	18.881	0.000664	0.000001				18.88	0.000761	0.000038			
293	Prologis Inc	PLD	$127.48	$3.21	2.52%	n/a	6.00%	9.80%	740.267	94.369	0.003317	0.000084				94.37	0.003804	0.000228	94.37	0.003712	0.000364
294	Philip Morris International Inc	PM	$106.25	$5.00	4.71%	4.05%	6.00%	5.13%	1,550.110	164.699	0.005788	0.000272	164.699	0.007347	0.000297	164.70	0.006639	0.000398	164.70	0.006478	0.000332
295	The PNC Financial Services Group Inc	PNC	$175.41	$6.00	3.42%	NMF	12.00%	5.09%	413.581	72.546	0.002549	0.000087				72.55	0.002924	0.000351	72.55	0.002853	0.000145
296	Pentair plc	PNR	$50.17	$0.84	1.67%	8.30%	12.50%	10.44%	165.400	8.298	0.000292	0.000005	8.298	0.000370	0.000031	8.30	0.000334	0.000042	8.30	0.000326	0.000034
297	Pinnacle West Capital Corp	PNW	$77.65	$3.44	4.43%	n/a	1.50%	n/a	113.001	8.775	0.000308	0.000014				8.77	0.000354	0.000005			
298	Pool Corp	POOL	$398.62	$4.00	1.00%	n/a	14.00%	10.00%	40.025	15.955	0.000561	0.000006				15.95	0.000643	0.000090	15.95	0.000628	0.000063
299	PPG Industries Inc	PPG	$126.49	$2.36	1.87%	14.27%	4.00%	11.98%	236.148	29.870	0.001050	0.000020	29.870	0.001332	0.000190	29.87	0.001204	0.000348	29.87	0.001175	0.000141
300	PPL Corp	PPL	$30.18	$0.96	3.18%	16.11%	NMF	n/a	735.903	22.210	0.000781	0.000025	22.210	0.000991	0.000160						
301	Prudential Financial Inc	PRU	$106.25	$4.80	4.52%	2.95%	5.00%	8.98%	375.000	39.844	0.001400	0.000063	39.844	0.001777	0.000052	39.84	0.001606	0.000080	39.84	0.001567	0.000141
302	Public Storage	PSA	$330.64	$8.05	2.43%	n/a	8.00%	7.05%	175.529	58.037	0.002040	0.000050				58.04	0.002339	0.000187	58.04	0.002283	0.000161
303	Phillips 66	PSX	$100.81	$3.88	3.85%	8.10%	NMF	11.06%	481.100	48.500	0.001704	0.000066	48.500	0.002163	0.000175				48.50	0.001908	0.000211
304	PVH Corp	PVH	$70.87	$0.15	0.21%	n/a	13.50%	6.12%	67.522	4.785	0.000168	0.000000				4.79	0.000193	0.000026	4.79	0.000188	0.000012
305	Quanta Services Inc	PWR	$119.00	$0.28	0.24%	16.84%	16.50%	n/a	143.709	17.101	0.000601	0.000001	17.101	0.000763	0.000128	17.10	0.000689	0.000114			
306	Pioneer Natural Resources Co	PXD	$277.94	$15.12	5.44%	17.40%	NMF	8.55%	241.959	67.250	0.002363	0.000129	67.250	0.003000	0.000522				67.25	0.002645	0.000226
307	QUALCOMM Inc	QCOM	$143.22	$3.00	2.09%	14.34%	19.00%	16.28%	1,120.000	160.406	0.005637	0.000118	160.406	0.007155	0.001026	160.41	0.006466	0.001229	160.41	0.006309	0.001027
308	Everest Re Group Ltd	RE	$282.50	$6.60	2.34%	n/a	17.50%	9.94%	39.438	11.141	0.000392	0.000009				11.14	0.000449	0.000079	11.14	0.000438	0.000044
309	Regency Centers Corp	REG	$68.21	$2.50	3.67%	n/a	12.50%	2.69%	172.362	11.757	0.000413	0.000015				11.76	0.000474	0.000059	11.76	0.000462	0.000012
310	Regions Financial Corp	RF	$22.09	$0.76	3.44%	n/a	10.00%	16.06%	934.500	20.643	0.000725	0.000025				20.64	0.000832	0.000083	20.64	0.000812	0.000130
311	Robert Half International Inc	RHI	$90.15	$1.72	1.91%	11.50%	11.50%	9.51%	110.514	9.963	0.000350	0.000007	9.963	0.000444	0.000051	9.96	0.000402	0.000046	9.96	0.000392	0.000037
312	Raymond James Financial Inc	RJF	$98.49	$1.36	1.38%	n/a	14.50%	n/a	208.249	20.510	0.000721	0.000010				20.51	0.000827	0.000120			
313	Ralph Lauren Corp	RL	$101.09	$3.00	2.97%	NMF	11.50%	8.96%	70.075	7.084	0.000249	0.000007				7.08	0.000286	0.000033	7.08	0.000279	0.000025
314	Resmed Inc	RMD	$203.46	$1.68	0.83%	NMF	13.50%	15.73%	146.285	29.763	0.001046	0.000009				29.76	0.001200	0.000162	29.76	0.001171	0.000184
315	Rockwell Automation Inc	ROK	$213.20	$4.50	2.11%	9.28%	9.50%	8.49%	116.262	24.787	0.000871	0.000018	24.787	0.001106	0.000103	24.79	0.000999	0.000095	24.79	0.000975	0.000083
316	ROLLINS INC	ROL	$35.46	$0.40	1.13%	n/a	9.50%	n/a	492.461	17.463	0.000614	0.000007				17.46	0.000704	0.000067			
317	Roper Technologies Inc	ROP	$442.44	$2.48	0.56%	7.70%	9.00%	10.50%	105.913	46.860	0.001647	0.000009	46.860	0.002090	0.000161	46.86	0.001889	0.000170	46.86	0.001843	0.000194
318	Ross Stores Inc	ROST	$85.02	$1.27	1.49%	NMF	13.50%	10.50%	351.392	29.875	0.001050	0.000016				29.88	0.001204	0.000163	29.88	0.001175	0.000123
319	Republic Services Inc	RSG	$133.84	$1.84	1.37%	10.49%	12.50%	10.53%	315.891	42.279	0.001486	0.000020	42.279	0.001886	0.000198	42.28	0.001704	0.000213	42.28	0.001663	0.000175
320	Raytheon Technologies Corp	RTX	$95.12	$2.20	2.31%	16.20%	7.00%	10.51%	1,487.215	141.464	0.004972	0.000115	141.464	0.006310	0.001022	141.46	0.005702	0.000399	141.46	0.005564	0.000585
321	SBA Communications Corp	SBAC	$336.61	$2.90	0.86%	NMF	NMF	n/a	107.829	36.296	0.001276	0.000011									
322	Signature Bank	SBNY	$216.27	$2.24	1.04%	n/a	NMF	9.50%	62.751	13.571	0.000477	0.000005							13.57	0.000534	0.000051
323	Starbucks Corp	SBUX	$78.50	$2.04	2.60%	7.88%	16.50%	11.74%	1,146.900	90.032	0.003164	0.000082	90.032	0.004016	0.000316	90.03	0.003629	0.000599	90.03	0.003541	0.000416
324	Schwab (Charles) Corp	SCHW	$70.10	$0.80	1.14%	NMF	9.00%	NMF	1,896.351	132.934	0.004672	0.000053				132.93	0.005359	0.000482			
325	Sealed Air Corp	SEE	$62.18	$0.80	1.29%	12.07%	9.50%	10.58%	146.084	9.084	0.000319	0.000004	9.084	0.000405	0.000049	9.08	0.000366	0.000035	9.08	0.000357	0.000038
326	Sherwin-Williams Co (The)	SHW	$268.04	$2.40	0.90%	14.70%	11.50%	13.19%	260.131	69.726	0.002450	0.000022	69.726	0.003110	0.000457	69.73	0.002811	0.000323	69.73	0.002742	0.000362
327	The J M Smucker Company	SJM	$125.37	$4.05	3.23%	1.61%	4.00%	n/a	108.458	13.597	0.000478	0.000015	13.597	0.000607	0.000010	13.60	0.000548	0.000022			
328	Schlumberger Ltd	SLB	$45.96	$0.70	1.52%	NMF	NMF	n/a	1,413.361	64.963	0.002283	0.000035									

329	Snap-On Inc	SNA	$221.88	$6.04	2.72%	4.60%	4.50%	7.86%	53.374	11.843	0.000416	0.000011	11.843	0.000528	0.000024	11.84	0.000477	0.000021	11.84	0.000466	0.000037
330	Southern Co (The)	SO	$75.66	$2.72	3.60%	6.10%	6.50%	4.00%	1,062.525	80.391	0.002825	0.000102	80.391	0.003586	0.000219	80.39	0.003241	0.000211	80.39	0.003162	0.000126
331	Simon Property Group Inc	SPG	$114.65	$6.80	5.93%	n/a	2.50%	3.64%	328.639	37.676	0.001324	0.000079				37.68	0.001519	0.000038	37.68	0.001482	0.000054
332	S&P Global Inc	SPGI	$349.48	$3.40	0.97%	n/a	12.50%	12.00%	339.900	118.788	0.004175	0.000041				118.79	0.004788	0.000599	118.79	0.004672	0.000561
333	Sempra	SRE	$163.86	$4.63	2.83%	6.83%	11.50%	5.64%	314.305	51.502	0.001810	0.000051	51.502	0.002297	0.000157	51.50	0.002076	0.000239	51.50	0.002026	0.000114
334	Steris Plc	STE	$228.20	$1.72	0.75%	n/a	11.50%	n/a	100.127	22.849	0.000803	0.000006				22.85	0.000921	0.000106			
335	State Street Corporation	STT	$72.49	$2.43	3.35%	10.73%	9.50%	8.00%	367.115	26.612	0.000935	0.000031	26.612	0.001187	0.000127	26.61	0.001073	0.000102	26.61	0.001047	0.000084
336	Seagate Technology Holdings plc	STX	$84.67	$2.80	3.31%	NMF	16.00%	1.21%	214.844	18.191	0.000639	0.000021				18.19	0.000733	0.000117	18.19	0.000715	0.000009
337	Constellation Brands Inc	STZ	$245.47	$3.20	1.30%	9.68%	5.00%	10.79%	162.763	39.953	0.001404	0.000018	39.953	0.001782	0.000172	39.95	0.001611	0.000081	39.95	0.001571	0.000170
338	Stanley Black & Decker Inc	SWK	$118.69	$3.63	3.06%	13.11%	8.50%	9.00%	150.965	17.918	0.000630	0.000019	17.918	0.000799	0.000105	17.92	0.000722	0.000061	17.92	0.000705	0.000063
339	Skyworks Solutions Inc	SWKS	$108.87	$2.24	2.06%	11.85%	15.50%	12.90%	160.926	17.520	0.000616	0.000013	17.520	0.000781	0.000093	17.52	0.000706	0.000109	17.52	0.000689	0.000069
340	Synchrony Financial	SYF	$37.04	$0.88	2.38%	NMF	6.00%	NMF	501.489	18.575	0.000653	0.000016				18.58	0.000749	0.000045			
341	Stryker Corp	SYK	$234.50	$2.78	1.19%	8.03%	6.50%	9.15%	378.154	88.677	0.003117	0.000037	88.677	0.003956	0.000318	88.68	0.003575	0.000304	88.68	0.003488	0.000319
342	Sysco Corporation	SYY	$84.18	$1.96	2.33%	NMF	16.50%	11.00%	509.476	42.888	0.001507	0.000035				42.89	0.001729	0.000285	42.89	0.001687	0.000186
343	AT&T Inc	T	$21.29	n/a	n/a	NMF	3.00%	3.57%	7,159.000	152.415	0.005357										
344	Molson Coors Beverage Company	TAP	$55.84	$1.52	2.72%	2.67%	NMF	4.74%	200.527	11.197	0.000394	0.000011	11.197	0.000499	0.000013				11.20	0.000440	0.000021
345	Bio-Techne Corp	TECH	$369.73	$1.32	0.36%	n/a	17.50%	NMF	39.234	14.506	0.000510	0.000002				14.51	0.000585	0.000102			
346	TE Connectivity Ltd	TEL	$129.39	$2.24	1.73%	n/a	10.50%	10.41%	322.174	41.686	0.001465	0.000025				41.69	0.001680	0.000176	41.69	0.001640	0.000171
347	Teradyne Inc	TER	$109.26	$0.44	0.40%	8.08%	12.00%	11.06%	160.203	17.504	0.000615	0.000002	17.504	0.000781	0.000063	17.50	0.000706	0.000085	17.50	0.000688	0.000076
348	Truist Financial Corp	TFC	$49.74	$1.98	3.98%	2.71%	6.50%	5.47%	1,331.414	66.225	0.002327	0.000093	66.225	0.002954	0.000080	66.22	0.002670	0.000174	66.22	0.002605	0.000142
349	Teleflex Inc	TFX	$287.74	$1.36	0.47%	10.40%	10.00%	10.74%	46.900	13.495	0.000474	0.000002	13.495	0.000602	0.000063	13.50	0.000544	0.000054	13.50	0.000531	0.000057
350	Target Corp	TGT	$161.88	$3.60	2.22%	19.59%	13.00%	12.91%	463.684	75.061	0.002638	0.000059	75.061	0.003348	0.000656	75.06	0.003026	0.000393	75.06	0.002952	0.000381
351	TJX Companies Inc (The)	TJX	$63.57	$1.18	1.86%	12.80%	15.00%	10.50%	1,174.434	74.659	0.002624	0.000049	74.659	0.003330	0.000426	74.66	0.003009	0.000451	74.66	0.002936	0.000308
352	Thermo Fisher Scientific Inc	TMO	$567.57	$1.20	0.21%	8.70%	10.00%	13.00%	391.462	222.182	0.007808	0.000017	222.182	0.009911	0.000862	222.18	0.008956	0.000896	222.18	0.008738	0.001136
353	Tapestry Inc	TPR	$34.50	$1.00	2.90%	NMF	15.00%	12.50%	251.802	8.687	0.000305	0.000009				8.69	0.000350	0.000053	8.69	0.000342	0.000043
354	T. Rowe Price Group Inc	TROW	$127.09	$4.90	3.86%	n/a	9.50%	5.92%	227.297	28.887	0.001015	0.000039				28.89	0.001164	0.000111	28.89	0.001136	0.000067
355	Travelers Companies Inc (The)	TRV	$179.04	$3.72	2.08%	7.06%	6.50%	3.45%	239.961	42.963	0.001510	0.000031	42.963	0.001916	0.000135	42.96	0.001732	0.000113	42.96	0.001690	0.000058
356	Tractor Supply Co	TSCO	$187.36	$3.68	1.96%	14.40%	14.50%	9.77%	111.882	20.962	0.000737	0.000014	20.962	0.000935	0.000135	20.96	0.000845	0.000123	20.96	0.000824	0.000081
357	Tyson Foods Inc	TSN	$89.61	$1.84	2.05%	n/a	4.50%	7.47%	361.549	32.398	0.001139	0.000023				32.40	0.001306	0.000059	32.40	0.001274	0.000095
358	Trane Technologies plc	TT	$138.08	$2.68	1.94%	18.58%	n/a	11.27%	233.860	32.287	0.001135	0.000022	32.287	0.001440	0.000268				32.29	0.001270	0.000143
359	Texas Instruments Inc	TXN	$176.76	$4.60	2.60%	10.00%	8.50%	9.33%	922.134	162.996	0.005728	0.000149	162.996	0.007271	0.000727	163.00	0.006570	0.000558	163.00	0.006411	0.000598
360	Textron Inc	TXT	$65.29	$0.08	0.12%	14.15%	10.50%	12.70%	215.083	14.043	0.000494	0.000001	14.043	0.000626	0.000089	14.04	0.000566	0.000059	14.04	0.000552	0.000070
361	UDR Inc	UDR	$47.80	$1.56	3.26%	n/a	10.50%	8.98%	318.401	15.220	0.000535	0.000017				15.22	0.000614	0.000064	15.22	0.000599	0.000054
362	Universal Health Services Inc	UHS	$124.61	$0.80	0.64%	9.46%	9.00%	4.11%	74.381	9.269	0.000326	0.000002	9.269	0.000413	0.000039	9.27	0.000374	0.000034	9.27	0.000365	0.000015
363	Unitedhealth Group Inc	UNH	$496.78	$5.80	1.17%	14.62%	12.00%	14.77%	938.172	466.065	0.016380	0.000191	466.065	0.020789	0.003039	466.07	0.018787	0.002254	466.07	0.018330	0.002707
364	Union Pacific Corp	UNP	$219.78	$5.20	2.37%	15.91%	9.50%	10.00%	628.025	138.027	0.004851	0.000115	138.027	0.006157	0.000979	138.03	0.005564	0.000529	138.03	0.005429	0.000543
365	United Parcel Service Inc	UPS	$182.25	$6.08	3.34%	14.10%	11.00%	8.95%	873.766	159.244	0.005597	0.000187	159.244	0.007103	0.001001	159.24	0.006419	0.000706	159.24	0.006263	0.000561
366	U.S. Bancorp	USB	$53.07	$2.02	3.81%	10.37%	6.00%	6.50%	1,485.740	78.848	0.002771	0.000105	78.848	0.003517	0.000365	78.85	0.003178	0.000191	78.85	0.003101	0.000202
367	Visa Inc	V	$212.17	$1.60	0.75%	18.15%	13.50%	16.44%	2,083.166	441.985	0.015533	0.000117	441.985	0.019715	0.003577	441.99	0.017816	0.002405	441.99	0.017383	0.002858
368	V.F. Corp	VFC	$50.46	$2.00	3.96%	NMF	8.00%	9.69%	388.323	19.595	0.000689	0.000027				19.59	0.000790	0.000063	19.59	0.000771	0.000075
369	Valero Energy Corp	VLO	$129.60	$3.92	3.02%	n/a	12.50%	6.00%	408.096	52.889	0.001859	0.000056				52.89	0.002132	0.000266	52.89	0.002080	0.000125
370	Vulcan Materials Co	VMC	$164.87	$1.60	0.97%	NMF	8.50%	17.85%	132.896	21.911	0.000770	0.000007				21.91	0.000883	0.000075	21.91	0.000862	0.000154
371	Vornado Realty Trust	VNO	$34.96	$2.12	6.06%	n/a	NMF	n/a	191.743	6.703	0.000236	0.000014									
372	VERISK ANALYTICS INC	VRSK	$174.92	$1.24	0.71%	9.20%	11.50%	10.23%	157.902	27.620	0.000971	0.000007	27.620	0.001232	0.000113	27.62	0.001113	0.000150	27.62	0.001086	0.000111
373	Ventas Inc	VTR	$56.74	$1.85	3.26%	n/a	10.50%	5.45%	399.696	22.679	0.000797	0.000026				22.68	0.000914	0.000096	22.68	0.000892	0.000049
374	Viatris Inc	VTRS	$12.27	n/a	n/a	NMF	n/a	6.75%	1,212.327	14.875	0.000523										
375	Verizon Communications Inc	VZ	$51.29	$2.57	5.01%	3.59%	3.00%	3.60%	4,199.644	215.400	0.007570	0.000379	215.400	0.009608	0.000345	215.40	0.008683	0.000260	215.40	0.008472	0.000305
376	Westinghouse Air Brake Technologies Corp	WAB	$94.46	$0.60	0.64%	n/a	9.50%	12.62%	182.648	17.253	0.000606	0.000004				17.25	0.000695	0.000066	17.25	0.000679	0.000086
377	Walgreens Boots Alliance Inc	WBA	$43.83	$1.91	4.36%	2.29%	5.00%	3.63%	863.773	37.859	0.001331	0.000058	37.859	0.001689	0.000039	37.86	0.001526	0.000076	37.86	0.001489	0.000054
378	WEC Energy Group Inc	WEC	$105.07	$2.96	2.82%	6.06%	6.00%	6.08%	315.435	33.143	0.001165	0.000033	33.143	0.001478	0.000090	33.14	0.001336	0.000080	33.14	0.001304	0.000079
379	Welltower Inc	WELL	$89.09	$2.50	2.81%	n/a	3.50%	8.28%	453.968	40.444	0.001421	0.000040				40.44	0.001630	0.000057	40.44	0.001591	0.000132
380	Wells Fargo & Co	WFC	$45.77	$1.05	2.29%	7.29%	11.50%	10.20%	3,790.352	173.484	0.006097	0.000140	173.484	0.007738	0.000564	173.48	0.006993	0.000804	173.48	0.006823	0.000696
381	Whirlpool Corp	WHR	$184.24	$7.00	3.80%	1.04%	7.00%	5.36%	56.202	10.355	0.000364	0.000014	10.355	0.000462	0.000005	10.35	0.000417	0.000029	10.35	0.000407	0.000022
382	Waste Management Inc	WM	$158.51	$2.60	1.64%	11.66%	8.00%	10.86%	415.160	65.807	0.002313	0.000038	65.807	0.002935	0.000342	65.81	0.002653	0.000212	65.81	0.002588	0.000281
383	Williams Cos Inc (The)	WMB	$37.06	$1.70	4.59%	5.10%	8.50%	3.50%	1,218.012	45.140	0.001586	0.000073	45.140	0.002013	0.000103	45.14	0.001820	0.000155	45.14	0.001775	0.000062
384	Walmart Inc	WMT	$128.63	$2.24	1.74%	9.53%	8.00%	5.50%	2,752.782	354.090	0.012444	0.000217	354.090	0.015794	0.001504	354.09	0.014273	0.001142	354.09	0.013926	0.000766
385	Berkley (W.R.) Corp	WRB	$71.13	$0.35	0.49%	9.00%	15.50%	9.00%	265.193	18.863	0.000663	0.000003	18.863	0.000841	0.000076	18.86	0.000760	0.000118	18.86	0.000742	0.000067
386	WestRock Company	WRK	$48.49	$1.00	2.06%	19.81%	17.00%	NMF	254.852	12.358	0.000434	0.000009	12.358	0.000551	0.000109	12.36	0.000498	0.000085			
387	West Pharmaceutical Services Inc	WST	$310.38	$0.72	0.23%	10.40%	17.00%	10.40%	74.076	22.992	0.000808	0.000002	22.992	0.001026	0.000107	22.99	0.000927	0.000158	22.99	0.000904	0.000094
388	Willis Towers Watson plc	WTW	$211.07	$3.28	1.55%	n/a	8.00%	15.64%	111.488	23.532	0.000827	0.000013				23.53	0.000949	0.000076	23.53	0.000926	0.000145
389	Weyerhaeuser Co	WY	$39.52	$0.72	1.82%	n/a	6.00%	n/a	744.498	29.423	0.001034	0.000019				29.42	0.001186	0.000071			
390	Xcel Energy Inc	XEL	$73.34	$1.98	2.63%	7.08%	6.00%	6.43%	544.653	41.034	0.001442	0.000038	41.034	0.001830	0.000130	41.03	0.001654	0.000099	41.03	0.001614	0.000104
391	Exxon Mobil Corp	XOM	$96.00	$3.52	3.67%	18.92%	NMF	NMF	4,212.543	404.404	0.014213	0.000521	404.404	0.018039	0.003413						
392	DENTSPLY SIRONA Inc	XRAY	$39.56	$0.50	1.26%	n/a	10.00%	n/a	215.452	8.523	0.000300	0.000004				8.52	0.000344	0.000034			
393	Xylem Inc	XYL	$84.25	$1.28	1.52%	n/a	9.00%	12.00%	180.093	15.173	0.000533	0.000008				15.17	0.000612	0.000055	15.17	0.000597	0.000072
394	YUM BRANDS INC	YUM	$121.47	$2.28	1.88%	9.70%	10.50%	11.71%	285.164	34.639	0.001217	0.000023	34.639	0.001545	0.000150	34.64	0.001396	0.000147	34.64	0.001362	0.000160
395	Zimmer Biomet Holdings Inc	ZBH	$120.21	$0.96	0.80%	7.00%	5.50%	6.16%	209.577	25.193	0.000885	0.000007	25.193	0.001124	0.000079	25.19	0.001016	0.000056	25.19	0.000991	0.000061
396	Zions Bancorporation National Association	ZION	$57.04	$1.58	2.77%	n/a	8.00%	1.18%	151.359	8.634	0.000303	0.000008				8.63	0.000348	0.000028	8.63	0.000340	0.000004
397	Zoetis Inc	ZTS	$170.93	$1.30	0.76%	11.05%	11.00%	11.78%	470.629	80.445	0.002827	0.000022	80.445	0.003588	0.000397	80.44	0.003243	0.000357	80.44	0.003164	0.000373
										28,454.052	1.000000		22,418.684	1.000000		24,807.744	1.000000		25,425.786	1.000000	
	Weighted Average											1.95%			11.03%			10.64%			10.12%
	Average Growth (IBES, Zacks, VL)																	10.60%			
																	DY+g	12.54%			

n/a Not Available
NMF Eliminated growth rates that were greater than 20%, as well as all negative values.

(a) Data for dividend paying components of S&P 500 index from fidelity.com (retrieved May 31, 2022).
(b) www.valueline.com (retrieved May 31, 2022).
(c) Est'd Div'd next 12 mos. divided by Price.
(d) www.zacks.com (retrieved May 31, 2022).
(e) Price multiplied by Shares Outstanding.

S&P Global
Market Intelligence

Table 1: ROEs authorized January 1990-September 2021

		Electric utilities			Gas utilities		
Year	**Period**	**Average ROE (%)**	**Median ROE (%)**	**Number of observations**	**Average ROE (%)**	**Median ROE (%)**	**Number of observations**
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	41	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
2014	Full year	9.91	9.78	38	9.78	9.78	26
2015	Full year	9.84	9.60	31	9.60	9.68	16
	1st quarter	10.29	10.50	9	9.48	9.50	6
	2nd quarter	9.60	9.60	7	9.42	9.52	6
	3rd quarter	9.76	9.80	8	9.47	9.50	4
	4th quarter	9.57	9.58	18	9.68	9.73	10
2016	**Full year**	**9.77**	**9.75**	**42**	**9.54**	**9.50**	**26**
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.74	9.60	19	9.68	9.55	8
2017	**Full year**	**9.74**	**9.60**	**53**	**9.72**	**9.60**	**24**
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.67	9.70	11	9.69	9.60	13
	4th quarter	9.42	9.50	11	9.53	9.60	14
2018	**Full year**	**9.60**	**9.58**	**48**	**9.59**	**9.60**	**40**
	1st quarter	9.73	9.70	12	9.55	9.70	4
	2nd quarter	9.58	9.50	12	9.73	9.73	3
	3rd quarter	9.55	9.60	7	9.80	9.90	3
	4th quarter	9.71	9.70	16	9.73	9.70	22
2019	**Full year**	**9.66**	**9.65**	**47**	**9.71**	**9.70**	**32**
	1st quarter	9.58	9.50	19	9.35	9.40	9
	2nd quarter	9.55	9.45	9	9.55	9.65	3
	3rd quarter	9.30	9.33	10	9.52	9.45	8
	4th quarter	9.32	9.50	17	9.47	9.50	14
2020	**Full year**	**9.44**	**9.45**	**55**	**9.46**	**9.42**	**34**
	1st quarter	9.46	9.25	10	9.71	9.74	10
	2nd quarter	9.40	9.43	10	9.48	9.42	6
	3rd quarter	**9.38**	**9.40**	**13**	**9.40**	**9.45**	**10**
2021	**Year-to-date**	**9.41**	**9.38**	**33**	**9.54**	**9.52**	**26**
LTM ended 9/30/2021		**9.38**	**9.40**	**50**	**9.51**	**9.52**	**40**

Data compiled Oct. 26, 2021
Year-to-date through Sept. 30, 2021
Source: Regulatory Research Associates, a group within S&P Global Market Intelligence

Source: S&P Rate Case - Pending and Past Template

					Increase Requested					Increase Authorized												
State	Company	Case Identification	Service	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Requested Equity Ratio (% of Total Capital)	Rate Base ($000)	Date	Rate Change ($000)	Return on Rate Base (%)	Return on Equity (%)	Equity Ratio (% of Total Capital)	Test Year End	Rate Base ($000)	Rate Base Valuation Method	Lag Months	Case Type	Decision Type	Phase-in? Yes/No	Interim Authorized? Yes/No
GA	Atlanta Gas L	D-42315 (202	Natural Gas	7/1/2020	37,802	7.72	NA	56.00	3,626,710	7/1/2021	37,822	7.72	NA	56.00	12/31/2021	3,608,710	Average	6.13	Distribution	Fully Litigated	No	No
CO	Black Hills Co	D-20AL-0380	Natural Gas	9/11/2020	13,546	6.94	9.95	50.00	337,956	1/6/2021	NA	NA	NA	NA		NA		3.90	Distribution	Fully Litigated	No	No
DE	Delmarva Pow	D-20-0150	Natural Gas	3/31/2020	11,631	7.15	10.30	50.37	399,719	1/6/2021	6,700	6.60	9.60	50.37	3/31/2020	NA	Average	10.67	Distribution	Settled	No	Yes
OR	Cascade Nat	D-UG 390	Natural Gas	3/31/2020	4,508	7.08	9.40	50.00	132,616	1/6/2021	3,230	7.07	9.40	50.00	12/31/2020	130,095	Average	9.37	Distribution	Settled	No	No
IL	Ameren Illinoi	D-20-0308	Natural Gas	2/21/2020	97,373	7.84	10.50	54.09	2,119,898	1/13/2021	76,129	7.14	8.67	52.00	12/31/2021	2,098,105	Average	10.80	Distribution	Fully Litigated	No	No
MN	CenterPoint E	D-G-008/GR-	Natural Gas	10/28/2019	62,032	7.41	10.15	51.39	1,308,856	1/14/2021	38,520	6.86	NA	NA	12/31/2020	1,307,721	Average	14.80	Distribution	Settled	No	Yes
IN	Southern Indi	Ca-44429-TD	Natural Gas	10/1/2020	1,746	NA	NA	NA	213,531	1/20/2021	1,746	NA	NA	NA	8/30/2020	213,631	Year-end	3.70	Limited Issue	Fully Litigated	No	No
IN	Indiana Gas C	Ca-44430-TD	Natural Gas	10/1/2020	1,404	NA	NA	NA	828,719	1/20/2021	1,404	NA	NA	NA	8/30/2020	828,719	Year-end	3.70	Limited Issue	Fully Litigated	No	No
KS	Atmos Energ	D-21-ATMG-1	Natural Gas	11/3/2020	1,703	NA	NA	NA	17,184	1/26/2021	1,695	NA	NA	NA	9/30/2020	18,917	Year-end	2.80	Limited Issue	Fully Litigated	No	No
NE	Black Hills Ne	D-NG-100	Natural Gas	6/1/2020	15,865	6.98	10.00	50.00	503,782	1/26/2021	10,686	6.71	9.50	50.00	12/31/2019	502,852	Year-end	7.97	Distribution	Settled	No	Yes
MT	MDU Resourc	D2020.06.07	Natural Gas	6/23/2020	6,648	7.16	9.80	50.21	79,903	2/18/2021	7,260	NA	NA	NA		NA		7.97	Distribution	Settled	No	Yes
TN	Piedmont Nat	D-20-00086	Natural Gas	7/2/2020	25,802	7.10	10.35	50.50	909,884	2/18/2021	16,250	6.85	9.80	50.50	12/31/2021	897,267	Average	7.63	Distribution	Settled	No	Yes
PA	Columbia Gas	D-R-2020-30	Natural Gas	4/24/2020	100,437	7.98	10.95	54.19	2,401,427	2/19/2021	63,549	7.41	9.86	54.19	12/31/2021	2,339,124	Year-end	10.03	Distribution	Fully Litigated	No	No
DC	Washington G	FC 1162	Natural Gas	1/13/2020	38,014	7.58	10.40	52.10	542,566	2/24/2021	19,500	7.05	9.25	52.10	12/31/2019	NA		13.60	Distribution	Settled	No	No
CA	Southwest Ga	A.19-08-015	Natural Gas	8/30/2019	6,800	7.44	10.50	53.00	NA	3/25/2021	3,000	7.11	10.00	52.00	12/31/2021	285,891	Average	19.10	Distribution	Settled	No	No
CA	Southwest Ga	A.19-08-015	Natural Gas	8/30/2019	1,900	7.75	10.50	53.00	NA	3/25/2021	0	7.44	10.00	52.00	12/31/2021	32,983	Average	19.10	Distribution	Settled	No	No
CA	Southwest Ga	A.19-08-015	Natural Gas	8/30/2019	4,500	7.18	10.50	53.00	NA	3/25/2021	3,400	7.44	10.00	52.00	12/31/2021	36,816	Average	19.10	Distribution	Settled	No	No
MD	Washington G	C-9651	Natural Gas	8/28/2020	28,413	7.73	10.40	54.55	1,725,348	4/9/2021	13,148	7.09	9.70	52.70	3/31/2020	1,213,373	Average	7.47	Distribution	Fully Litigated	No	No
ND	MDU Resourc	C-PU-20-379	Natural Gas	8/26/2020	7,710	7.10	9.80	50.31	181,880	5/6/2021	5,865	6.85	9.30	50.31	12/31/2021	NA		8.40	Distribution	Settled	No	Yes
MO	Liberty Utilitie	C-GR-2021-0	Natural Gas	12/31/2020	1,086	NA	NA	NA	7,595	5/12/2021	516	NA	NA	NA	10/31/2020	3,450	Year-end	4.40	Limited-Issue	Fully Litigated	No	No
WA	Cascade Nat	D-UG-200568	Natural Gas	6/19/2020	7,093	7.22	9.80	50.40	401,930	5/18/2021	-391	6.96	9.40	49.10	12/31/2019	409,282	Year-end	11.10	Distribution	Fully Litigated	No	No
NY	Corning Natur	C-20-G-0101	Natural Gas	2/27/2020	6,031	7.28	10.30	50.77	71,615	5/19/2021	-766	6.28	8.80	48.00	1/31/2022	69,117	Average	14.90	Distribution	Fully Litigated	No	No
IN	Northern Indi	Ca-45330-TD	Natural Gas	2/2/2021	1,068	NA	NA	NA	142,900	6/16/2021	1,068	NA	NA	NA	12/31/2020	142,900	Year-end	3.77	Limited-Issue	Fully Litigated	No	No
PA	PECO Energy	D-R-2020-30	Natural Gas	9/30/2020	68,976	7.63	10.95	53.38	2,463,855	6/17/2021	29,118	7.26	10.24	53.38	6/30/2022	2,425,859	Year-end	8.67	Distribution	Fully Litigated	No	No
KY	Louisville Gas	C-2020-0350	Natural Gas	11/25/2020	32,940	7.47	10.00	53.13	1,081,738	6/30/2021	20,360	NA	9.43	NA	6/30/2022	NA		7.23	Distribution	Settled	No	No
WV	Hope Gas, Inc	C-20-0746-G	Natural Gas	8/30/2020	28,712	6.91	10.20	48.70	244,877	7/27/2021	12,937	5.90	9.54	46.26	12/31/2019	206,570	Average	10.00	Distribution	Fully Litigated	No	No
IN	Indiana Gas C	Ca-44430-TD	Natural Gas	4/1/2021	3,669	NA	NA	NA	665,430	7/28/2021	3,651	NA	NA	NA	12/31/2020	665,220	Year-end	3.93	Limited-Issue	Fully Litigated	No	No
IN	Southern Indi	Ca-44429-TD	Natural Gas	4/1/2021	508	NA	NA	NA	224,150	7/28/2021	508	NA	NA	NA	12/31/2020	224,150	Year-end	3.93	Limited Issue	Fully Litigated	No	No
KS	Black Hills Ka	D-21-BHCG-	Natural Gas	3/21/2021	1,534	NA	NA	NA	66,709	7/29/2021	1,624	NA	NA	NA	12/31/2020	66,659	Year-end	2.30	Limited-Issue	Fully Litigated	No	No
NH	Liberty Utilitie	D-DG-20-105	Natural Gas	7/31/2020	8,575	7.47	10.51	50.10	346,131	7/30/2021	6,299	6.96	9.30	52.00	12/31/2019	NA	Year-end	12.13	Distribution	Settled	Yes	Yes
KY	Delta Natural	C-2021-0009	Natural Gas	2/26/2021	3,867	NA	NA	NA	22,209	8/6/2021	3,567	NA	NA	NA	12/31/2020	22,209	Year-end	5.33	Limited-Issue	Fully Litigated	No	No
WI	Wisconsin Ele	D-5-AF-107	Natural Gas	3/30/2021	0	NA	NA	NA	NA	8/11/2021	0	NA	NA	NA	12/31/2022	NA		4.47	Distribution		No	No
WI	Wisconsin Pu	D-6-AF-107	Natural Gas	3/30/2021	0	NA	NA	NA	NA	8/11/2021	0	NA	NA	NA	12/31/2022	NA		4.47	Distribution		No	No
WI	Wisconsin Ga	D-5-AF-100	Natural Gas	3/30/2021	0	NA	NA	NA	NA	8/11/2021	0	NA	NA	NA	12/31/2022	NA		4.47	Distribution		No	No
NY	Brooklyn Unio	C-19-G-0309	Natural Gas	4/30/2019	119,763	6.77	9.65	48.00	4,907,792	8/12/2021	4,710	6.34	8.80	48.00	3/31/2021	4,921,871	Average	27.83	Distribution	Settled	Yes	No
NY	KeySpan Gas	C-19-G-0310	Natural Gas	4/30/2019	37,505	6.74	9.65	48.00	3,280,515	8/12/2021	-22,630	6.32	8.80	48.00	3/31/2021	3,343,777	Average	27.83	Distribution	Settled	Yes	No
OK	CenterPoint E	Ca-PUD2021	Natural Gas	3/15/2021	-844	NA	NA	NA	78,996	8/19/2021	-884	NA	NA	NA	12/31/2020	NA		5.23	Distribution	Settled	No	No
VA	Roanoke Gas	C-PUR-2021-	Natural Gas	6/1/2021	1,427	7.30	NA	NA	26,713	8/25/2021	1,425	7.03	NA	NA	9/30/2022	26,645	Average	2.83	Limited-Issue	Fully Litigated	No	No
ID	Avista Corpor	C-AVU-G-21-	Natural Gas	1/29/2021	1,003	7.30	9.90	50.00	174,709	9/1/2021	-700	7.05	9.40	50.00	12/31/2019	172,311	Average	7.17	Distribution	Settled	Yes	No
IL	North Shore G	D-20-0810	Natural Gas	10/15/2020	6,139	6.81	10.00	52.50	355,540	9/8/2021	4,084	6.60	9.67	51.58	12/31/2021	363,361	Average	10.83	Distribution	Fully Litigated	No	No
MI	Michigan Gas	C-U-20718	Natural Gas	3/22/2021	13,126	5.72	10.20	42.62	403,888	9/9/2021	9,250	NA	9.85	NA	12/31/2022	NA		5.70	Distribution	Settled	No	No
VA	Virginia Natur	C-PUR-2020-	Natural Gas	6/1/2020	50,183	7.75	10.35	54.00	1,059,154	9/14/2021	43,000	7.05	9.50	51.89	12/31/2019	NA		15.67	Distribution	Settled	No	Yes
AR	CenterPoint E	D-17-010-FR	Natural Gas	4/5/2021	12,605	4.37	NA	32.91	952,006	9/23/2021	10,358	4.45	NA	32.27	9/30/2022	920,136	Year-end	5.70	Distribution	Fully Litigated	No	No
WA	Avista Corpo	D-UG-200901	Natural Gas	10/30/2020	10,866	7.43	9.90	50.00	441,923	9/27/2021	8,078	7.12	9.40	48.50	12/31/2019	441,923	Average	11.07	Distribution	Settled	No	No
MA	Boston Gas C	DPU 20-120	Natural Gas	11/13/2020	219,009	7.41	10.50	53.44	3,015,435	9/30/2021	142,012	6.98	9.70	53.44	3/31/2020	2,698,874	Year-end	10.75	Distribution	Fully Litigated	Yes	No
IN	Southern Indi	Ca-45447	Natural Gas	10/30/2020	27,929	5.88	10.15	45.74	469,328	10/6/2021	20,490	5.78	5.70	45.74	12/31/2021	469,328	Year-end	11.37	Distribution	Settled	Yes	No
WA	Northwest Na	D-UG-200994	Natural Gas	12/18/2020	9,406	6.91	9.40	49.00	247,267	10/21/2021	8,600	5.81	NA	NA		NA		10.23	Distribution	Settled	Yes	No
VA	Virginia Natur	PUR-2021-00	Natural Gas	7/30/2021	8,075	NA	NA	NA	82,100	10/25/2021	8,023	NA	NA	NA	10/31/2022	81,902	Average	2.90	Limited-Issue	Fully Litigated	No	No
MO	Spire Missouri	C-GR-2021-0	Natural Gas	12/11/2020	111,475	7.23	9.95	54.25	2,777,221	10/27/2021	72,228	6.37	9.37	49.06	9/30/2020	2,599,375	Year-end	10.67	Distribution	Fully Litigated	No	No
MA	NSTAR Gas C	DPU 21-107	Natural Gas	9/15/2021	24,814	NA	NA	NA	NA	10/29/2021	13,616	NA	NA	NA		NA		1.47	Distribution	Fully Litigated	No	No
IN	Indiana Gas C	Ca-45468	Natural Gas	12/15/2020	20,739	6.32	10.15	46.22	1,610,799	11/17/2021	5,987	6.16	9.80	46.21	12/31/2021	1,616,799	Year-end	11.13	Distribution	Settled	Yes	No
NJ	New Jersey N	D-GR21030	Natural Gas	3/30/2021	164,641	7.46	10.50	56.21	2,547,636	11/17/2021	79,269	6.84	9.60	54.00	6/31/2021	2,523,000	Year-end	7.73	Distribution	Settled	No	No
GA	Atlanta Gas L	D-42315 (202	Natural Gas	7/31/2021	92,763	7.54	NA	56.00	3,889,325	11/15/2021	50,617	NA	NA	56.00	12/31/2022	3,874,845	Average	4.00	Distribution	Settled	No	No
IL	Northern Illin	D-21-0098	Natural Gas	1/14/2021	292,009	7.29	10.35	54.46	4,738,385	11/18/2021	240,224	5.96	9.75	54.46	12/31/2022	4,852,130	Average	10.27	Distribution	Fully Litigated	No	No
KS	Kansas Gas S	D-22-KGSG-	Natural Gas	8/26/2021	7,615	NA	NA	NA	154,462	11/18/2021	7,586	NA	NA	NA	6/30/2021	154,473	Year-end	3.30	Limited-Issue	Fully Litigated	No	No
NY	Central Hudso	C-20-G-0429	Natural Gas	8/27/2020	14,285	6.61	9.10	50.00	539,769	11/18/2021	4,586	6.45	9.00	50.00	6/30/2022	547,365	Average	14.53	Distribution	Settled	Yes	No
WI	Wisconsin Po	D-6680-UR-1	Natural Gas	3/5/2021	15,387	7.44	10.00	52.50	488,856	11/18/2021	15,387	7.44	10.00	52.50	12/31/2023	488,856	Average	6.57	Distribution	Settled	Yes	No
WI	Northern Stat	D-4220-UR-1	Natural Gas	7/2/2021	12,954	7.31	10.00	52.50	223,260	11/18/2021	12,868	7.31	10.00	52.50	12/31/2023	223,260	Average	4.63	Distribution	Settled	Yes	No
WI	Madison Gas	D-3270-UR-1	Natural Gas	5/3/2021	5,332	7.16	9.80	55.00	309,797	11/23/2021	4,155	NA	9.80	55.00	12/31/2022	NA	Average	6.80	Distribution	Settled	Yes	No
OK	Oklahoma Na	Ca-PUD2021	Natural Gas	5/28/2021	28,693	7.53	9.25	58.55	1,716,149	11/30/2021	15,282	7.20	9.40	58.55	12/31/2020	1,726,463	Year-end	6.20	Distribution	Settled	No	No
MD	Columbia Gas	C-9664	Natural Gas	5/14/2021	5,430	7.72	10.85	53.23	187,154	12/3/2021	2,425	7.08	9.65	52.95	3/31/2021	187,144	Average	6.77	Distribution	Fully Litigated	No	No
VA	Columbia Gas	C-PUR-2021-	Natural Gas	8/13/2021	6,906	NA	NA	NA	148,533	12/6/2021	2,715	NA	NA	NA	12/31/2022	147,691	Average	3.87	Limited-Issue	Fully Litigated	No	No
MI	DTE Gas Com	C-U-20940	Natural Gas	2/12/2021	170,647	5.59	10.25	39.92	5,606,205	12/9/2021	84,173	5.41	9.90	39.23	12/31/2022	5,537,080	Average	10.00	Distribution	Fully Litigated	No	No
CO	Black Hills Co	D-21AL-0236	Natural Gas	6/1/2021	14,593	6.94	9.95	50.26	346,182	12/13/2021	6,498	6.56	9.20	50.26	12/31/2020	303,186	Average	6.50	Distribution	Settled	No	No
PA	Columbia Gas	D-R-2021-30	Natural Gas	3/30/2021	98,300	7.89	10.95	54.34	2,673,612	12/16/2021	58,500	NA	NA	NA	12/31/2022	NA		8.70	Distribution	Settled	No	No
WV	Mountaineer	C-21-0393-G	Natural Gas	7/30/2021	5,757	8.85	NA	52.90	132,748	12/16/2021	5,504	8.85	NA	52.90	12/31/2022	132,890	Average	4.63	Limited-Issue	Settled	No	No
IN	Northern Indi	Ca-45330-TD	Natural Gas	8/24/2021	286	NA	NA	NA	194,342	12/22/2021	286	NA	NA	NA	6/30/2021	194,540	Year-end	4.00	Limited-Issue	Fully Litigated	No	No
MO	Union Electric	C-GR-2021-0	Natural Gas	3/31/2021	9,403	6.94	9.93	51.93	316,461	12/22/2021	5,000	NA	NA	NA	12/31/2020	313,000	Year-end	6.87	Distribution	Settled	No	No
IA	Black Hills Io	D-RPU-2021-	Natural Gas	6/1/2021	10,544	7.65	10.15	50.01	301,546	12/28/2021	5,907	6.75	9.60	50.01	12/31/2020	300,923		7.00	Distribution	Settled	No	Yes
KY	Duke Energy	C-2021-0019	Natural Gas	6/1/2021	15,226	7.06	10.30	50.70	465,321	12/28/2021	9,171	6.54	9.38	51.34	12/31/2022	465,487	Average	7.00	Distribution	Settled	No	No
KY	Columbia Ga	C-2021-0018	Natural Gas	5/28/2021	26,693	7.45	10.30	52.64	446,223	12/28/2021	18,311	6.89	9.35	52.64	12/31/2022	431,140	Average	7.13	Distribution	Settled	No	No
KS	Black Hills Ka	D-21-BHCG-	Natural Gas	5/1/2021	10,203	7.06	10.15	56.34	236,335	12/30/2021	6,611	NA	NA	NA	12/31/2020	NA		7.60	Distribution	Settled	No	No

January-September 2021 (Matches September RRA Report)	**9.54**
January-December 2021	**9.56**
Third Quarter 2021	**9.59**

S&P Global
Market Intelligence

Table 1: ROEs authorized, 1990-March 2022

		Electric utilities			Gas utilities		
Year	Period	Average ROE (%)	Median ROE (%)	Number of observations	Average ROE (%)	Median ROE (%)	Number of observations
1990	Full year	12.70	12.77	38	12.68	12.75	33
1991	Full year	12.54	12.50	42	12.45	12.50	31
1992	Full year	12.09	12.00	45	12.02	12.00	28
1993	Full year	11.46	11.50	28	11.37	11.50	40
1994	Full year	11.21	11.13	28	11.24	11.27	24
1995	Full year	11.58	11.45	28	11.44	11.30	13
1996	Full year	11.40	11.25	18	11.12	11.25	17
1997	Full year	11.33	11.58	10	11.30	11.25	12
1998	Full year	11.77	12.00	10	11.51	11.40	10
1999	Full year	10.72	10.75	6	10.74	10.65	6
2000	Full year	11.58	11.50	9	11.34	11.16	13
2001	Full year	11.07	11.00	15	10.96	11.00	5
2002	Full year	11.21	11.28	14	11.17	11.00	19
2003	Full year	10.96	10.75	20	10.99	11.00	25
2004	Full year	10.81	10.70	21	10.63	10.50	22
2005	Full year	10.51	10.35	24	10.41	10.40	26
2006	Full year	10.32	10.23	26	10.40	10.50	15
2007	Full year	10.30	10.20	38	10.22	10.20	35
2008	Full year	10.41	10.30	37	10.39	10.45	32
2009	Full year	10.52	10.50	41	10.22	10.26	30
2010	Full year	10.37	10.30	61	10.15	10.10	39
2011	Full year	10.29	10.17	42	9.92	10.03	16
2012	Full year	10.17	10.08	58	9.94	10.00	35
2013	Full year	10.03	9.95	49	9.68	9.72	21
2014	Full year	9.91	9.78	38	9.78	9.78	26
2015	Full year	9.84	9.60	31	9.60	9.68	16
2016	Full year	9.77	9.75	42	9.54	9.50	26
	1st quarter	9.87	9.60	15	9.60	9.25	3
	2nd quarter	9.63	9.50	14	9.47	9.60	7
	3rd quarter	9.66	9.60	5	10.14	9.90	6
	4th quarter	9.74	9.60	19	9.68	9.55	8
2017	**Full year**	**9.74**	**9.60**	**53**	**9.72**	**9.60**	**24**
	1st quarter	9.75	9.90	13	9.68	9.80	6
	2nd quarter	9.54	9.50	13	9.43	9.50	7
	3rd quarter	9.67	9.70	11	9.69	9.60	13
	4th quarter	9.42	9.50	11	9.53	9.60	14
2018	**Full year**	**9.60**	**9.58**	**48**	**9.59**	**9.60**	**40**
	1st quarter	9.73	9.70	12	9.55	9.70	4
	2nd quarter	9.58	9.50	12	9.73	9.73	3
	3rd quarter	9.55	9.60	7	9.80	9.90	3
	4th quarter	9.71	9.70	16	9.74	9.70	23
2019	**Full year**	**9.66**	**9.65**	**47**	**9.72**	**9.70**	**33**
	1st quarter	9.58	9.50	19	9.35	9.40	9
	2nd quarter	9.55	9.45	9	9.55	9.65	3
	3rd quarter	9.30	9.33	10	9.52	9.45	8
	4th quarter	9.32	9.50	17	9.50	9.60	15
2020	**Full year**	**9.44**	**9.45**	**55**	**9.47**	**9.44**	**35**
	1st quarter	9.46	9.25	10	9.71	9.74	10
	2nd quarter	9.39	9.43	11	9.48	9.42	6
	3rd quarter	9.38	9.40	13	9.43	9.50	11
	4th quarter	9.34	9.40	21	9.59	9.63	16
2021	**Full year**	**9.38**	**9.38**	**55**	**9.56**	**9.60**	**43**
2022	1st quarter	9.35	9.25	12	**9.38**	**9.40**	**6**
LTM ended 3/31/2022		**9.36**	**9.35**	**57**	**9.50**	**9.50**	**39**

Data compiled April 25, 2022
Source: Regulatory Research Associates, a group within S&P Global Commodity Insights

Start Date 5/1/2022
End Date 5/31/2022
Field PX_LAST

Date	MOODUAVERAGE Index	MOODUAA Index Last Price	MOODUA Index Last Price	MOODUBAA Index Last Price
5/31/2022	4.69	4.42	4.65	5.01
5/27/2022	4.66	4.40	4.62	4.97
5/26/2022	4.66	4.40	4.62	4.97
5/25/2022	4.71	4.48	4.66	5.00
5/24/2022	4.76	4.52	4.70	5.05
5/23/2022	4.86	4.63	4.80	5.14
5/20/2022	4.80	4.57	4.74	5.08
5/19/2022	4.88	4.65	4.82	5.16
5/18/2022	4.86	4.64	4.80	5.14
5/17/2022	4.93	4.69	4.88	5.21
5/16/2022	4.84	4.62	4.79	5.12
5/13/2022	4.85	4.63	4.80	5.12
5/12/2022	4.73	4.49	4.69	5.00
5/11/2022	4.76	4.53	4.72	5.03
5/10/2022	4.84	4.61	4.80	5.10
5/9/2022	4.91	4.68	4.87	5.17
5/6/2022	4.90	4.65	4.87	5.17
5/5/2022	4.84	4.59	4.81	5.11
5/4/2022	4.68	4.43	4.65	4.96
5/3/2022	4.70	4.45	4.67	4.97
5/2/2022	4.74	4.51	4.71	5.01
May 2022 Utility Average	4.79	4.55	4.75	5.07

```
--> RESET
Initializing NLOGIT Version 4.0.1 (January 1, 2007).
--> reset$
Initializing NLOGIT Version 4.0.1 (January 1, 2007).
--> read
   ;names
   ;format=.xls
   ;file=f:\rra.xls
   ;labels=1$
--> regress;lhs=rp;rhs=one,int;ar1$

+----------------------------------------------------+
| Ordinary    least squares regression               |
| Model was estimated Jun 14, 2022 at 02:43:54PM     |
| LHS=RP      Mean                 =  .3796680E-01   |
|             Standard deviation   =  .1614055E-01   |
| WTS=none    Number of observs.   =       165       |
| Model size  Parameters           =         2       |
|             Degrees of freedom   =       163       |
| Residuals   Sum of squares       =  .4424637E-02   |
|             Standard error of e  =  .5210088E-02   |
| Fit         R-squared            =  .8964388       |
|             Adjusted R-squared   =  .8958034       |
| Model test  F[  1,   163] (prob) =1410.95 (.0000)  |
| Diagnostic  Log likelihood       =  634.3124       |
|             Restricted(b=0)      =  447.2360       |
|             Chi-sq [  1]  (prob) = 374.15 (.0000)  |
| Info criter. LogAmemiya Prd. Crt. = -10.50227      |
|             Akaike Info. Criter. = -10.50227       |
| Autocorrel  Durbin-Watson Stat.  =  .7104166       |
|             Rho = cor[e,e(-1)]   =  .6447917       |
+----------------------------------------------------+
+--------+--------------+----------------+--------+--------+----------+
|Variable| Coefficient  | Standard Error |t-ratio |P[|T|>t]| Mean of X|
+--------+--------------+----------------+--------+--------+----------+
 Constant|   .07339584       .00102671     71.486   .0000
 INT     |  -.46316960       .01233061    -37.563   .0000    .07649259


+--------------------------------------------+
| AR(1) Model:    e(t) = rho * e(t-1) + u(t) |
| Initial value of rho       =       .64479  |
| Maximum iterations         =          100  |
| Method = Prais - Winsten                   |
| Iter=  1, SS=      .003, Log-L= 679.015158 |
| Iter=  2, SS=      .003, Log-L= 679.258599 |
| Iter=  3, SS=      .003, Log-L= 679.294973 |
| Iter=  4, SS=      .003, Log-L= 679.302209 |
| Iter=  5, SS=      .003, Log-L= 679.303247 |
| Iter=  6, SS=      .003, Log-L= 679.302887 |
| Final value of Rho    =            .709375 |
| Iter=  7, SS=      .003, Log-L= 679.302319 |
| Durbin-Watson:   e(t) =            .581249 |
| Std. Deviation:  e(t) =            .005616 |
| Std. Deviation:  u(t) =            .003958 |
| Durbin-Watson:   u(t) =           2.223074 |
```

```
| Autocorrelation: u(t) =          -.111537 |
| N[0,1] used for significance levels       |
+-------------------------------------------+
+--------+--------------+----------------+--------+--------+----------+
|Variable| Coefficient  | Standard Error |b/St.Er.|P[|Z|>z]| Mean of X|
+--------+--------------+----------------+--------+--------+----------+
 Constant|    .07804349      .00247625     31.517   .0000
 INT     |   -.52552235      .02927632    -17.950   .0000    .07649259
 RHO     |    .70937539      .05503804     12.889   .0000
```

WORKPAPERS

TO

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

Workpapers to the Direct Testimony of Timothy S. Lyons are voluminous and are being provided in electronic format.

VII. CONSOLIDATION OF SERVICE AREAS

Consolidation of service areas is a major point of disagreement between TGS and CEP/Coalition. TGS proposes to consolidate the EPSA, PSA, and DCSA into a single service area and to set rates based on the total cost to serve the new, consolidated WTSA. In support, TGS offers that service area consolidation is in the public interest because it: is supported by Texas law and Commission precedent, better reflects TGS's operational realities, and results in administrative and regulatory efficiencies. A map showing TGS's service areas is attached to this PFD as Attachment B. Staff supports consolidation of these service areas as being reasonable and supported by two recent Court of Appeals holdings and at least 13 prior Commission dockets.[39] CEP and Coalition both oppose.

TGS offers that service area consolidation is supported by Texas law and Commission precedent. According to TGS, the Commission has a long-established policy of approving consolidation and system-wide rates, and that doing so reflects the regulatory framework established in the Texas Utilities Code.[40] In particular, TGS highlights the Commission's actions in GUD Nos. 9400, 9488, and 10174. In GUD No. 9400, the Commission adopted system-wide rates for an area that included over 400 cities from Austin to Dallas—a decision ultimately upheld by the Third Court of Appeals.[41] In GUD No. 9488, the Commission adopted system-wide rates for a broad geographic area even though customers in some cities would experience rate decreases and customers in other cities would experience rate increases.[42] In GUD No. 10174, the Examiners precluded litigation of the issue of consolidation altogether, stating that the Commission has "a long-established policy allowing utilities within the State of Texas to seek system-wide rates."[43] Additionally, TGS notes numerous prior dockets where the Commission approved the use of system-wide rates: GUD Nos. 9670, 9762, 9869, 10170, and 10174 (Atmos Energy); and GUD Nos. 9791, 9902, and 10038 (CenterPoint Energy).[44]

TGS offers that service area consolidation better reflects TGS's operational realities. Caron Lawhorn, Senior Vice President, Commercial, for ONE Gas, testified that consolidating service areas provides for more efficient management of regulatory matters and rate-setting efficiencies, and aligns with the functional model by which ONE Gas operates and manages utility operations throughout ONE Gas.[45] Jim Jarrett, Vice President of Operations for TGS, testified that decision-making processes, operations, and management are now centralized in the WTSA, which means that service area boundaries are no longer indicative of TGS's actual

[39] Closing Brief of the Staff of the Railroad Commission of Texas, filed Aug. 3, 2016 ("Staff Initial Br."), at 2 (citing *City of Dallas v. R.R. Comm'n of Tex.*, No. 03-06-00580-CV, 2008 WL 4823225, at *1 (Tex. App.—Austin, Nov. 6, 2008, no pet.) (mem. op.), and *Amarillo v. R.R. Comm'n of Tex.*, No. 08-14-00193-CV, 2016 WL 3020304, at *1 (Tex. App.—El Paso, May 25, 2016, no pet.)).

[40] Initial Brief of Texas Gas Service Company, A Division of ONE Gas, Inc., filed Aug. 3, 2016 ("TGS Initial Br."), at 4-6.

[41] GUD No. 9400, Final Order (May 25, 2004); *City of Dallas*, 2008 WL 4823225, at *4, 8-9 (noting that the City of Dallas opposed consolidation based, in part, on arguments that under consolidation Dallas would be subsidizing the utility's customers in other parts of the state).

[42] TGS Initial Br. at 5 (discussing GUD No. 9488, Final Order (Nov. 23, 2004)).

[43] *Id*. at 5 (quoting GUD No. 10174, Examiners' Letter No. 29).

[44] *Id*. at 5-6.

[45] TGS Ex. 5, Direct Testimony of Caron A. Lawhorn on Behalf of Texas Gas Service Company ("Lawhorn Test."), at 11-12.

operations.[46] According to TGS, the centralization of these activities has allowed TGS to make more efficient use of employees and to control costs by improving consistency in processes.[47] Mr. Jarrett testified that: supervisors in the EPSA have responsibility for activities such as leak survey across the entire WTSA; one supervisor retains responsibility for cathodic protection throughout the WTSA; and the engineering team in the EPSA has responsibility throughout the WTSA.[48] Mr. Jarrett further testified that operational leadership for the EPSA, PSA, and DCSA is located in El Paso, and the proximity of the EPSA, PSA, and DCSA "affords the opportunity for these service areas to share equipment and deploy resources in a manner that allows [TGS] to quickly respond to emergencies."[49] TGS maintains that these operational changes already have taken place, and that consolidation simply reflects the operating changes that already have occurred.[50]

TGS offers that service area consolidation results in administrative and regulatory efficiencies. Consolidation will allow TGS to prepare only one cost-of-service filing for future rate changes instead of three—something TGS maintains would result in uniformity and consistency in rate setting, and would be more economical and efficient for TGS, customers, and regulators.[51] According to TGS, it would maintain approximately 26 total tariffs for the consolidated WTSA, rather than the existing 125 tariffs in the EPSA, PSA, and DCSA, as separate service areas.[52]

Opposition by CEP and Coalition

Neither CEP nor Coalition submitted pre-filed testimony that directly challenged consolidation, though both opposed consolidation during the Hearing and in post-Hearing briefs.

CEP offers that the EPSA has been a distinct service area for more than 40 years and characterizes TGS's requested consolidation as punitive to EPSA ratepayers because it imposes a substantially greater increase on those customers while cutting rates for customers in the smaller PSA and DCSA.[53] CEP also states that rates under TGS's proposed consolidation would be "discriminatory" and "prejudicial" to EPSA customers.[54] CEP acknowledges that Commission policy has favored consolidation, but offers that consolidation needs to make sense and not discriminate against one group of customers.[55]

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[46] *See* TGS Ex. 6, Direct Testimony of Jim Jarrett on Behalf of Texas Gas Service Company ("Jarrett Test."), at 5-10.
[47] *Id*. at 7-10.
[48] *Id*.; Tr. at 91-92 (July 19, 2016) (Jarrett testifying).
[49] TGS Ex. 6 (Jarrett Test.) at 10.
[50] *Id*. at 11.
[51] *Id*. at 10-11.
[52] TGS Initial Br. at 6 (citing TGS Response to Examiner RFI 1-1 (July 29, 2016)).
[53] Trial Brief of the City of El Paso, filed July 18, 2016 ("CEP Trial Br."), at 2.
[54] *Id*.; see *also* Post Hearing Brief of the City of El Paso, filed Aug. 4, 2016 ("CEP Initial Br."), at 6 ("In the instant case the 'West Texas Service Area' is nothing new, it is a mere device to provide discrimination in rates.").
[55] CEP Trial Br. at 2.

In its exceptions to the PFD, CEP provided the below chart to highlight the rate impact of consolidation on EPSA customers.[56]

Service Area	Stand Alone Errata Requested Increase	Consolidated Requested Increase	Difference
EPSA	$12,296,801	$14,063,105	$1,766,801
PSA	$583,801	($1,538,777)	($2,122,578)
DCSA	$(14,205)	$13,250	$27,455

CEP also argues that TGS failed to provide specific evidence with respect to certain operational and administrative efficiencies identified by TGS's witnesses, or their specific rate impact to customers.[57] CEP offers that consolidation here is not proper because the EPSA, PSA, and DCSA are "geographically discrete, not connected by any TGS pipeline, have different gas supplies, and have different system characteristics."[58] According to CEP, these factors distinguish this case from the prior Commission dockets relied upon by TGS, where the Commission approved system-wide rates.[59]

Coalition characterizes the proposed consolidation as "transparent cost-shifting" that hikes rates for current EPSA customers to subsidize the smaller PSA and DCSA.[60] Coalition also argues that the majority of the prior Commission dockets cited by TGS, where the Commission approved system-wide rates, was the result of settled negotiations and therefore cannot constitute established Commission policy.[61] According to Coalition, the EPSA, PSA, and DCSA are "independent and isolated" from each other and the sharing of networks is "minimal to nonexistent," and therefore consolidation would not be of any benefit to customers.[62] Like CEP, Coalition states that the result of service area consolidation would be "discriminatory" and "prejudicial."[63] In its exceptions to the PFD, Coalition states that TGS's own service map[64] "shows the immense distance and sprawl among the areas proposed for consolidation."[65] Coalition further states EPSA rates "should be lower because its population is denser, pipe distances are closer making attendant maintenance and operations costs lower, and capital investment less."[66]

[56] City of El Paso's Exceptions to Proposal for Decision, filed on Sept. 9, 2016 ("CEP Exceptions"), at 4 (citing to the evidentiary record).
[57] *See* CEP Initial Br. at 6-9; *see also* Reply Brief of the City of El Paso, filed Aug. 10, 2016 ("CEP Reply Br."), at 5-6.
[58] *See* CEP Initial Br. at 2-9.
[59] *See id*. at 6; *see also* CEP Reply Br. at 4-5, 7.
[60] Initial Brief of the Coalition of Cities Served by Texas Gas Service Company, filed Aug. 3, 2016 ("Coalition Initial Br."), at 1-2.
[61] *Id*. at 2.
[62] *Id*. at 2-4.
[63] *Id*. at 3-4 ("In fact, TGS's proposed rates for the EPSA under consolidation present a hefty hike to those customers. This result alone is unreasonable, preferential, prejudicial and discriminatory, and in conflict with state law.").
[64] *See* Attachment B to this Amended PFD.
[65] Coalition of Cities Exceptions to the Proposal for Decision, filed on Sept. 9, 2016 ("Coalition Exceptions"), at 2.
[66] *Id*. at 2-3.

In response to CEP and Coalition, TGS argues that prior Commission dockets establish precedent supporting consolidation, and that CEP and Coalition misstate the rate impact of consolidation. TGS states that it will not earn more revenues through consolidation, as argued by CEP and Coalition, and that any increased revenues from one area under consolidation will be offset by decreased revenues from other areas.[67] TGS also maintains that consolidation does not result in a "hefty" rate hike; rather, the vast majority of the increase in the EPSA in this case is caused primarily by changes to the revenue requirement in the EPSA, not the effects of consolidation.[68] TGS offers that, under consolidation, average EPSA residential bills increase by only $0.29 more than they would without consolidation.[69] TGS also states the geographic distance among the WTSA cities is similar to distances among cities in service areas by other Texas gas utilities, and that interconnection of facilities has no bearing on the consolidation decision in this case.[70]

Examiner Findings and Recommendation

Despite liberal use by parties of the word "precedent" on this issue, no prior Commission or Texas court decision binds the Commission here to approve or disapprove service area consolidation. The Commission can—and should—decide this issue based on the facts and evidence unique to this case, applying the proper legal standard. The Examiners, having done this, recommend that TGS's proposed service area consolidation be approved.

Legal Standard and Prior Cases

The Commission, in its informed discretion, may approve service area consolidation if it considers consolidation to be appropriate and in the public interest. While no statute speaks directly to service area consolidation, the Legislature and Third Court of Appeals have provided the Commission with general guidance. GURA Section 101.002 (Purpose and Findings) provides that "[GURA] is enacted to protect the public interest inherent in the rates and services of gas utilities."[71] GURA Section 104.003 (Just and Reasonable Rates) authorizes the Commission to treat as a single class two or more municipalities that a gas utility serves if the Commission considers that treatment to be "appropriate."[72] In *City of Dallas*, the Court of Appeals stated that the geographic aspects of rate design are left to the Commission's "informed discretion."[73]

While not binding on the Commission to determine this issue in TGS's favor, the Court of Appeals has informed the type and sufficiency of evidence needed to meet the above standard. In *City of Dallas*, the Court of Appeals concluded that the Commission had a reasonable basis for approving rates applicable to all areas in Texas served by a gas utility.[74] In that case, the

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[67] Reply Brief of Texas Gas Service Company, a Division of ONE Gas, Inc., filed Aug. 10, 2016 ("TGS Reply Br."), at 4-5.
[68] *Id*. at 5.
[69] *Id*.; *see also* TGS Ex. 17, Direct Testimony of F. Jay Cummings on Behalf of Texas Gas Service Company ("Cummings Test."), at Exhibits FJC-5 and FJC-6.
[70] TGS Reply Br. at 4.
[71] Tex. Util. Code § 101.002(a).
[72] *Id*. § 101.003(a).
[73] *See City of Dallas*, 2008 WL 4823225, at *9 (citing *Nucor Steel v. Pub. Util. Com'n of Texas*, 168 S.W.3d 260, 269 (Tex. App.—Austin 2005, no pet.)).
[74] *Id*. at *7-10.

utility's rates previously had been set on a municipality-by-municipality or region-by-region basis. The party opposing consolidation in *City of Dallas* made virtually the same principal arguments that CEP and Coalition now make: that there had been a historical practice of setting separate rates for the service areas; that one such service area was an "integrated system" with a lower cost of service compared to other areas served by the utility; that shifting to system-wide rates would force customers in one locality "to subsidize" customers in other parts of the state; and that consequently the system-wide rates were "discriminatory" to the customers in that area.[75] Considering these arguments, the Court of Appeals nevertheless found substantial evidence to support the Commission's approval of system-wide rates, noting the wide discretion of the Commission.[76]

<u>No Basis for Discrimination</u>

TGS's proposed service area consolidation is not discriminatory or prejudicial. There is no credible evidence that TGS's proposed consolidation constitutes—or results in—a "discriminatory" or "prejudicial" act, as argued by CEP and Coalition. On the contrary, the evidence shows that TGS's proposed consolidation would result in system-wide rates for all EPSA, PSA, and DCSA customers in the newly-formed WTSA. As the Court of Appeals has made plain, system-wide rates *avoid* unreasonable rate differences between localities or between classes of service.[77] There is no credible evidence that TGS will charge unreasonably different rates between localities or between classes of service in the proposed WTSA once it is formed. Accordingly, there is no merit to claims that consolidation is discriminatory or prejudicial to anyone.

<u>WTSA</u>

Here, the weight of the evidence supports consolidation. In making this finding, the Examiners gave no weight to prior Commission dockets since they do not bind the Commission here and involve different facts. The Examiners considered the holding in *City of Dallas* only to the extent that the Court of Appeals informed the applicable legal standard for service area consolidation in Texas, as well as the type and sufficiency of evidence needed to meet that standard. As far as evidence considered, the Examiners looked only to the facts unique to TGS's proposed consolidation of the EPSA, PSA, and DCSA in this docket, as contained in the evidentiary record.

TGS demonstrated through credible testimony that consolidating the EPSA, PSA, and DCSA into a single WTSA is likely to result in numerous administrative and regulatory efficiencies, and those efficiencies will benefit WTSA customers. Specifically, consolidation likely will reduce the number of cost-of-service analyses and rate-filing packages that TGS must prepare each time it seeks to change rates within these areas. This allows rate changes to be implemented uniformly and consistently, which is more economical, efficient, and cost-effective for TGS and its customers.

TGS also demonstrated that a consolidated WTSA will better reflect existing centralized operations, management, and decision-making processes. At the ONE Gas level, certain

[75] *Id.* at *1, 9.
[76] *Id.* at *10.
[77] *See id.* at *9 ("There is no dispute that uniform, statewide rates would comply with these requirements.").

activities—such as project planning and management—now are organized around function rather than geography. At the TGS level, many employees now have responsibilities for certain functions across many service areas.

In opposition, CEP and Coalition make essentially the same arguments considered by the Court of Appeals in *City of Dallas*: that the EPSA historically has had its own rates, it is an integrated system with a lower cost of service compared to the PSA and DCSA, and that consequently the EPSA customers will be "subsidizing" PSA and DCSA customers in the consolidated WTSA. While the factual circumstances in *City of Dallas* are different than here—as correctly noted by CEP and Coalition[78]—the Court of Appeals in that case found substantial evidence to support the Commission's approval of system-wide rates, despite essentially the same arguments in opposition.

The *City of Dallas* holding does not bind the Commission to make the same determination here, but it does inform that these opposition arguments may not address sufficiently—and perhaps may avoid—the legal standard that consolidation be appropriate and in the public interest. CEP and Coalition both argue, convincingly, that consolidation may result in EPSA customers paying higher rates in the future in the consolidated WTSA than they otherwise might as a standalone service area. In fact, the evidence supports this.[79] However, the "public interest" may be broader than the specific interests of any one locality or its customers, and may include more than quantifiable rate impacts. Here, even if these opposing arguments are accepted as true, the weight of the evidence still shows that consolidation likely will result in numerous operational and administrative efficiencies beneficial to *all* customers in the proposed WTSA.

Furthermore, the EPSA-focused arguments by CEP and Coalition do not consider that the 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*."[80] 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.[81] 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.

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[78] *See, e.g.*, Coalition Exceptions at 2 ("In [*City of Dallas*], the service area in Dallas and the surrounding areas were in fact, one large, integrated and interconnected area that had developed to the extent that they had become adjacent and almost indistinguishable from each other.").
[79] *Compare* TGS Ex. 17 (Cummings Test.) at Exhibit FJC-5 with Exhibit FJC-10 (showing the average EPSA residential bills increasing in certain cases by $0.29 more with consolidation than without consolidation).
[80] Tex. Util. Code § 101.002 (Purpose and Findings) (emphasis added).
[81] *Id*. § 104.051 (Establishing Overall Revenues).

<u>Conclusion</u>

Considering the evidence, the Examiners find that consolidation of the EPSA, PSA, and DCSA into a single WTSA is appropriate and in the public interest. Accordingly, the Examiners recommend that TGS's proposed service area consolidation be approved.

VIII. REVENUE REQUIREMENT

The Commission is required to establish TGS's overall revenues at an amount that will permit TGS a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.[82] Here, TGS requests a total revenue requirement of $82,613,050.[83] As treated below, the Examiners recommend that TGS's total revenue requirement be $78,171,546.

A. Rate Base

TGS requests a total rate base amount of $266,650,553. This represents TGS's invested capital used to provide gas utility service to its customers. The majority of TGS's capital investment has not been challenged and therefore is presumed to have been reasonably and necessarily incurred.[84] The few rate base issues that are in dispute are capital investment for the Journey program ("Journey"), sales tax amounts, cash working capital ("CWC"), and TGS's use of a "tapping fee" mechanism for certain customers.

CEP recommends a reduced rate base of $259,747,532. CEP primarily recommends that Journey be excluded. CEP also estimates a higher negative CWC amount, something that would reduce the rate base further. In support, CEP provided testimonial evidence from Mark Garrett (J.D.), an attorney, certified public accountant, and President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation, and consulting services.[85]

Staff's recommended rate base amounts do not differ from those contained in TGS's revised schedule.[86] Staff contends that TGS's use of a "tapping fee" mechanism is discriminatory and recommends its elimination, which would increase plant in service by $623,804.[87] Staff also recommends removal from plant in service of $32,262 in duplicative sales tax.[88] In support, Staff provided testimonial evidence from Erin Cromleigh (Financial Analyst in the Market Oversight Section of the Oversight and Safety Division) and Sarah Montoya (Financial Analyst in the Market Oversight Section of the Oversight and Safety Division).

[82] Tex. Util. Code § 104.051 (Establishing Overall Revenues).
[83] In its original SOI, TGS requested a revenue requirement of $82,124,177.
[84] *See* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities).
[85] CEP Ex. 2, Direct Testimony of Mark E. Garrett ("Garrett Test."), at 3.
[86] TGS Ex. 20, Rebuttal Testimony of Janet L. Buchanan on Behalf of Texas Gas Service Company ("Buchanan Rebuttal Test."), at 10, 12.
[87] Staff Ex. 2, Direct Testimony of Erin Cromleigh, as redacted ("Cromleigh Test."), at 22.
[88] Staff Ex. 3, Direct Testimony of Sarah Montoya ("Montoya Test."), at 8.

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 one percent of the gross receipts of the utility for utility services rendered to the public.[65]

No party disputes that TGS maintains its books and records in accordance with Commission requirements.

Considering the evidence, the Examiners find that TGS has established that it complied with these Commission rules. Accordingly, TGS is entitled to the presumption set forth in Commission Rule 7.503 (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities) that the unchallenged amounts shown in its books and records are presumed to have been reasonably and necessarily incurred.[66]

VII. CONSOLIDATION OF THE CTSA, GCSA, AND THE CITY OF BEAUMONT

A. Consolidation of Service Areas and the City of Beaumont

All issues in this proceeding, but one, have been resolved through the Settlement.[67] The consolidation of service areas is the sole contention amongst the parties. Although Staff remains silent on this issue, Cities disagree with TGS's and GCSC's positions regarding consolidation of the CTSA and GCSA. Cities, however, do not oppose the proposed merger of the Beaumont Service Area with the GCSA, because the Beaumont Service Area has a limited number of customers and is geographically similar to the GCSA.[68] Also, the parties agree not to litigate TGS's request to consolidate the City of Beaumont into the GCSA as it is part of the Settlement– that the City of Beaumont should be consolidated into the GCSA even if the CTSA and GCSA are not consolidated to create the Central-Gulf Coast Service Area ("CGSA").[69]

TGS proposes to consolidate the CTSA, GCSA, and the City of Beaumont into a new combined service area known as the CGSA and to set rates based on the cost of providing service to the entire proposed CGSA. In support, TGS offers that consolidation is just, reasonable, and in the public interest because (1) GURA and Commission rules authorize and encourage service area consolidation; (2) consistent and long-standing Commission precedent supports consolidation; (3) Cities' arguments against consolidation ignore fundamental ratemaking principles; (4) the impact of consolidation on rates, residential customer bills, and the cost of gas is reasonable; (5) the Legislature created a regulatory system that encourages gas utilities to seek administrative and regulatory efficiencies; and (6) service area consolidation reflects TGS's current operations.

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[65] TGS Ex. 6 (McTaggart Direct) at 22; *see* 16 Tex. Admin. Code § 7.5414 (Advertising, Contributions, and Donations).
[66] *See* 16 Tex. Admin. Code § 7.503(a) (Evidentiary Treatment of Uncontroverted Books and Records of Gas Utilities) ("In any proceeding before the Commission involving a gas utility that keeps its books and records in accordance with Commission rules, the amounts shown on its books and records as well as summaries and excerpts therefrom shall be considered prima facie evidence of the amount of investment or expense reflected when introduced into evidence, and such amounts shall be presumed to have been reasonably and necessarily incurred; provided, however, that if any evidence is introduced that an investment or expense item has been unreasonably incurred, then the presumption as to that specific investment or expense item shall no longer exist and the gas utility shall have the burden of introducing probative evidence that the challenged item has been reasonably and necessarily incurred.").
[67] Letter to ALJ from Kate Norman, counsel for TGS, filed on May 12, 2020 (stating the parties agree City of Beaumont should be consolidated into the GCSA and agree it is not necessary to hold a hearing on the merits solely for the consolidation issue but instead the parties should submit briefs to the ALJ and Examiners to consider the issue); Hearings Letter No. 27 (Abatement of Prehearing Deadlines), issued on May 13, 2020 (accepting the parties' briefs to consider the issue of consolidation); Joint Stipulation Regarding Evidentiary Record Cited in Briefing from Kate Norman, counsel for TGS, filed May 22, 2020 at 1 (stating that the parties have settled all issues except TGS's request to consolidate the CTSA, GCSA, and the City of Beaumont into a new, combined GCSA and that the parties agree to file initial and reply briefs related to the litigation of the service area consolidation issue).
[68] Cities Ex. 1 (Nalepa Direct) at 14; Cities Initial Brief filed on May 26, 2020 ("Cities Initial Br.") at 4.
[69] TGS Ex. 45 (Settlement) at 2 ¶ 2.

TGS propounds that service area consolidation is supported by GURA, Commission rules, and Commission precedent. TGS claims the Commission has consistently approved a utility's request for system-wide rates or service area consolidation.[70] To support its contentions, TGS highlights several Commission actions, specifically GUD No. 10506, 10174, 9488, and 9400. In GUD No. 10506, the Commission approved consolidation of TGS's then-existing El Paso Service Area, Permian Service Area, and Dell City Service Area to create TGS's West Texas Service Area despite the El Paso area being more densely populated, like the CTSA, and the Permian area being more dispersed over a sparsely populated area, similar to the GCSA.[71] In GUD No. 10174, the Commission approved Atmos Energy's consolidation request even though there were rate disparities among city groups without consolidation.[72] In GUD No. 9488, the Commission approved system-wide rates for a large geographic area even though customers in some cities would experience rate decreases and customers in other cities would experience rate increases.[73] In GUD No. 9400, the Commission approved system-wide rates for an area that included over 400 cities and spanned a geographic region from Austin to Dallas despite strong opposition from the City of Dallas, which argued that its purportedly lower stand-alone cost of service should determine the rates to be charged within the City of Dallas.[74] The Third Court of Appeals subsequently upheld the Commission's decision in GUD No. 9400 by affirming the Commission's authority to approve uniform rates throughout a given service area and finding that setting uniform rates is consistent with GURA and the Commission's rules.[75]

TGS admits that CTSA's proposed volumetric rates are higher under consolidation than stand-alone rates and consolidated rates are lower than stand-alone rates for GCSA residential customers.[76] The Rates and Regulatory Director for TGS testified that the GCSA is relatively small compared to the CTSA so the benefit of consolidation to the average GCSA customer is greater than the relatively small cost of consolidation for the average CTSA customer.[77] However, TGS alleged rate impacts do not justify maintaining separate service areas since differences in stand-alone rates compared to consolidated rates have not precluded consolidation in prior cases. In GUD Nos. 10506, 10174, and 9488, the Commission approved consolidation despite disparities amongst the city groups.[78]

TGS purports that consolidation will achieve efficiencies for both customers and TGS. According to TGS, these efficiencies will lead to just and reasonable rates and operations. Specifically, TGS claims consolidation will lead to administrative efficiencies related to rate filings and tariffs.[79] For example, TGS asserts reducing the number of service areas will immediately reduce the number of rate case filings, which will pass significant legal and administrative cost

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[70] TGS Initial Br. at 5. TGS noted thirteen dockets where the Commission approved the use of system-wide rates: GUD Nos. 10526 (TGS), 10506 (TGS), 10488 (TGS), 10174 (Atmos Energy), 10170 (Atmos Energy), 10038 (CenterPoint), 9902 (CenterPoint), 9869 (Atmos Energy), 9791 (CenterPoint), 9762 (Atmos Energy), 9670 (Atmos Energy), 9488 (West Texas Gas), and 9400 (Atmos Energy). TGS Initial Br. at 6. In GUD No. 10526 (TGS), the CTSA was created, the Commission approved multiple cost of gas clauses as a result of a settlement agreement, and rate case expenses for TGS and the cities totaled $668,354.56. TGS Initial Br. at 13-14.
[71] TGS Initial Br. at 2, 11-12; TGS Ex. 26 (McTaggart Rebuttal) at 10.
[72] TGS Initial Br. at 12. Citing from GUD No. 10174, Ms. McTaggart noted that with consolidation in GUD No. 10174, residents in Atmos's Lubbock Division would experience a rate increase while some residents in the West Texas Division would experience a rate decrease. *Id.*; TGS Ex. 26 (McTaggart Rebuttal) at 11.
[73] TGS Initial Br. at 12. Ms. McTaggart cited from GUD No. 9488: the city of Balmorhea would experience a rate decrease of 4.87% and customers in the city of Paint Rock would experience a 22.98% rate increase. *Id.*; TGS Ex. 26 (McTaggart Rebuttal) at 11.
[74] TGS Initial Br. at 5, 9.
[75] *Id*.
[76] TGS Ex. 26 (McTaggart Rebuttal) at 9; TGS Initial Br. at 11.
[77] TGS Ex. 26 (McTaggart Rebuttal) at 9; TGS Initial Br. at 11 (comparing the $0.15 to $0.47 increase for incorporated CTSA residential customers under consolidated rates to the $(1.36) to $(3.12) decrease for incorporated GCSA residential customers for rates calculated based on the consolidation of service areas).
[78] TGS Initial Br. at 11-12; TGS Ex. 26 (McTaggart Rebuttal) at 10-11.
[79] TGS Ex. 6 (McTaggart Direct) at 5-6; TGS Ex. 26 (McTaggart Rebuttal) at 3-14; TGS Initial Br. at 14.

savings on to ratepayers.[80] TGS argues not only will consolidation allow more municipalities to pool their resources in order to reduce each municipality's individual expense to review future filings,[81] but consolidation will also reduce the number of tariffs TGS and its regulators (the Commission and cities) must administer and maintain.[82]

According to TGS, service area consolidation better reflects TGS's current operations. The Vice-President of Operations for TGS testifies TGS is the operating division of ONE Gas, which operates a natural gas distribution company to customers in Oklahoma, Kansas and Texas.[83] TGS explains its corporate activities are centralized in Tulsa, Oklahoma, and activities that affect TGS throughout Texas are centralized at a statewide level.[84] TGS describes its functional operating model, which has been in place since 2013, as allowing ONE Gas to operate its LDCs as one company, rather than three separate companies—it is organized by function as opposed to geographic region or location allowing for a centralized approach to decision-making processes and management of the gas service.[85]

The Vice-President of Operations for TGS also testifies that centralized functions and departments at a statewide level encourages efficiency and consistency, allows for effective monitoring of the status of TGS's assets, offers consistent responses to customers, and yields efficient deployment to provide timely customer service.[86] TGS clarifies not only does it organize the workload by function, but it also focuses on integrating systems and process changes to support implementation and use of technology related to construction, maintenance, and replacement of assets, which has led to more efficient operations.[87] TGS maintains that the proposed consolidation simply reflects the operating changes that have already occurred since the existing areas have similar operations, already share personnel for certain services, and rely on centralized management of certain functions and operations.[88]

Furthermore, TGS asserts the geographical distance among cities in the proposed CGSA is not unique as the distance between cities in the proposed CGSA is consistent with other consolidated service areas in Texas.[89] TGS alleges the climate differences through the proposed CGSA are not problematic because small differences in weather will not impact rates in the CGSA and the proposed CGSA Weather Normalization Adjustment Clause adjusts for weather separately for the four weather zones within the proposed CGSA.[90] TGS also maintains that the differences in gas consumption are not significant. In TGS's proposed CGSA, residential average usage in the CTSA is 30 Ccf per month and 28 Ccf per month in the GCSA, but TGS argues this

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[80] TGS Ex. 6 (McTaggart Direct) at at 6; TGS Ex. 26 (McTaggart Rebuttal) at 14; TGS Initial Br. at 14. According to TGS, in GUD No. 10526, the CTSA was created and rate case expenses for TGS and the cities totaled $668,354.56. TGS Initial Br. at 13-14. In 10488 (TGS), the GCSA was created and rate case expenses for TGS and the cities totaled $865,965. TGS Initial Br. at 14. By combining the CTS and GCSA, TGS expects to proceed in the future with a single rate case filing for the two areas to avoid the expense associated with two rate case filings. TGS Initial Br. at 14.
[81] TGS Ex. 6 (McTaggart Direct) at 6; TGS Ex. 26 (McTaggart Rebuttal) at 14; TGS Initial Br. at 14.
[82] TGS Ex. 26 (McTaggart Rebuttal) at 13; TGS Initial Br. at 14.
[83] TGS Ex. 5 (Norman Direct) at 4.
[84] TGS Initial Br. at 15.
[85] TGS Ex. 5 (Norman Direct) at 7; TGS Initial Br. at 15.
[86] TGS Ex. 5 (Norman Direct) at 8; TGS Initial Br. at 15-16. Functions that are centralized at a statewide level include leak survey, cathodic protection, pressure control and measurement, and line locating. TGS Ex. 5 (Norman Direct) at 8. Departments centralized at the statewide level include Financial Accounting, Fleet, Customer Information Center, Dispatch, and Gas Supply. *Id*.
[87] *Id*.
[88] *Id*.at 10.
[89] TGS Ex. 26 (McTaggart Rebuttal) at 6; TGS Ex. 26a (McTaggart Rebuttal Workpapers); TGS Initial Br. at 9. In TGS's proposed CGSA, Port Arthur and Austin are 254 miles apart. TGS Initial Br. at 9. In Atmos Energy's West Texas Division, Pampa and Odessa are 315 miles apart. *Id*. In CenterPoint's existing Beaumont/East Texas Division, Redlick and Anahuac are 309 miles apart. *Id*.
[90] TGS Ex. 26 (McTaggart Rebuttal) at 6, TGS Ex. 26a (McTaggart Rebuttal Workpapers); TGS Initial Br. at 9. In TGS's proposed CGSA, the difference in January lows between Galveston and Austin is 4 degrees. TGS Initial Br. at 9. In Atmos Energy's West Texas Division, the difference in January lows between Pampa and Odessa is 9 degrees. *Id*. In CenterPoint's existing South Texas Division, the difference in January lows between Austin and San Diego (in Duval County) is 7 degrees. *Id*.

degree of difference in gas consumption has not prevented consolidation in prior cases.[91] In a 2016 case consolidating TGS's GCSA, the residential average usage in Galveston was 25 Ccf per month compared to 32 Ccf per month in South Jefferson County yet the Commission still approved consolidation to create the GCSA.[92] In GUD No. 10506, consolidation was approved where El Paso's residential average usage was 38 Ccf per month and the Permian was 43 Ccf per month.[93] And, TGS references, a 2016 case approving consolidation and creation of the CTSA, which showed Austin's residential average usage was 32 Ccf per month while South Texas was 26 Ccf per month.[94]

Finally, TGS contends the rates of population growth with the proposed CGSA are typical because differing growth rates among cities within a service area appears to be the norm.[95] Specifically, TGS alleges the pace of growth for areas on the proposed CGSA is comparable to rates of growth for other consolidated service areas in the state.[96]

B. GCSC Does Not Oppose Consolidation

The GCSC does not object to consolidation of the CTSA, GCSA, and the City of Beaumont into a single service area.[97] GCSC believes there appears to be "no extraordinary circumstances" that would distinguish the facts of this case from the facts presented in prior Commission cases approving consolidation after it reviewed the direct testimony of Cities' witness, Karl Nalepa, and TGS's direct and rebuttal testimonies.[98] GCSC said it reviewed the factors the Commission considered when approving GUD No. 10506.[99]

In GCSC's factual analysis between GUD No. 10506 and this case, the GCSC found the parties claiming opposition in both cases argued (1) consolidation would result in cost-shifting that would raise rates for one group of customers while subsidizing other groups of customers, (2) the proposed service areas were geographically discrete and were therefore inappropriate for consolidation, and (3) the utility had failed to provide specific evidence with respect to certain operational and administrative efficiencies or any specific rate impact to customers.[100] Despite these arguments, GCSC noted the Commission adopted the Examiners' findings and approved the consolidation.[101]

GCSC posits that it is not conceivable a cost-shifting scenario could be so extreme as to be unreasonable in this case.[102] GCSC thereby concludes TGS has presented undisputed evidence that its operating model, which is already organized based on employee functions or activities rather than geographic location, would undeniably result in fewer cost-of-service analyses and rate filing packages that must be filed through the consolidation of service areas.[103]

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[91] TGS Initial Br. at 10.
[92] TGS Ex. 26 (McTaggart Rebuttal) at 7; TGS Initial Br. at 10.
[93] TGS Ex. 26 (McTaggart Rebuttal) at 7; TGS Initial Br. at 10.
[94] TGS Ex. 26 (McTaggart Rebuttal) at 7; TGS Initial Br. at 10.
[95] TGS Initial Br. at 10.
[96] TGS Ex. 26 (McTaggart Rebuttal) at 6; TGS Initial Br. at 10. In TGS's proposed CGSA, Austin is growing at a 20.2% pace while Galveston is growing at a rate of 5.7%. TGS Ex. 26 (McTaggart Rebuttal) at 6; TGS Initial Br. at 10. In Atmos Energy's existing West Texas Division, Odessa is growing at a rate of 20.7% while Pampa is shrinking at a rate of 4.2%. TGS Ex. 26a (McTaggart Rebuttal) at 6; TGS Initial Br. at 10. In CenterPoint's existing South Texas Division, Austin is growing at a pace of 20.2% while Duval County is shrinking at a 4.9% rate. TGS Ex. 26 (McTaggart Rebuttal) at 6; TGS Initial Br. at 10.
[97] Initial Brief of the GCSC, filed on May 22, 2020 ("GCSC Initial Br.") at 2.
[98] *Id*. at 2-3.
[99] GCSC Initial Br. at 3. Listing the factors as (1) that consolidation would likely result in numerous administrative and regulatory efficiencies that would benefit customers; (2) that consolidation would likely be more economical, efficient, and cost-effective for the utility and for customers by reducing the number of cost-of-service analyses and rate-filing packages that must be addressed; (3) that a consolidated service area would better reflect existing centralized operations, management, and decision-making processes; and (4) that consolidation would likely result in greater uniformity and consistency for the utility and its customers. *Id*.
[100] *Id*. at 3-4.
[101] *Id*.at 4.
[102] *Id*.; *see* TGS Ex. 26 (McTaggart Rebuttal) at 9.
[103] GCSC Initial Br. at 5.

Thus, the GCSC does not oppose consolidation of the CTSA, GCSA, and the City of Beaumont into a single service area – the CGSA.

C. Opposition by Cities

Cities contest consolidation of the CTSA with the GCSA and submitted several arguments. First, Cities argue TGS has not met its burden to prove consolidation is appropriate and in the public interest as it improperly relies on precedent and has not proven the benefits of consolidation outweighs the detriment to CTSA and GCSA customers. Cities purports the Commission is not bound by precedent, the Commission must have a reasonable basis to approve consolidation, and the Commission must evaluate the facts and evidence unique in each case when determining whether consolidating service areas will result in unjust, unreasonable, and discriminatory rates.[104]

Cities oppose being incorporated into a system-wide rate that it believes will create subsidies and disparate treatment for the regions.[105] Furthermore, Cities argue TGS failed to quantify the benefits of consolidation—TGS failed to prove that consolidating the CTSA and GCSA is appropriate and in the public interest.[106] Cities insist consolidation of the CTSA and GCSA will be detrimental to customers as customers in both service areas will experience discriminatory rates and subsidize customers located in an entirely different region of the state.

Cities argue the service areas TGS previously consolidated were similarly situated in terms of geography and weather.[107] However, the service areas in this case are located in completely different geographical regions of the state, which lead to differences in consumption, weather events, and utility infrastructure requirements.[108] Cities assert that even TGS's recommended weather normalization adjustment ("WNA), which would use distinct weather adjustment factors area for customers based on their location, is problematic. Cities stress that the WNA negates the benefits of system-wide rates, because the rates will be adjusted differently in each service area.[109]

Cities' witness, the President of ReSolved Energy Consulting, LLC, an independent utility consulting company, testified to the differences from a climate and economic activity perspective. Cities explained that differences in temperature extremeness and weather events drive consumption patterns.[110] For example, in colder months and in peak demand months, the CTSA customers use more gas; thus, more costs are allocated based on energy or on peak demand to the CTSA whereas GCSA residential customers use less gas on average because of the less severe winters along the coast.[111] The service areas also experience weather event extremes such as hurricanes and ice storms or flood events. Since hurricanes typically occur in the GCSA (e.g., Hurricane Harvey), Cities urged their costs should only be recovered in the GCSA.[112] Similarly, Cities recommended ice storms or flood events that only occurred in the CTSA should only be recovered from the CTSA customers.[113]

Cities suggests a similar approach in its discussion of TGS's proposed Pipeline Integrity Testing ("PIT") Rider to the consolidated service areas by noting the CTSA is the only service

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[104] Cities Initial Brief, filed on May 26, 2020 ("Cities Initial Br.") at 4; Cities' Ex. No. 1 (Nalepa Direct) at 10:9-10:11.
[105] Cities Initial Br. at 4.
[106] Cities argue TGS has not quantified the alleged "numerous administrative and regulatory efficiencies" or how they will benefit its customers. *See* Cities Initial Br.; Cities Reply Brief, filed June 5, 2020.
[107] Cities Initial Br. at 7.
[108] *Id*.
[109] *Id*.at 12.
[110] Cities' Ex. No. 1 (Nalepa Direct) at 11.
[111] *Id*.) at 12; *see also* Cities Initial Br. at 11. Review of a January bill shows CTSA residential customers at 82.3 Ccf and GCSA residential customers averaging 69.9 Ccf per month or 15 percent less. Cities' Ex. No. 1 (Nalepa Direct) at 12.
[112] *Id*.; *see also* Cities Initial Br. at 11-12.
[113] *Id*. at 12.

area that incurs PIT expenses because the GCSA does not have any transmission pipelines.[114] TGS insists that to require customers located in the GCSA to pay for costs they did not and could not incur will only continue to occur if the service areas are consolidated.[115] However, in the settlement agreement, the parties agree that the PIT Rider will apply only to the CTSA, regardless of the outcome of the litigated consolidation issue.[116]

From an economic activity perspective, Cities explores how the CTSA is growing much more rapidly than the GCSA. Cities illustrate how the CTSA has been experiencing a significant growth in the number of customers and system investments while the GCSA has seen a decline in the number of customers and only moderate increases in investments.[117] Since the GCSA's last rate case in GUD No. 10488 (July 2016) and the CTSA's last rate case in GUD No. 10526 (January 2017), Cities describe how the annual growth rate for plant additions (gross plant plus construction completed not classified) in the CTSA was 11.7% and 3.4% in the GCSA;[118] how the number of customers in the CTSA has experienced an average annual growth rate of 1.4% while the GCSA has experienced a loss of 0.3% per year;[119] and how gas volumes in the CTSA increased by an annual growth rate of 0.6% but the gas volumes in the GCSA declined by nearly 9% per year.[120]

Finally, according to Cities, the CTSA and GCSA differ much more at an economic activity perspective than at a climate perspective. Cities attest that the CTSA has been experiencing significant growth in the number of customers, and consequently, system investment while the GCSA has seen a decline in the number of customers and only moderate increases in investment.[121] Cities believe that because of this disparate growth, customers in the GCSA will be allocated and pay for a portion of the growth being seen in the CTSA under a consolidated service area.[122]

D. Examiners' Findings and Recommendation[123]

In its decision on the service area consolidation issue, the Commission is not bound to prior Commission or Texas court decisions. Instead, it is based on the unique facts and evidence presented in this case using the proper legal standard. The Examiners have considered all the evidence admitted and recommend TGS's proposed consolidation be approved.

1. Legal Standard and Prior Cases

While no statute speaks directly to service area consolidation, the Commission, in its informed discretion, may approve service area consolidation if it considers consolidation to be

[114] Cities' Ex. No. 1 (Nalepa Direct) at 29.
[115] Cities Initial Br. at 12.
[116] TGS Ex. 45 (Settlement) at 7 ¶ 20.
[117] Cities' Ex. No. 1 (Nalepa Direct) at 13.
[118] *Id*. at 13; *see also* Cities Initial Br. at 13. CTSA's gross plant plus construction completed not classified increased by $262 million, or 56% and the GCSA increased by 16%. Cities' Ex. No. 1 (Nalepa Direct) at 13.
[119] *Id*.at 13; *see also* Cities Initial Br. at 13. The number of customers in the CTSA increased by 173,000 and the number of customers in the GCSA declined by 8,000. *Id*.
[120] Cities' Ex. No. 1 (Nalepa Direct) at 13.
[121] Cities Initial Br. at 13; Cities' Ex. No. 1 (Nalepa Direct) at 13. Mr. Nalepa explained that since its last rate case, gas volumes in the CTSA have increased by an average annual growth rate of 0.6% while gas volumes in the GCSA have declined by nearly 9% per year. Cities' Ex. No. 1 (Nalepa Direct) at 13.
[122] *Id*.
[123] While the facts of this case are distinct, the legal treatment on utility service area consolidation in Texas, which is contained in the GUD No. 10506 Proposal for Decision, applies here as well as the decision by the Third Court of Appeals in the City of Dallas, which provided the applicable legal standard for service area consolidation in Texas. *See* GUD No. 10506, *consolidated*, First Amended Proposal for Decision, issued September 16, 2020, pp. 8-14 (applying the legal treatment on utility service area consolidation in Texas); City of Dallas v. R.R. Comm'n of Tex., No. 03-06-00580-CV, 2008 WL 4823225 (Tex. App. – Austin, Nov. 6, 2008, no pet.) (mem. op.).

appropriate and in the public interest.[124] GURA Section 104.004 (Unreasonable Preference or Prejudice Prohibited) prohibits unreasonable differences concerning rates of service between *localities* or between *classes of service*[125] and restricts the variations between rates within municipalities and their environs.[126] GURA Section 101.002 (Purpose and Findings) provides that "[GURA] is enacted to protect the public interest inherent in the rates and services of gas utilities."[127] GURA Section 104.003 (Just and Reasonable Rates) authorizes the Commission to treat as a single class two or more municipalities that a gas utility serves if the Commission considers that treatment to be "appropriate."[128] Furthermore, the Third Court of Appeals in *City of Dallas v. R.R. Comm'n of Tex.*, No. 03-06-00580-CV, 2008 WL 4823225 (Tex. App. – Austin, Nov. 6, 2008, no pet.) (mem. op.) states that the geographic aspects of rate design are left to the Commission's "informed discretion."[129]

While the facts of this case are distinct, the legal treatment on utility service area consolidation in Texas contained in the GUD No. 10506 PFD applies here as well.[130]

While not binding, the Court of Appeals in *City of Dallas* was persuasive and provided guidance. In *City of Dallas*, the utility's rates previously had been set on a municipality-by-municipality or region-by-region basis.[131] Cities made similar arguments that the party opposing consolidation in *City of Dallas* made: that shifting to statewide rates would force customers in one location "to subsidize" customers in other areas served by the utility, which would be "unfair, unjust, and unreasonable," and that statewide rates were unjust and discriminatory to customers in areas of lower cost of service.[132] Despite these arguments, the Court of Appeals still found substantial evidence to support the Commission's approval of system-wide rates, noting the Commission's broad discretion in approving rates applicable to all areas in Texas served by a gas utility.[133]

2. No Basis for Discrimination[134]

TGS's proposed service area consolidation is not discriminatory or prejudicial. There is no credible evidence that TGS's proposed consolidation constitutes, or results in, a "discriminatory" or "prejudicial" act, as argued by Cities. On the contrary, the evidence shows that TGS's proposed consolidation would result in system-wide rates for all CTSA, GCSA, and City of Beaumont customers in the newly formed CGSA. As the Court of Appeals has made plain, system-wide rates *avoid* unreasonable rate differences between localities or between classes of service.[135] There is no credible evidence that TGS will charge unreasonably different rates between localities or between classes of service in the proposed CGSA once it is formed. Accordingly, there is no merit to claims that consolidation is discriminatory or prejudicial to anyone.

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[124] Tex. Util. Code § 101.002 (Purpose and Finding); *see also* City of Dallas v. R.R. Comm'n of Tex., No. 03-06-00580-CV, 2008 WL 4823225 (Tex. App. – Austin, Nov. 6, 2008, no pet.) (mem. op.) (noting that when a statute is silent as to a rate design process under PURA, the Legislature has left it to the commission's informed discretion).
[125] Tex. Util. Code § 104.004(3).
[126] Tex. Util. Code § 104.006 (Rates for Area Not in Municipality); *see also* 16 Tex. Admin. Code § 7.220(a).
[127] Tex. Util. Code § 101.002(a).
[128] *Id*. § 101.003(a).
[129] *See City of Dallas*, 2008 WL 4823225, at 9 (citing *Nucor Steel v. Pub. Util. Com'n of Texas*, 168 S.W.3d 260, 269 (Tex. App.—Austin 2005, no pet.)).
[130] *See* GUD No. 10506, *consolidated*, First Amended Proposal for Decision, issued September 16, 2020, pp. 8-14.
[131] *Id.* at 1.
[132] *Id.* at 1, 4.
[133] *Id.* at 10.
[134] *See generally* GUD No. 10506, *consolidated* at 12.
[135] *See id.* at 9 ("There is no dispute that uniform, statewide rates would comply with these requirements.").

3. Central-Gulf Coast Service Area ("CGSA")[136]

The Examiners looked only to the facts unique to TGS's proposed consolidation of the CTSA, GCSA, and City of Beaumont in this docket, as contained in the evidentiary record, when considering the contested issue. Although the prior decisions are instructive in that they reflect the Commission's established broad policy discretion in approving system-wide rates, as reinforced by the Third Court of Appeals in *City of Dallas* and as emanated from the statutory provisions of GURA, they do not bind the Commission to make the same determination here. The Examiners did consider the holding in *City of Dallas* but only to the extent that the Court of Appeals informed the applicable legal standard for service area consolidation in Texas, as well as the type and sufficiency of evidence needed to meet that standard. The Examiners also considered and applied the legal treatment contained in the GUD No. 10506 PFD on utility service area consolidation in Texas. Here, the weight of the evidence supports consolidation.

Through credible testimony, TGS demonstrated that consolidation of the CTSA, GCSA, and City of Beaumont into a single CGSA is likely to result in numerous administrative and regulatory efficiencies and that those efficiencies will benefit CGSA customers. Specifically, 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 these areas.[137] Thus, rate changes will be implemented uniformly and consistently, which is more economical, efficient, and cost-effective for TGS and its customers.

TGS also demonstrated that a consolidated CGSA will better reflect existing centralized operations, management, and decision-making processes. At the ONE Gas level, certain activities now are organized around function rather than geography. At the TGS level, many employees now have responsibilities for certain functions across many service areas.

In opposition, Cities insists that the GCSA has a lower cost of service compared to the CTSA and that consequently the GCSA customers will be "subsidizing" CTSA customers in the consolidated CGSC. Similar arguments were made in *City of Dallas*. While the factual circumstances in *City of Dallas* are different than here, the Court of Appeals in that case found substantial evidence to support the Commission's approval of system-wide rates. Although the *City of Dallas* holding does not bind the Commission to make the same determination here, it does inform that these opposition arguments may not sufficiently address the legal standard that consolidation be appropriate and in the public interest.

Cities convincingly argue that consolidation may result in CTSA customers paying higher rates in the future in the consolidated CGSA than they otherwise might as a standalone service area. In fact, the evidence supports this.[138] However, the "public interest" may be broader than the specific interests of any one locality or its customers and may include more than quantifiable rate impacts.[139] The weight of the evidence still shows that consolidation likely will result in numerous operational and administrative efficiencies beneficial to *all* customers in the proposed CGSA even if Cities' arguments are accepted as true.

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[136] *See generally* GUD No. 10506, *consolidated* at 12-13 (applying the legal treatment on utility service area consolidation in Texas).
[137] *See* TGS Ex. 37 (Simmons Rebuttal) at 6 ("Consolidation results in greater administrative efficiencies by reducing annual reconsolidations and oversight responsibility for [TGS's] regulators. In addition, customers benefit from aggregate cost sharing resulting in improved cost of gas rate stability with minimal impact to CTSA cost of gas rates.").
[138] *See Id*. at 6, TGS Ex. NAS-R-1 (Analysis of the cost impacts of consolidated cost of gas rates compared to the historical separate service area cost of gas rates from June 2019 through February 2020 showed the average residential CTSA customer's cost of gas would increase by $0.13 monthly and the average residential GCSA customer's cost of gas would decrease by $1.53 monthly); *see also* TGS Ex. 26 (McTaggart Rebuttal) at 9 (showing how the CTSA proposed volumetric rates are higher under consolidation than stand-alone rates and how consolidated rates are lower than stand-alone rates for GCSA residential customers).
[139] *See* GUD No. 10506, *consolidated* at 13.

The Commission must also balance the interests of TGS, which Cities did not consider in its arguments. 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*."[140] Gas utilities 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.[141] It is unreasonable, then, to require gas utilities to strive for efficiency in their operations to earn a reasonable return, while at the same time denying gas utilities the opportunities to economize and streamline their operations by consolidating service areas—where doing so is appropriate and in the public interest.

Finally, the Commission has broad discretion in matters of geographic rate design including the setting of system-wide rates for a consolidated service area. Through credible testimony and in consideration of the facts unique to TGS's proposed consolidation of the CTSA, GCSA, and City of Beaumont, as contained in the evidentiary record, the evidence shows that system-wide rates throughout the CGSA avoid unreasonable rate differences between customers and localities even when considering (1) the geographic distance between and among cities in the CGSA, (2) the climate or weather differences between and among cities in the CGSA, (3) the differences in gas consumption between and among cities in the CGSA, and (4) the rates of population and customer growth between and among cities in the CGSA.

4. Conclusion

Considering the evidence, the Examiners find the consolidation of the CTSA and GCSA into a single CGSA is appropriate and in the public interest. Accordingly, the Examiners recommend that TGS's proposed service area consolidation be approved.

VIII. UNANIMOUS SETTLEMENT AGREEMENT

Except for consolidation, the Settlement resolves all other issues in GUD No. 10928 and the consolidated dockets. The parties—TGS, Staff, Cities, and GCSC—participated in discovery and settlement negotiations and agree that resolution of this docket by settlement will significantly reduce the amount of reimbursable rate case expenses associated with this docket.[142] The parties agree that the rates, terms, and conditions reflected in the Settlement, subject to the Commission's Final Order on consolidation, comply with the rate-setting requirements of GURA Chapter 104 (Rates and Services).[143] A copy of the Settlement is **Attachment 3** to this PFD.[144]

The Examiners have reviewed the Settlement and find that its terms and rate elements for both consolidation and stand-alone service area are just, reasonable, in the public interest, and consistent with the requirements of the Texas Utilities Code and applicable Commission rules. Accordingly, the Examiners recommend that the Settlement be approved, specifically the Settlement terms as they relate to a consolidated service area as discussed below.

A. Revenue Requirement

Under the Settlement, TGS will receive a $10.3 million base rate increase for its consolidated CGSA – a reduction of $5.37 million, 34 percent, from TGS's amended request prior

[140] Tex. Util. Code § 101.002 (Purpose and Findings) (emphasis added).
[141] Tex. Util. Code § 104.051 (Establishing Overall Revenues).
[142] TGS Ex. 45 (Settlement) at 2.
[143] *Id*. at 2 ¶ 3; *see* Tex. Util. Code, Ch. 104.
[144] Attachment 3 excludes voluminous receipts and invoices related to TGS's, Cities', and GCSC's incurred rate case expenses, treated later in the PFD.

Texas Gas Service Company, a Division of ONE Gas, Inc.
WNSA ISOS RTCS TYE December 31, 2021

WTSA One-Time Charge.xlsx
Summary
1 OF 2

	Sum of Calculated Revenue	WTSA Customer Count	One-Time Charge (Rounded)	Total Recovery	Rounding Diff
RES	$589,673.52	264,552	2.23	589,950.96	277.44
COM	111,259.62	14,931	7.45	111,235.95	(23.67)
PUB AUTH	29,629.14	1,076	27.54	29,633.04	3.90
IND	11,220.66	47	238.74	11,220.78	0.12
MUNI WATER PUMP	2,483.54	20	124.18	2,483.60	0.06
	$744,266.48			744,524.33	257.85

Texas Gas Service Company, a Division of ONE Gas, Inc.
WNSA ISOS RTCS TYE December 31, 2021

WTSA One-Time Charge.xlsx
Uncollected ElPaso Activity
2 OF 2

REGULATORY EXPENSE
Uncollected Revenue from IRA Case No. 00006161 approved in appeal Case No. 6942
Rate Jurisd 7650ELPA-I

LINE NO.	Gas Sales Revenue Description	Sum of Bill Count	IRA Case No. 00006161	Sum of Calculated Revenue
	(a)	(b)	(c)	(d)
9	RES	242,664	$2.43	$589,673.52
10	COM	14,452	7.62	110,124.24
11	COM A/C	126	7.62	960.12
12	PUB AUTH	987	29.57	29,185.59
13	PUB AUTH A/C	5	29.57	147.85
14	MUNI WATER PUMP	23	107.98	2,483.54
15	IND	43	207.79	8,934.97
16	FORT BLISS - CITY GATE	19		-
17	IRRIGATION	1		-
18	**Total**	**222,013**		**741,509.83**
19				
20				
21				
22	**Transportation Revenue Description**	**Sum of Bill Count**	**IRA Case No. 00006161**	**Sum of Calculated Revenue**
23	COGEN	2.00	7.62	15.24
24	COM	21.00	7.62	160.02
25	PUB AUTH	10.00	29.57	295.70
26	IND	11.00	207.79	2,285.69
27	CUSTOM	4.00		-
28	**Total**	**48.00**		**2,756.65**
	GRAND TOTAL	**222,061.00**		**744,266.48**

WORKPAPERS

TO

DIRECT TESTIMONY

OF

PAUL H. RAAB

Workpapers to the Direct Testimony of Paul H. Raab are voluminous and are being provided in electronic format.

WORKPAPERS

TO

DIRECT TESTIMONY

OF

JANET M. SIMPSON

Workpapers to the Direct Testimony of Janet M. Simpson are voluminous and are being provided in electronic format.

WORKPAPERS

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OF

RONALD E. WHITE

Workpapers to the Direct Testimony of Ronald E. White are voluminous and are being provided in electronic format.